STANDARDS COMMITTEE

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STANDARD APPLICATION GUIDE

TPL-001-4

VERSION 2.0

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The MRO Subject Matter Expert Team is an industry stakeholder group which includes subject matter experts from MRO member organizations in various technical areas. Any materials, guidance, and views from stakeholder groups are meant to be helpful to industry participants; but should not be considered approved or endorsed by MRO staff or its board of directors unless specified.

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The Midwest Reliability Organization (MRO) Standards Committee (SC) is committed to providing training and non-binding guidance to industry stakeholders regarding existing and emerging Reliability Standards. Any materials, including presentations, were developed through the MRO SC by Subject Matter Experts (SMEs) from member organizations within the MRO region.

In 2014, SMEs in the field of System Operator Communications were brought together to prepare a guide for complying with NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).

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Acknowledgement

This publication was developed by a team of SMEs from MRO member organizations within the MRO footprint. The development of SME teams is an ongoing effort to produce unified application guides for MRO and its Registered Entities.

The TPL-001-4 SME Team Chair, Chuck Lawrence (American Transmission Company), wishes to acknowledge and thank those who dedicated efforts and contributed significantly to this publication. The MRO, MRO Standards Committee and their organizational affiliations include:

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INTRODUCTION

NERC Reliability Standard TPL-001-4 Transmission System Planning Performance Requirements (TPL-001-4) replaced the previous suite of Transmission Planning Reliability Standards - TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0a. The new standard, TPL-001-4, is applicable to Transmission Planners (TP) and Planning Coordinators (PC).

There were many modifications in TPL-001-4, compared to the predecessor TPL Standards. A few notable modifications are:[1]

- A system model maintenance requirement (R1)
- Short circuit analysis and corrective action requirements (R2.3 & R2.8)
- Spare equipment strategy requirements (R2.1.5)
- Inclusion of dynamic load modeling (R2.4.1)
- Higher system performance for extra high voltage contingency events, such as extra high voltage (EHV) bus faults, internal breaker faults, N-1-1 Contingency events that involve a generator (Table 1)
- Limitations on the amount of non-Consequential Load Loss following planning events (Table 1)
- Addition of shunt device Contingency events (Table 1, P1-4, P3-4, P4-4, P5-4, P6-3)
- Opening of a line section without a fault (P2.1)
- Differentiation between Bus-tie and non-Bus-tie breakers (Table 1 P2 & P4)
- Addition of generation plus another Element Contingency events (Table 1, P3)
- Obligation to consider both stuck breaker and system protection relay failure events (Table 1 P4 & P5)
- Additional extreme event contingency events, such as loss of two Elements without system adjustment (N-2), loss of two generating plants (Table 1, Extreme Events)
- Removed a few extreme event contingency events (such as non-redundant Special Protection System (SPS)/Remedial Action Scheme (RAS) Misoperation [former TPL-004-0 D12 & D13] and power swing oscillations due to event in another Regional Entity area [former TPL-004-0 D14])

OVERVIEW

Purpose: *Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.*

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[1] All references in this application guide to Table 1 are in reference to Table 1 – Steady State & Stability Performance Planning Events of NERC Reliability Standard TPL-001-4 –Transmission System Planning Performance Requirements.

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The key objectives of this TPL-001-4 Standard Application Guide (SAG) are:[2]

- To provide additional clarification on the terms and requirements of TPL-004-1
- To provide potential criteria and practices to be considered during the application of selected requirements

METHODOLOGY

This section contains suggested methodology to meet the requirements of TPL-001-4. These methods represent the intended best practices of members of the MRO TPL-001-4 SAG Subject Matter Expert (SME) Team.[3]

Coordination of Planning Assessment Responsibilities

Prior to undertaking Planning Assessment responsibilities related to Requirements R1-R6, according to TPL-001-4, each PC and its TPs shall identify each entity's individual responsibilities and those which are joint/shared. Once the PC and TPs responsibilities have been identified, document the responsibilities. Refer to the SAG section 'Evaluating TPL-001-4, Requirement R7' for further details.

Evaluating TPL-001-4, Requirement 1

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-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. *System models shall represent:*

1.1.1. Existing Facilities
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
1.1.3. New planned Facilities and changes to existing Facilities
1.1.4. Real and reactive Load forecasts
1.1.5. Known commitments for Firm Transmission Service and Interchange
1.1.6. Resources (supply or demand side) required for Load

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[2] Version 1.0 of this Standard Application Guide TPL-001-4 (SAG TPL-001-4 V1.0) contained guidance for Requirements R1 and R7 due to the enforcement date of January 1, 2015 for NERC TPL-001-4. Version 2.0 of this Standard Application Guide TPL-001-4 contains the guidance for the entire standard.

[3] The applicable Elements to be assessed according to the TPL-001-4 are those classified Bulk Electric System (BES) Elements according to the BES Definition Reference Document V2 April 2014, which became effective on July 1, 2014.

R1 Application and Documentation

In order to ensure the System models are accurate, the TPs and PCs should verify that the R1.1 all applicable Elements for its corresponding area are represented in the System models that are to be used to perform the analyses in TPL-001-4 Requirements R2, R3, and R4. It is recommended that each TP and PC document both the process and the implementation of its process for ensuring that the required elements are included in the System models. The recommended documentation should identify information sources and criteria used to select the data for each element. Each TP and PC should either reference the applicable regional or PC model building manual used to document its System model building details or create a model building manual of its own. The information used to develop system models is constantly changing. Therefore, it is important to identify a point in time when no further changes are incorporated into the system model. Provide the rationale for deciding appropriate "cut-off" dates for any of the data required in R1.1.

1.1.1 – Existing Facilities

- Obtain existing Facilities information from applicable Transmission Owners (TOs), Generation Owners (GOs), and Distribution Providers (DPs).

Documentation considerations – Identify the information sources and have a list of the newly implemented existing Facilities. As an example, this list should contain the facility description, facility characteristics, and the in-service or retirement date.

1.1.2 – Known generation or Transmission Facility outages

- Obtain known outages information from applicable (in its area or in an adjacent area) Reliability Coordinators (RCs), Generator Operators (GOPs), or Transmission Operators (TOPs). For TPs and PCs whose RC collects the outage information from GOPs, TOPs and adjacent RCs, they can collect the outage information simply from their RC.
- Only include known outages of BES Elements.
- Examples of criteria for selecting the known outages:
  - Approved, scheduled, and/or submitted outages
  - Maintenance and/or construction outages
  - Outages with a duration of at least six months within the planning horizon

Documentation considerations – Identify the information sources and have a list of known outages for the new planning horizon. The list should contain the type of outage and the anticipated out of service time dates of each outage.

1.1.3 – New planned Facilities and planned changes to the existing Facilities

- Obtain new and changed planned Facilities information from applicable TOs, GOs, and DPs.
- Examples of criteria for selecting the new and changed Facilities:
  - Projects that have a granted interconnection agreement
  - Owner-budgeted projects
  - State-approved projects
  - Planning Coordinator-approved projects

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Documentation considerations – Identify the information sources and have a list of new and changed Facilities. The list might contain the type of Facility and planned in service or change date.

1.1.4 – Real and reactive Load forecasts

- Dispersed (bus-by-bus) real and reactive demand Load forecast information could be obtained from applicable load serving entities. [Note: The reference to load serving entities is meant to include both those that are registered or non-registered to obtain the most accurate Load forecast information possible.]
- If the Load forecasts obtained from the applicable load serving entities are adjusted to create different seasonal or Load level cases, then the TP or PC should document how the Load forecasts were adjusted, including the assumptions and basis (e.g. historical conditions) that were used in the process.

Documentation considerations – Identify the information sources and have lists of the real and reactive Load forecasts for each model year and set of system conditions.

- o The lists might contain the real and reactive power at each load interconnection.
- o If adjusted Load forecasts were developed, then also have documentation of the Load forecast development process.
- o If Load forecast information was obtained through NERC, regional, and/or PC models, then consider having a copy of the model building methodology.

1.1.5 – Known commitments for Firm Transmission Service and Interchange

<u>Firm Transmission Service</u>

- Obtain Transmission Service information from applicable Transmission Service Providers (TSPs)
- Examples of criteria for selecting Firm Transmission Service commitments:
  - o Tariff obligations
  - o Non-tariff obligations
  - o Historical transfers that are treated as firm

Documentation considerations – Identify the information sources and have a list of Firm Transmission Service lists that may contain the type of service, amount of service, duration, applicable year/season, and applicable operating condition.

<u>Interchange</u>

- Obtain Interchange information from pairs of applicable Balancing Authorities (BAs) or from pairs of applicable control areas (intra-BA commitments)
- Examples of criteria for selecting Interchange commitments:
  - o Tariff obligations
  - o BA interchange commitments
  - o Intra-BA (control area) interchange commitments
  - o Historical interchanges that are treated as firm.

Documentation considerations – Identify the information sources and have lists of the applicable Interchange. The lists that may contain the type of interchange, interchange

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entity pairs, amount of power, duration, applicable year/season, and applicable operating conditions.

1.1.6 – Resources required for Load

- Obtain resource information from applicable entities that evaluate supply or demand side resources, such as GOs, RPs, DPs, or load serving entities
- Examples of criteria for selecting the resources:
  - Type of generation dispatch used (e.g. economic merit order, security constrained economic dispatch order)
  - Intermittent resource (wind, solar) capacity assumptions
  - Resources not incorporated in the Load forecast (R1.1.3)
  - Retail-owned, backup, or supplemental generation
  - Demand side management

Documentation considerations – Identify the information sources and have a list of the applicable Resources. The list might contain the type of resource type (base load, peaking intermittent, etc.), minimum and maximum available power capability, dispatch order, applicable year/season, and applicable operating condition.[4]

<u>Other potential communication and coordination considerations related to R1.1.2</u>

Have communication and coordination be focused between each PC and TP with assistance from the RC to minimize potential seams issues between neighboring PCs and TPs. The benefit of these actions is that it will be more efficient for each PC and TP to obtain applicable outage information from its internal and adjacent RCs, GOPs, and TOPs through its RC.

RCs should make relevant outage information from its GOPs, TOPs, and adjacent RCs available to its PCs and TPs. RCs may be able to obtain some relevant outage information from its adjacent RCs through the Security Data Exchange (SDX).

Evaluating TPL-001-4, Requirement 2

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. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

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. Qualifying studies need to include the following conditions:*

[4] NERC Reliability Standards MOD-010-0 and MOD-012-0 will be retired effective July 1, 2016 and will be replaced by the NERC Reliability Standard MOD-032-1, which has mandatory effective dates of July 1, 2015 (R1) and July 1, 2016 (R2-R4). It is the understanding of the SAG TPL-001-4 SME Team that NERC will address any references to these standards in the next version of NERC Reliability Standard TPL-001

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

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

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. 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 System response:

- *Real and reactive forecasted Load.*
- *Expected transfers.*
- *Expected in service dates of new or modified Transmission Facilities.*
- *Reactive resource capability.*
- *Generation additions, retirements, or other dispatch scenarios.*
- *Controllable Loads and Demand Side Management*
- *Duration or timing of known transmission outages.*

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies 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.

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.

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.*

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.

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.*

***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, Part2.6 and shall include documentation to support the technical rationale for determining material changes.*

***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.

***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. 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:

- *Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.*
- *Installation, modification, or removal of Protection Systems or Special Protection Systems*
- *Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.*
- *Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.*
- *Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.*
- *Use of rate applications, DSM, new technologies, or other initiatives.*

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

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

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

2.8. *For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:*

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

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

R2 Application and Documentation

In order to ensure that future BES system performance deficiencies are identified and mitigated before they are expected to occur, each TP and PC must prepare an annual Planning Assessment of its portion of the BES. It is recommended that each TP and PC develop and retain documentation for each R2 sub-requirement. Application of selected R2 sub-requirements and suggestions are noted below.

The Planning Assessments that are referred to in R2 are the current conclusions regarding the future reliability of the system based on the results of steady state studies/simulations performed for R3 and the stability studies/simulations performed for R4. The expected reliability of the system is assessed annually, but new studies/simulations do not have to be performed annually when the previous studies/simulations are still valid and qualified to be used to formulate the latest Planning Assessment.

R2.1.1 – Declare whether Year one or year two was assessed. Document how the selected year is defined. The system peak load is the coincident Peak Demand forecasted within each entity's applicable area for the year to be assessed. In some systems, the system peak load is the summer peak, while in other systems, it is the winter peak. In some cases, both the summer and winter peak may be appropriate. For example, a system may be winter peaking but the system might exceed thermal limits in the summer peak case due to the lower values of summer thermal ratings.

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R2.1.2 – Declare which Near-Term year was assessed. Document the rationale behind the selected year. Assessing year five may allow the analysis to be a qualified past study for up to four more years (per R2.6.1) of the Near-Term horizon. Document the method used to define the off-peak load condition.

R2.1.3 – Model known outage(s) [R1.1.2 outages] by simulating the outage(s) for the time period that they are scheduled to occur in the simulation of steady state P1 contingencies. Known outages in an adjacent area may be appropriate to model.

R2.1.4 – Sensitivity cases

Select sensitivity conditions may stress the system in some appropriate manner. The system stresses could be related to credible past or prospective future thermal loading, steady state voltage, voltage/angular stability or other operating conditions.

General conditions to consider are:

- Operational history and/or historical trends to determine if the sensitivity is within a range of credible conditions
- Generation dispatch variations (e.g. different wind speeds, hydro availability during drought, coal exports)
- Variable load conditions either higher or lower than nominal load forecasts (e.g. faster or slower load growth, potential large load additions or retirements, above-peak, off-peak, light load)
- Intra-BA interchange if this may affect a TP's area
- Real and reactive forecasted Load.

  Modify Load forecasts from those modeled in the required cases. This could include any material change from loads in the required models,

  - Higher than 50/50 peak assumption than that used in MOD-010 & MOD-012 (e.g. 80/20 peak or 90/10 peak)
  - Higher or lower growth rates for five or ten year models
  - Seasonal off-peak conditions (winter peak (if lower than summer peak), summer peak (if lower than winter peak), spring-fall peak)
  - Light load conditions because high steady state transmission voltages may occur (either wide area or local area) or there is less generation angular stability due to more local generation off line is possible
  - Common coincident peak demand between load serving entities that are highly integrated with each other
  - Adjustments to the power factors for different load levels or trends (e.g. off-peak, light load, future power factor shifts)

Specific conditions to consider from the choices that are cited in the standard are:

- <u>Expected transfers</u>

  If there have been historical power transfers that were materially different from the expected Firm Transmission Service or Interchange, then consider sensitivity cases with expected transfers that are derived from the historical conditions.

- Expected in service dates of new or modified Transmission Facilities

  If there are expected in service dates of new or modified Transmission Facilities that have a high likelihood of being earlier or later than planned, then consider sensitivity cases with earlier or later in service dates.

- Reactive resource capability

  If there are reactive resources that may be significantly higher or lower than reported or planned, then consider sensitivity cases with the credible reactive resources capability differences.

- Generation additions, retirements, or other dispatch scenarios.

  If there are generation additions or retirements that are plausible, but have uncertain commitments or timing (e.g. EPA rules, incomplete interconnection plans), then consider sensitivity cases with the credible plans.

  If there are dispatch scenarios could be materially different from the firm generation scenarios, then consider sensitivity cases which include them. These scenarios may include variations and geographical diversity of intermittent resources (wind, solar, or hydroelectric); non-dispatchable generation; generation affected by cooling or fuel variations (e.g. hydroelectric plants with run-of-the-river variations, coal shortages, natural gas transmission shortages).

- Controllable loads and Demand-Side Management.

  If there are controllable loads and DSM that may be materially different from the load forecast cases, then consider sensitivity cases with credible modeling of controllable loads and DSM.

- Duration or timing of known transmission outages

  If there are known outages of transmission Facilities or large load reductions that are not finalized or may have uncertain duration or timing, then consider sensitivity cases with the credible transmission outages

R2.1.5 – Have a high level description of the spare equipment strategy and a list of the identified spare equipment deficiencies for one year or more (including, but not limited to, BES transformers, BES inductor banks, BES FACTS, etc.). Simulate the applicable equipment outage(s) for the time period that they are expected to be unavailable for the P0 condition and along with simulating the steady state P1 and P2 contingencies for the pertinent area around the outage, which may include an adjacent system.

R2.2.1 – Declare which year was assessed and have a written of the rationale for the selection of the chosen year. Use of year 10 may allow the analysis to be a qualified past study for up to four more years (per 2.6.1) of the Longer-Term horizon.

R2.3 – Build a Near-Term planning horizon short circuit model with all included generation appropriate to the model in service. Include projects in the short circuit model that were included in the near-term planning model. Build a model that includes adequate time for circuit breaker replacement or current limiting projects that would reduce short circuit levels.

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Document the criteria used to determine the interrupting duty of applicable circuit breakers, as well as the criteria for determining what over-duty level requires breaker replacement or short circuit current reduction measures.

R2.4 – Stability analysis covers the investigation of system impacts that can be simulated with dynamic power system software. So, stability analysis will simply be referred to as "dynamic" analysis in this document.

- Dynamic voltage stability is the circumstance where the results of dynamic simulation meets the transient voltage response criteria (R5).
- Dynamic angular stability is the circumstance where the results of dynamic simulation does not exceed the criteria for instability (R6).

R2.4.1 – Declare which year was assessed and have a written rationale for the selection of the chosen year. Use year 5 because the analysis may be applicable for the Near-Term horizon for up to four more years (per R2.6.1). Determine how dynamic load modeling will be accomplished. One approach can be use power flow software routines that convert estimated load type percentages (industrial, commercial, residential, rural) to proxy dynamic load percentages. The estimated load type percentages may be developed on an entity aggregate basis or entity load tap-by-tap basis depending on what the Transmission Planners develop for their areas. Dynamic load modeling only needs to be applied to the Loads that are expected to affect the simulation results. These Loads may be limited to a geographic area that is less than the TP or PC area or may extend across TP or PC areas.

R2.4.2 – Declare which year was chosen. Document the rationale behind the selected year. Consider using year five for general stability analysis because the analysis may be applicable for the near term horizon for up to four more years (per R2.6.1). One approach can be to select a case with off-peak load conditions that are 70% of the peak forecast.

R2.4.3 – Select sensitivity cases for the Stability analyses that were selected for steady state analysis in R2.4.1 and R2.4.2. If there are known sensitivity conditions that may cause Stability reliability issues, then use those sensitivity cases in addition to the steady state ones.

R2.5 – Interpret the requirement to call for assessing the impact of generation additions or generation changes, not assessing the impact of proposed transmission or distribution changes. Material generation additions and changes are generally represented in the planning models according to Requirement R1.1.3. Part 2.5 requires documentation to support the technical rationale for determining which changes are considered to be material. If this documentation is not included in the planning model documentation, then it should be developed by the TP and PC during the assessment. Examples of material generation changes that may be included in the technical rationale are: generation rewinds, plant auxiliary improvements, excitation system modifications, or even the retirement of a generation unit that are proposed to be implemented in the longer-term planning horizon.

R2.6 – This requirement is optional depending on the determination made for steady state (R2.2), for short circuit (R2.3), for near-term stability (R2.4), and longer-term stability (R2.5).

R2.6.1 – If you want to use an analysis that is more than five years old, then have written documentation of the technical rationale. Possible rationale may be:

- For steady state analysis that there is a large margin between the simulation results and the operating limits compared to changes in the Load forecast change or changes to the system
- For short circuit analysis, the margin of short circuit capability is far below the short circuit duty.
- For Stability analysis, there may be a large margin between the simulation results and the stability limits compared to the dynamic characteristic of System elements and the stability characteristic of the local system.

R2.6.2 – If a PC or TP wants to use an analysis that is one to five years old for their Planning Assessment or performs certain analyses on a cyclical basis (such as two year cycle, three year cycle, five year cycle), then they should have written documentation that supports that no material changes to the System have occurred since the previous analysis that warrant re-simulation in the current year. For example, explain why no change, or no significant change, have occurred in the system (generation, transmission, or distribution) since the completion of the supporting analysis to change the results significantly.

R2.7 – Develop a Corrective Action Plan (CAP) to address each of the performance deficiencies that were identified in the current Planning Assessment and document how the CAP removed the performance deficiency. CAPs can be altered in subsequent Planning Assessments and should be retained through multiple Planning Assessments until the CAP is either implemented or cancelled.

R2.7.1 – A spreadsheet or table could be used to maintain the list of System deficiencies and the associated actions needed to address them.

R2.7.2 Include CAPs in the R2.7.1 spreadsheet or table that address specific system performance deficiencies occurring in multiple sensitivity case analyses or include the rationale in the R2.7.1 spreadsheet or table when CAPs are not necessary.

R2.8 – Document the short circuit CAP with a written description of the plans and include the list of system deficiencies and associated actions (R2.8.1).

Evaluating TPL-001-4, Requirement 3

R3. *For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

3.3. *Contingency analyses 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.

3.3.2. 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.

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

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

3.5. *Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list 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.*

R3 Application and Documentation

R3.3.1 – Simulate the removal of elements due to the actions of automatic tripping schemes, which could include, but are not limited to, SPSs, RASs, UVLSs, and certain system operating schemes by incorporating the expected actions into applicable event contingency entries or supplemental simulation means.

R3.3.1.1 – Collect known steady state voltage trip information from GOs related to the generating unit, including its auxiliary equipment. When the GO does not provide known voltage trip values, a TP could develop a generic criteria for generator voltage tripping points. A TP could use the minimum and maximum voltage tripping values at the Point of Interconnection (e.g. high side of the GSU transformer). For example, assumed values of a minimum of 90% and a maximum of 110% could be used.

R3.3.1.2 – If the loading of any circuits exceed their normal or emergency rating, then check to determine whether the relay loadability rating of the circuit is exceeded.

One approach to assist with the checking when relay loadability limits are exceeded is to collect and maintain the relay loadability ratings for all BES circuits in your TP area and enter them in the Rate C field of the base case. When a circuit is loaded above the relay loadability rating, simulate the tripping of the circuit.

R3.4 – Develop a rationale for the selection of planning event contingencies that are expected to be more severe. The rationale may be reason that BES Elements of higher capacity or loading would be more severe than smaller Elements. The number of line circuit contingencies might be reduced by reasoning that breaker-to-breaker contingencies would be more severe than line section contingencies, or line circuit above a certain voltage level would be more severe than lower voltage lines, or line circuits with higher intact loading levels would be more severe that more lightly loaded lines. Consider using screening criteria for determination of most severe contingences. For example using historically studied system events and comparing their steady state voltage and thermal severity indexes to contingencies studied in R2.4.

R3.4.1 – PCs are expected to provide contingencies in its area that may impact its adjacent PC Systems to its adjacent PCs. TPs are expected to provide contingencies in its area that may impact its adjacent TP Systems to its adjacent TPs and its own PC.

R3.5 – Consider the same advice in R3.4 for planning event contingencies, for extreme event contingencies.

Evaluating TPL-001-4, Requirement 4

R4. *For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

4.1.2. For planning events P2 through P7: 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.

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4.2. *Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.*

4.3. *Contingency analyses 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

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. 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.

4.4. *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.

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. 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.

R4 Application and Documentation

R4.1.1 – Establish criteria for determining when a generator is classified as losing synchronism. Choose a generating unit angle difference threshold, a low transient voltage threshold, or an out-of-step relay model. Select angle difference proxy threshold(s) that are considered acceptable for loss of synchronism and document the technical basis for the selection(s). The suggested low transient voltage is 70% of the nominal voltage for the post-fault recovery voltage threshold.

R4.1.2 – If a generator pulls out of synchronism as the result of any P2 to P7 contingency event, then consider using distance relay modeling (actual and/or generic) to analyze and monitor whether any apparent impedance swings may exceed the relay tripping values. Suggested tripping impedance values for a proxy distance relay model settings could be 100% for the Zone A circle, 125% for the Zone B circle, and 150% for the Zone C circle.

If a relay tripping value is exceeded, then identify all of the elements that are tripped by the relay. Next determine whether the tripped elements include any Transmission system elements other than the generating unit and its directly connected Facilities. Facilities are directly connected to a generating unit could include, but is not limited to, the associated GSU transformer and the generator lead to the transmission interconnection facilities, auxiliary load, capacitor banks, and SVCs.

R4.1.3 – Each entity is advised to check for acceptable damping using both their own criteria, as well as the other applicable entity (e.g. TPs have to also check against the PCs' damping criteria and PCs must check against each TPs' damping criteria in each TP's area).

R4.3.1 – Simulate the removal of elements due to the actions of automatic dynamic tripping schemes, which could include, but are not limited to, SPSs, RASs, UVLSs, and certain system operating schemes by modeling the schemes in the dynamic data files or by actions incorporated into applicable event contingency entries.

R4.3.1.3 – System Protection operation due to transient swings includes relays that act in less than five seconds. These relays could include, but are not limited to, distance relays, voltage relays, and overcurrent relays.

R4.3.2 – Include automatic control devices that perform their actions within the transient stability timeframe. For example, fast switched capacitors, but not capacitors whose controls perform the switching after 45 or 60 seconds.

R4.4 –Develop a written rationale that is used to select the contingencies to be included in the more severe list. This rationale may consider such factors as: proximity of the fault to the generator for angular stability, proximity to the weakest parts of the system for voltage stability, the amount of resulting cascading, or the amount of load and/or generation that may be tripped as a result of the contingency.

R4.4.1 – PCs should provide contingencies in its area that may impact its adjacent PC Systems to its adjacent PCs. TPs should provide contingencies in its area that may impact its adjacent TP Systems to its adjacent TPs and its own PC.

Evaluating TPL-001-4, Requirement 5

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

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R5 Application and Documentation

Create a written document for all of the applicable criteria and provide an explanation for any criteria that are not applicable to your area of responsibility. A Planning Coordinator's criteria may apply to some or all of its Transmission Planners and may recognize the Transmission Planner's criteria for its area. If a Transmission Planner adopts its Planning Coordinator's criteria, then it should consider retaining a copy of the criteria for compliance documentation records.

Evaluating TPL-001-4, Requirement 6

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

R6 Application and Documentation

Create a written document for all of the applicable criteria or methodology and provide an explanation for any criteria or methodology that are not applicable to your area of responsibility. These criteria or methodologies should be included or cited in the Planning Assessment. A Planning Coordinator's criteria or methodology may apply to some or all of its Transmission Planners and may recognize the Transmission Planner's criteria or methodology for its area. If a Transmission Planner adopts its Planning Coordinator's criteria or methodology, then the TP should consider retaining a copy of the PC's criteria or methodology for its own compliance documentation.

Evaluating TPL-001-4, Requirement 7

R7. *Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R7 Application and Documentation

The responsibility for this requirement belongs to the PC with support from its TPs. Prior to the undertaking the Planning Assessment responsibilities related to Requirements R1-R6, according to TPL-001-4, each PC and its TPs shall identify each entity's individual responsibilities and those which are joint/shared. It is suggested that each PC with support from its TPs create a written document of the delineation of all the resulting individual and joint responsibilities among the TPs in its area.

Documentation consideration - It's recommended that each PC obtain written confirmation from its TPs that it determined and identified individual and joint responsibilities in conjunction with them.

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As depicted in Figure1, each PC develops the responsibilities for itself and its own TPs.

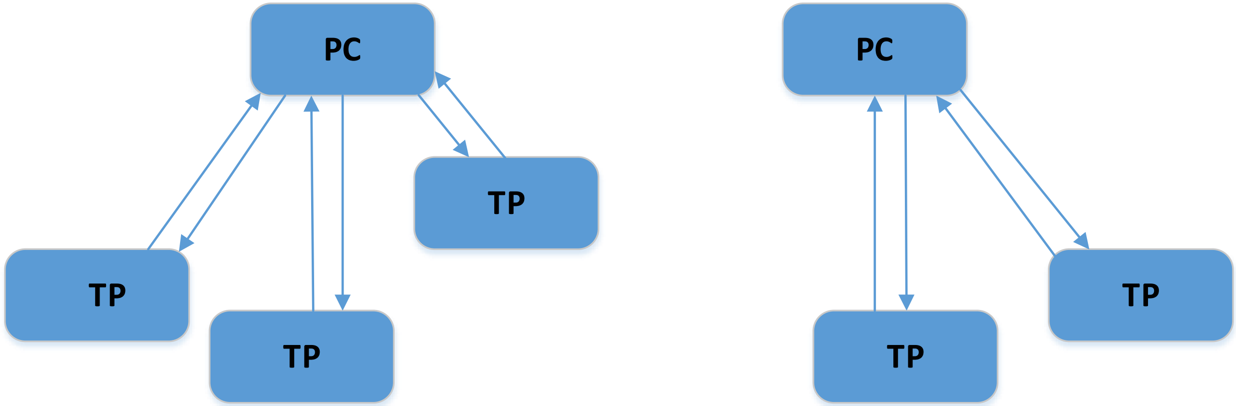

Figure 1.[5] Example of Responsibility Identification Paths between Planning Coordinators and Transmission Planners

Evaluating TPL-001-4, Requirement 8

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

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

R8 Application and Documentation

The applicability of this requirement can be interpreted to obligate Planning Coordinators to provide its Planning Assessment to adjacent Planning Coordinators and Transmission Planners provide its Planning Assessment to its adjacent Transmission Planners.

Maintain a list of the applicable entity registrations and recipients of these communications. Send a periodic request to the applicable recipients to verify whether the contact information is still valid. Have an exploder list to receive these communications and provide it to the entities that must contact you. This practice would provide the communication to multiple individuals (e.g. accountable manager, accountable SME(s), applicable compliance support(s), legal support) just in case some individuals would on be out of the office, moved to a different function, or moved to different company.

Retain a copy of all of the applicable dated requests and dated response communications (e.g. emails) for your compliance documentation.

[5] Some segments of a TP's area may be in different PC areas. In this case, the affected PCs could consider only identifying the individual or joint responsibilities that relate to the portion of the TP area that is in its PC area.

Table 1 Items

General Items

Document the meaning of a generator. The meaning could be a single generator, a single generator unit or a combination of multiple generator units that are tripped together due to direct or dependent relationships. These could include, but are not limited to, the following:

- All generating units at a wind farm
- A set of combined cycle generating units (gas turbine and steam turbine combinations)
- A set of cross-compound generating units.
- A synchronous condenser

Back-to-back DC converters are not explicitly categorized as a DC lines in the standard, but an entity may consider including them in the P1-5, P3-5, P6-4, and P7-2, planning event categories and the steady state and stability '1.' extreme event categories.

Suggested Bus-Tie Breaker Identification:

- A circuit breaker that is positioned to connect two individual substation bus configurations (NERC Bus-Tie Breaker Definition).
- Individual Substation Bus Configuration - An individual substation bus configuration is usually a bus that has bus differential protection.

<u>Selected Planning Contingency Events Considerations</u>

Breaker-to-breaker events which include components of P1-1 (generator), P1-2 (line), P1-3 (transformer), or P1-4 (shunt device) may be considered as a single event and may not need to be duplicated.

For stability analysis, consider fault locations on the Element (e.g. line, transformer) that represent the more severe contingencies.

P1-1 – These contingencies represent a three phase fault on the terminal of a BES generating unit with normal (primary) clearing. For cross-compound and combined cycle generating units, the contingency event includes the tripping/reduction of the associated generation. Consider whether auxiliary load will be tripped, reduced or transferred in association with the tripping of the generating unit.

When the breaker for clearing the generator fault is on the high side of the GSU transformer, the contingency includes the loss of both the GSU transformer and any associated generators. So, these P1-1 contingencies may not need to be duplicated as P1-3 contingencies.

P1-2 – These contingencies represent a three phase fault on a BES line circuit with normal (primary) clearing. These outages are event-based (breaker-to-breaker) contingencies.

P1-3 – These contingencies represent a three phase fault on a BES transformer circuit with normal (primary) clearing. These outages are event-based (breaker-to-breaker) contingencies.

P1-4 – These contingencies represent a three phase fault on a BES shunt device with normal (primary) clearing. Multiple shunt device outages are modeled as a single event if they are connected to the interconnection bus through the same breaker. Shunt devices include capacitor banks, inductor banks, and shunt power electronic devices, such as Static Var Compensators.

P2-1 – These contingencies represent the opening of a line section in a normally networked transmission line without a fault, such as inadvertent tripping of one terminal of a tapped line or a multi-terminal line. This category evaluates all normally networked lines that have one or more taps. Each open line section is modeled as the opening of only one end of the line at a time with a protective switching device. All P2-1 contingencies are "no load loss allowed" contingencies.

Three-terminal lines should be studied by opening each of the three source points individually in order to evaluate post-contingency loading.

To summarize:

Two-terminal lines with no radial load taps:	No need to include in P2.1
Two-terminal lines with any radial load taps:	Include in P2.1
Multi-terminal lines:	Include in P2.1

P2-3 and P2-4 - For dynamic analysis, consider whether performing the extreme stability event 2.e of three phase fault contingencies could be efficient for screening when 2.e results show that P2-3 or P2-4 performance criteria are met and therefore eliminate the need to perform the applicable P2-3 or P2-4 SLG fault contingencies.

P3 – System operator or automatic actions that would be performed within 30 minutes after the first contingency should be included among the System adjustment actions.

For stability analysis, there is no need to simulate the initial loss of a generator. The fact that the standard allows for system adjustments following the initial contingency indicates that sufficient time will have passed between contingencies and any system transient response will have been completely damped prior to the second contingency. The second contingency should be simulated from a starting case that represent the initial outage of the generator and any previously identified system adjustments.

P3-1 – These contingencies represent the prior outage of a generating unit followed by system adjustments and a subsequent three phase fault on another generating unit with normal clearing. Since these contingencies are combinations of two generators, each combination pair only needs to be listed once. It assumed that for steady state analysis, the sequence of the generator unit outages in each pair produces the same final result. These outages are all event-based contingencies.

P4-1 to P4-5 – For steady state analysis, if any of these contingences are the same as a corresponding P2-3 (non-bus tie breaker fault) contingencies since the applicable non-bus tie breaker is located at the Element terminal. So, the applicable P2-3 contingencies may not need to be duplicated as P4-1 to P4-5 contingencies.

For dynamic analysis, consider whether performing the extreme stability events 2.a – 2.d of three phase fault contingencies could be efficient for screening when 2.a – 2.d results show that P4 performance criteria are met and therefore eliminate the need to perform the P4-1 to P4-5 SLG fault contingencies.

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P4-6 – For steady state analysis, if any of these contingences are the same as a corresponding P2-4 (Bus-tie Breaker fault) contingencies since the applicable Bus-tie Breaker is located at the Element terminal. So, the applicable P2-4 contingencies may not need to be duplicated as P4-6 contingencies.

P5-1 to P5-5 – Identify non-redundant (no secondary) protective relays that are in your BES, especially bus differential relays and pilot-wire receiver relays (for stability purposes). As mentioned in Note #13, the applicable relay functions or types are: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). For locations where non-redundant relays exist, determine the impact of the failure of that relay and decide whether a P5-1 to P5-5 event needs to be analyzed.

For steady state analysis, consider if any of these contingences are the same as a corresponding P2-3 (non-Bus-tie Breaker fault) contingency. So, the applicable P2-3 contingencies may not need to be duplicated as P5-1 to P5-5 contingencies.

For dynamic analysis, the extreme stability events 2.a - 2.d of three phase fault contingencies could be efficient for screening when 2.a - 2.d results show that P5 performance criteria are met and therefore eliminate the need to perform the P5-1 to P5-5 SLG fault contingencies.

P5-6 – For steady state analysis, consider whether any of these contingences are the same as a corresponding P2-4 (Bus-tie Breaker fault) contingency since the applicable Bus-tie Breaker is located at the Element terminal. So, the applicable P2-4 contingencies may not need to be duplicated as P5-6 contingencies.

P6 – For steady state analysis, consider listing the contingencies that are combinations of two BES Elements only once because the sequence of the Element outage in each pair produces the same system impact result. System operator or automatic actions that would be performed within 30 minutes after the first contingency should be included among the System adjustment actions.

For stability analysis, there is no need to simulate the initial (non-generator) contingency. The fact that the standard allows for system adjustments following the initial contingency indicates that sufficient time will have passed between contingencies and any system transient response will have been completely damped prior to the second contingency. The second contingency should be simulated from a starting case that represent the initial outage and any previously identified system adjustments.

Selected Extreme Contingency Events Considerations

SS-E2.a (loss of tower line with three or more circuits)
These contingencies represent an outage of a tower line (common structure) with three or more BES transmission circuits. An entity may consider simulating an outage of all of the BES and non-BES transmission circuits.

SS-E2.b (all transmission lines in a common right-of-way)
A "common right-of-way" is either a single right-of-way or multiple rights-of-way physically adjacent to one another (i.e. no separation between rights-of-way).

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These contingencies represent an outage on all the transmission circuits in a common Right-of-Way (ROW) that include at least two BES circuits. An entity may consider simulating an outage of all BES and non-BES overhead or underground transmission circuits within a common right-of-way with normal clearing.

For ROWs with only two BES circuits, each applicable SS-E2.b contingency outages the same Elements as the corresponding P6.1 or P7.1 contingency and does not have to be duplicated. For ROWs with three or more BES overhead circuits on a common tower line, each applicable SS-E2.b contingency outages the same Elements as the corresponding SS-E2.a contingency and does not have to be duplicated.

All remaining SS-E2.b contingencies with three or more BES overhead or underground circuits that share a ROW are applicable. Only the combinations of overhead or underground BES circuits are listed.

SS-E2.c (loss of one voltage level plus transformers at a switching station or substation)
These contingencies represent an outage of all the Elements at one BES voltage level plus the transformers connected to that voltage level at the switching station or substation with normal clearing. For a three-winding transformer with breakers on each winding, the contingency may simply open one winding and leave the other two windings in service. For a three-terminal line circuit with breakers on each terminal, the contingency may open one terminal and leave the other two terminals in service. The same-voltage bus outages are event-based contingencies with prior normal system conditions.

For substations that are connected by only one BES transmission circuit and no shunt reactive device connected at the same voltage level, then each applicable SS-E2.c contingency outages the same Elements as the corresponding P1.2 contingency and does not have to be duplicated. For substations that are connected by only two BES transmission circuits and no shunt reactive devices connected at the same voltage level, then each applicable SS-E2.c contingency outages the same Elements as the corresponding P6.1 or P7.1 contingency and does not have to be duplicated.

All remaining SS-E2.c contingencies involving substations that are connected by three or more BES transmission circuits are applicable.

SS-E2.d (loss of all generating units at a generating station)
These contingencies represent an outage of all transmission generating units at the same generating station with normal clearing when there is at least one BES generating unit at the station. An entity may consider simulating an outage of all BES and non-BES generating units at the generating station that are interconnected to the BES. The generating unit outages are event-based contingencies with prior normal system conditions.

If there are only one or two BES generating units at a generating station, then each applicable SS-E2.d contingency outages the same Elements as the corresponding P1.1 or P3.1 contingency and does not have to be duplicated.

SS-E2.e (loss of a large Load or major Load center)
These contingencies represent an outage of all the BES line or transformer circuits that feed a local network with a large Load or major Load center with normal clearing. The line circuit outages are event-based contingencies with prior normal system conditions.

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Document the criteria for the identification of "a large Load" and "a major Load center".

If there are only one or two BES circuits feeding the Load, then each applicable SS-E2.e contingency outages the same Elements as the corresponding P1.2, P1.3, P6.1, P6.2, or P7.1 contingency and does not have to be duplicated.

Table Notes

An entity may consider that the combinations of circuits that share a cumulative distance of one mile or less are excluded.

Remember the stipulations and that only P1, P2.1, and P3 are planning events.

Revision History

Revision	Effective Date	Author(s)	Approved By	Summary of Changes
1.0	3/15/15	SMET	MRO SC	Address Requirements 1 and 7 only to meet early effective date of January 1, 2015.
2.0	8/31/15	SMET	MRO SC	Address Requirements 2 through 6, Requirement 8, and Table 1 in the original SAG.

APPENDIX A: REFERENCES

1. NERC Reliability Standard TPL-001-4. http://www.nerc.com/files/TPL-001-4.pdf

2. Bulk Electric System Reference Document, Version 2, April 2014. http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

APPENDIX B: Selected Terms from the NERC Glossary of Terms

The following terms are listed for quick reference from the May 19, 2015 version of the NERC Glossary of Terms. Other NERC Glossary Terms are available on the NERC website at: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Bus-tie Breaker: *A circuit breaker that is positioned to connect two individual substation bus configurations.*

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

Contingency: *The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.*

Element: *Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.*

Facility: *A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)*

Firm Transmission Service: *The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.*

Interchange: *Energy transfers that cross Balancing Authority boundaries.*

Load: *An end-use device or customer that receives power from the electric system.*

Near-Term Transmission Planning Horizon: *The transmission planning period that covers Year One through five.*

Non-Consequential Load Loss: *Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.*

Peak Demand: *1.The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.*

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

System: *A combination of generation, transmission, and distribution components.*

Transmission: *An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.*

Year One: *The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.*