TPL 001-4 Modeling Reference Document

This document submitted to NERC for consideration as "Implementation Guidance." NERC chose not to endorse the document. Visit NERC's [compliance guidance website] for more information.

NATF subject-matter experts are reviewing NERC's rationale for non-endorsement and will determine appropriate next steps and guidance for use of this document.

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Introduction and Purpose

NATF Modeling reference document, *TPL 001-4 Modeling Reference Document,* is intended to provide guidance regarding the use of consistent, industry-wide approaches to certain topics in NERC Standard TPL-001-4. This document does not replace, change, or interpret any requirements in the NERC Reliability Standards or other applicable criteria.

This Reference Document does not create binding norms, establish mandatory reliability standards, or create parameters by which compliance with Reliability Standards is monitored, or enforced. In addition, this reference document is not intended to take precedence over any regional procedure. It is recognized that individual Planning Coordinators (PCs) and Transmission Planners (TPs) may use alternative and/or more specific approaches that they deem more appropriate for their planning purposes.

Topic 1: Development of models for TPL-001-4 Studies

The following sections provide guidance for Transmission Planners on items for consideration when meeting the modeling requirements of TPL-001-4.

Part 1: Transmission Planner Compliance with R1.1

Requirement 1.1 of TPL-001-4 places several modeling requirements on the Transmission Planner involving the topology of their transmission system model. All but two of these requirements, R1.1.2 and R1.1.5, are covered in Requirement 1 of MOD-032. See below for the TPL-001-4 R1.1 requirements and their corresponding MOD-32 requirement as applicable.

1.1. *System models shall represent:*

1.1.1. *Existing Facilities* (MOD-032-1 ATTACHMENT 1)

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* (MOD-032-1 ATTACHMENT 1)

1.1.4. *Real and reactive Load forecasts* (MOD-032-1 ATTACHMENT 1)

1.1.5. *Known commitments for Firm Transmission Service and Interchange*

1.1.6. *Resources (supply or demand side) required for Load* (MOD-032-1 ATTACHMENT 1)

Modeling Known Outages

Transmission Planners need to explain their outage planning processes for R1.1.2. Then, incorporate information on steps to be taken to ensure models, used for studies to support the assessment, include known outages of at least six months. For instance, most companies have an ongoing process for development of a generation outage schedule. The current version of the schedule should be reviewed for inclusion of, "*Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months*" in the models.

Modeling Firm Transmission Service and Interchange

When building models to ensure generation resources are allocated to the appropriate Balancing Authority Areas (BAA), interchange coordination should be performed. This allows generation in each BAA to be accurately dispatched and meet the BAA's load plus losses. The interchange coordination should consider all transactions with confirmed annual firm transmission service (for one year or longer, including consideration of rollover rights) along the entire path, from source to sink, and have a firm energy contract for the resource. The amount of interchange in any given year/season may not utilize the full capacity allowed under the transmission service or energy contract. Also, the amount of interchange for a year/season should represent the amount expected, and agreed upon, between planners of firm capacity expected to serve load.

For example, the amount of renewable resources expected to be available varies and should be accounted for depending on season and time of day.

The recommendation is to capture the information identifying the source generation and the associated transmission service request numbers.

It is important that the area where generation resources are expected to be sinking verify that the transfer is properly modeled and ensured the area's load will be served reliably. The omission of such firm transfers can create both transmission system reliability concerns, as well as resource planning issues. Transmission system reliability concerns are created because the models, when used for evaluation of transmission service requests and planning studies, would not contain the flows associated with these firm transfers that are expected to occur in real time. Resource planning issues, such as double counting of resources and incorrect utilization or dispatch priority of generation, may also not be recognized.

Generation resources and transmission service are frequently not contracted for the entire 10 years of the planning horizon for which the models are developed. Coordination of interchange for these cases will require some judgment because all of the required elements (generation contract, source to sink transmission service) may not be available. Information provided by load customer resource forecasts and plans, rollover of transmission service, and duration of energy contracts should be considered when interchange coordination, particularly in the out-year cases, is being performed.

Modeling Procedure Documents

It is recommended that Transmission Planners create modeling procedure documents that record compliance with the modeling requirements of MOD-032 and TPL-001-4. These could be created at the Transmission Planner or Planning Coordinator levels. Examples of such documents are located in the Reference Documents Section on page 29.

Part 2: Transmission Planner Compliance with R2.1.4 and R2.4.3

Requirements 2.1.4 and 2.4.3 of TPL-001-4 require Transmission Planners to vary the basic assumptions used in their transmission system models to analyze the impact on study results. These Requirements are shown below:

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*

2.4.3 *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.*

Developing Sensitivity Cases

It is recommended that Transmission Planners incorporate the building of sensitivity cases into their annual model building process as much as possible. Transmission Planners should coordinate with their Planning Coordinators on needed sensitivity cases to minimize work on their part and benefit all Transmission Planners under the Planning Coordinator. Reference the modeling procedure documents provided in Part 1 for an example.

It is important to note that the basic assumptions varied by the Transmission Planner should be valid, realistic scenarios. The requirements state that a measurable change in system performance/response respectively should be demonstrated in the sensitivity cases. The Transmission Planner should be cautious in creating sensitivity cases that satisfy this language while still being valid scenarios and should be prepared to defend any assumptions made.

Some additional items the Transmission Planner should consider include:

1. Sensitivity assumptions should be coordinated with neighboring Transmission Planners when applicable.
2. Three sensitivity cases are required in the steady-state analysis. A system peak year one or year two, a system peak year five, and an off-peak for one of the five years.
3. Two sensitivity cases are required in the transient stability analysis. A Near Term Transmission Planning Horizon system peak for one of the five years and an off-peak for one of the five years.
4. Corrective Action Plans do not need to be developed to meet the performance requirements of a single sensitivity case. The Transmission Planner should document why they believe Corrective Action Plans are required or not required if violations of performance requirements are found in one or multiple sensitivity cases.

Part 3: Transmission Planner Compliance with R2.1.5

Requirement 2.1.5 of TPL-001-4 requires Transmission Planners to study the impact of the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer). The studies shall be performed for the P0, P1, and P2 categories. This Requirement is shown below:

3.1 *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.*

Creating a Spare Equipment Strategy

If a Transmission Planner does not already have a spare equipment strategy in place, they may want to create one. The general approach to doing this is to create a list of all, long-lead transmission equipment and create a spare equipment strategy around that equipment. Strategies for consideration, but are not limited to, are listed below:

1. One for one spare transmission equipment in stores and their availability/mobility
2. The ability to temporarily move/transfer redundant transmission equipment (i.e. a substation that has more than one transformer) until ordered replacements arrive
3. Available partnerships with neighboring Transmission Planners to cover each other for certain types of transmission equipment

Evaluating the Impact of Equipment Unavailability

Once a Transmission Planner decides on a strategy, the next step is to create a subset list of their Transmission equipment that is not covered by their spare equipment strategy. A suggested list of transmission equipment to evaluate for long-lead time includes:

- Auto-Transformers
- Generator Step-Up Transformers
- Phase-Shifting Transformers
- Gas Insulated Substations
- Synchronous Condensers
- HVDC Transformers for HVDC Facilities
- Interconnection transformers for FACTS (e.g., SVC) Installations
- Spare Thyristors/IGBTs for HVDC Facilities/FACTS Installations

The Transmission Planner will need to run studies for each piece of equipment such that it is out-of-service in their base case before category P0, P1, and P2 analysis is performed. Steady-State should be considered and the rationale documented. Case Types/Scenarios studied should be consistent with those performed for each Transmission Planners Near-

Term Assessment. A Corrective Action Plan will need to be developed for any issues identified.

Part 4: Transmission Planner Compliance with R2.4.1

Realistic power system models are essential for reliable grid planning and operations. The NERC TPL Reliability Standard requires that Transmission Planners and Planning Coordinators use adequate load models in studies that support power system stability assessments. The load model requirement for stability analysis of system peak load is shown below:

> ***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.

Load Model Types

Transmission Planners and Planning Coordinators typically have several possible types of load models for stability studies to choose from. Some examples are listed below:

- Static Load Models:
  - ZIP – Constant Power / Current / Impedance Model
  - LDFR – Frequency Dependent Model
  - IEEL – Voltage and Frequency Polynomial Model
- Dynamic Load Models:
  - CIM5/CIM6 – Induction Motor Model
  - CLOD – Complex Load Model
  - CMLD Composite Load Model

Which Model Types Can Be Used to Satisfy TPL requirements?

Requirement R2.4.1 states that the load model used shall:

1. Represent the expected dynamic behavior of Loads that could impact the study area
2. Consider the behavior of induction motor Loads

Static models such as ZIP models, frequency dependent models, and polynomial models of voltage and frequency do not represent induction motor behavior over the range of voltage and frequency deviations that occur during significant fault events. Therefore, these models cannot solely be used as, *"An aggregate System Load model which represents the overall dynamic behavior of the Load."* They could be used in conjunction with dynamic load models listed above as they have been used in transmission reliability studies to replicate FIDVR events.

Also, additional requirements may apply for some entities depending on specific regional requirements. Some regions have explicitly created requirements that all functional entities shall meet.

Other Consideration in Satisfying TPL requirements

Selecting an acceptable load model type can be a first step, but this is not enough to meet the new NERC TPL requirements. Since there is an expectation that the dynamic load model represents the expected dynamic behavior of loads, appropriate parameters should be chosen for the model to represent the behavior of loads in the functional entities' planning area. If a Transmission Planner has no previous experience in using dynamic load models then there may not be any available information about the load composition in the area. Here are a few options they can consider:

1. Published reports or presentations from neighbors could be a good source of a load model that could be quickly applied to an adjacent area.
2. If there is good data available from a grid event, then any of the induction motor models could be used to adjust parameters to obtain a model for the area. If detailed load information is not available in an area, then an area-wide model would be easier to develop and meets the requirements of the TPL standards. In the end, even if a model were constructed using detailed information about load characteristics that could be applied to each bus in a planning area, this model would still need to be validated using grid events.
3. WECC and EPRI have already performed significant research into the load characteristics in the WECC area. Any of this information that is publically available could be useful in developing a model for an area that has a similar climate to one of the temperature zones included in the WECC model. Even if some load parameters may vary, this could serve as an initial model for an area that had no previous model data available.
4. For the past several years, EPRI has been studying load composition for different regions across the country. Planners could make arrangements with EPRI to learn more about this.
5. A CLOD model could be used based on the research performed by Southern Company and documented in an IEEE paper (see Reference Documents Section on page 29).

Topic 2: Use of past studies in annual assessments, extreme event analysis, "more severe" impact analysis, contingency coordination and sharing of the Planning Assessment

Requirement R2.6 of the Standard

2.1 *Past studies may be used to support the Planning Assessment if they meet the following requirements:*

2.1.1 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.

2.1.2 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.

Guideline for Determining Use of Past Studies

If PCs and/or TPs utilize past studies then a technical rationale should be available. Possible rationale may be, but is not limited to:

1. There is a large margin between the simulation results and limits detailed in planning criteria. Changes in the study area's model (e.g. load forecast, generation dispatch, interchange, topology) from previous study periods are deemed insignificant and would not be expected to produce measurable changes in simulation results.
2. Consideration can be given when large margins exist (e.g. the of short circuit duty is far below the short circuit capability, transmission elements are well below their ratings, or margin to voltage collapse is large) as to whether measurable changes in simulation results would be expected.

Additionally, a rationale must be available for determination of material changes. Material changes include, but are not limited to:

1. Growth/reduction in demand
2. Types of devices modeled and updates to those devices
3. Changes in generation (retirements, additions, capacity improvements, etc.)
4. Alternative load models (i.e. changes in composite load model)
5. System topology changes (transmission, generation, distribution, etc.)

Requirement R3.4, R3.5, R4.4, and R4.5 of the Standard

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.*

3.5 *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.*

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.*

4.5 *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.*

Guideline for development of contingency lists for R3.4, R3.5, R4.4, and R4.5

If feasible, simulation of all P1-P7 planning events and extreme events should be considered by the PC and TP. If not, then a rationale should be developed to document the criteria for events selected for simulation. Some but not all items to consider when developing the rationale are:

1. Past studies
2. SME judgement
3. Historical data from past operating events
4. Overlap of facilities removed by different contingencies (caution: timing/sequence of facilities removed may change impact in stability studies)

Guideline for evaluation of extreme events

The PC and TP should consider developing criteria for the evaluation of the impact of extreme events. The criteria, at a minimum, should include an evaluation of the extreme events to determine if Cascading occurs. Additionally, the PC and TP could consider criterion for the following:

1. Loss of significant customer demand exceeding a defined MW threshold as determined by the PC and TP or impacting a certain area (e.g. densely populated urban area, military facility)
2. Significant loss of generating capacity
3. The inability of the model to reach a stable post-event solution

4. Impacts are identified beyond the PC and TP area

The probability of an extreme event, its impact, and possible mitigating actions should be considered in the evaluation of actions that should be taken as a result of simulation of extreme events.

Requirement R3.4.1 of the Standard

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.*

Guideline for Contingency Coordination

The PC and TP are responsible for coordination of Contingency lists with adjacent PCs and TPs. These lists should include contingencies which may impact the adjacent PC and TP Systems. The rationale for contingency selection should be documented by participating PCs and TPs. Some but not all items for consideration are:

1. Development of algorithms to identify potential contingencies to share with adjacent PC/TP
2. Frequency of contingency coordination to be agreed upon by each PC and TP
3. Contingencies identified during system analysis and recommended by adjacent PC/TP

Requirement R8 of the Standard

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]

Topic 3: Cascading Criteria and Methodology

Background

NERC Reliability Standard TPL-001-4 R6 states: 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.

Cascading Definition from NERC Glossary

The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Recommendations

The criteria and methodology used in analysis to identify potential Cascading events with the purpose of preventing their occurrence should include, but are not limited to:

1. The Transmission Planner is responsible for identifying planning and extreme events that may result in potential Cascading-based on engineering knowledge of the transmission system. The Transmission Owner and Transmission Planner work in conjunction with each other, as needed, to identify potential scenarios for evaluation that could lead to Cascading. The determination of Cascading can consider:
    a. Post-contingency overloads
    b. Post-contingency voltages
    c. Protective relay settings (e.g. overcurrent relays)
    d. Load loss
    e. Generation loss
    f. System stability (if transient stability analysis is performed)
        i. Transient voltage response
        ii. Negatively damped oscillations
        iii. Tripping of lines due to apparent impedance swings
        iv. Frequency excursions
        v. Long-term voltage recovery
2. For the purposes of performing Cascading analysis, the Transmission Planner performs appropriate steady-state studies in cooperation and coordination with the appropriate Transmission Owners.
    a. For the initiating event, resultant overloaded BES facilities above a predetermined threshold (set by the Transmission Planner) are subsequently removed and the power-flow case resolved.
    b. Continue until case either fails to converge or there are no more BES overloads above the predetermined threshold or step a. is repeated a predetermined number of times.

c. Voltage levels will be assessed at each step of the power-flow solution.

d. Consider shedding bus loads or tripping generation where the voltage falls below a predetermined threshold. This action can be treated like an overloaded line where all or a portion of the load at the violating buses are tripped in each cascade step or the under voltage load shed can be performed only in cases which fail to converge in order to increase the likelihood of a solution. Convergence might be obtained by shedding bus load in cases which fail to converge, allowing the thermal overloads or low voltages to continue to be observed in subsequent stages.

e. Each step in the Cascade event should be reviewed to identify any internal load pockets in the studied BA, which when reduced to a single source due to the Cascade actions, may cause non-convergence in the solution. Dropping the internal BA Load pocket will often allow the Cascade event solution to converge allowing for continued analysis of the event's impact.

3. The Transmission Planner performs more in-depth system analysis which may include transient stability/dynamics analysis.

4. Indication of a potential Cascading event may include, but is not limited to:

   a. Consideration of magnitude of loss of load as established by the PC or TP

   b. Overloads over a predetermined threshold occur a predetermined number of successive times. Each successive time the overloaded facilities are removed from service and the case resolved.

   c. Event causes loss of facilities sequentially spreading beyond an area predetermined by studies (e.g. beyond the TP's area boundary)

   d. Case fails to converge after subsequent overloaded facilities are removed

   e. Consideration of a number of transmission lines predicted to trip due to apparent impedance swings as established by the PC or TP.

Summary

The final criteria/methodology for determination of potential Cascading events is the responsibility of the Transmission Planner working in coordination with the appropriate Transmission Owners. Possible sources for the development of such criteria/methodology include the NATF CIP-014 Requirement R1 Guideline document.

Topic 4: Generating Unit Low Voltage Ride-Through Capabilities and Simulations

Introduction

System voltages may be disturbed from normal operating conditions during typical transmission system events, such as electrical faults. Under faulted conditions and during subsequent system restoration to a new equilibrium, it is common for portions of the power system to experience voltage sag[1]. The capability of power system components and associated system protective devices to maintain connectivity to the transmission system during voltage sag events is called low-voltage ride-through (LVRT). Overall power system reliability is enhanced by the ability of generating units, which commonly utilize voltage or frequency protective devices, to ride-through voltage sags and contribute positively to system dynamics experienced during post-fault restoration.

While the dynamic response of power system components, such as generating units, is well understood, unfortunately, ride-through capabilities vary widely. This may best be summarized as stated in the IEEE Recommended Practice for Electric Power Distribution for Industrial Plants[2]:

> *'There is a wide range of susceptibility and ride-through capability in plant equipment manufactured today, and there are no recognized standards that apply to this equipment."*

The proper simulation and study of faulted and post-faulted transmission topology are of particular interest to Transmission Planners (TP)[3]. This NATF reference document is intended to offer guidance specific to generating unit low voltage ride-through considerations, in support of analysis required by TPL-001-4/R3 for steady-state simulation and TPL-001-4/R4 for stability simulation, as part of the Planning Assessment of Near-Term and Long-Term Transmission Planning Horizons. It is understood that in some cases, the TP may not have specific details regarding the voltage ride-through performance for generating units. Therefore, this NATF reference document offers guidelines for the use of technical criteria drawn from PRC-024 and other informational sources, for proper simulation and screening of generating units during TPL studies.

Purpose

The purpose of this reference document is to:

1. Discuss important considerations for simulating generating unit LVRT
2. Provide some key considerations when applying LVRT criteria for units within the TP study area
3. Suggest prerequisites and methods for the performance of steady-state and stability studies that consider generating unit LVRT capabilities towards the requirements of TPL-001-4

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[1] IEEE Standard 1159-2009 defines a voltage sag, a synonym to the IEC term *dip*, in three categories: instantaneous lasting 0.5-30 cycles, momentary lasting 30 cycles to 3 seconds, and temporary from 3-60 seconds.

[2] IEEE Standard 141-1993(R1999)/15.2.3.1, pg. 680.

[3] Defined in "Glossary of Terms Used in NERC Reliability Standards", updated May 19, 2015.

TPL-001-4 Requirements 3.3.1 and 4.3.1

Simulation is an integral part of performing a Planning Assessment, as required by TPL-001-4. This includes steady-state simulation, requirements given in TPL-001-4/R3, and stability simulation, requirements given in TPL-001-4/R4. When performing Contingency analysis guidance is given to the TP in R3.3.1 and R4.3.1 (identical language):

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

Further, R3.3.1 and R4.3.1 specify that the impacts of generator tripping, and tripping when relay loadability limits are exceeded, shall be included in Contingency analysis. With regards to the topic of LVRT, the TP shall consider nearly identical guidance specified in R3.3.1.1 and R4.3.1.2 (language differences are embossed for clarity):

> *From R3.3.1.1*: *"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."*

> *From R4.3.1.2*: *"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."*

Given that minimum generator ride-through voltage limitations and generator low-voltage ride-through capabilities shall be considered during Contingency analysis, the remainder of this topic is dedicated to addressing factors that the TP should consider and methods of performing appropriate simulations.

Load Voltage Ride-Through Key Considerations

The typical TP may have multiple types and capacities of generating units within their study area. Many factors influence the simulation of generating units for the purpose of performing Contingency analysis. The following section highlights some of the factors that TPs should consider when preparing to perform simulations.

Generating Unit Low Voltage Ride Through

Voltage sag and its impact upon the reliability of the Bulk Electric System (BES) is particularly critical at generating stations. Synchronous generators provide the majority of primary voltage control and reactive support to the transmission system and its Loads. Ensuring that generating units operate within voltage limits is foundational to proper power system operation. Voltage ridethrough, considering both high and low-voltage excursions, is determined by two key parameters: voltage magnitude and duration. Based on R3.3.1 and R4.3.1 of TPL-001-4, this reference document focuses on the minimum generator or ride-through low voltage limitations.

The TP should pay close attention to the per unit voltage base when assessing voltage ride-through characteristics of a generating unit. When using the voltage ride-through characteristics available in PRC-024, the TP should be aware that the per unit base voltage used is referenced to the point of interconnection meaning the transmission (high voltage) side of the generator step-up or collector transformer; as described in footnote 2 of Requirement R2 of PRC-024.

The generating unit ride-through duration from Appendix 2 of PRC-024, shown in Figure 4-1, denotes the “no trip zone” based on high and low-voltage ride-through durations. It is noted that generator voltage protection typically monitors unit terminal voltage while the per unit voltage quantities given in Appendix 2 of PRC-024 refer to generating unit voltage at the point-of-interconnection with the BES.

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Figure 4-1. Ride-Through Duration, PRC-024, Attachment 2.

Given that generating unit protection systems often employ voltage relays (e.g. Type 27 and Type 59), the “Voltage Ride-Through Time Duration Curve” contained in PRC-024-2[4], and shown in Figure 4-2, illustrates the magnitude-time requirements for protective relay settings necessary to ensure generating units remain connected during voltage disturbances. The time-duration characteristic of Figure 4-2 is based upon the parameters shown in Figure 4-1. In all cases, generating units may trip within a portion of the “no trip zone” given the exceptions to PRC-024 R2, e.g., documented and communicated regulatory or equipment limitations.

[4] PRC-024-2 aligns the applicability of PRC-024-1 with the revised definition of the BES. The existing standard, PRC-024-1, retires at midnight of the day immediately prior to the Effective Date of PRC-024-2, enforceable on 7/1/2016. For consistency in this document, henceforth PRC-024 will be used as the referenced standard.

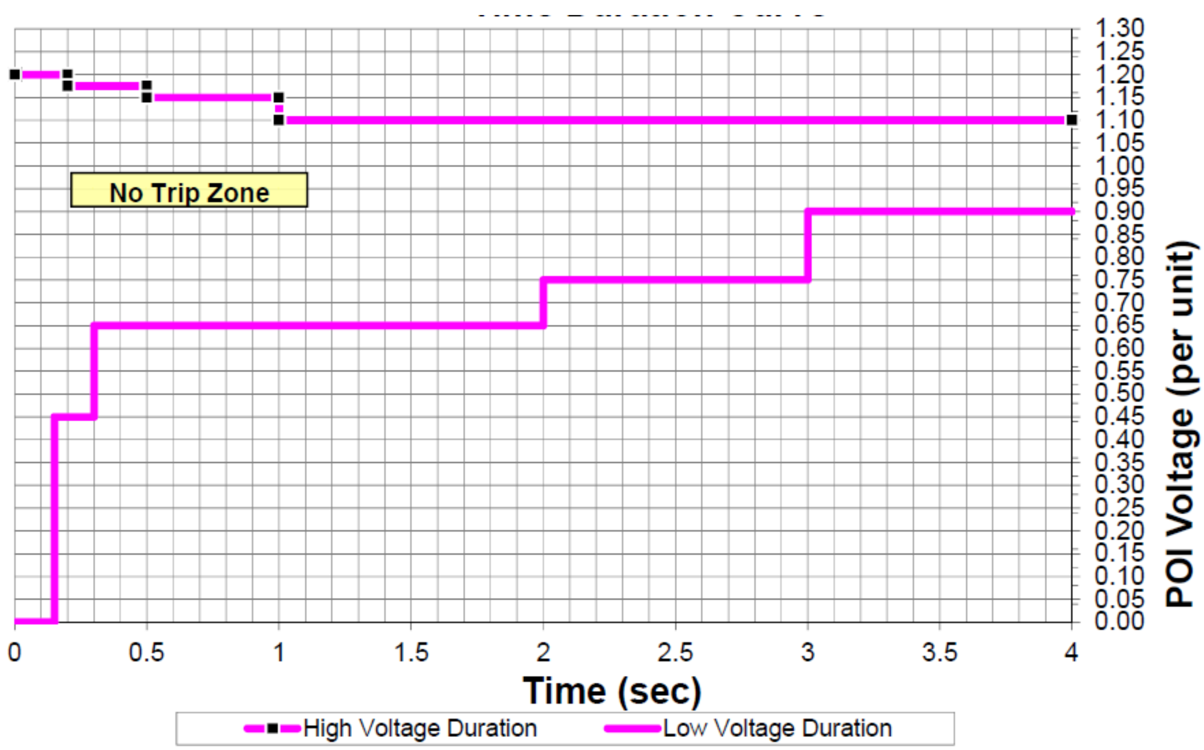

Figure 4-2. Voltage Ride-Through Time Duration Curve, PRC-024 Attachment 2.

Low Voltage and Auxiliary Systems

For many companies, the protective relay guidance given in PRC-024 forms adequate simulation constraints for the performance of Contingency analysis. However, experience has shown that the dynamic response of generation station service loads to voltage sags may lead to sympathetic tripping of the units themselves. In other words, generating units rely upon support systems that may be sensitive to voltage sags. These supportive loads may, when disturbed, stall, trip on their own, or otherwise contribute to the loss of the generating unit. As stated in IEEE Standard 666-2007 "Design Guide for Electric Power Service Systems for Generating Stations":

> *"most generator unit auxiliary loads can tolerate some interruption in power before shutdown conditions begin to occur. The duration of power interruption is dependent on the specific item of equipment. The limiting auxiliary loads should be determined to ensure that there is no adverse effect on unit operation during the power interruption. In addition, if the voltage drops below 75% to 80% of the equipment rating during transfer, electrically held motor starter contacts may open and interrupt power service to equipment. Motors essential to unit operation may have latched breakers or contactors so that they will not drop out during this transient condition. Sustained low-voltage conditions may also affect the torque-generating capability of the motors and may cause the loads to stall."*

Critical support system equipment, such as fuel supply equipment, combustion ventilation, control power distribution, cooling systems, and lubrication may be adversely affected by voltage sags. Examples include: nuclear reactor coolant pumps, coal-combustion feeders/augers, condensate pumping, etcetera. It is recommended that TPs scrutinize generating units within their study area and identify sensitive auxiliary generating station loads that may require more restrictive magnitude-duration constraints than those given in PRC-024 Attachment 2.

Interconnection Requirements and Distributed Generation

As renewable generation integration within the total energy supply has increased, the importance of voltage ride-through capability for renewable plants has likewise increased. Renewable plants, including wind and photovoltaic generating units, traditionally employ sensitive voltage and frequency protection settings to disconnect from the power system given even slight disturbances.

It may be difficult for the TP to determine specific LVRT capabilities of renewable generating units or collector systems connected to the bulk electric system. However, companies may employ specific interconnection requirements for LVRT based on unique technical or tariff requirements. In general, tariffs may specify LVRT requirements for wind generating plans subject to FERC Order No. 661, specifying that the wind facility remains online during voltage disturbances. Commonly, LVRT requirements for interconnection are consistent with PRC-024 requirements and may include special provisions as specified by the Transmission Service Provider. For generation facilities to be connected to a utility's distribution system, various requirements may be applicable; an example: California Rule 21 for generation facilities interconnecting under California Independent System Operator (CAISO) Distribution Provider tariff.

Two key standards, IEEE 1547 and UL 1741, provide specifications for safe and reliable interconnection of distributed resources (DR), also referred to as distributed energy resources (DER). It is typical in the United States for state-wide DER interconnection requirements to be consistent with IEEE 1547 while the DER assets themselves require UL certification. Presently, IEEE 1547 is undergoing a major revision and it is anticipated that significant changes, including an increase to the 10 MVA nameplate capacity threshold, is expected in late 2016. Generating resources connected at the distribution level are typically not subject to FERC jurisdiction and NERC Reliability Standards. For consistency, companies may consider using the voltage ride-through characteristic, shown in Figure 4-2, when studying renewable generating units or DER during Contingency analysis.

Approaches to Simulating Low Voltage Ride-Through

Transmission Planners need solid methodological guidance to properly simulate how generating units respond during Contingency analysis, given LVRT capabilities. This section is intended to offer a practical approach for performing simulation studies that consider the requirement specified in R3.3.1.1 and R4.3.1.2 of TPL-001-4.

Simulation prerequisites

The following prerequisites apply to both steady-state and stability simulations:

1. For all generating units, within the study area, with LVRT capabilities that conform to the PRC-024 Attachment 2 voltage ride-through time duration curve, this curve will form the basis of the minimum generator steady-state and ride-through voltage limitations for study, per R3.3.1.1. The TP should note, from "Curve Details" in PRC-024 Attachment 2: "The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the

reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES)."

2. The TP should use specific voltage ride-through time duration characteristics for any generating units within the study area that have been identified or reported as having a more restrictive LVRT magnitude-time characteristic than defined by the PRC-024 Attachment 2, including more stringent limitations that may be imposed by the employment of local generation plant auxiliary or support equipment.
3. The TP should be aware that, in some cases, the generating unit owner may communicate certain protection system details to the Planning Coordinator (PC) directly. The TP should coordinate any such information with the PC prior to initiating study.
4. The TP should consider any Special Protection Systems (SPS), Remedial Action Scheme (RAS), or other documented regulatory and/or equipment limitations that the PC has communicated to the TP for the purpose of properly establishing LVRT criteria for study.

Steady-State Simulations

Steady-state simulations are typically performed such that normal automatic operation of system components occurs prior to the final solution convergence. For Contingency analysis, the converged steady-state conditions are presumed to be at equilibrium after the contingent element is taken out-of-service and automatic system operations have occurred. Thus, for the purpose of steady-state simulations, it is reasonable to assume that at least three seconds have occurred following the contingent event. This expired duration will be useful for interpreting the LVRT magnitude-time characteristic for generating units.

Key steady-state assumptions:

1. The ride-through voltage limitations provided by the "no trip zone" of PRC-024 Attachment 2 are more limiting than the generator steady-state voltage criteria unless otherwise noted. Actual limits for specific generators may be monitored if known.
2. For all generating units, within the study area, with LVRT capabilities that conform to the PRC-024 Attachment 2 voltage ride-through time duration curve, the static portion of the "no trip zone" for a duration greater than 3.0 seconds corresponds to a ride-through voltage criteria of 0.90 per unit.
3. Voltage limitations due to station service voltage requirements may be used as binding constraints, if known and more restrictive than the "no trip zone" of PRC-024 Attachment 2.
4. Protection system details are important to properly simulate undervoltage protection for generating units. If undervoltage protection relays monitor voltage at the high side of the GSU transformer, this bus should be monitored as part of the steady-state analysis. Conversely, if undervoltage protection relays monitor voltage at the generating unit terminal, the low side of the GSU transformer bus should be monitored as part of the steady-state analysis. In cases where the GSU is not explicitly modeled, the voltage at the bus to which the generator is connected is assumed to correspond to the voltage on the high side of the GSU, and should be monitored there.

Proposed methodology:

1. List all generator buses to be monitored by selecting all generation buses of within the study area.
2. Develop a list of bus numbers, representing the point of interconnection to the bulk electric system, for each of the generators to be monitored within the study area (based on units identified in Step 1).
3. Monitor voltages at all buses listed in Step 2, i.e. at generator points-of-interconnection.
4. Obtain a post-contingent steady-state load flow solution.
5. Determine all buses where monitored voltage is below 0.90 p.u., representing the voltage magnitude-time characteristic criteria for three seconds or greater. Use more limiting magnitude-time criteria (e.g. 0.92 p.u.), if such limits exist for the unique generating unit. (The purpose of this step is to determine locations that indicate a high likelihood where generating units may trip due to low voltage, if sustained longer than three seconds.) It is recommended that any generating unit connected to a monitored bus experiencing low-voltage be further researched to determine specific LVRT characteristics for use in simulation and screening.
6. Trip (i.e. remove from service) all generators failing to meet LVRT criteria from Step 5. It is important to note that in steady state analysis, it may be overly conservative to remove a generating unit from service based on the results from Step 5. However, without other evidence or definitive generating unit LVRT characteristics, removing generating units from service based upon the results from Step 5 is a reasonable simulation assumption.
7. Re-simulate the specific contingency for the case(s) that indicated that one (or more) generating units tripped and did not ride-through the voltage sag, using the same solution parameters.
8. Repeat Steps 4, 5, 6, and 7 until all monitored generator voltages are within allowed ranges.

Proposed text for the purpose of documenting study in Planning Assessment reports:

1. "Generator voltage limitations are assumed to be per static values of the voltage ride-through time duration curve in Appendix 2 of PRC-024, *[add, if necessary]* for all generating units except: *[list generators with more limiting trip settings according to Assumption #4; including limits]*."
2. "In *[case ID]*, the following generator(s) was tripped due to ride-through voltage limitations: *[list]*".

Stability Simulations

Stability simulations require small-time scale simulation of power system dynamic response given a fault condition and the subsequent post-fault recovery. Various commercial and in-house developed software solutions exist to assist in screening stability analysis simulation results, but visual inspection of the response curves remains common in the industry.

Key stability assumptions:

1. The ride-through voltage limitations provided by the “no trip zone” of PRC-024 Attachment 2 are more limiting than the generator steady-state voltage criteria unless otherwise noted. Actual limits for specific generators may be monitored if known.
2. Voltage magnitudes should be monitored throughout the simulation window. A simulation window of at least three to four seconds assures that a sufficient duration has been simulated to apply all voltage steps of the “no trip zone” defined in PRC-024 Attachment 2.
3. Voltage limitations due to station service voltage requirements may be binding constraints, if applicable and known. However, these limitations may not normally occur within the time frame of a stability simulation.
4. Protection system details are important to properly simulate undervoltage protection for generating units. If undervoltage protection relays monitor voltage at the high side of the GSU transformer, this bus should be monitored as part of the stability analysis. Conversely, if undervoltage protection relays monitor voltage at the generating unit terminal, the low side of the GSU transformer bus should be monitored as part of the stability analysis.

Proposed methodology:

1. Determine all generator voltage channels that will be monitored for low voltage magnitude-time conditions.
2. If using a software-based screening tool for determining violations of the LVRT magnitude-time characteristic criteria for generating units, ensure that the proper criteria are encoded. If using protection system set points within the stability simulation setup itself, ensure that the proper LVRT criteria per applicable generating unit are encoded.
3. Conduct stability simulation to obtain dynamic response results.
4. Make note of any generators that were automatically tripped by protection system models used in the simulation software. Additionally, take note of any renewable generating units, such as wind and solar units, that may have LVRT characteristics incorporated into their dynamic model used for simulation.

5. Depending on the screening tool used, determine which generating units are indicated by the simulation results to require tripping due to exceeding[5] the LVRT magnitude-time criteria. If visual inspection of output channels was used, it may be sufficient to compare the time-duration characteristic of PRC-04 Attachment 2 to the simulation output plots. To aid visual inspection, a time-duration template made of transparent material and properly scaled to overlay the stability simulation trace, may assist the rapid determination of a criteria violation.
6. For all generating units that did not pass LVRT magnitude-time criteria, establish trip conditions within the stability simulation setup to ensure that the unit will be removed from service after the appropriate duration determines from the previous simulation results.
7. Re-simulate the specific contingency for the stability case that indicated that one (or more) generating units tripped and did not ride-through the voltage sag.
8. Repeat Steps 4, 5, and 6 until all monitored generator voltages are within allowed ranges, or other study termination criteria, such as the detection of cascading, is reached.

Proposed text for the purpose of documenting study in Planning Assessment reports:

1. "Generator voltage limitations are assumed per the voltage ride-through time duration curve in Appendix 2 of PRC-024, *[add, if necessary]* for all generating units except: *[list generators with more limiting trip settings according to Assumption #4; including limits]*."
2. "In *[case ID]*, the following generator(s) was tripped due to ride-through voltage limitations: *[list]*".

[5] To be clear, exceeding in this context implies that the specific monitored voltage of interest was below LVRT criteria, i.e. too low for too long of a period of time.

Topic 5: Damping Criteria

Background

Requirement R4.1.3 related to the stability portion in TPL-001-4 'Transmission System Planning Performance Requirements':
For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

Damping Ratio

The purpose of establishing this guideline for the development of a minimum proposed damping criterion is to assure small signal stability of the Bulk Electric System (BES). System damping is characterized by the damping ratio, zeta (ζ). The damping ratio provides an indication of the length of time an oscillation will take to dampen.

Let $\lambda_i = \sigma_i \pm j\omega_i$ be the i-th eigenvalue of the state matrix A. The real part of the eigenvalue gives the exponential decay rate and the imaginary part gives the (damped) angular frequency of the oscillation for the i-th eigenvalue. The damping ratio is given by:

$$\zeta = \frac{-\sigma}{\sqrt{\sigma^2 + \omega^2}}$$

Assumptions

For power system dynamics, we are primarily concerned with power system modal frequencies between 0.1 Hz and 4 Hz. Therefore, after a disturbance, the purpose of a damping criterion is to ensure that the coupled oscillators (generating units) connected to the power system can return to a stable equilibrium within an acceptable time period. The damping ratio of the fundamental second-order differential equation that describes large power system behavior is useful in characterizing the post-disturbance response. When positive, this ratio (ζ) represents a key ratio of how much energy is reduced at the modal frequency and leads to an exponential envelope of successive damped sinusoidal peaks. Working backward, using T to denote a period of the oscillation, it can be shown that the logarithmic decrement (δ) of successive peaks (n) is:

$$\delta = \frac{1}{n}\ln\left[\frac{x(t)}{x(t+nT)}\right]$$

In terms of decrement:

$$\zeta = \frac{1}{\sqrt{1 + \left(\frac{2\pi}{\delta}\right)^2}}$$

Thus, for successive peaks (n=1),

$$\frac{x(t)}{x(t+T)} = e^{\frac{2\pi}{\sqrt{\frac{1}{\zeta^2}-1}}}$$

Although eigenvalue decomposition can be used to derive the spectral content affecting the second-order system damping ratio, it is uncommon in power system analysis industry practice. Alternatively, when evaluating the effect of damping on a system quantity, such as a voltage or rotor angle waveform, the practice of successive peak reduction is commonly used. In short, this involves evaluating the post-disturbance response and, whether numerically or visually, determine that each successive peak is satisfactorily smaller according to an established criterion. In tabular form, the damping ratio directly relates to the peak reduction for the modal sinusoid of interest. It is noted that, as this is an exponentially decaying function in the time domain, only the first peak reduction is given in Table 5-1 (i.e., the maximum reduction).

Table 5-1. First peak reductions for different damping ratios

Damping ratio	Successive peak is % lower than prior peak	Damping ratio	Successive peak is % lower than prior peak
1%	6.1%	11%	50.1%
2%	11.8%	12%	53.2%
3%	17.2%	13%	56.1%
4%	22.2%	14%	58.9%
5%	27.0%	15%	61.5%
6%	31.5%	16%	63.9%
7%	35.7%	17%	66.2%
8%	39.6%	18%	68.3%
9%	43.3%	19%	70.4%
10%	46.8%	20%	72.3%

The impulse response leading to oscillatory behavior of the natural frequency component, at a modal frequency of interest, can by expressed in the time domain as:

$$x(t) = Ae^{-\zeta\omega_0 t} sin\left(\left[\sqrt{1-\zeta^2}\right]\omega_0 t + \phi\right)$$

where ω_0 denotes the (natural) angular frequency and the phase component is assumed as zero.

Basis for Selection of Damping Criteria

Power system oscillations of interest in the Eastern Interconnection typically fall in the range of 0.4 - 1.0 Hz. Development of the below presented damping criterion is based on the frequency range of 0.4 - 1.0 Hz.

The two primary measures of damping for selection of a practical damping criterion are the settling time and the damping ratio. Here, the settling time is defined as the time required for an oscillation to be reduced to a specified (to be defined) percentage of the initial peak value. The damping ratio may be derived for each oscillation mode from the exponential decay associated with that mode. Settling time can for instance, be measured from a plot from a time domain simulation. To make this approach practical, the settling time would need to be interpolated from a time domain simulation of 20 or 30 seconds.

The settling time, damping ratio, and natural frequency of oscillation are interrelated. Establishing a damping criterion based on settling time ensures oscillations are damped in a fixed time, but requires greater damping for lower frequency oscillations. Establishing a damping criterion based on damping ratio requires the same damping for all oscillations, but allows longer settling times for lower frequency oscillations.

Correlation of time domain results to damping ratio from a 1995 New England study is provided in Table 5.2. Determination of adequate system damping in this study was based on engineering judgment. A number of oscillations were selected from the study. For each oscillation, the damping over four (4) periods of the oscillation was measured, a corresponding damping ratio was calculated, and a comparison was made to study commentary on the observed damping.

Table 5-2. Time Domain Results and Damping Ratios

Frequency	Damping (4 Periods)	Damping Ratio (ζ)	Study Comments
0.33 Hz	58%	0.035	positive damping
0.44 Hz	54%	0.031	stable
0.33 Hz	67%	0.044	stable
0.44 Hz	30%	0.014	unacceptable damping
0.44 Hz	58%	0.035	fair damping
0.44 Hz	56%	0.033	stable
0.44 Hz	39%	0.020	poor damping
0.44 Hz	50%	0.028	fair damping

From Table 5-2, it is possible to conclude that a damping ratio of 0.030 or greater provides acceptable damping, while a damping ratio of 0.015 or below is unacceptable. For a damping ratio of 0.030, all oscillations down to 0.4 Hz have a 1% settling time less than 1 minute; and oscillations down to 0.2 Hz have a 1% settling time less than 2 minutes.

An example of a damping criterion to ensure acceptable damping of power oscillations is hence to require a 1% settling time of one (1) minute or less for all oscillations with a frequency of 0.4 Hz or higher, which corresponds to a minimum damping ratio of 0.03 (or 3%). This corresponds to a 53% reduction in the amplitude of an oscillation over four (4) successive periods, since

$$f(t) = \frac{x(t_0) - x(t_1)}{x(t_0)} = 1 - e^{-\zeta\omega_0 t} = 53.0\%$$

where t_0 is the initial time, $t_1 = 4\,(2\pi)/\omega_0$ is the time corresponding to four (4) successive periods (both in seconds), ζ = 0.03 is the damping ratio, and $\Phi = 0$ is the phase angle (in radians).

The first peak reductions for different damping ratios in Table 5-1 , are calculated with $t = 2\pi/\omega_0$, where a damping ratio of 0.03 corresponds to a first peak reduction of 17.2%.

Regions with other oscillations of interest could develop the damping criterion using a similar approach as the one discussed above.

Study Methodologies

Frequency domain or time domain analysis may be utilized to determine acceptable system damping. Either of the following three methodologies can be used to determine if the damping criterion is met:

<u>Methodology 1:</u>
An eigenvalue analysis of the linearized state matrix in small signal stability studies can explicitly identify the damping ratio of all questionable modes (oscillations).

<u>Methodology 2:</u>

Time domain analysis may be utilized to determine system damping. The time domain analysis requires running a transient stability simulation for sufficient time such that only a single mode of oscillation remains. A reduction in the magnitude of the oscillation should then be observed over the last few periods of the oscillation, measuring from the point where only a single mode of oscillation remains in the simulation. To ensure that adequate system damping is observed, a sufficient number of system quantities including generator rotor angles, electric power, speed, voltages, and interface transfers should be analyzed. The phase angle reference should be carefully selected to avoid averaging and coherency of the oscillations.

<u>Methodology 3:</u>

The time domain response of system quantities such as generator rotor angles, electric power, speed, voltages, and interface transfers can be analyzed using Prony analysis, which estimates damping coefficients for a predetermined number of modes (oscillations). The phase angle reference should be carefully selected to avoid averaging and coherency of the oscillations.

Topic 6: Transient Voltage Criteria

See NATF Transient Voltage Criteria Reference Document as listed in the References Document section.

Reference Documents

Topic 1: Development of models for TPL-001-4 Studies

- ERAG MMWG Procedure Manual
- SPP MDWG Model Development Procedure Manual
- MISO MOD-032 Model Data Requirements and Reporting Procedures
- ERCOT Planning Guide
- WECC Data Preparation Manual
- Transmission Voltage Recovery Following a Fault Event in the Metro Atlanta Area, IEEE/Southern Company, 2000
- SS-38 Load Modeling White Paper, NPCC, 4/11/2013
- TPL-001-4 Dynamic Load Modeling, PJM Planning Committee, 5/7/2015

Topic 3: Cascading Criteria and Methodology

- NATF CIP-014 Requirement R1 Guideline

Topic 5: Damping Criteria

- ISO New England Planning Procedure PP3, Reliability Standards for the New England Area Bulk Power Supply System. -Appendix "C" Damping Criterion
- FRCC Stability Criteria for Transmission Planning Performance TPL-001-4
- WECC Criterion – TPL-001-WECC-CRT-3 - Transmission System Planning Performance Posting 5. October 27-December 30, 2015.
- Damping Criterion Basis Document, ISO New England, Approved by the Stability Task Force, April 1, 2009

Topic 6: Transient Voltage Criteria

- NATF Transient Voltage Criteria Reference Document