North American Transmission FORUM

Community Confidentiality Candor Commitment

NATF TPL-001-4 Reference Document

Version3.0 (Open)
Approval Date: 12/05/2018

Versioning

Version History

Date	Version	Notes
02/09/2016	2016-1	Original version
09/14/2016	2016-2	Open version
12/05/2018	3.0	Updates and revisions

Review and Update Requirements

- Review: every 5 years
- Update: as necessary

Contents

Introduction and Purpose

This NATF reference document is intended to provide guidance regarding the use of consistent, industry-wide approaches to certain topics in North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4.

DISCLAIMER: This document does not create, replace, change, or interpret any requirements in the NERC Reliability Standards or other applicable criteria, nor does it create binding norms by which compliance with NERC Reliability Standards is monitored or enforced. In addition, this reference document is not intended to take precedence over any company or regional procedure. It is recognized that individual companies may use alternative and/or more specific approaches that they deem more appropriate.

Format

To enhance the usability of the document and provide proper credit to NERC, language from NERC Reliability Standard TPL-001-4 is shown in grey highlights [1][1], while the NATF guidance, with references as appropriate, is shown without highlights.

For example:

Language from Standard

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]*

NATF Guidance

Requirement R1

Create modeling procedure documents that record compliance with the modeling requirements of MOD-032[2] and TPL-001-4. These could be created at the Transmission Planner or Planning Coordinator levels…

Text in the appendix is also NATF guidance, with references as appropriate.

[1] All language from TPL-001-4 shown in the grey highlights is quoted as-is from the standard. See "Standard TPL-001-4 — Transmission System Planning Performance Requirements" at https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United%20States

[2] Multiple references are made to NERC Reliability Standard MOD-032. See "MOD-032-1 — Data for Power System Modeling and Analysis" at https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United%20States

TPL-001-4 Requirement R1

Language from Standard

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

NATF Guidance

Requirement R1

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. An example of such a document is the "MISO MOD-032 Model Data Requirements and Reporting Procedures[3]."

Requirement R1.1. System Models

Requirement 1.1 of TPL-001-4 specifies a number of modeling requirements for the Transmission Planner/Planning Coordinator involving the topology of their transmission system models. 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-032 requirements 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)***

[3] See https://www.misoenergy.org/planning/system-modeling/mod-032-1/

It may be helpful to document the information source(s), criteria, and "cut-off" date used for each sub-part item.

Requirement R1.1.2 Modeling Known Outages

Include an explanation of the 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 and transmission 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. IRO-017 Outage Coordination[4] [1] R4 requires that each Planning Coordinator and Transmission Planner "shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.".

Requirement R1.1.5 Modeling Firm Transmission Service and Interchange

When building models to ensure generation resources are allocated to the appropriate Balancing Authority Areas (BAAs), 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 ensure the area's load will be served reliably. The omission of such firm transfers can create 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

[4] See "Standard IRO-017-1 — Outage Coordination" at https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United%20States

transmission service, and duration of energy contracts should be considered when performing interchange coordination, particularly in the out-year cases.

TPL-001-4 Requirement R2

Language from Standard

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:

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.

NATF Guidance

Requirement R2.1.4. Sensitivity Cases

Requirement R2.1.4 of TPL-001-4 requires the Transmission Planner/Planning Coordinator to vary the basic assumptions used in their transmission system models to analyze the impact on study results.

Developing Sensitivity Cases

Incorporate the building of sensitivity cases into annual model building processes 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 noted in section "TPL-001-4 Requirement R1" 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 and 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 the following:

1. Sensitivity assumptions should be coordinated with neighboring Transmission Planners when applicable.
2. Three sensitivity cases are required in the steady-state analysis, at least one for each of the following three base cases:
    a. System peak year one or year two
    b. System peak year five
    c. System off-peak for one of the first five years
3. Two sensitivity cases are required in the transient stability analysis, at least one for each of the following two base cases:
    a. System peak for one of the first five years
    b. System off-peak for one of the first five years
4. Corrective Action Plans do not need to be developed to meet the performance requirements of a single sensitivity case. Documentation as required under R2.7.2 should be provided in instances where the performance requirement of two or more sensitivity cases are not met for the same facility(ies).

Language from Standard

> **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.

NATF Guidance

Requirement R2.1.5. Spare Equipment Strategy

Requirement R2.1.5 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."

Review the Spare Equipment Strategy

The general approach to doing this is to create a list of all long-lead-time transmission equipment and review the spare equipment strategy around that equipment. Strategies for consideration may include, but are not limited to:

1. One-for-one (i.e., in-kind) 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 in which no TPL-001-4 system performance deficiencies are caused by temporary movement or transfer of the transmission equipment) until ordered replacements arrive
3. Available partnerships with neighboring Transmission Planners to cover each other for certain types of transmission equipment

Evaluate the Impact of Equipment Unavailability

Once a Transmission Planner reviews the strategy, the next step is to create a subset list of their Transmission equipment that due to lead time could have unavailability of one year or more. A suggested list of transmission equipment to evaluate for long lead time includes:

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

The Transmission Planner will need to run steady state 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 for all cases under R2.1.[5] The rationale should be documented. Case types/scenarios studied should be consistent with the conditions that the System is expected to experience during the possible unavailability of the long-lead-time equipment. A Corrective Action Plan will need to be developed for any issues identified.

[5] The pending TPL-001-5 standard will require this analysis also be performed for stability studies for all cases under R2.4.

Language from Standard

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.

NATF Guidance

In performing the short circuit analysis as called for in Requirement 2.3:

- The analysis should be performed looking far enough into the future in order to allow sufficient lead time to accomplish a breaker replacement.
- The analysis should be performed against a threshold value of something less than 100% of the breaker rating, (e.g., 95% or breaker rating) in order to provide lead time to accomplish a breaker replacement allowing for anticipated load growth.

Language from Standard

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.

NATF Guidance

Requirement R2.4.1. Load Models

Realistic power system models are essential for reliable grid planning and operations. The NERC TPL-001-4 Reliability Standard requires that Transmission Planners and Planning Coordinators use adequate load models in studies that support power system stability assessments.

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

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

Which Model Types Can Be Used to Satisfy TPL-001-4 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 fault-induced delayed voltage recovery (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-001-4 Requirements

Selecting an acceptable load model type can be a first step, but this is not enough to meet the new NERC TPL-001-4 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 their planning area. If a Transmission Planner has no previous experience in using dynamic load models, 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-001-4 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 publicly 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 "Transmission Voltage Recovery Following a Fault Event in the Metro Atlanta Area" [2] published by IEEE in 2000.

Language from Standard

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.

NATF Guidance

Requirement R2.4.3. Sensitivity Cases

Requirement R2.4.3 of TPL-001-4 requires Transmission Planners to vary the basic assumptions used in their transmission system models to analyze the impact on study results.

Developing Sensitivity Cases

Incorporate the building of sensitivity cases into annual model building processes 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 noted in section "TPL-001-4 Requirement R1" 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 and 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 the following:

1. Sensitivity assumptions should be coordinated with neighboring Transmission Planners when applicable.
2. Three sensitivity cases are required in the steady-state analysis, one for each of the following three base cases:
   a. System peak year one or year two
   b. System peak year five
   c. System off-peak for one of the first five year
3. Two sensitivity cases are required in the transient stability analysis, one for each of the following two base cases:
   a. System peak for one of the first five years
   b. System off-peak for one of the first five years

Language from Standard

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.

NATF Guidance

Requirement R2.6. Use of Past Studies in Annual Assessments

Guideline for Determining Use of Past Studies

If Planning Coordinators and/or Transmission Planners utilize past studies, then a technical rationale should be available. Possible rationale may be, but is not limited to, 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. 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 (e.g., changes in composite load model)
5. System topology changes (transmission, generation, distribution, etc.)

Language from Standard

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.

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.

NATF Guidance

For 2.7, System adjustments, which are applied between the initial contingency and the subsequent contingency for P3 and P6 events to achieve acceptable System performance, are not Corrective Action Plans (CAPs). These system adjustments should be evaluated by System Operations for feasibility and validity before being chosen. Any chosen System adjustments should be mentioned in the Planning Assessment and shared with System Operations.

For 2.7.1, a table or spreadsheet could be used to list each System deficiency that was found and the corresponding Corrective Action Plans intended to mitigate the deficiency. There will not always be a one-to-one correspondence, as one Corrective Action Plan may mitigate multiple deficiencies. It would be helpful to include which contingency event(s) is expected to cause each System deficiency.

Before any Operating Procedures are designated as a Corrective Action Plan, they should be evaluated by System Operations for feasibility and validity[6].

For 2.7.4, the review of continued validity and need for Corrective Action Plans, which were identified in the previous Planning Assessment, can be performed in different ways. One approach is to simulate the contingency events that resulted in System deficiencies in the previous Planning Assessment without the Corrective Action Plans that are planned for implementation. And then check whether the System performance is still deficient or the need date of the performance deficiency has changed.

Language from Standard

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.

NATF Guidance

If the Corrective Action Plan (e.g., breaker replacement, reactor installation, etc.) cannot be implemented in time, then an interim solution, such as temporary system reconfiguration and/or operating procedure, may need to be implemented until the permanent solution is in place.

[6] Operating Procedures that System Operations develops for the operating horizon may be different from those developed for the Planning Assessment due to various operating condition differences, such as economic generation dispatch and interchange

TPL-001-4 Requirement R3

Language from Standard

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]*

NATF Guidance

Requirement R3

Determine the years and seasons to be studied in accordance with R2.1 and R2.2 so that appropriate contingency files can be created for the simulations to be run. Changes to system topology, generation, relaying, tie-lines, etc. over time can create the need for files to be adjusted to the year/seasons to be studied. At some point, changes to the models must be prohibited to create a known starting condition for the years/seasons that are to be studied.

Language from Standard

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.

NATF Guidance

Requirement R3.3.1.1

See Appendix: Generating Unit Low-Voltage Ride-Through Capabilities and Simulations

Language from Standard

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

NATF Guidance

Requirement R3.3.1.2

When results indicate that loading on a Transmission element exceeds the normal or emergency rating, check whether the relay loadability limit of the Transmission element is also exceeded. If a Transmission element is loaded above the relay loadability limit, complete a subsequent simulation that includes the tripping of the

Transmission element as the protective relay (e.g., overcurrent) would have tripped the line because of the element's level of overloading. Repeat the process as necessary.

Language from Standard

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.

NATF Guidance

Requirement 3.4. and R 3.5. Development of Contingency Lists

If feasible, simulation of all P1-P7 planning events and extreme events should be considered by the Planning Coordinator and Transmission Planner. If not, a written 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. Subject-matter expert judgement (to be supplemented with data or analysis)
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)

The logic and basis for making changes to the contingency lists should be maintained in a written document for future reference and understanding.

Guideline for Contingency Coordination

The Planning Coordinator and Transmission Planner are responsible for coordination of Contingency lists with adjacent Planning Coordinators and Transmission Planners. These lists should include contingencies that may impact the adjacent Planning Coordinator and Transmission Planner Systems. The rationale for contingency selection should be documented by participating Planning Coordinators and Transmission Planners. Some, but not all, items for consideration are:

1. Development of processes and procedures to identify potential contingencies to share between adjacent Planning Coordinators/Transmission Planners
2. Frequency of contingency coordination to be agreed upon by each Planning Coordinator and Transmission Planner
3. Contingencies identified during system analysis and recommended by adjacent Planning Coordinators/Transmission Planners

Guideline for Evaluation of Extreme Events

The Planning Coordinator and Transmission Planner should develop 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 would occur.

Additionally, the Planning Coordinator and Transmission Planner could consider criteria for the following:

1. Loss of significant customer demand exceeding a defined MW threshold, as determined by the Planning Coordinator and Transmission Planner, 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 identified beyond the Planning Coordinator and Transmission Planner 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.

TPL-001-4 Requirement R4

Language from Standard

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.

NATF Guidance

Requirement 4.1.3 Acceptable Damping

Damping Ratio

The purpose of establishing this guideline for the development of a minimum proposed damping criterion is to ensure acceptable transient stability damping 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, determining 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 (i.e., the maximum reduction) is given in table C.

Table C. 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 damping criterion presented below is based on the frequency range of 0.4 - 1.0 Hz.

The two primary measures for selecting 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 D. 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 D. 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 D, 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 C, 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:

- **Methodology 1**

  An eigenvalue analysis of the linearized state matrix in small signal stability studies can explicitly identify the damping ratio of all questionable modes (oscillations).

- **Methodology 2**

  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 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.

- **Methodology 3**

  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.

Language from Standard

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.

NATF Guidance

Requirement R4.3.1.1

See Appendix: Generating Unit Low-Voltage Ride-Through Capabilities and Simulations

Language from Standard

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

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

4.3.2. 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.

NATF Guidance

Requirement R4.4. and R4.5. Development of Contingency Lists and Evaluation of Extreme Events

Guideline for Development of Contingency Lists for R4.4, and R4.5

If feasible, simulation of all P1-P7 planning events and extreme events should be considered by the Planning Coordinator and Transmission Planner. If not, a written 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. Subject-matter expert judgement (to be supplemented with data or analysis)
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)

The logic and basis for making changes to the contingency lists should be maintained in a written document for future reference.

Guideline for Evaluation of Extreme Events

The Planning Coordinator and Transmission Planner should develop 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 would occur. Additionally, the Planning Coordinator and Transmission Planner could consider criteria for the following:

1. Loss of significant customer demand exceeding a defined MW threshold as determined by the Planning Coordinator and Transmission Planner or impacting a certain area (e.g., densely populated urban area, military facility)
2. Loss of significant generating capacity
3. The inability of the model to reach a stable post-event solution
4. Impacts identified beyond the Planning Coordinator and Transmission Planner 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.

TPL-001-4 Requirement R5

Language from Standard

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]*

NATF Guidance

Requirement R5

Have one or more documents that contain the BES criteria for each of the three types of criteria cited in R5. The criteria may be within any combination of your planning criteria or regional planning criteria documents, such as ISO or Regional Entity documents. Consider reviewing your planning criteria document(s) annually and updating them as needed.

A. **System steady state voltage limits**

   Have one or more documents that identify your BES steady state voltage limits. The documents should include the high and low levels for “normal” (pre-contingency) conditions and for “emergency” (post-contingency) conditions for your applicable area. If you have exception voltage limits, make sure they are documented.

B. **Post-contingency voltage deviation criteria**

   Have one or more documents that identify BES post-contingency voltage deviation limits for your applicable area. The documents should include the general (default) voltage deviation limits. If you have exception deviation limits for specific system conditions or event categories, make sure they are documented.

C. **Transient voltage response criteria**

   Have one or more documents that identify your transient voltage response criteria. The documents should include at least one low-voltage level and maximum length of time. If you have more than one transient voltage response criterion, make sure they are documented. Consider adopting criteria that is recommended in the NATF Transient Voltage Criteria Reference Document.

TPL-001-4 Requirement R6

Language from Standard

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]*

NATF Guidance

Requirement R6

Have one or more documents that contain(s) the criteria or methodology to identify system instability for each of the three types of BES instability cited in R6, or any other conditions defined. The documents should include the definition and a description of each type of System instability[7]. The criteria and methodologies may be within any combination of your planning criteria and methodology or regional planning criteria and methodology documents, such as ISO or Regional Entity documents. Consider reviewing your planning criteria and methodology documents annually and updating as needed.

A. Cascading

a. Definition

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. [from the NERC Glossary of Terms] [3]

Note that cascading, with a lower case "c" is different from the definition of Cascading in the NERC Glossary of Terms. Consider the interpretation that cascading is the successive loss of system elements beyond those tripped by Protection systems or other automatic controls as a direct result of a TPL-001-4 contingency. The subsequent, successive system elements can include, but are not limited to, lines, transformers, generators, reactive resources, and loads. According to the NERC definition, cascading becomes Cascading when the cascading results in a specific type of widespread electric service interruption. Electric service interruption generally refers to the loss of load in MWs. The criteria for "widespread" can vary by Interconnection or regional area. Each Planning Coordinator and Transmission Planner should document its criteria for widespread for each of its areas. Each Planning Coordinator and Transmission Planner should document its understanding of what "cannot be restrained from sequentially spreading beyond an area predetermined by studies" means.

Also note that the word, Cascading, in header note "a" of Table 1 – Steady-State and Stability Performance Planning Events should be understood to be "Cascading" as defined in the NERC Glossary of Terms.

b. Suggested Description

[7] Each Transmission Planner and Planning Coordinator needs to develop separate definitions or Transmission Planner could choose to adopt its respective Planning Coordinator's definition.

The final criterion or 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-014-2 R1 Guideline" document.

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 the following:

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 the location and magnitude of loss of load as established by the Planning Coordinator or Transmission Planner.

   b. Consideration of the location and magnitude of loss of generation as established by the Planning Coordinator or Transmission Planner.

   c. Overloads over a predetermined threshold (e.g., 125% of seasonal emergency rating) occur a predetermined number of successive times (e.g., three successive times). Each successive time, the overloaded facilities are removed from service and the case resolved.

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

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

   f. Consideration of a number of transmission lines predicted to trip due to apparent impedance swings as established by the Planning Coordinator or Transmission Planner.

B. Voltage instability

a. Suggested Description

For steady state voltage stability, consider a definition based on P-V or Q-V criteria for a given BES bus and the power flow levels on its branches. Samples:

- Positive reactive power margin for P0-P1 events at a minimum of 105% of the transfer path.
- Positive reactive power margin for P2-P7 events at a minimum of 102.5% of the transfer path.

For transient voltage stability, consider the following:

- Recovery to a level of pre-contingency initial voltage with a given time for load buses serving load.
- Transient voltage drip below % voltage for a given timeframe.
- Voltage oscillation exhibits positive damping within given timeframe.

C. Uncontrolled islanding

a. Suggested Description

- Consider islanding by fault protection or automatic controls, such as UVLS, RAS, etc.
- Consider islanding by Transmission operating actions, such as tripping for loading a given percentage above the highest Facility emergency rating.

TPL-001-4 Requirement R7

Language from Standard

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]*

NATF Guidance

Requirement R7

Planning Coordinators are accountable for this requirement and are to use some method to collect Transmission Planner input for the determination and identification of each entity's individual and joint responsibilities.

- Maintain a written document of each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. Consider annually reviewing the document and update as needed.
- Have documentation that you determined and identified each entity's individual and joint responsibilities in conjunction with each of your Transmission Planners. Consider soliciting feedback from each of your Transmission Planners before finalizing any revision of the individual and joint responsibilities document. Store the solicitation document and all Transmission Planner responses that were received.

TPL-001-4 Requirement R8

Language from 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]*

NATF Guidance

Requirement R8

Each Planning Coordinator and Transmission Planner must distribute their own annual Planning Assessment to the applicable entities.

- Store the date that the Planning Assessment was completed.
- Maintain a list of applicable registered entities and the associated contact(s) that should be sent the Planning Assessment. Consider reviewing the list annually, before the Planning Assessment is distributed, and update as needed.
- Consider keeping the CEII information in a separate document from the main Planning Assessment. Label every page of the separate information as CEII. Distribute the main Planning Assessment without special security/confidentiality measures. Provide the CEII information through special/confidentially means to legitimate individuals/entities.
- Store the transmittal(s) and date the Planning Assessment was distributed to the applicable entities and which functional entities were sent the Planning Assessment.
- Store the written requests for Planning Assessment information from functional entities that have a valid reliability need for it.
- Consider keeping a log of written requests for the Planning Assessment from functional entities with a reliability-related need for it. Include at least the date of the written request and the date of the response. Consider also including the requestor and the individual that handled the response.

Language from Standard

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.

NATF Guidance

Requirement R8.1

- Store the documented comments on the Planning Assessment results, including the date and comment submitter.

- Store the written response to the comments, including the date and sender. Consider courtesy copying any applicable Planning Coordinators or Transmission Planners.
- Consider keeping a log of documented comments on the results of the Planning Assessment. Include at least the date that the documented comments were received and the date that the response was sent. Consider also including the requestor, the location/link where the requestor's documented comments are stored, the individual(s) that prepared the response, the manager(s) that approved the response, the location/link where the responder's documented comments are stored.
- Be careful not to include CEII in the response unless it is necessary. If CEII must be included in the response, label every page of the separate information as CEII and provide the CEII information through special/confidentially means to legitimate individuals/entities.

Appendix: 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[8]. 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"[9]:

> *"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. This appendix is intended to offer guidance specific to generating unit low-voltage ride-through considerations, in support of analysis required by TPL-001-4 Requirement R3 for steady-state simulation and TPL-001-4 Requirement 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 Transmission Planner may not have specific details regarding the voltage ride-through performance for generating units. Therefore, this appendix offers guidelines for the use of technical criteria drawn from PRC-024[10] and other informational sources, for proper simulation and screening of generating units during TPL-001-4 studies.

Purpose

The purpose of this appendix is to:

1. Discuss important considerations for simulating generating-unit LVRT.
2. Provide some key considerations when applying LVRT criteria for units within the Transmission Planner study area.

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[8] 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.

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

[10] Multiple references are made to NERC Reliability Standard PRC-024. See "Standard PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings" at https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United%20States

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.

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 Requirement R3 and stability simulation requirements given in TPL-001-4 Requirement R4. When performing Contingency analysis, guidance is given to the Transmission Planner 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 load limits are exceeded, shall be included in Contingency analysis. With regards to the topic of LVRT, the Transmission Planner shall consider the guidance specified in R3.3.1.1 and R4.3.1.2:

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 appendix is dedicated to addressing factors that the Transmission Planner should consider and methods of performing appropriate simulations.

Load Voltage Ride Through Key Considerations

The typical Transmission Planner may have multiple types and capacities of generating units within its 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 Transmission Planners should consider when preparing to perform simulations.

Generating Unit Load Voltage Ride Through

Voltage sag and its impact upon the reliability of the 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 ride through, 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 ride-through low-voltage limitations.

The Transmission Planner 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-024-2, the Transmission Planner 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-024-2.

The generating unit ride-through duration from attachment 2 of PRC-024-2, shown in Figure A, 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 attachment 2 of PRC-024 -2refer 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 A. 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 attachment 2 of PRC-024-2 illustrates the magnitude-time requirements for protective relay settings necessary to ensure generating units remain connected during voltage disturbances. The time-duration characteristic as shown in Figure B is based upon the parameters shown in Figure A. 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).

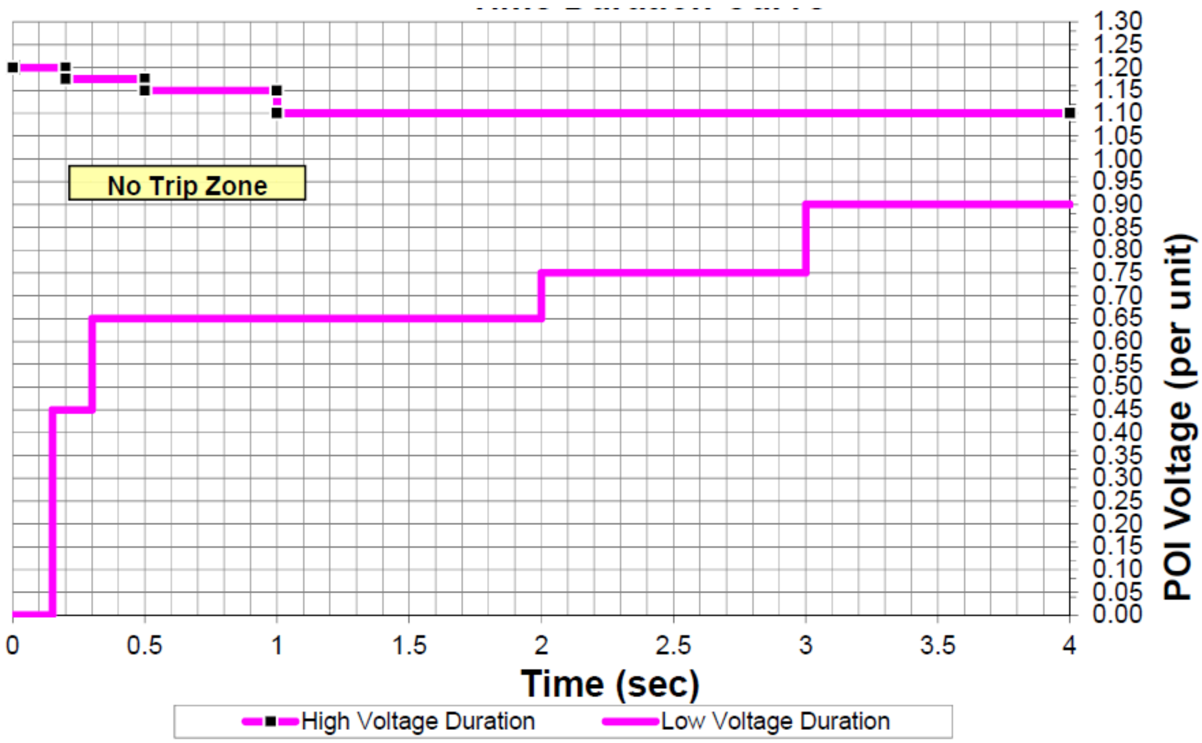

Figure B. Voltage Ride-Through Time Duration Curve, PRC-024 Attachment 2

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, etc. It is recommended that Transmission Planners scrutinize generating units within their study areas and identify sensitive auxiliary generating station loads that may require more-restrictive magnitude-duration constraints that 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 Transmission Planner to determine specific LVRT capabilities of renewable generating units or collector systems connected to the BES. 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 (e.g., 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, 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. 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 B, 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 in the study area with LVRT capabilities that conform to the PRC-024-2 attachment 2 voltage ride-through time duration curve (Figure B), this curve will form the basis of the minimum generator steady-state and ride-through voltage limitations for the study, per R3.3.1.1. The Transmission Planner should note the following as stated in the "Curve Details" section of PRC-024-2 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 Transmission Planner should use specific voltage ride-through time duration characteristics for any generating units within the study area that 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 employment of local generation plant auxiliary or support equipment.

3. The Transmission Planner should be aware that, in some cases, the generating unit owner may communicate certain protection system details to the Planning Coordinator directly. The Transmission Planner should coordinate any such information with the Planning Coordinator prior to initiating study.

4. The Transmission Planner should consider any Special Protection Systems (SPS), Remedial Action Scheme (RAS), or other documented regulatory and/or equipment limitations that the Planning Coordinator has communicated to the Transmission Planner 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 in 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 within the study area.

2. Develop a list of bus numbers, representing the point of interconnection to the BES, 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 attachment 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 ensures 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.

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 models 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[11] 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-024 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 is determined 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.

[11] 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).

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 attachment 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]*".