ENTERGY TRANSMISSION
LOCAL PLANNING GUIDELINES AND CRITERIA

The purpose of this document is to outline and define the transmission planning guidelines and criteria that are used in planning the Entergy Transmission System.

Revision Date: November 2024

Revision History

Revision Date	CHANGE DESCRIPTION
9/2021	• Minor change to voltage criteria • More detail on timing of projects • Other minor wording changes
8/2022	• Establishing a minimum inertia criterion • Adding a 2% margin when evaluating a breaker’s fault interrupting capability • Frequency Section addition to specify frequency should not vary more than .05 Hz. • Voltage criteria expanded for different types of contingencies. • Added Stability as part of the spare equipment evaluation (TPL-001-5) • Other minor changes to clarify or add more detailed explanation of the planning process
12/2022	• Long Term Planning System Intact Load Serving Capability Section added. • Asset Renewal Program section added to document that Entergy submits Asset Renewal Programs into the MISO MTEP • Voltage Criteria – wording to account for any exceptions to the voltage criteria • Updated links and procedures referred to in the criteria. • Cascading Criteria – further clarification of when and why the criteria is applied. • Minimum level of mitigation for a Corrective Action Plans (CAP) involving construction or modification of facilities
11/2023	• Added Commitment Guides to section 9 involving Operating guides. • Minor wording changes • Added Revision History
11/2024	• Removed secondary voltage dip criteria. • Revised the maximum acceptable load loss criteria to only account for non-consequential load loss for stability contingencies. • Clarified the steady state voltage stability limit determination criteria.

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1 PURPOSE

The purpose of this document is to define the local transmission planning guidelines and criteria that are used in planning the Entergy Operating Companies' transmission system.

2 REFERENCES

- NERC Reliability Standards (http://www.nerc.com/pa/Stand/Pages/default.aspx)
- SERC Standards http://www.serc1.org/program-areas/standards-regional-criteria/regional-criteria-and-guidelines
- NERC Glossary of Terms Used in NERC Reliability Standards (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)
- NERC BES Definition Reference Document (http://www.nerc.com/pa/RAPA/Pages/BES.aspx)
- MISO Transmission Planning Business Practices Manual BPM 020 (https://www.misoenergy.org/legal/business-practice-manuals/)

3 DOCUMENT REVIEW

This document will be reviewed annually by the Entergy Transmission Planning department. To the extent any modifications are determined appropriate, such modifications will be supplied to MISO in accordance with the MISO Tariff.

4 DEFINITIONS

Bulk Electric System (BES): In general, the BES is considered to include all Transmission Elements operated at 100 kV or higher and all real power and reactive power resources connected at 100 kV or higher. Transformers with a secondary connection less than 100 kV are generally considered as non-BES elements. However, it is recognized that parts of the transmission system operated at <100 kV could possibly impact the BES and may need to be included in the BES definition. Likewise, parts of the transmission system operated at >100 kV may also be excluded from the BES definition. The potential inclusion or exclusion of parts of the transmission system from the BES definition will be determined by the recommended process outlined in the NERC "Glossary of Terms Used in NERC Reliability Standards".

Non-Bulk Electric System (BES) Facilities: Entergy's 69kV and higher facilities which do not meet the definition of the BES as defined by the NERC BES Definitions

Combined Cycle Power Plant Module: A combined cycle generating facility (or unit) is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine (ST) to generate additional electricity.

Corrective Action Plan: A description of actions to be taken to correct a system deficiency identified through reliability planning studies. This description normally contains a brief description of the plan, schedule for completing those actions, steps to prevent reoccurrence (if necessary), and the effect on reliability of the bulk electric system.

Operating Guide: An action or set of actions developed to address real-time or anticipated system operating constraints. Operating guides can be manual or automatic.

System Reconfiguration: A change in the transmission system topology due to transmission operator action or pre-planned automatic switching.

Critical Clearing Time (CCT): CCT is a measure of generating unit stability. It is the maximum fault time in cycles or seconds that a generating unit can withstand a three phase or a single-phase fault condition before losing synchronism. The larger the CCT, the more stable the unit is considered to be.

Large-disturbance rotor angle stability or transient stability: Ability of the power system to maintain synchronism when subjected to a severe disturbance, such as a short circuit on a transmission line.

Local Planning Criteria: Shall mean the transmission planning criteria described in this document and generally referred to as the “local reliability criteria”.

Transmission Planning: Entergy Services Transmission Planning group.

CMLD / CLOD Load Models: CMLD (WECC Composite Load Model) and CLOD (Complex Load Model) are used in transient angular and voltage stability studies. These composite load models represent both static and dynamic load components, including machine inertial and dynamics. At a given bus, the real and reactive power load can be divided into large motors, small motors, three-phase motors, single-phase motors, and constant MVA loads.

5 RESPONSIBILITIES

The development of the Local Planning Criteria is the responsibility of Transmission Planning.

6 INTRODUCTION

The Local Planning Criteria are used in performing planning studies (load flow, short circuit, and stability) for the Entergy transmission system. The Local Planning Criteria are used to measure the system's security and adequacy and are based on the NERC Reliability Standards, the SERC standards, and any required criteria set forth in the applicable MISO Transmission Planning Business Practices Manual while also reflecting the specific characteristics of the portions of the interconnected transmission system owned by the Entergy Operating Companies.

7 ASSESSMENT OF TRANSMISSION SYSTEM PERFORMANCE

The Local Planning Criteria cite certain NERC Reliability Standards, namely TPL-001-5. Other NERC Reliability Standards may result in additional mitigation plans, operating guides, system reconfigurations or transmission projects being identified.

7.1 Reliability Assessment

The reliability assessment is performed in accordance with NERC Reliability Standards and associated guidance from MISO and SERC to understand and to document the performance of the transmission system under various potential scenarios. The assessment includes the simulation of system performance during and after a wide array of single and multiple contingency events.

Planning studies are to be carried out for projected annual system peak load conditions, but the evaluations should also consider load levels such as off peak and other sensitivities as needed or required.

7.2 Voltage and Transmission Thermal Loading

The Entergy system shall be designed such that foreseeable normal configurations and applicable contingency conditions meet the stated voltage criteria and thermal limitations of the transmission system.

7.3 **Voltage Criteria**

Voltage level	System Normal (No contingency) [3]		Planning Events in Effect[3]		P6 Planning Events in Effect[3]	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu	Vmin (pu)	Vmax (pu)
≥ 300 kV	0.975	1.05[1]	0.95[2]	1.05 [1]	0.90[2]	1.05 [1]
>100 kV and < 300 kV	0.95	1.05	0.92	1.05	0.90	1.05
Other BES facilities, Radially operated facilities, and facilities operated at >60kV and <100 kV	0.95	1.05	0.90	1.05	0.90	1.05
Nuclear plant off-site buses	within the parameters established for each plant					
Note 1: In some parts of the Entergy EHV system, voltages up to 1.075 p.u. are considered acceptable if the area is influenced by the voltage criteria requirements of neighboring transmission systems Note 2: Stations greater than 300 kV that solely consist of a radial line terminating through an autotransformer into facilities less than 300 kV adhere to the voltage criteria of the lower voltage facilities. Note 3: Voltage limits at specific buses may vary from these values based on specific transmission customer or Entergy equipment considerations. Exceptions to this voltage criteria are documented in the Model Data Repository.						

Switching of capacitor banks or reactors and/or automatic adjustments of transformer taps may be used to ensure that acceptable voltage limits are achieved. It should be assumed that all generating plants maintain their specified voltage or reactive power schedules in accordance with NERC Reliability Standard VAR-002.

The established steady state voltage criteria is well above known generator voltage ride through limitations. Corrective Action Plans are in place for all Single Contingency and Multiple Contingency events that violate the steady state voltage criteria.

7.4 **Special Voltage Requirements for Nuclear Plants**

In addition to the above-mentioned general voltage criteria, nuclear plant buses (providing offsite power to the nuclear plants) are monitored to their respective Nuclear Plant Interface Requirements (NPIR) as stated in the NERC Standard NUC-001. The special voltage requirement for each individual Nuclear Plant is detailed in the nuclear procedure ENS-DC-199 or respective Nuclear Plant Operating Agreement (NPOA). As described in the nuclear procedure ENS-DC-199, Transmission Planning shall perform a NPIR analysis as a part of the reliability assessment. If the system performance does not meet the requirements of NPIRs, necessary Corrective Action Plan/s shall be developed.

7.5 **Basis for Facility Ratings**

Transmission Planning Models contain Entergy Facility Ratings based on Reliability Management Manual Facility Ratings (RMM-PR-014). 125% thermal loading threshold will be utilized to indicate an automatic trip of transmission facilities by the protection system.

7.6 Transmission Thermal Loading Criteria

Transmission facility thermal ratings establish the maximum amount of electrical current that a transmission circuit can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements due to thermal expansion. The system shall be planned such that all applicable facility ratings will not be exceeded. The limiting element of each transmission circuit or segment shall be the element with the lowest thermal rating.

7.7 Spare Equipment Evaluation

Entergy completes a spare equipment evaluation annually to evaluate the impact of the loss of major Transmission equipment on the BES that has a lead time of one year or more (such as a transformer) to the transmission system. A list of BES equipment that has a lead time of one year or more is identified by Entergy to begin this analysis. If there is no spare equipment available to replace the long lead time equipment, then the equipment will be modeled out of service. The power flow models utilized shall include

- System peak Load for either Year One or year two, and for year five.
- System Off-Peak Load for one of the five years.

After the power flow models have been updated, an analysis is performed simulating P0, P1, and P2 planning events (described in sections 8.1 and 8.2). The results are reviewed for thermal, voltage, and stability violations. If a violation occurs due to the use of a de-rated spare piece of equipment a second P0, P1, and P2 analysis is run with that spare equipment out of service. If this analysis reveals a violation, then a Corrective Action Plan, which may include an operating guide or additional sparing, is developed and communicated to Entergy's operations personnel and MISO which serves as Entergy's Planning Coordinator.

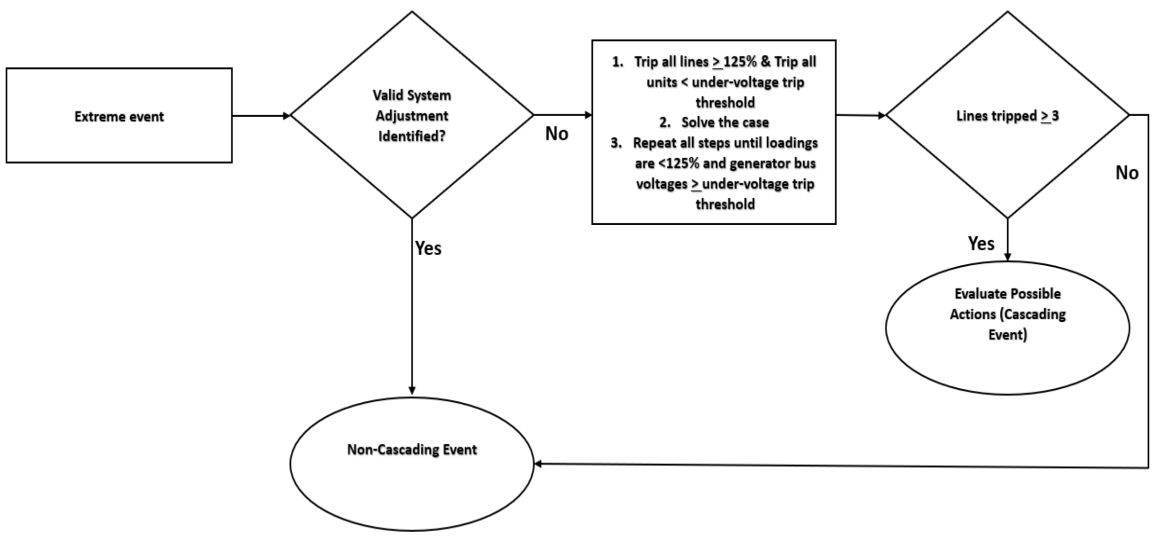
7.8 **Cascading Outage Test Methodology**

For P0-P7 events, if a contingency event meets the requirements to be considered a cascading event, it also violates the facility ratings and/or voltage criteria for those facilities and will already require a Corrective Action Plan. Due to this need to develop a Corrective Action Plan to address the initial violation, it is not necessary to apply the cascading test methodology to a P0-P7 event.

For Extreme events, Entergy applies the cascading test methodology defined below to determine if any event results in a cascade and evaluates potential actions to reduce the likelihood or mitigate the consequences of the event.

As a baseline for the assessment, Entergy assumes that all lines will trip at 125% of their normal rating, and all units have an under-voltage trip threshold of 0.9 per unit. These thresholds are placeholders based on the minimum performance criteria of the equipment. If a cascade is shown to occur due to an extreme event, the placeholder values can be verified against the actual equipment and the cascade re-evaluated manually at the verified thresholds.

In some instances, multiple elements in series may exceed 125% and tripping one of the elements results in the remaining elements to be within their applicable facility rating. In these instances, the result is considered as a single tripping event.



7.9 Load Serving and Import Capability – Long Term System Intact

Maintaining sufficient load serving capability margin is critical to operating a reliable transmission system while facilities are offline. With the rapidly changing generation resource portfolio and load diversity, there has become an evident need to closely monitor and maintain a minimum load serving capability margin for certain regions of the Entergy transmission system in the Long-Term Planning Horizon during the TPL-001 assessment. When an area is deemed to not maintain the load serving/import capability required for the area, a Corrective Action Plan shall be proposed and submitted to the MISO MTEP. Corrective Action Plans shall be planned to be in service in time to alleviate any violations of the load-serving criteria for that area.

7.10 Asset Renewal Programs

Entergy has a program that focuses on addressing existing aged and/or degraded transmission line and transmission substation assets. As part of the program, there is a continuous review of asset health to prioritize those replacements and develop a plan of action. The renewal programs are reported to MISO at an annual budgetary level. Any deviations to the program budget will be communicated to MISO and stakeholders through the formalized MTEP Quarterly Update process.

8 PLANNING EVENTS

The following table is a summary of which transmission system events, at a minimum, shall be considered in the reliability assessment of the transmission system. All BES and select Non-BES facilities shall be monitored. Each event is described in more detail in subsequent sections.

TPL Event Category	BES[1]	Non-BES[2]
P0	Yes	Yes
P1	Yes (All)	Yes (All)
P2	Yes (All)	P2.1 only required
P3	Yes (All)	Not required
P4	Yes (All)	Not required
P5	Yes (All)	Not required
P6	Yes (All)	Not required
P7	Yes (All)	Not required

1. Transmission system events on the BES are considered per the requirements of the NERC Reliability Standard TPL-001-5.
2. Transmission system events on the non-BES are considered as a good practice to maintain reliability on the non-BES.

Note: In the case of a combined cycle power plant module, the total module output will be considered as a "generator" in the Planning Event assessment. An exception will be where the generator owner has communicated to Transmission Planning that independent operation of the individual generating units of the module is possible. In this case, the assessment will reflect the appropriate outage state of the generating unit(s).

8.1 Category P0 Evaluation: No Contingencies (All Facilities in Service)

Per the requirements of the NERC Reliability Standard TPL-001-5 and under normal conditions (Category P0) with all facilities in service.

- All equipment and/or facility loadings shall be within its applicable facility rating as discussed in section 7.5 of this document.
- All transmission bus voltages shall remain within criteria as specified in section 7.3 of this document.
- There shall be no loss of demand, curtailed firm transfers, or cascading outages.

To the extent thermal or voltage limits are exceeded, transmission upgrade projects, temporary operating guides, and/or system reconfigurations must be identified to address such limitations.

8.2 Category P1 or P2 Evaluation: Single Contingency

P1 contingencies include the loss of a single transmission system element with normal operation of the protection system. Transmission line, transformer, and shunt device contingencies disconnect all equipment that would normally be isolated by breakers or fault interrupting switches in event of a fault. Generator contingencies disconnect the generator device and other generator devices that would trip concurrently with that device, such as a train in a CCGT plant.

P2 contingencies include abnormal operation of the protection system and faults within substations. A breaker opening without a fault opens the attached line section. A bus section fault in a breaker station disconnects all equipment attached to that bus section up to the isolating breakers. A bus section fault at a station without breakers is included in the P1 branch outage contingency. An internal breaker fault creates a System fault which must be cleared by protection on both sides of the breaker.

Following such an event:

- Any equipment and/or facility shall be loaded within its applicable facility rating, as discussed in section 7.5 of this document.
- All Substation bus voltage levels shall remain within criteria as specified in section 7.3 of this document.
- Stability (angular and voltage) of the network shall be maintained consistent with the criteria defined in section 11 of this document.
- Cascading outages shall not occur.

To address overloads, under voltages, or any other system deficiencies resulting from the Category P1 & P2 evaluation, Entergy may employ various solutions including but not limited to the following: temporary operating guides, upgrades of existing facilities, installation of new facilities, and/or system reconfigurations.

8.3 Category P3 Evaluation: Multiple Contingency

Category P3 contingencies combine a P1 generator contingency event with system adjustments such as redispatch and reconfiguration of the transmission system, followed by a second P1 contingency event. Following such an event:

- Any equipment and/or facility shall be loaded within its applicable facility rating as discussed in section 7.5 of this document.
- All Substation bus voltage levels shall remain within criteria as specified in section 7.3 of this document.

- To maintain the overall reliability of the interconnected transmission systems, a system adjustment such as a generation re-dispatch is allowed for units as specified in section 9.2.
- Stability (angular and voltage) of the network shall be maintained consistent with the criteria defined in section 11 of this document.
- Cascading outages shall not occur.

If system adjustments as permitted in section 9 are not sufficient to address overloads, voltage violations, or any other system deficiencies resulting from the Category P3 evaluation, Entergy may employ various solutions including but not limited to the following: temporary operating guides, upgrades of existing facilities, installation of new facilities, and/or system reconfigurations.

8.4 Category P4 or P5 Evaluation: Multiple Contingency

Category P4 events in steady-state are equivalent to category P2 internal breaker fault contingencies, and are studied the same way.

Category P5 events include the loss of all facilities that would eventually trip through action of functioning relays surrounding the failed relay.

Following such an event:

- Any equipment and/or facility shall be loaded within its applicable facility rating as discussed in section 7.5 of this document.
- All Substation bus voltage levels shall remain within criteria as specified in section 7.3 of this document.
- Stability (angular and voltage) of the network shall be maintained consistent with the criteria defined in section 11 of this document.
- Cascading outages shall not occur.

To address overloads, under voltages, or any other system deficiencies resulting from the Category P4 or P5 evaluation, Entergy may employ various solutions including but not limited to the following: temporary operating guides, upgrades of existing facilities, installation of new facilities, and/or system reconfigurations.

8.5 Category P6 Evaluation: Multiple Contingency

Category P6 contingencies combine a P1 non-generator contingency event with system adjustments, followed by a second P1 contingency event. Following such an event:

- Any equipment and/or facility shall be loaded within its applicable facility rating as discussed in section 7.5 of this document.

- All Substation bus voltage levels shall remain within criteria as specified in section 7.3 of this document.
- To maintain the overall reliability of the interconnected transmission systems, a system adjustment such as reconfiguration of the transmission system, generation re-dispatch, and/or non-consequential load loss (NCLL) is allowed as specified in section 9.
- Stability (angular and voltage) of the network shall be maintained consistent with the criteria defined in section 11 of this document.
- Cascading outages shall not occur.

If system adjustments and/or non-consequential load loss as permitted in section 9 are not sufficient to address overloads, under voltages, or any other system deficiencies resulting from the Category P6 evaluation, Entergy may employ various solutions including but not limited to the following: temporary operating guides, upgrades of existing facilities, installation of new facilities, and/or system reconfigurations.

8.6 Category P7 Evaluation: Multiple Contingency

Category P7 contingencies consist of the combination of two P1 line contingencies that represent adjacent circuits on a common structure for more than one mile.

Following such an event:

- Any equipment and/or facility shall be loaded within its applicable facility rating, as discussed in section 7.5 of this document.
- All Substation bus voltage levels shall remain within criteria as specified in section 7.3 of this document.
- Stability (angular and voltage) of the network shall be maintained consistent with the criteria defined in section 11 of this document.
- Cascading outages shall not occur.

To address overloads, under voltages, or any other system deficiencies resulting from the Category P7 evaluation, Entergy may employ various solutions including but not limited to the following: temporary operating guides, upgrades of existing facilities, installation of new facilities, and/or system reconfigurations.

8.7 Extreme Contingency Evaluation: Multiple Contingency

Entergy will evaluate extreme event conditions as required in NERC TPL-001-5. Extreme events studied include but are not limited to:

- Two P1 contingencies occurring without the opportunity to perform system adjustments.

- Loss of a tower line with three or more circuits for more than one mile, using the combination of the P1 contingencies for each circuit.
- Loss of all transmission lines on a common right of way for more than one mile, using the combination of the P1 contingencies for each line.
- Loss of an entire voltage level at a substation, including connected transformers.
- Loss of all generating units at a generating station, using the combination of the P1 contingencies for each unit at the station.
- Loss of two generating stations.
- Loss of multiple generators due to the loss of a large gas pipeline

If the analysis concludes there is a Cascading Event 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 and documented in the annual assessment report.

9 CORRECTIVE ACTION PLANS & MITIGATIONS ALLOWED BY NERC TPL-001-5

In the day-to-day operation of the transmission system, the use of operating guides, commitment guides, system reconfigurations, and Corrective Action Plans are developed and implemented on an as needed basis to manage the transmission system during both normal operations and special circumstances such as planned generator or line outages. These mitigation actions may be utilized on the Entergy transmission system to relieve real time or post-contingent loading on a transmission facility, to honor a previously identified stability limitation, or to mitigate a real time or post-contingent high voltage or low voltage violation. MISO, as the Reliability Coordinator for the transmission systems of the Entergy Operating Companies, may employ a particular operating guide, commitment guide, system reconfiguration, or other mitigation action. Mitigating actions may include, but are not limited to, the following:

- Re-dispatch of all Market Participants on the MISO system

- Limit pre-contingency flow on designated critical transmission facilities

- Reconfigure the transmission system for pre-contingent or post-contingent conditions

Entergy may also choose to employ Corrective Action Plans such as the use of series reactors, under voltage load shedding programs, under frequency load shedding programs, and other technology solutions to address constraints identified through its reliability analyses.

Long term planning operating guides, including the use of emergency ratings, may be developed and documented as an interim mitigation method. Long term planning operating guides may be used to help facilitate the timing of a permanent corrective action that is planned. Operating guides must be communicated to transmission operations for inclusion into the near-term planning processes.

Commitment guides developed and maintained by MISO for day-to-day unit commitment are not relied upon in Entergy's Long-Term Planning compliance cases. The use of commitment guides is an operational tool, similar to an operating guide, and as such can be used as an interim mitigation to help facilitate a permanent Corrective Action Plan.

When determining a Corrective Action Plan that involves the construction of new facilities or modification of existing facilities for a thermal constraint, the highest loading during the planning horizon on the constraint being addressed shall be no more than 95% of the applicable facility rating. Where prudent, Corrective Action Plans should be designed such that loading on the constraints being addressed is below 80% of the applicable facility rating.

9.1 System Reconfigurations

System reconfigurations are available as an acceptable Corrective Action Plan for identified transmission constraints. Establishment of permanent system reconfigurations (such as normally open points) are developed and communicated by long-term transmission planning.

For P6 planning events, if a system adjustment involves a system reconfiguration, a further test will be performed to validate the reconfiguration scenario and ensure that the new reconfiguration will not create other violations to this criterion. The following steps are to be performed:

- For each N-1, the N-1 should be removed from the case which contains the full set of system adjustments implemented.
- An additional P1 contingency analysis shall be performed on each N-1 case with system adjustments implemented.
  - All resulting branch loadings should be $\leq$125%.
  - Voltages should be within voltage limits detailed in section 7.3 above.
  - For thermal issues under 125%, utilize any other mitigation measures permitted by the NERC TPL-001-5 standard, including Non-Consequential Load Loss, to return facilities to their normal rating.

9.2 Generation re-dispatch

All MISO Market Participating units are available for system re-dispatch for events in which the NERC Reliability Standard TPL-001-5 allows for System adjustments.

- Unit dispatch may be both increased and decreased; however, the change to system dispatch must remain a net zero in order to maintain Area Interchange Control.
- Units located in MISO South may only be committed and dispatched up to the currently listed MISO NRIS + ERIS amount.
- Units may only be re-dispatched down to their modeled PMIN value before being turned “Off”.
- Where limited options for re-dispatch exist, sensitivities associated with the availability of those units shall be considered.
- Generation dispatched by capacity factors, such as solar and wind units, shall not be re-dispatched above their base case output assumptions.
- Battery installations shall not be re-dispatched above their base case output assumptions, unless it is part of the design of the battery facility.

For P3 planning events in which re-dispatch is utilized as part of a system adjustment, after a valid system adjustment, the post-contingent loading of the constrained element(s) should meet the following criteria:

- Flow on the constrained elements reduced to <95% of applicable facility ratings
- Constrained substation voltages should be resolved to:
    - >0.96 p.u. for BES facilities ≥ 300 kV
    - >0.93 p.u. for BES facilities >100 kV and < 300 kV
    - >0.90 for radially operated facilities and non-BES facilities

Additionally, once a potential re-dispatch is found to alleviate the original planning event, a further test will be performed to validate the re-dispatch scenario and ensure that the new dispatch profile will not create other violations to this criterion. The following steps are to be performed:

- The contingent BES transmission element shall be placed back into service.
- An additional P1 contingency analysis shall be performed (with the original “outaged” generating unit(s) and the re-dispatch scenario in effect).
    - All resulting branch loadings should be <95% (unless previously identified to be between 95% and 100% due to another planning event).
    - All resulting Substation voltages should be resolved to >0.96 p.u. for BES facilities ≥ 300 kV, >0.93 p.u. for BES facilities >100 kV and < 300 kV and >0.90 for radially operated facilities and non-BES facilities.

For P6 planning events in which re-dispatch is utilized as a part of a system adjustment, after a valid system adjustment, the post-contingent loading of the constrained element(s) should be reduced to <125% of its applicable continuous facility rating and all Substation voltages should be resolved to applicable limits from the voltage criteria table above in section 7.3.

After a set of adjustments, which are assumed to be implemented after the first N-1 event, is shown to reduce loading to under 125%, NCLL may be used as a mitigation after the second N-1 event if any line should remain loaded over 100%.

9.3 Non-consequential Load Loss

Some NERC TPL Planning Events allow non-consequential load loss to occur:

- If the amount of non-consequential load loss is calculated to be greater than 300 MW (DOE reportable load loss), documentation and continued monitoring of the event and development of a Corrective Action Plan beyond non-consequential load loss is encouraged to mitigate transmission system impact.

- If the calculated non-consequential load loss is greater than 1000 MW (IROL trigger), a Corrective Action Plan is required and will be submitted as part of the near term or long term transmission plan as applicable.

9.4 Corrective Action Plan Timing

Corrective action plans for steady state analyses are typically proposed to address the voltage criteria requirements of Sections 7.3 and 7.4 and/or the transmission thermal loading criteria of Section 7.5 based on the year and season identified in the annual reliability analysis. If the Corrective Action Plan involves a physical transmission project (new line, re-conductor, capacitor banks, etc…) the project's initial recommended in-service date is based on the actual year of the violation. The compliance need by date may vary from the recommended in-service date based on the required compliance cases built during the assessment year.

Corrective Action Plans that have been approved or are pending approval in the MISO Transmission Expansion Process (MTEP) are included in the base case modeling assumptions consistent with the year and season the need was identified or the updated construction feasibility date. All other Corrective Action Plans are not included in the base case assumptions and the system need is re-evaluated in the current assessment.

In some instances, subsequent annual reliability analysis or ad hoc reliability analysis may indicate that the voltage or thermal criteria may not be violated as initially identified in the previous assessment. If the subsequent assessment indicates that over the ten-year planning horizon the thermal loading of the project driver remains at 95% or greater of its applicable facility rating, the project should continue to be targeted to meet the original project in-service date or any updated construction feasibility date. Likewise, for voltage criteria driven projects, if subsequent annual reliability analyses indicate that voltages do not improve to greater than 0.97 p.u. for P0 planning events, or for P1 to P7 planning events to greater than 0.94 p.u. (BES) or 0.92 p.u. (Non-BES) over the ten-year planning horizon, the project should continue to be targeted to meet the original project in-service date or any updated construction feasibility date.

9.5 Shunt Device Sizing

The recommended size and/or number of capacitor or reactor banks used as a solution to address voltage issues shall be such that the pre-contingent switching of the individual shunt devices will limit the steady state voltage change to no greater than a ±0.03 p.u. voltage change during each switching operation. Additionally, for capacitor or reactor banks utilized as part of a Corrective Action Plan, the banks must be developed such that the final steady-state corrected voltage equals or exceeds the voltage threshold driving the need for the Corrective Action Plan by 0.03 per unit.

9.6 Common Transmission Structures

In order to maintain operational flexibility, the double circuiting of transmission lines (multiple circuits on common structures) should be avoided if double circuiting results in the need for unsafe work practices or where a simultaneous planned outage of both facilities is not practical. Additionally, the double circuiting of transmission lines as part of a Corrective Action Plan should avoid placing the mitigating transmission line on the same structure as the contingent transmission line over a significant distance. Double circuiting of transmission circuits more than one mile in length must be reviewed by long term transmission planning for potential reliability impacts.

10 SYSTEM STABILITY EVALUATION

For evaluating potential instability issues within the Entergy System, different types of stability studies are routinely performed. These studies can be broadly classified into three categories:

- **Transient Stability Studies**: These are time domain simulations performed to identify first swing stability limits on generating units or plants.
- **Small Signal Stability Studies**: These studies are associated with identifying power system oscillation problems on the system and establishing angular stability limits on transmission lines.
- **Voltage Stability Studies**: These studies are performed to identify voltage stability problems in the system and define the power transfer limits as well as maximum load serving capability in a given area.

Transient Stability Studies: Stability simulations are performed to examine the dynamic behavior of the generators and their effect on the Bulk Electric System. Fault events defined in Categories P1 through P7 of the NERC Reliability Standards TPL-001-4/5 are considered in transient stability studies. Transient stability studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 of TPL-001-4/5. The system shall be stable for three-phase and single-line-to-ground faults that are normally cleared. The system shall also remain stable for all three-phase and single-line-to-ground faults that are cleared following a stuck breaker condition. If there is any instability associated with three-phase stuck breaker faults, the area of instability should remain confined to a generating plant or units within the plant without jeopardizing the integrity of the Bulk Electric System or leading to cascading, voltage instability, or uncontrolled islanding.

The stability analysis is normally performed using one or more commercial software programs. The dynamics programs only simulate the positive sequence network. However, unbalanced faults involve the positive, negative, and zero sequence networks. For unbalanced faults, the equivalent fault admittance must be inserted in the positive sequence model between the faulted bus and ground to simulate the effect of the negative and zero sequence networks. Since the programs inherently model the positive sequence fault impedance, the sum of the negative and zero sequence Thevenin impedances needs to be added and entered as the fault impedance at the faulted bus. The value of negative and zero sequence Thevenin impedance is typically obtained from short circuit programs. Representation of load is very important in transient stability studies. Composite load models will be used for stability studies.

While performing transient stability studies, the system is monitored for generator instability, voltage recovery, and damping of the oscillations. The criteria used in transient stability studies for analyzing problems is shown in section 11.A.

Modeling of breaker failure in transient stability studies: A breaker failure/stuck breaker scenario following a three-phase or single-phase fault shall be simulated using the following sequence of events:

A. *Three-Phase Stuck Breaker Fault*

   Depending upon whether the primary breaker is an Independent Pole Operated (IPO) or non-IPO breaker, one of the following two types of breaker failure scenarios is evaluated.

   a. Three-phase-to-ground stuck breaker faults (for non-IPO breakers):

      Following the simulation of the three-phase fault, the faulted line is tripped at the far end from the fault by the remote breaker opening in normal clearing time. The three-phase fault remains in place for the duration of delayed clearing of the backup breakers. When the fault is cleared, all of the facilities impacted by the backup breaker clearing are taken out of service.

b. Three-phase-to-ground stuck breaker faults (for IPO breakers configured to trip a single pole):

   Following the simulation of the three-phase fault, the faulted line is tripped at the far end from the fault by the remote breaker opening in normal clearing time. The three phase fault is converted to a single-line-to-ground fault after the normal clearing time to reflect the operation of an IPO breaker. The single-line-to-ground fault remains in place for the duration of the backup breaker clearing time. The fault is then cleared and all of the facilities impacted by the backup breaker are taken out of service.

B. *Single Phase Stuck Breaker Fault*

   Following the simulation of the single-phase fault, the faulted line is tripped at the far end from the fault by the remote breaker opening in normal clearing time. The single-line-to-ground fault remains in place for the duration of the backup breaker clearing time. The fault is then cleared and all of the facilities impacted by the backup breaker are taken out of service. All line trips are assumed to be permanent (i.e., no high speed re-closing is utilized).

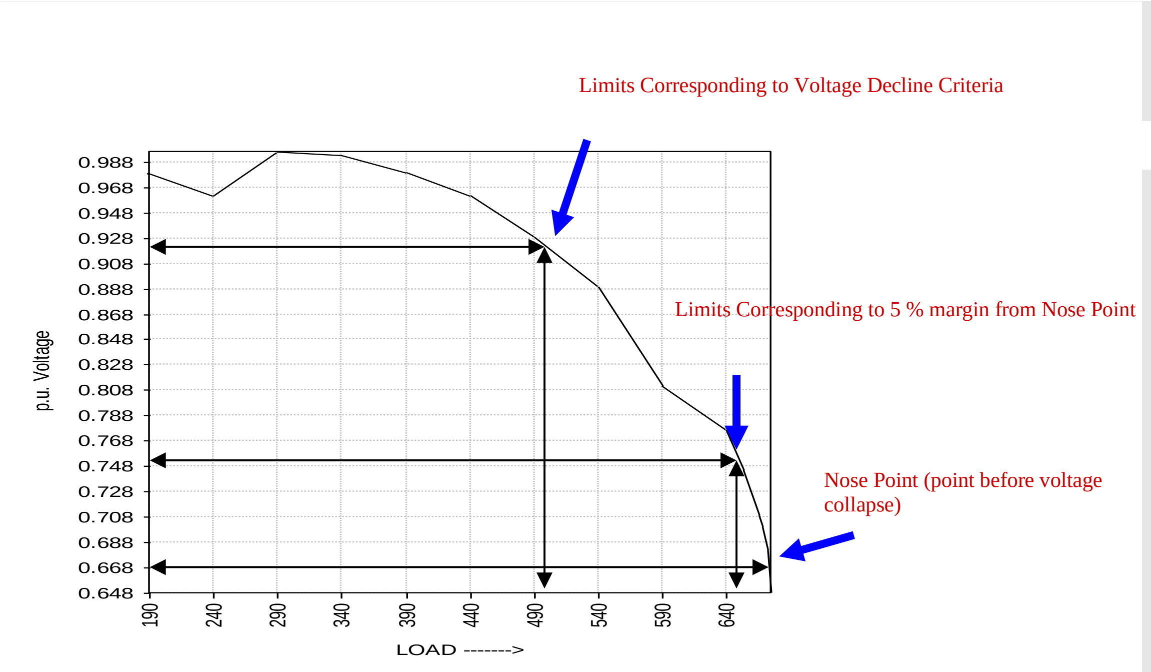
Generator instability: If the synchronous generator rotor angle deviation with respect to a "distant" generator is more than 180 degrees, the generator has a tendency to slip poles and thus lose synchronism with the remainder of the interconnected system. A loss of synchronism creates mechanical stresses on the generator shaft and can reduce its life span or damage the unit. In stability studies, any deviation of rotor angle beyond 180 degrees is considered as instability of the generator. Further evaluation is necessary in order to determine whether this instability is limited to a specific generator or sets of generators that could cause a larger area to become unstable and result in Cascading Outages. Please refer to section 11.C for cascading criteria. For inverter-based resources, generator instability is defined as undamped voltage oscillations seen at the generator terminal bus which may indicate control instability/interaction with nearby generators or FACTs devices.

Small Signal Stability Studies: Although power system oscillations can be screened as part of transient stability studies, in order to perform a detailed power system oscillation analysis, programs such as SSAT are utilized. These programs can provide different modes (eigenvalues) in an oscillation and the damping associated with the particular mode. Entergy's criteria require a minimum of 3% damping for all of the power system oscillations for P1-P7 events. Refer to section 11.A.3 for Entergy's damping criteria.

Voltage Stability Studies: Voltage stability studies can be classified into two broad categories: Steady State Voltage Stability and Dynamic Voltage Stability.

A. Steady State Voltage Stability Study

The Steady State Voltage Stability Study is performed to identify transfer limits between a defined source(s) and a sink or load(s) in a given area using Power-Voltage (PV) analysis. PV analysis examines the relationship between power (P) delivered into a region and the voltage (V) of the load buses in the area. Programs such as PSS/E, TARA or VSAT can be used for performing Steady State Voltage Stability Analysis. Voltages at critical buses are plotted with respect to the power transfer level or load level, and as the system approaches the insecure point of operation, the voltages reduce sharply with the increase of power transfer. In the insecure zone voltages reduce as power transfer or load is increased.
A typical PV curve is shown in the figure below.



As shown in the figure above, the power transfer limit is considered as the point with 5% margin from the nose point of the PV curve under the worst contingency condition.

Additionally, at least 30% reactive reserve margin is required in a given area under N-0 conditions.

B. *Dynamic Voltage Stability Study*

A Dynamic Voltage Stability Study is performed in order to study the Fault Induced Delayed Voltage Recovery (FIDVR) phenomenon. FIDVR events can lead to a fast voltage collapse due to stalling of motors and excessive reactive power needs on the system. In order to study FIDVR, Dynamic Voltage Stability Studies have to be performed with complex load models which include induction motors. The guidelines for using complex load models are given below:

Load Modeling for Dynamic Voltage Stability Studies

There are various load models available for use in the Dynamic Voltage Stability Studies, including complex load models (CLOD), induction motor models (CIM5), and composite load models (CMLD). Entergy utilizes one of the above models or a combination to represent load in dynamic voltage stability studies.

New Generator Interconnections: For Generator Interconnection (GI) Stability Studies and TPL Reliability Stability Studies only, new generation requests (for GI studies) or generation with an executed Generator Interconnection Agreement (GIA) since performance of the last reliability assessment (for TPL studies) will be studied with all generation local to the new generator at full output to determine whether the aggregate of the generation can be injected into the transmission system without experiencing transient stability issues for local faults.

11 STABILITY CRITERIA

The following criteria shall be applied during the Stability Evaluations as discussed in section 10.

A. **Transient Stability**: While performing transient stability studies, the system is monitored to check for generator instability, voltage dips, and proper damping of the oscillations.

1. *First Swing Instability Angular Criteria*

   If the generator rotor angle deviation with respect to a "distant" generator is more than 180 degrees, the generator has a potential to slip poles or become unstable. This condition is unacceptable as it will create a great stress on the generator shaft and may reduce its life span. For screening purposes, any deviation of rotor angle beyond 180 degrees is considered instability of the generator. Further analysis has to be performed in order to determine whether the generator is marginally stable or unstable by monitoring rotor angles.

   For P1, P2 (EHV only), P3, P4 (EHV only), and P5 (EHV only) planning events, no generating unit shall pull out of synchronism and no inverter-based resource shall contribute to undamped oscillations at the generator terminal bus voltage.

   For P4 (HV only), the system should not experience loss of more than 500 MW of non-consequential generation in the Entergy Operating Companies.

   For P2 (HV only), P5 (HV only), P6, and P7 planning events, the system should not experience loss of more than 2000 MW of non-consequential generation involving two or more plants in the Entergy Operating Companies.

2. *Voltage Recovery Criteria*

   Voltage Recovery criteria is used when motor models are used in stability studies.

   a. Motor Model

      For P1, P2 (EHV only), P3, P4 (EHV only), and P5 (EHV only) planning events, all transmission buses (load buses only) shall recover to:
      - above 80% voltage within 2 seconds of the initial fault and
      - above 90% voltage within 10 seconds of the initial fault.

      For P2 (HV only), P4 (HV only), P5 (HV only), P6, and P7 planning events, transmission buses (load buses only) shall recover to:
      - above 80% voltage within 4 seconds of the initial fault and

- above 90% voltage within 10 seconds of the initial fault.

For P4 (HV only), 300 MW loss of non-consequential load is acceptable. Loss of load due to under-voltage protection for Motor A, B, C, or D loads or stalling for Motor D loads is not considered as either consequential or non-consequential and is not included.

For P2 (HV only), P5 (HV only), P6, and P7 planning events, 1000 MW loss of non-consequential load is acceptable. Loss of load due to under-voltage protection for Motor A, B, C, or D loads or stalling for Motor D loads is not considered as either consequential or non-consequential and is not included.

b. Generator POI Voltage Criteria

NERC Standard PRC-024 will be applied at the transmission point of interconnection for generators.

3. *Power System Oscillation Criteria*

In all the stability studies, the power swings after the fault is cleared shall be analyzed for damping. A minimum of 3% damping is required for the system to be secure for P1-P7 events. If the damping is less than 3%, it should be flagged, and further investigation has to be performed to ensure that low damping would not adversely affect the system reliability.

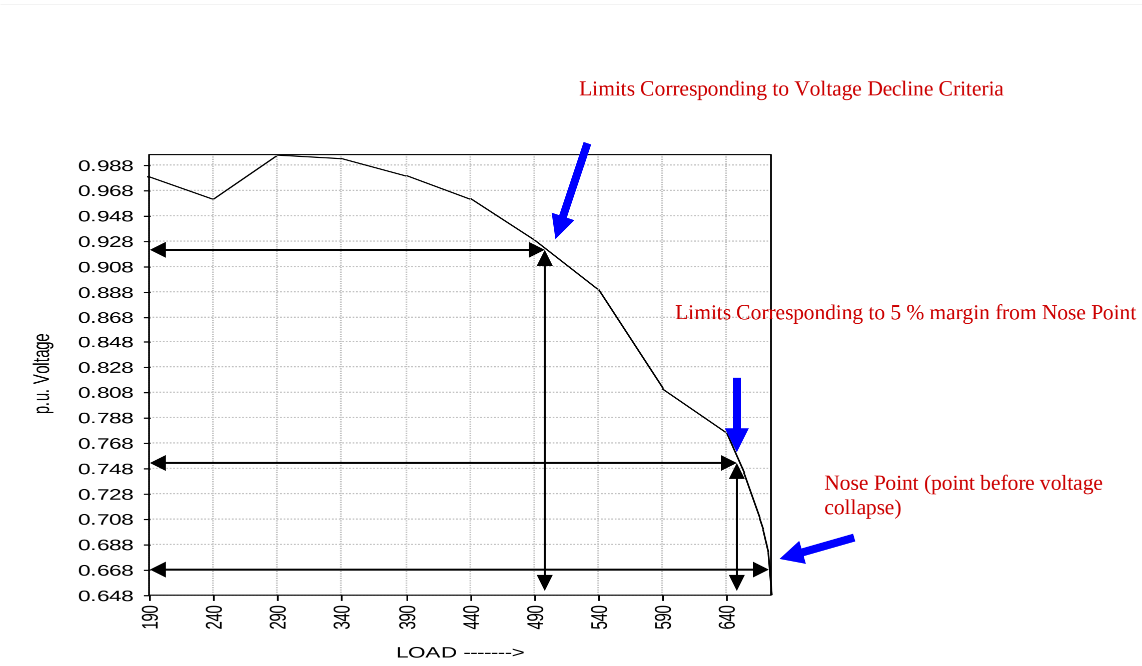
4. High Voltage Criteria

Refer to Voltage Criteria in Table in Section 7.3 of this document.

B. **Voltage Stability**: Voltage stability can be classified into two broad categories. Steady State Voltage Stability and Dynamic Voltage Stability.

1. *Steady State Voltage Stability Criteria*

Steady State voltage stability simulations involve PV curve analysis. The voltage stability limit is defined based on 5% margin from the nose point under the worst contingency condition as illustrated in the figure below.



2. *Dynamic Voltage Stability Criteria*

This criterion is same as the voltage recovery criteria covered in section 11.A.2.

C. **Cascading Criteria**: These criteria shall be utilized for screening stability analysis results obtained for Extreme Events pursuant to compliance with NERC Reliability Standard TPL-001-4/5. *Criteria Application: (applicable to 100 kV and above voltage level)*

The contingency should be flagged and an evaluation of the possible actions to mitigate the consequences shall be conducted provided one or more of the following conditions are met:

a. Loss of more than 2000 MW of generation (consequential + non-consequential) involving two or more plants in the Entergy Operating Companies footprint due to transient instability and voltage issues.

b. Contingencies resulting in generation instability on neighboring systems will be notified to the neighbor Planning Coordinator and/or Transmission Planner as defined per TPL 4.4.1.

c. Refer to voltage recovery criteria in section 11.A.2.a.

D. **Criteria for recommending Power System Stabilizers (PSS) on generating units**

The installation of power system stabilizers is required for all new synchronous generators interconnected to the BES with a total rated capacity greater than 50 MVA as recommended by the SERC Power System Stabilizer Guideline. A PSS is also required for existing units with rated capacity greater than 50 MVA when installing a new static exciter or digital voltage regulator. The installation of a PSS may be required for new synchronous generators rated less than or equal to 50 MVA or interconnected at a voltage level below 100 kV if the Transmission Planner identifies a need for a PSS through system studies or operating experience.

12 Short Circuit Evaluation

Short circuit studies are performed to determine the maximum fault duty on circuit breakers and other equipment and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies.

Short circuit currents are calculated using a full representation of the Entergy network while neighboring networks are represented by appropriate system equivalences and transfer impedances. The representation of neighboring networks shall be updated annually.

When assessing the duties associated with circuit breakers, bus bars, bus section/couplers and ground grids, it is assumed that all generators which may operate within the near-term planning horizon are on line, and all transmission facilities are in service and operating as designed.

Short circuit studies for determining impedance for modeling unbalanced faults in stability studies typically assumes all generators are on line. Breaker operations and resultant loss of elements may be accounted for in the calculation. Entergy will conduct these short circuit studies using models maintained by Transmission Planning.

The need to perform short circuit evaluations is driven by, but is not limited to, the following factors: transmission projects (line upgrades, network reconfigurations, new transmission lines, new autotransformers) and generation projects (new generator/s addition, generator uprate or refurbishment).

Prior to finalizing a Corrective Action Plan, the reasonableness of the generation dispatch used during the assessment will be considered. Circuit breakers are identified to be upgraded when the short circuit level is determined to be within 2% of exceeding the fault interrupting duty of the breaker(s). The 2% margin is provided to address uncertainties in the model.

13 Frequency

During normal operations (no system disturbance), the frequency should not vary more than 0.05 Hertz from 60 Hertz.

14 Inertia

A minimum inertia criterion of 125 GW*s has been defined as the level at which the Entergy system can be reliably operated with existing and planned internal frequency response resources. Corrective action plans would be identified for scenarios that fall below this threshold.