ITC HOLDINGS PLANNING CRITERIA 100 kV AND ABOVE

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***** References to ITC are references to ITC Holdings Corp. together with all of its subsidiaries, unless otherwise noted.

Contents

1. References & Definitions

TPL-001-5.14 – NERC Transmission System Planning Performance Requirements.

This version replaces PLA-0002 Rev 012 dated 02/26/2026 and titled “ITC Holdings Planning Criteria 100kV and Above”.

Transmission System(s) – The ITC Transmission (“ITCT”), Michigan Electric Transmission Company (“METC”), and ITC Midwest (“ITCM”) transmission systems will collectively be referred to as the “Transmission Systems”.

The ITC Great Plains (“ITCGP”) system is planned according to the SPP planning criteria. The SPP criteria can be found on the SPP website at the following link by searching for “Planning Criteria”: https://www.spp.org/

Cascading Event – Either of the following simulation results would be indicative of a cascading event.

1. Following an initiating event (contingency), three or more additional element(s)[1] are tripped.

2. Following an initiating event (contingency), one or more additional element(s)[1] trip(s) resulting in 1000 MW or more of load being lost[2] or 2,000 MW or more of generation being lost[2].

2. Goal

This document describes the criteria to be used in assessing the reliability of the Transmission Systems operating at 100 kV and above, defined by NERC as the Bulk Electric System (BES). This criterion is intended to develop and maintain a Transmission System that anticipates future system needs and provides transmission service in a cost-effective manner, while accommodating for planned and unplanned system outages needed to facilitate system improvement and system maintenance. During the development of projects and operating solutions, consideration will be given to devising a Transmission System that is resilient, reliable, and minimizes the probability of initiating cascading failures.

[1] Elements would include Bulk Electric System (“BES”) lines and transformer circuits. In this instance, an element consists of all equipment within the primary zone of protection.

[2] This does not include load/generation lost as a consequence of the initiating event.

This document defines and explains the ITC Holdings Planning Criteria and will be reviewed and updated as necessary. The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the Transmission Systems. Some deviation from these criteria may be justified as a result of special, economic or unusual considerations, but in no case shall such a deviation result in failure to meet all relevant minimum NERC, RRO or RTO requirements or other mandatory standards. Instances in which a deviation from these criteria are justified should not necessarily be considered to conflict with this criterion or to justify revising the criteria but should be recognized as unusual and special cases. The reliability implications of all such deviations shall be quantified to the extent possible or otherwise qualified sufficiently to ensure minimal impacts on system reliability. The planning criteria in this manual are guidelines to assist planning engineers when developing capital project and/or operating solution proposals for anticipated system needs.

ITC recognizes the impossibility of anticipating and testing for all possible contingencies that could occur on either the present or the future Bulk Electric System[3] ("BES"). This transmission planning criteria should serve primarily to measure the strength of the Transmission Systems to withstand a wide spectrum of contingencies, rather than comprise a detailed listing of probable disturbances. The ITC Holdings Planning Criteria is based not on whether specific contingencies for which the system is being tested are themselves highly probable but rather on whether they constitute an effective and practical means to stress the system and thus test its ability to avoid uncontrolled power interruptions.

In meeting the above objectives, planning engineers must be aware of available equipment, understand construction limitations, and understand the practical needs of operating the electrical system. Thermal overloading can shorten equipment life and lead to sudden failures. Operating the Transmission Systems at abnormal voltages can also cause equipment failures and/or voltage sensitive equipment to be adversely affected, and compromise safety clearances. Planning engineers also need to be cognizant of intangible considerations, such as the social and political implications of transmission projects which can include visual and ecological effects. Many of these considerations cannot be guided by exact rules and engineering judgment must be factored into project proposals. In summary, the material gathered in this manual is intended to provide basic system planning guidelines. Each planning engineer, however, must still apply integrity, ingenuity, experience and judgment to develop projects which lead to an economic and reliable wholesale power system that supports long term access to diverse, reliable and economical generation.

[3] These planning criteria are applicable for all ITCT, METC, and ITCM Bulk Electric System facilities as defined by NERC.

2.1. NERC & RRO Reliability Criteria

ITC Holdings Planning Criteria aims to ensure the Transmission Systems meet or exceed all relevant minimum requirements of the North American Electric Reliability Corporation ("NERC") Transmission Planning ("TPL") standards and those of all applicable Regional Reliability Organizations ("RRO"). ITCT and METC are members of the ReliabilityFirst RRO ("RF"), and ITCM and ITCGP are members of the Midwest Reliability Organization ("MRO"). The effects of DER will be analyzed and shall meet the performance requirements identified within this planning criteria.

3. Steady State Voltage & Thermal Loading Criteria

To avoid equipment damage and ensure safety, equipment loadings and voltages projected in system models should be maintained within the limits as defined in Table 1. Some form of mitigation will be proposed for projected violations of these planning criteria as identified through the planning processes as appropriate. Mitigation could include development of capital project(s), system re-configuration/operating procedures, generation re-dispatch, or some combination thereof. While an acceptable means of mitigation, the application of system re-configuration/operating procedures on the BES would typically be limited as an interim solution where either known or expected system changes or upgrades would provide a robust, long-term system solution.

3.1. System Load

These planning criteria shall apply to all load levels forecasted for the Transmission Systems, as detailed in Table 1. Transmission studies are performed for a variety of load levels including peak, shoulder peak load, and light load scenarios. To the extent possible, load on systems external to the Transmission Systems should be modeled with load levels similar to the load levels modeled on the Transmission Systems.

3.2. Facility Loadings

Applicable facility ratings shall not be exceeded. This includes normal ratings for P0 events and applicable emergency ratings for all other events unless otherwise noted. Normal and emergency ratings are developed in accordance with ITC's Facility Ratings Methodology. The rating applied shall be of an appropriate duration considering both the limiting piece of equipment and the contingencies considered.

3.3. Generation Dispatch

When evaluating the expected performance of the Transmission Systems, generation shall be dispatched in an assumed economic and probabilistic basis considering historical dispatch for each applicable load level and specific customer identified generation resources. In all models, including those representing system "normal" conditions, reasonable assumed forced and scheduled generator outages shall be considered.

It may be appropriate to consider conditions with multiple generator units unavailable in an area particularly if the conditions being studied may be prevalent for an extended period of time. Further, the system should be analyzed to consider vulnerability to extended generation outages or the permanent retirement of generation.

3.4. Shutdown Scenarios

NERC TPL standards specify that system models shall be studied for selected known outages of generation or transmission facilities. These known system outages shall be selected with a documented outage coordination procedure or technical rational thus providing a significant, continuous time during the year when a system element can be shut down for inspection, maintenance, adjacent hazard removal and/or element replacement. Each shutdown shall be studied for both P0 and P1 contingencies with system peak and off-peak conditions.

For system loading levels up to those at which shutdowns are to be considered, the ITC Holdings Planning Criteria necessitates the avoidance of non-consequential load loss for shutdown plus contingency scenarios (NERC Category P1 events with the prior shutdown of another power system element). These scenarios consider the loss of a generator, transmission circuit, transformer, shunt device or single pole of a DC line under conditions with a pre-existing shutdown of another generator, transmission circuit, transformer, shunt device, protection system[4] or single pole of a DC line. The shutdown in these scenarios would constitute taking a facility out of service for inspection, maintenance, adjacent hazard removal, long term forced outages and/or element replacement. The intent of this criterion is to ensure sufficient infrastructure exists to allow the required maintenance of equipment while being able to withstand the relatively higher probability of a NERC category P1 (single) event.

3.5. System Adjustments

System adjustments can include actions such as supervisory controlled or automatic operation of bus-tie circuit breakers, switching of transmission circuits, transformers, series or shunt devices, or adjustment of controllable elements such as LTC transformers, phase angle regulators, HVDC lines, generator voltage regulators or other such devices.

System adjustments can also include re-dispatch of generation, system reconfiguration, or load shed as a planned solution to Transmission issues. Load shedding is only allowed during the period in which it takes to complete corrective action plan to mitigate the violation. These issues shall be within the following parameters:

1. The system adjustment must bring the flow on the monitored facility to below 95% of its applicable rating.

[4] Protection system outages include those that require the shutdown of a single transmission bus.

2. All generation re-dispatch must be less than or equal to 600 MW increment/decrement.

3. Transmission reconfiguration will include no more than 1 transmission line or transformer removal. Opening one end of a transmission line without de-energizing it is not considered a removal.

In each scenario, the planning engineer will need to use engineering judgment to determine the appropriateness of the re-dispatch, system reconfiguration, and load loss as a planned solution to the Transmission issues being addressed. For instance, it may be appropriate to exclude nuclear generation and units designated as System Support Resources ("SSR") from the sink subsystem and non-dispatchable generation such as Solar, wind or hydro plants from the source subsystem. To the extent practicable, financial implications should be taken into consideration when utilizing re-dispatch as a solution.

3.6. Single Contingency Followed by Operator Action Followed by Another Single Contingency

The forced outage of a single transmission circuit, transformer, shunt device, protection system[5] or single pole of a DC line followed by operator interaction and then followed by another forced outage of a single transmission circuit, transformer, shunt device or single pole of a DC is considered to be a NERC Category P6 event. NERC Reliability Standards require all system elements to be within applicable thermal and voltage limits following both the first and second forced outage, however, they allow for load shedding following the second forced outage as long as all system elements remain within applicable thermal and voltage limits[5]. This could include load shed via automatic devices such as under voltage or under frequency load shedding schemes or operator-initiated actions in order to keep the loading of elements within longer term emergency ratings and voltages within established limits.

3.7. Voltage Deviation Criteria

3.7.1. Capacitor & Reactor Switching

The maximum percent change (step-change) in system voltage for capacitor and reactor switching under normal system conditions shall be 3%. The test for this criterion will be conducted via steady state load flow analysis with automatic controlling devices such as switched shunts, load tap changing ("LTC") transformers and phase angle regulating transformers ("PARS") locked. Dynamic VAR devices such as static VAR compensator ("SVCs") should be allowed to control voltage during these simulations. Transient simulations may be required to ensure equipment will be sized to avoid harmonic resonance.

[5] After the first event and prior to the second event the system can be reconfigured so that supply to a defined pocket of load would be lost as the direct consequence of second event.

3.7.2. Loss of Generation or Transmission Elements

The Transmission Systems will be monitored for voltage deviations greater than 8% after the loss of any common mode single initiating event on the BES. This is exclusive of radial connected (isolated) non-load serving buses resulting as a consequence of the event. The test for this criterion will be conducted via steady state load flow analysis with automatic controlling devices such as switched shunts, LTC transformers,and PARS allowed to adjust. Dynamic VAR devices such as SVCs should also be allowed to control voltage during these simulations. Voltage deviations greater than 8% could indicate voltage sensitive areas and may require mitigation. For bus voltages found which do not meet these guidelines, a static voltage stability analysis (P-V curve or equivalent) will be performed. Voltage instability is defined as the knee of the P-V curve. The system is planned such that it will operate with 5% or greater margin from the voltage instability point.

3.8. Extreme Events

The Transmission Systems will be evaluated using a number of extreme contingencies that are judged by ITC to be significant. It is not expected that it will be possible to evaluate all possible facility outages that would be considered to be NERC extreme events. If an extreme event is projected to be a Cascading Event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event should be conducted.

3.9. Geomagnetic Disturbance Events

The Transmission Systems will be evaluated utilizing geomagnetic disturbance (GMD) events per the NERC TPL-007 standard. Benchmark and Supplemental Event geoelectric field strengths will be considered, in addition to outages of reactive power compensation devices and other transmission facilities being removed as a result of protection system operation or misoperation due to harmonics during the GMD event. These events are described further in Table 2. If a *GMD Initial Condition* or *GMD Outage Event* is projected to violate its performance requirement (i.e. Voltage Violation or Cascading Event respectively), a Corrective Action Plan will be created to address how the performance requirements of Table 2 will be met.

3.10. Other Considerations

Tests should be applied as appropriate to examine the system’s susceptibility to voltage collapse. The reactive reserve in an area (comprised of “unused” reactive capability of generators, shunt capacitors and/or any other reactive power producing devices) should be monitored in studies to identify possible voltage collapse scenarios. Scenarios resulting in low reactive reserves may be an indication of possible voltage collapse and should be documented and mitigated as appropriate.

Certain contingencies result in non-load serving buses (i.e. current flow is not present) being isolated from all sources of the same or higher voltage. For these scenarios, it is not necessarily considered a violation of the planning criteria when voltages on the isolated buses are projected to be outside the parameters of Table 1.

4. Stability Criteria

Stability refers to the ability of a synchronous machine, inverter-based generator, or power system to reach an acceptable steady-state operating point following a disturbance. Power plants should maintain generator rotor angle, voltage and frequency stability and have no adverse impact on the rest of the system, including other connected generators, when operating within the normal voltage or VAR schedule or power factor range at the point of interconnection for the appropriate contingency categories as directed in Table 1.

4.1. System Loading

Planning simulations are intended to represent operating conditions that are severe yet credible. Stability simulations will be conducted using system models with varying system load levels from light load through peak load.

Planning will coordinate with the Operations department to ensure system conditions represented in simulations requested by the Operations or Maintenance departments match the projected system conditions to the extent practicable. Simulations performed at the request of the Operations or Maintenance departments will be performed utilizing the closest load level planning model available.

4.2. Generation Dispatch

When evaluating the Transmission Systems' expected performance, in the absence of specific customer identified generation resources, generation shall be dispatched in an assumed economic and probabilistic basis considering historical dispatch for each applicable load level. In all models, including those representing system "normal" conditions, reasonable assumed forced and scheduled generator outages shall be considered.

It may be appropriate to consider conditions with multiple generator units unavailable in an area especially if the conditions being studied may be prevalent for an extended period of time. Further, as appropriate the system should be analyzed to consider vulnerability to extended generation outages or the permanent retirement of generation.

Studies to determine transmission needs for a given power plant will be based on the maximum reasonable expected generation output from that plant. Adverse, but credible, dispatch scenarios for other nearby generation shall also be considered.

In order to ensure stability margins are maintained, stability studies for individual power plants will be performed considering operation of each applicable unit connected to the Transmission Systems. To the extent practicable, these studies will be performed across applicable power factor ranges and within voltages as directed in Table 1 for normal system conditions at the point of interconnection. Where the plant does not have the capability to achieve the entire voltage and/or power factor range described above, it will be tested throughout the actual feasible voltage and power factor range at the point of interconnection.

4.3. Determination of Generator Rotor Angle Instability

For P1 through P7 planning events as described in Table 1, no synchronous machine shall pull out of synchronism. In general, if a synchronous machine's rotor angle swings approximately 180 degrees away from the system/area reference generator and will not swing back, this shall be considered pulling out of synchronism. A synchronous machine being disconnected from the Transmission Systems by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.

Limited exceptions may be considered on a case-by-case basis at ITC's discretion for P2 through P7 events which may cause a synchronous machine to pull out of synchronism if 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.

4.4. Transient Voltage Response

4.4.1. Transient/Dynamic Voltage Dip Criteria

<u>ITC*Transmission* (Area 219), METC (Area 218), and ITC Midwest (Area 627)</u>
For NERC TPL contingencies P1 through P7, voltages at all buses on the Transmission Systems should not drop below 0.70 per unit after the fault clears and the first swing for more than 0.5 second (30 cycles) unless customers have identified more stringent requirements. The duration for the minimum voltage dip starts after the first full swing post clearing of the fault.

4.4.2. *Transient/Dynamic Voltage Recovery Criteria*

<u>ITC*Transmission* (Area 219), METC (Area 218) and ITC Midwest (Area 627)</u>
For NERC TPL contingencies P1 through P7, voltage at all buses on the Transmission Systems should recover to the applicable post-contingency steady-state low voltage level as detailed in Table 1, within 8.0 seconds of clearing of the fault[6] unless customers have identified more stringent requirements.

[6] Planning assessments should also consider all applicable Nuclear Plant Interface Requirements.

4.5. System Oscillation Damping

For all P0 through P7 planning events, as described in Table 1 below, the rotor angle of synchronous machines shall remain within the specified limits. The damping ratios and active power (MW) oscillations of synchronous machines and inverter-based resources shall also remain within the specified limits. Normal operation of any load shall not cause a synchronous machine or inverter-based resource to exceed these limits. Elevated oscillations or insufficient damping in synchronous machines or inverter based resources beyond the criteria specified below generally indicates system sensitivity and shall be evaluated to determine whether mitigation is required.

1. Minimum 3% damping ratio for any decomposed sinusoid oscillation mode in the target frequency range of 0.1 Hz to 2.0 Hz.

2. Maximum oscillation amplitudes of 1.0° for synchronous machine rotor angle.

3. Maximum oscillation amplitudes of 5.0 MW for synchronous machine and/or inverter-based generators with rated active power equal to or below 500 MW.

4. Maximum oscillation amplitudes of 1% of the rated generator active power for synchronous machines and/or inverter-based generators with rated active power greater than 500 MW.

4.6. Other Considerations

<u>Dynamic Fault Ride Through</u>

All synchronous machines, inverter-based resources and/or other dynamic control devices shall be able to ride through the applicable faults in Table 1 with the system adhering to the criteria described above. This includes:

1. Fossil, Nuclear, and Hydro Synchronous Machines

2. Non-synchronous generation sources such as wind power or solar energy, etc.

3. Dynamic VAR devices such as Static VAR Compensators (SVC), STATCOM, Synchronous Condensers, etc.

4. Energy Storage Devices

5. HVDC Devices

<u>Apparent Impedance Swings</u>

Apparent impedance swings into zone A and/or zone B of distance relays protecting any line/branch not tripped through normal fault clearing are unacceptable for NERC Category P3 through P7 events. Additional transmission elements will not be allowed to trip after the fault is cleared.

5. Short Circuit Criteria

Short circuit currents are evaluated in accordance with applicable industry standards.

In general, fault currents must be within the specified momentary and/or interrupting ratings for the devices for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactance.

6. Power Quality & Reliability Criteria for Delivery Points

Details of Power Quality and Reliability Criteria for Delivery Points are covered in the individual Interconnection Agreement documents with the Load Serving Entities. The Planning Engineer shall propose projects as required in those agreements.

7. End of Life

Transmission infrastructure needs to be periodically replaced as equipment reaches its end of life. ITC takes several factors into account when determining equipment replacement timelines including:

1. Maintenance cost/history – older equipment is commonly more expensive to maintain due to potentially in-depth tear down requirements for maintenance and/or hard-to-obtain obsolete parts.

2. System Performance – faulty equipment causes system devices to mis-operate or impair operations, lose communication or not alarm properly. Newer equipment typically possesses improved functionality that can increase performance beyond what was originally installed.

3. Technology – older technology in some equipment has proven through industry knowledge and operational experience to be prone to premature problems or failure. This is commonly detected through routine maintenance and electrical testing to determine the extent of wear or damage that may be present.

4. Age – when the expected design life of equipment is exceeded, there is increased risk of failure.

7.1. Substation Equipment

ITC utilizes an annual asset replacement program to replace existing assets based on the factors discussed above. This program allows for the timely replacement of equipment and for the reduction of system performance problems while concurrently making certain that the priority of the most urgent work takes precedent. While the program provides a good guideline, external factors may dictate changes in the priority. These changes could include equipment costs, the ability to obtain outages necessary to perform work, resource (field labor) availability, changes in technology increasing or decreasing expected life cycles, etc. The program includes equipment such as circuit breakers/switchers, protective equipment (relay/control), DC battery and charging systems, surge arresters, instrument transformers, disconnect switches, transformers, wood poles and other miscellaneous line equipment (insulators, cross-arms, etc.).

7.2. Operational Concerns

The transmission system may operationally experience loading conditions that are not modelled or simulated in planning timeframes. This may result voltage or real time loadings that test the limits of equipment and cause undue constraints on the system. ITC may utilize these operational constraints to prioritize projects to address these facility limits

As both overhead and underground facilities continue to age, they may experience increasing failure rates that could degrade system reliability. Maintenance, partial rebuild or complete rebuild activities need to be undertaken on aging circuits throughout the ITC systems to maintain acceptable levels of system reliability.

ITC utilizes various factors when considering a partial or full rebuild of circuits. These factors include but are not limited to operational history, current maintenance needs, age and type of equipment and circuit importance based on various load serving functions (amount or type of load or generation impacted by the outage of a facility). Factors such as these are used to help prioritize the replacement of aging circuits across the ITC systems.

8. Coordination with Neighboring Systems

The Transmission Systems have interconnections with neighboring systems. These systems include neighboring transmission systems, distribution systems and generators. The contractual commitments with the interconnected neighbors, as well as interconnected operations require coordinated joint planning with these neighboring systems as well as consideration of the networks contiguous to those interconnections. The ITCT and METC systems are planned by the same Transmission Planning entity and thus are not required to perform the same coordination as is required for other transmission to transmission interconnections.

9. Remedial Action Schemes (RAS)

New Remedial Action Schemes ("RAS") will not be installed on the Transmission Systems. The installation of a RAS on a neighboring system whose purpose is to mitigate potential issues on the Transmission Systems will not be allowed.

For those RAS that have already been placed in service, periodic reviews should be performed to ensure that the scheme is deactivated when the conditions requiring its use no longer exist or to determine if system improvements to remove the RAS are warranted.

10. Facility Connections

For details on ITC's Connection Criteria, see ITC Facility Connection Requirements posted on ITC's website: www.itc-holdings.com

10.1. Generator Interconnections

As noted in Table 1 and consistent with MISO West's generator interconnections practices, ITCM does not consider P3 and P6 contingencies for generator interconnection Studies.

ITCT and METC do not consider P3 and P6 contingencies for generator interconnection Steady State Analysis while they do consider P3 and P6 contingencies for generator interconnection Stability Analysis. Generators are studied at maximum dispatch output and mitigations are required for the studied system for load levels up to 85% for ITCT and METC.

11. Table 1 – Steady State & Stability Performance Planning Events[k, l]

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

ITCT, METC, and ITCM Specific Notes:

k. All criteria will be tested at system load levels up to 100% of forecasted peak system loading unless otherwise noted, and applicable at all system load levels.

l. All Nuclear Plant Interface Requirements ("NPIRs") shall be monitored and upheld.

NERC Category	Initial Condition	Event [1,14,15]	BES Level [3]	ITCT and METC [19]					ITCM [19]				
				Fault Type [2,20]	Interruption of Firm Transmission Service Allowed [4,17,18]	Non-Conse-quential Load Loss Allowed [17,18]	Minimum Voltage (pu)	Maximum Voltage [24] (pu)	Fault Type [2,20]	Interruption of Firm Transmission Service Allowed [4,17]	Non-Conse-quential Load Loss Allowed[17]	Minimum Voltage (pu)	Maximum Voltage [16,24] (pu)
P0 System Normal	Normal System	None	EHV, HV	N/A	None	None	0.97	1.07	N/A	None	None	0.95	1.05
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	EHV, HV	3Φ	None[9]	None[12]	0.92	1.07	3Φ	None[9]	None[12]	0.93	1.10
		5. Single Pole of a DC Line		SLG					SLG				
P1 Single Contingency with Prior Shut Down[21] (Shutdown plus contingency)	Loss of one of the following followed by system adjustments. 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Protection System 6. Single Pole of a DC Line	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	EHV, HV	3Φ	None[9]	None[12]	0.92	1.07	3Φ	None[9]	None[12]	0.93	1.10
		5. Single Pole of a DC Line		SLG					SLG				
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	EHV, HV	N/A	None[9]	None[12]	0.92	1.07	N/A	None[9]	None[12]	0.93	1.10
		2. Bus Section Fault	EHV	3Φ	None[9]	None	0.92	1.07	SLG	None[9]	None	0.93	1.10
			HV	3Φ	None[25]	None[25]	0.92	1.07	SLG	None	None	0.93	1.10
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	EHV	SLG	None[9]	None	0.92	1.07	SLG	None[9]	None	0.93	1.10
			HV	SLG	None[25]	None[25]	0.92	1.07	SLG	None[9]	None	0.93	1.10
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	EHV	SLG	None[9]	None	0.92	1.07	SLG	None[9]	None	0.93	1.10
			HV	SLG	None[25]	None[25]	0.92	1.07	SLG	None[9]	None	0.93	1.10
P3 [22,23] Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	EHV, HV	3Φ	None[9]	None[12]	0.92	1.07	3Φ	None[9]	None[12]	0.93	1.10

NERC Category	Initial Condition	Event [1,14,15]	BES Level [3]	ITCT and METC [19]					ITCM [19]				
				Fault Type [2,20]	Interruption of Firm Transmission Service Allowed [4,17,18]	Non-Conse-quential Load Loss Allowed [17,18]	Minimum Voltage (pu)	Maximum Voltage [24] (pu)	Fault Type [2,20]	Interruption of Firm Transmission Service Allowed [4,17]	Non-Conse-quential Load Loss Allowed[17]	Minimum Voltage (pu)	Maximum Voltage [16,24] (pu)
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-bus-tie-breaker) attempting to clear a fault on one of the following: . Generator . Transmission Circuit . Transformer[5] . Shunt Device[6] . Bus Section	EHV	2Φ	None[9]	None	0.92	1.07	SLG	None[9]	None	0.93	1.10
			HV		None[25]	None[25]	0.92	1.07		None	None	0.93	1.10
		. Loss of multiple elements caused by a stuck breaker (bus-tie-breaker) attempting to clear a fault on the associated bus	EHV, HV	2Φ	None[25]	None[25]	0.92	1.07	SLG	None	None	0.93	1.10
P5 Multiple Contingency (Fault plus Non-redundant component of a Protection System failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: . Generator . Transmission Circuit . Transformer[5] . Shunt Device[6] . Bus Section	EHV	SLG	None[9]	None	0.92	1.07	SLG	None[9]	None	0.93	1.10
			HV	SLG	None[25]	None[25]	0.92	1.07	SLG	None	None	0.93	1.10
P6 [22,23] Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by system adjustments. . Transmission Circuit . Transformer[5] . Shunt Device[6] . Single Pole of a DC Line	Loss of one of the following: . Transmission Circuit . Transformer[5] . Shunt Device[6]	EHV, HV	3Φ	None[25]	None[25]	0.92	1.07	3Φ	None	None	0.93	1.10
		. Single Pole of a DC Line		SLG					SLG				
P7 Multiple Contingency [8] (Common structure)	Normal System	The loss of: . Any two adjacent (vertically or horizontally) circuits on common structure[11] . Loss of a bipolar DC line	EHV, HV	SLG	None[25]	None[25]	0.92	1.07	SLG	None	None	0.93	1.10

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11]
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non- redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   i. 3Ø internal breaker fault.
   j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbance

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and PARS.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain

closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times.
    b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center).
    c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit).
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Table 1 – Steady State & Stability Performance ITCT, METC, and ITCM Specific Footnotes (Planning Events and Extreme Events)
14. Simulations will consider the removal of all elements that protection systems and other controls are expected to automatically disconnect for each event. 15. Unless otherwise specified, steady state analysis should generally be performed with automatic control devices (tap changers, switched shunts, PAR transformers, etc.) set to control after each event. 16. The maximum system normal voltage for 115 kV busses on the ITCM system is 107%. 17. Consequential load loss as well as consequential generation loss is acceptable as a direct consequence of any event. 18. Allowable load loss is the sum of load lost as a direct consequence of the event, non-consequential load shed, and Interruption of Firm Transmission Service to get within applicable limits. 19. Some buses have individual voltage limits. These are reviewed on a case-by-case basis. System studies may monitor and plan some buses to more stringent voltages due to contractual obligations with the Load Serving Entities. 20. Unless otherwise noted, it is assumed that faults are cleared with normal clearing. All protective equipment is assumed to have worked as intended and within design guidelines. For P4 events in METC and ITCT, the simulated fault shall be a 2- Φ to Ground (L-L-G) fault. 21. Prior outage or Shutdown outage plus contingencies are studied at system load levels up to 85% for ITCT and METC and 70% for ITCM. This is the maximum load level to which this part of the criteria should be applied. This part of the criteria does not apply to steady-state analysis for generator interconnection process per Section 10.1. 22. In ITCT and METC, prior outage or shutdown outage plus contingencies are studied as part of the generator interconnection process for stability analysis. Studied generators are studied at maximum dispatch output and mitigations are required for studied system at load levels up to 85% for ITCT and METC. 23. Consistent with MISO West Region's DPP practices, P3 and P6 contingencies are not considered as part of the generator interconnection process in ITCM. 24. Applicable to 765kV only –The maximum voltage limit is 1.03 pu for P0 system normal and 1.046 pu for all other system conditions. 25. Load shedding is only allowed during the period in which it takes to complete the corrective action plan to mitigate the violation.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

   a. Date, time, and location for the meeting

   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote12

   c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:

   a. System Load level and estimated annual hours of exposure at or above that Load level.

   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected
   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

12. Table 2 – Steady State Planning GMD Event

Steady State:

1. Voltage collapse, Cascading and uncontrolled islanding shall not occur. The performance requirements of *Cascading Event* shall be met.
2. Generation and load loss are acceptable as a consequence of the steady state planning *GMD Outage Event*, up to levels defined in *Cascading Event*.
3. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings

NERC Category	GMD Initial Condition Performance Requirements					GMD Outage Event Performance Requirements		
	Description	ITCT & METC[d]		ITCM[d]		Description	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
		Minimum Voltage	Maximum Voltage	Minimum Voltage	Maximum Voltage			
P0 System Normal	Normal System	0.97	1.07	0.95	1.05	None	No	No
Benchmark GMD Event GMD Event with Outages	1. System as may be postured in response to space weather information[a], and then 2. GMD Event[b]	0.92	1.07	0.92	1.07	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[c]	Yes[c]
Supplemental GMD Event GMD Event with Outages	1. System as may be postured in response to space weather information[a], and then 2. GMD Event[b]	0.90	1.10	0.90	1.10	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Footnotes for Table 2 - Steady State Planning GMD Event:

a) The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.

b) The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1 to NERC Standard TPL-007.

c) Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. An evaluation of possible actions designed to reduce the likelihood or to wmitigate Load loss or curtailment of Firm Transmission Service shall be conducted.

d) ITC Great Plains shall utilize the SPP Planning Coordinator performance requirements for GMD Events.

13. Pre-P&P Portal Revision History

Effective Date	Revision Number	Individual Making Edits	Reason / Comments
02/20/15	000	Carlo Capra	Updated planning criteria to coincide with NERC TPL-001-4
03/02/16	001	Carlo Capra	Performed annual review, updated SPP criteria link and updated damping criteria for Midwest
01/26/17	002	Carlo Capra	Added ITCI, a definition of cascading and an end-of-life criteria.
08/15/18	003	Charles Marshall	Updated planning criteria to align with current planning practices, modified sections 3.7.2 “Loss of Generation or Transmission Elements” to clarify voltage deviation criteria, modified all of section 4.3 “Stability Criteria” to delineate ITC*Transmission*, METC, and ITCM criteria, and added Section 10 “Facility Interconnections” to reference ITC’s Facility Connection Requirements

14. P&P Portal Revision History

Date Published	Revision Number	Individual Making Edits	Reason / Comments
02/25/19	000	Ruth Kloecker	Updated planning criteria to coincide with NERC TPL-001-4
02/25/19	001	Ruth Kloecker	Republishing to get version to 004
02/25/19	002	Ruth Kloecker	Republishing to get version to 004
02/26/19	003	Ruth Kloecker	Republishing to get version to 004
02/27/19	004	Ruth Kloecker	Updated 4.4.1 Transient/Dynamic Voltage Dip Criteria and 4.4.2 Transient/Dynamic Voltage Recovery Criteria for ITCT, METC, and ITCM
03/06/20	005	Ruth Kloecker	Annual Review. Revised 3.5 System Adjustment Criteria, P Events for 4.3 Determination of Generator Rotor Angle Instability, and Revised Criteria for 4.5 System Oscillation Damping

02/12/21	006	Ruth Kloecker	Annual Review. Revised P Events for Section 4.3 Determination of Generator Rotor Angle Instability and Section 4.6 Default Ride Through Criteria.
03/10/22	007	Ruth Kloecker	Annual Review. Minor changes.
11/15/22	008	Josh Niemi	Added section *3.9 Geomagnetic Disturbance Events* and *Table 2 Steady State Planning GMD Event*.
09/27/23	009	Ruth Kloecker	Annual Review. Converted to TPL-001-5.1. Removed references to ITCI.
03/14/25	010	Ruth Kloecker	Annual Review. Updated sections 7.2 and 10.1. Other minor changes.
09/25/25	011	Jonathan Goldsworthy	Annual Review. Renumbered and relocated ITCT, METC, and ITCM specific footnotes for Table 1. Updated Table 1 for 765kV Voltage limits
02/06/26	012	Ruth Kloecker	Annual Review. Added language to address possible oscillation impacts due to large loads.
5/27/26	013	Jennifer Amberg	Made edits to system adjustments section, small edits for consistency throughout and updates to steady state table on consequential and non-consequential load loss.