ITC Holdings Planning Criteria 100 kV & Above

ITC A FORTIS COMPANY	Category:	Planning	
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Contents

1. References & Definitions

TPL-001-4 – NERC Transmission System Planning Performance Requirements.

Transmission Systems – The ITC Transmission ("ITCT"), Michigan Electric Transmission Company ("METC"), ITC Midwest ("ITCM"), and ITC Interconnection ("ITCI") 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 – While accurately simulating a cascading event is extremely difficult, 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 ITC Holdings operating company Transmission Systems operating at 100 kV and above. This transmission planning criteria is intended to ensure a Transmission System that allows for reliable transmission service. The implementation of projects and operating solutions identified by application of these planning criteria shall result in Transmission Systems for which the probability of initiating cascading failures is very low. The criteria should also ensure operating flexibility including, but not limited to, allowing for maintenance outages.

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 is 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.

[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.

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 making 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 as a means 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. 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 in order to develop projects which lead to an economic and reliable power system that supports long term access to diverse, reliable and economical generation.

2.1. NERC & RRO Reliability Criteria

This ITC Holdings Planning Criteria helps 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, METC, and ITCI are members of the ReliabilityFirst RRO ("RF"), ITCM is a member of the Midwest Reliability Organization ("MRO") and ITCGP is a member of the Southwest Power Pool Reliability Organization ("SPP").

3. Steady State Voltage & Thermal Loading Criteria

In order 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, generation re-dispatch, other operating procedures or some combination of the above.

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

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, as appropriate, 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 represent known outages of generation or transmission facilities with duration of at least six months. While outages of transmission facilities do not typically require six month durations there must be 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.

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

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

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 within the following parameters:

1. All generation utilized in the re-dispatch must have a generation shift factor[5] of at least 3% on the monitored facility.

2. When dispatching generation up, the generator with the greatest generation shift factor on the monitored facility cannot be utilized in the re-dispatch. If there are multiple generators at the same location, the largest generator should not be included. In instances where the output of smaller generators at the plant with the greatest generation shift factor is reliant on the larger generator, all generators at the plant that rely on the output of the larger generator should be excluded.

3. No more than 10 individual conventional fuel generators or individual wind plants[6] can be utilized in the re-dispatch. This includes the total number of units dispatched up and down.

4. No more than 1,000 MW shall be used to increment and no more than 1,000 MW shall be used to decrement.

In each re-dispatch scenario the planning engineer will need to use engineering judgment to determine the appropriateness of the re-dispatch. 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 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

[5] The generation shift factor will be the percent change on the monitored facility caused by an increase (or decrease) in generation at a specific plant with the contingent facility out of service (Outage Transfer Distribution Factor).
[6] Wind plants in this instance refers to wind farms or the combination of all individual wind turbines that make up a wind plant or wind farm that connects to the transmission system at one interconnection point.

elements to be within applicable thermal and voltage limits following both the first and second forced outage, however allow for load shedding following the second forced outage as long as all system elements remain within applicable thermal and voltage limits[7]. 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 transformers ("LTC") and phase shifting transformers ("PARS") locked. Dynamic VAR devices such as DVARs and 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.

3.7.2. Loss of Generation or Transmission Elements

The Transmission Systems should be monitored for voltage deviations greater than 5% after the loss of any transmission element or generator connected to the transmission system. Voltage deviations of greater than 5% could indicate voltage sensitive areas and may require mitigation. 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 transformers ("LTC") and phase shifting transformers ("PARS") locked. Dynamic VAR devices such as DVARs and SVCs should be allowed to control voltage during these simulations.

3.8. Extreme Events

The Transmission Systems will be evaluated using a number of extreme contingencies that are judged by ITC to be critical. 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. 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 producing low reactive reserves may be an indication of possible voltage collapse and should be documented and mitigated as appropriate.

[7] 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.

Certain contingencies result in buses 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 and adverse, but credible, dispatch scenarios for other nearby generation shall 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 planning events as described in Table 1, no synchronous machine shall pull out of synchronism. In general, a synchronous machine's rotor angle swinging more than 180 degrees away from the system/area reference generator would be considered pulling out of synchronism. A synchronous machine being disconnected from the Transmission Systems by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

For planning events P2 through P7, when a synchronous machine pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected facilities.

4.4. Transient Voltage Response

Dynamic Voltage Dip Criteria

Voltages at all busses on the Transmission Systems should not drop below 0.70 per unit after the first swing for more than 5 cycles. The duration for the minimum voltage dip starts after the first swing post clearing of fault.

Dynamic Voltage Recovery Criteria

Voltage at all buses on the Transmission Systems should recover to the applicable post-contingency steady-state voltage level as detailed in Table 1, within 1.0 second of the clearing of the fault[8].

4.5. System Oscillation Damping

For all P1-P7 contingencies as identified in Table 1 below, synchronous machine rotor angle and inverter based source active power (MW) oscillation damping ratios shall stay within the limits described below.

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. Minimum oscillation amplitudes of 1.0° for synchronous machine rotor angle.

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

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

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

4.6. Other Considerations

Dynamic Fault Ride Through

All synchronous machines and/or inverter based generation sources 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 and Hydro Synchronous Machines

2. Generation sources that utilize electronic power converters to deliver the power to the transmission grid such as wind power or solar energy.

3. Dynamic VAR devices such as Static VAR Compensators (SVC), Statcom, etc.

4. Energy Storage Devices

5. HVDC Devices

Apparent Impedance Swings

Apparent impedance swings into zone A and/or zone B of distance relays protecting any line/branch that has not been directly faulted, are unacceptable for NERC Category P1 and P2 events, unless actual relays will not trip for the event. 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, unless it can be demonstrated that a relay trip will not result in instability, uncontrolled separation, or cascading outages.

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. Overhead & Underground Lines

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 in order 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.

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.

Table 1 – Steady State & Stability Criteria [a,b]

NERC Category	Initial Condition	Event [c,d]	BES Level [e,f,g]	ITCT, METC & ITCI [h]				ITCM [h]			
				Fault Type [i]	Allowable Load Loss [j,k]	Minimum Voltage	Maximum Voltage	Fault Type [i,l]	Allowable Load Loss [j]	Minimum Voltage	Maximum Voltage [m]
P0 System Normal	Normal System	None	EHV, HV	N/A	None	97%	107%	N/A	None	95%	105%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	EHV, HV	3Φ	None	92%	107%	3Φ	None	93%	110%
		5. Single Pole of a DC Line		SLG				SLG			
P1 Single Contingency with Prior Shut Down [n] (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 4. Shunt Device	EHV, HV	3Φ	None	92%	107%	3Φ	None	93%	110%
		5. Single Pole of a DC Line		SLG				SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	EHV,HV	N/A	None	92%	107%	N/A	None	93%	110%
		2. Bus Section Fault	EHV	3Φ	None	92%	107%	SLG	None	93%	110%
			HV	3Φ	100 MW	92%	107%	SLG	None	93%	110%
		3. Circuit Breaker (non-bus-tie breaker) Fault	EHV	SLG	None	92%	107%	SLG	None	93%	110%
			HV	SLG	300 MW	92%	107%	SLG	None	93%	110%
		4. Circuit Breaker (bus-tie breaker) Fault	EHV	SLG	None	92%	107%	SLG	None	93%	110%
			HV	SLG	300 MW	92%	107%	SLG	None	93%	110%
P3 Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	EHV, HV	3Φ	None	92%	107%	3Φ	None	93%	110%
		5. Single Pole of a DC Line		SLG				SLG			

NERC Category	Initial Condition	Event [c,d]	BES Level [e,f,g]	ITCT, METC & ITCI [h]				ITCM [h]			
				Fault Type [i]	Allowable Load Loss [j,k]	Minimum Voltage	Maximum Voltage	Fault Type [i,l]	Allowable Load Loss [j]	Minimum Voltage	Maximum Voltage [m]
P4 Multiple Contingency (Fault plus stuck breaker)	Normal System	Loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker) attempting to clear a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	EHV	2Φ	None	92%	107%	SLG	None	93%	110%
			HV	2Φ	300 MW	92%	107%	SLG	None	93%	110%
		6. Loss of multiple elements caused by a stuck breaker (bus-tie-breaker) attempting to clear a fault on the associated bus	EHV, HV	2Φ	300 MW	92%	107%	SLG	None	93%	110%
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	EHV	SLG	None	92%	107%	SLG	None	93%	110%
			HV	SLG	300 MW	92%	107%	SLG	None	93%	110%
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by system adjustments. 1. Transmission Circuit 2. Transformer [l] 3. Shunt Device 4. Single Pole of a DC Line	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	EHV, HV	3Φ	300 MW	92%	107%	3Φ	None	93%	110%
		4. Single Pole of a DC Line		SLG				SLG			
P7 Multiple Contingency [o] (Common structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure 2. Loss of a bipolar DC line	EHV, HV	SLG	300 MW	92%	107%	SLG	None	93%	110%

Notes for Steady State & Stability Criteria Table:

a) 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.

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

c) Simulations will consider the removal of all elements that protection systems and other controls are expected to automatically disconnect for each event.

d) Unless otherwise specified, steady state analysis should generally be performed with automatic control devices (tap changers, switched shunts, phase shifting transformers, etc.) set to control after each event.

e) BES level references include extra-high voltage ("EHV") facilities defined as greater than 300 kV and high voltage ("HV") facilities defined as the 100 kV to 300 kV 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.

f) If the event analyzed involves BES elements at multiple system voltage levels, the lowest system voltage level of the element(s) removed for the event determines the stated performance criteria regarding allowances for interruption of firm transmission service and non-consequential load loss.

g) For non-generator step up transformer outage events, the reference voltage as used in note f 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 phase shifting transformers.

h) 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.

i) Unless otherwise noted, it is assumed that faults are cleared with norma1 clearing. All protective equipment is assumed to have worked as intended and within design guidelines.

j) Consequential load loss as well as consequential generation loss is acceptable as a consequence of any event.

k) Allowable load loss is the sum of load lost as a consequence of the event and non-consequential load shed to get within applicable limits.

l) A one-cycle safety margin shall be used for all ITCM clearing times, including normal and delayed clearing times.

m) The maximum system normal voltage for 115 kV busses on the ITCM system is 107%.

n) Shutdown 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. It is also valid at lower system load level for instance when studying the impact of wind generation dispatched at a load level less than system peak.

o) Any two circuits of a multiple circuit tower line excludes transmission circuits where multiple circuit towers are used over a cumulative distance of 1 mile or less in length.

10. 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.