ITC Holdings Planning Criteria Below 100 kV

ITC A FORTIS COMPANY	Category:	Planning	
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Contents

1. References & Definitions

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

Transmission System - The ITC Midwest (“ITCM”) low voltage (below 100 kV) and high voltage (above 100 kV) transmission systems will collectively be referred to as the “Transmission Systems”.

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)[4] trip(s) resulting in 1000 MW or more of load being lost[2] and/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 Midwest low voltage transmission (below 100 kV[3]) system. This low voltage transmission planning criteria is intended to result in an ITC Midwest low voltage transmission system that economically and reliably allows our low voltage transmission system customers to serve load from generation of choice. The criteria should also ensure operating flexibility including, but not limited to, allowing for maintenance outages.

This manual defines and explains the current planning criteria and will be reviewed and updated as required. The planning criteria contained in this manual are, in general, to be uniformly interpreted and utilized in the testing and planning of the ITC Midwest low voltage transmission system unless some deviation is justified as a result of special, economic or unusual considerations. Such instances 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 reliability impacts. The planning criteria in this manual are <u>guidelines</u> to assist the planning engineer in making capital project and/or operating solution proposals for anticipated system needs.

[1] Elements would include Transmission System lines and/or 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.
[3] For these criteria, this includes transformers with a low side voltage rating below 100 kV.

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 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.

3.1. System Loading

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 loading 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 low voltage transmission system, 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 (such as designated network resources). In all models, including those representing system "normal" conditions, reasonable assumed forced and scheduled generator outages shall be considered.

When planning the low voltage transmission system, it is appropriate to consider conditions with largest generating unit or plant (greater than or equal to 200 MVA name plate on a common fuel source) in a given area off-line, and a forced outage on any given piece of low voltage transmission equipment (line section or transformer) within the same area. This is to ensure that the low voltage transmission system is not being designed to be dependent on local area generation being available and on-line to perform at an acceptable level.

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 load levels up to those at which shutdowns are to be considered, the low voltage transmission system is to be planned to avoid non-consequential load loss at the low voltage transmission system level for shutdown plus contingency scenarios on the ITC Midwest Bulk Electric System ("BES") (NERC Category P1 events with the prior shutdown of another power system element). These scenarios consider the loss of a generator, BES transmission circuit, BES transformer, BES shunt device or single pole of a DC line under conditions with a pre-existing shutdown of another generator, BES transmission circuit, BES transformer, BES shunt device, BES 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. The low voltage transmission system shall meet applicable Planning Criteria during shut down scenarios on the Bulk Electric System.

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. 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.

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. Opening one end of a transmission line without de-energizing it is not considered a removal.

4. Total load loss for each scenario shall not exceed the loss of more load than is permissible than that identified in Table 1.

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

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

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 BES transmission circuit, BES transformer, BES shunt device, BES protection system or single pole of a DC line followed by operator interaction and then followed by another forced outage of a single BES transmission circuit, BES transformer, BES 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 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.

The low voltage transmission system is planned to stay within its applicable thermal and voltage limits for any such NERC Category P6 event on the Bulk Electric System.

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 banks will also be sized to avoid harmonic resonance.

3.8. 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.

[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.

Certain contingencies result in buses being isolated from all sources of the same or higher voltage. For these scenarios, it is not necessary 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 are, to the extent practicable, credible. 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 (such as designated network 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 with automatic voltage regulator(s) set at applicable voltage schedule(s).

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 system 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 ITC Midwest lower voltage transmission system 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.

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. 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 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

Non-dispatchable generation resources and transmission devices will also be bound by voltage ride-through and frequency ride-through requirements as identified by the generator/equipment manufactures and owners across the normal voltage and/or VAR operating schedules at the points of interconnection.

Apparent Impedance Swings

Apparent impedance swings into the zone A and/or 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 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 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 low voltage transmission system has 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. Joint planning is accomplished by participation in several regional planning groups.

9. Remedial Action Schemes (RAS)

New Remedial Action Schemes (“RAS”) will not be installed on the low voltage transmission system. The installation of a RAS on a neighboring system whose purpose is to mitigate potential issues on the low voltage transmission system 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]	ITCM [e] Fault Type [f,i]	ITCM [e] Allowable Load Loss [g,]	ITCM [e] Minimum Voltage [m,n,o,p,q]	ITCM [e] Maximum Voltage [j,n,q,r]
P0 [u] System Normal	Normal System	None	N/A	None	95%	105%
P1 [u] Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Φ	None	93%	110%
		5. Single Pole of a DC Line	SLG			
P1 [v] 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	3Φ	None	93%	110%
		5. Single Pole of a DC Line	SLG			
P2 [u] Single Contingency	Normal System	1. Opening of a line section w/o a fault	N/A	None	93%	110%
		2. Bus Section Fault	SLG	None	93%	110%
		3. Circuit Breaker (non-bus-tie breaker) Fault	SLG	None	93%	110%
		4. Circuit Breaker (bus-tie breaker) Fault	SLG	None	93%	110%
P3 [v] 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	3Φ	None	93%	110%
		5. Single Pole of a DC Line	SLG			
P4 [v] 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	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	SLG	None	93%	110%
P5 [v] 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	SLG	None	93%	110%
P6 [v] Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by system adjustments. 1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single Pole of a DC Line	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single Pole of a DC Line	SLG	None	93%	110%

NERC Category	Initial Condition	Event [c,d]	ITCM [e]			
			Fault Type [f,i]	Allowable Load Loss [g,]	Minimum Voltage [m,n,o,p,q]	Maximum Voltage [j,n,q,r]
P7 [v] Multiple Contingency [l] (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	SLG	None	93%	110%
N/A [s] Multiple Contingency (Two overlapping singles on low voltage transmission system)	Loss of one networked low voltage transmission system source transformer followed by system adjustments	Loss of one low voltage transmission system source transformer followed by system adjustments	N/A	None	93%	110%
N/A [t] Multiple Contingency (Two overlapping singles on low voltage transmission system)	Outage of local area generator/plant greater than 200 MVA	Loss of one of the following: 1. Low voltage transmission system circuit 2. Low voltage transmission system source transformer	N/A	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) 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.

f) 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.

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

h) 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.

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

j) The maximum post event voltage for 115 kV busses on the ITCM system is 107%.

k) 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.

l) 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.

m) The Minimum Voltage requirement for 69 kV retail users without voltage regulation is 97.5 % normal, and 95.0% post-contingency. This includes Cargill (Eddyville), Griffin Wheel, Keokuk Steel, and Ogilvie Mills.

n) System Normal Minimum and Maximum Voltage limits for 34.5 kV are 102% and 108% respectively.

o) Contingent minimum bus voltage is 99% for 34.5 kV.

p) Voltage must be restorable to 93% for 69 kV and 99% for 34.5 kV after system adjustments. Action must be taken within 30 minutes of disturbance.

q) The 34.5 kV limits are only applicable to the 34.5 kV source buses, i.e. only at stations where a higher voltage (69 kV & above) has been stepped down to 34.5kV. These limits shall not apply to the collector buses of generators.

r) System studies should monitor and plan to the System Normal Maximum Voltage.

s) NERC criteria is not applicable to transformers with low side windings <100 kV, but as part of a spare equipment strategy and to ensure ability to serve load during replacement of long lead time system components, double contingencies will be performed on networked low voltage transmission transformers.

t) NERC criteria is not applicable to equipment operated below 100 kV, but to ensure the low voltage transmission system is not being designed to be dependent on local generation, connected at any voltage level, additional contingency analysis is performed to evaluate potential system issues and solutions.

u) While not applicable to non-BES elements, NERC category P0, P1 (single contingency), and P2 outages are run on non-BES facilities as part of the low voltage transmission planning criteria. The low voltage transmission system must stay within its applicable limits when these outages are taken on both the BES system and low voltage transmission system.

v) NERC category P1 (shutdown + contingency), P3, P4, P5, P6, and P7 outages are only run on BES system elements, and the low voltage transmission system must stay within its applicable limits for these outages.

10. Revision History

Effective Date	Revision Number	Individual Making Edits	Reason / Comments
12/09/15	000	Initial Version	Updated planning criteria to coincide with NERC TPL-001-4
01/26/17	001	Staff	Added definition of cascading and end of life criteria.
03/06/20	002	Ruth Kloecker	Annual Review. Revised 3.5 System Adjustment Criteria and Revised Criteria for 4.5 System Oscillation Damping