SCOPE

This document is the ATC system Planning Criteria. These criteria define system performance requirements. Consideration is given to ensure a safe and reliable transmission system. These criteria address customer expectations and compliance with NERC standards. These criteria apply to the ATC transmission system operated at 69-kV and above, unless noted otherwise.

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies and new operating procedures, as appropriate. The criteria described below will be subject to change at any time at ATC's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, extraordinary events, safety issues, operation issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

Defined Terms

NERC, ATC, and industry terms are used throughout the document. Unless defined in the body of the document or in "Glossary of Terms NERC Reliability Standards"[1], any capitalized term herein shall have the meaning set forth in Section 8.

[1] https://www.nerc.com/files/glossary_of_terms.pdf

1. STEADY STATE CRITERIA AND IMPLEMENTATION

ATC's steady state system performance requirements must be in compliance with the currently enforceable version of NERC Reliability Standard TPL-001. Furthermore, the criteria and implementation requirements are applicable to non-BES[2] unless otherwise noted. The criteria and implementation requirements are summarized in Table A:

[2]https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf

Table A: Steady State Criteria and Implementation

Category	Event Description	Fault Type	Voltage Level (10)	Criteria							Implementation					
				Voltage (pu) (1) (2) (3) (7) (11)		Thermal Ratings	Voltage Deviation (4)(9)	Interruption of Firm Transmission Service Allowed (11)	Non-Consequential Load Loss Allowed (5)(6)(11)	Voltage Stability (8)	Automatic Model Adjustments Allowed	Automatic – RAS, UVLS, and SPS Allowed	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	NERC Cascading Allowed
				Min	Max											
P0	System Intact	NA	EHV, HV, non-BES	0.95	1.05	100% of Normal	NA	No	No	Stable w/Margin	Yes	No	No	No	No	No
P1	System Intact + Loss of the following events (Generator, Transmission Circuit, Transformer, Shunt Devices)	3Ø	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
P2.1	System Intact + Open line w/o fault	NA	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
P2.2	System Intact + Bus section fault	SLG	EHV	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	10%	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P2.3	System Intact + Non-bus-tie breaker faults	SLG	EHV	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	10%	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P2.4	System Intact + Bus-tie breaker fault	SLG	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P3	**First Contingency**: Loss of generator unit	3Ø	EHV, HV	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	In-between outages (following First Contingency in anticipation of Second Contingency)			0.9	1.1	100% of Emergency	NA	No	No	Stable	Yes	Yes	Yes	No	Yes	No
	After Second Contingency: Loss of P1			0.9	1.1	100% of Emergency	NA	No	No	Stable	Yes	Yes	No	No	No	No
P3	**First Contingency**: Loss of generator unit	3Ø	non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	In-between outages (following First Contingency in anticipation of Second Contingency)			0.9	1.1	100% of Emergency	NA	Yes	No	Stable	Yes	Yes	Yes	No	Yes	No
	After Second Contingency: Loss of P1			0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable	Yes	Yes	No	No	No	No
P4.1-P4.5	System Intact + Stuck breaker event on all but bus tie breaker	SLG	EHV	0.9	1.1	100% of Emergency	NA	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P4.6	System Intact + Stuck bus-tie breakers	SLG	EHV, HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No

Category	Event Description	Fault Type	Voltage Level (10)	Criteria							Implementation					
				Voltage (pu) (1) (2) (3) (7) (11)		Thermal Ratings	Voltage Deviation (4)(9)	Interruption of Firm Transmission Service Allowed (11)	Non-Consequential Load Loss Allowed (5)(6)(11)	Voltage Stability (8)	Automatic Model Adjustments Allowed	Automatic – RAS, UVLS, and SPS Allowed	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	NERC Cascading Allowed
				Min	Max											
P5 (12)	System Intact + Fault (Generator, Transmission Circuit, Transformers, Shunt Devices, Bus Section) + relay failure to operate	SLG	EHV	0.9	1.1	100% of Emergency	NA	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P6	**First Contingency**: Loss of P1(except gen)	3Ø	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	In-between outages (following First Contingency in anticipation of Second Contingency)			0.9	1.1	100% of Emergency	NA	Yes	No	Stable	Yes	Yes	Yes	No	Yes	No
	After Second Contingency: Loss of P1(except gen)			0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable	Yes	Yes	No	No	No	No
P7	System Intact + Loss of the following events (Any two adjacent circuits on common structure or of a bipolar DC line)	SLG	EHV, HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
Maintenance	Planned P1 or P2.1 Outage + P1		EHV, HV	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	Planned P1 or P2.1 Outage + P1		non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
Extreme Events																Yes

(1) All voltage limits should be met with the net generator reactive power limited to 90 percent of the reported maximum reactive power capability.

(2) The steady state voltage should be stable at all ATC buses

(3) Voltage levels that differ from this range will be considered, if they are acceptable to the affected transmission customer or needed to address specific ATC equipment limitations. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001).

(4) Post contingency voltage deviation (percent change of actual pre-contingency and post contingency steady state voltage) of greater than 10% is not allowed

(5) For Categories where load curtailment is acceptable, consideration may be given to operating procedures that are designed to shed a minimum amount of load.

(6) For Categories where load curtailment is unacceptable, system design should ensure that element loading cannot exceed the applicable rating. Temporary excursions are acceptable if a Remedial Action Scheme (RAS) will reduce loadings automatically (i.e. no manual intervention) to acceptable loading levels in the applicable timeframe. The acceptable loading levels after RAS operation cannot exceed the applicable rating.

(7) For distribution transformers, voltage measurements shall be made at the high side.

(8) See Section 1.3 " Steady State Voltage Stability" for details

(9) NA means Not Available

(10) EHV is defined as ATC owned equipment at 300 kV and above, HV is defined as ATC owned equipment less than 300 kV and greater than or equal to 100 kV, and non-BES is defined as ATC owned equipment between 69 kV and 99 kV.

				Criteria							Implementation					
Category	Event Description	Fault Type	Voltage Level (10)	Voltage (pu) (1) (2) (3) (7) (11) Min	Max	Thermal Ratings	Voltage Deviation (4)(9)	Interruption of Firm Transmission Service Allowed (11)	Non-Consequential Load Loss Allowed (5)(6)(11)	Voltage Stability (8)	Automatic Model Adjustments Allowed	Automatic – RAS, UVLS, and SPS Allowed	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	NERC Cascading Allowed
(11) For further details on re-dispatch and Non-Consequential Load Loss, refer to Note 9 and Note 12 in Table 1 of TPL-001-4 [3]																
(12) a. For P5.2 events, ATC models outages of non-redundant communication systems that aren't monitored and reported at a Control Center in the same manner as outages of non-redundant relays. b. Non-BES P5.2 events, relay and communication system outages are evaluated near generating units.																

[3] Footnote 9 in TPL-001-4

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.

Footnote 12 in TPL-001-4

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.

1.1 Cascading Criteria

No NERC Cascading should occur for applicable P1 through P7 contingencies or maintenance outage (planned single element outage excluding bus and breaker) followed by a P1 Contingency.

If NERC Cascading occurs for Extreme Disturbance Events, then an evaluation of possible actions that would reduce the likelihood or mitigate the consequences of the extreme event should be performed.

A cascading outage has occurred when Total Load at Risk exceeds ATC's IROL threshold of 1000 MW to enable restoration of the system to within normal limits.

1.2 NERC Uncontrolled Islanding

ATC's definition of uncontrolled islanding has occurred when a total load of any island exceeds 1000 MW.

1.3 Steady State Voltage Stability

The transmission system is required to be voltage stable and respect a Control Point for all P0 through P7 Contingencies. The Control Point is defined as the pre-Contingency real power flow that is 98 percent of the voltage stability System Operating Limit (SOL). Except for P3 and P6 Contingencies, the SOL is defined as the pre-Contingency real power flow that results in the post-Contingency real power flow that is 95 percent of the post-Contingency P-V curve nose. For P3 and P6 Contingencies, the SOL is defined as the pre-Contingency real power flow that results in the post-Contingency real power flow that is 100 percent of the post-Contingency P-V curve nose (i.e. no margin is required).

Steady state voltage stability assessments are performed on a selective basis using engineering judgment. Otherwise, acceptable steady state voltage stability is assumed to exist. If analysis identifies steady state voltage instability, requiring the need for voltage stability flowgates, then the following definitions are applied.

- The Power-Voltage (P-V) curve nose is the short-term, steady state voltage stability transfer point where the maximum real power interface flow occurs. If there is no inflection point at the maximum transfer level on the P-V curve, then the last solved point will be used as the P-V curve nose.
- If an Interconnection Reliability Operating Limit (IROL) is determined to exist, then the IROL is defined as the pre-Contingency real power flow that results in the post-Contingency P-V curve nose.
- If the calculated SOL occurs at a point on the P-V curve that results in a low voltage violation at the critical bus (the bus that is most voltage-sensitive to the power transfer), then the SOL is reduced to the maximum pre-Contingency real power flow that does not result in a voltage violation at the critical bus.

Steady state voltage stability analysis must demonstrate that the nose of the post-Contingency P-V curve occurs at a voltage that is less than or equal to the applicable bus low voltage limit as coordinated with the applicable Planning Coordinator and/or by any applicable Transmission Owner(s) (e.g., the Minnesota – Wisconsin Export Interface (MWEX) limitation of 95 percent of nominal voltage at the Arrowhead 230-kV bus). This requirement is in place to assure adequate system voltage stability and reactive power resources for P0 through P7 Contingencies.

The system is designed for all planning events to ensure that all applicable steady state voltage stability IROLs will not be exceeded.

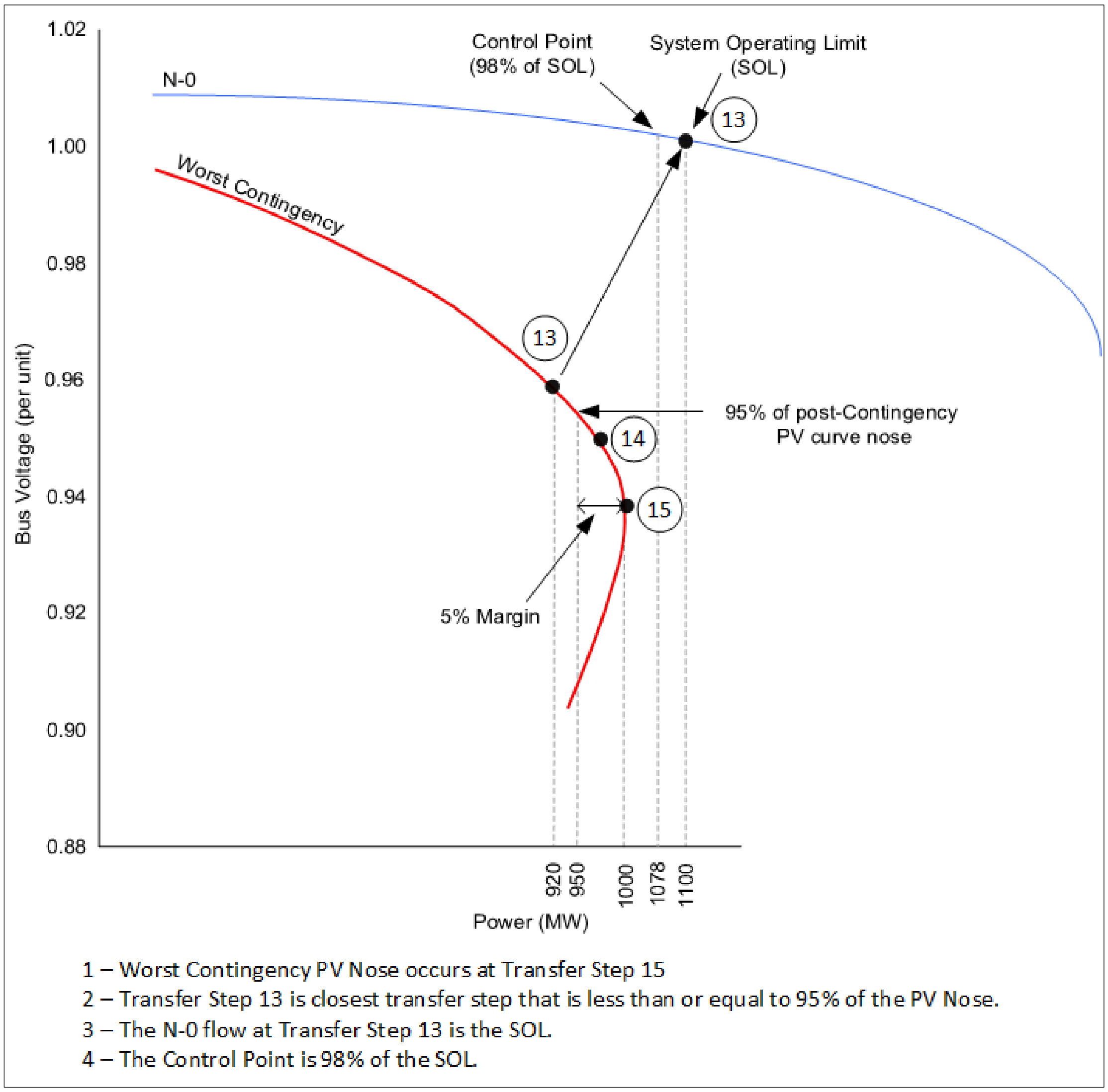


Figure 1: Practical Implementation of ATC Voltage Stability Criteria

1.4 Generation Redispatch Limitations

For events where generation redispatch is allowed as a mitigation option, redispatch of Hydro and Nuclear resources is not allowed. However, fast starting units (certain gas and diesel), solar (down only), wind (down only), and any other remaining online units in the study models are allowed. For Nuclear Generation redispatch exceptions, review PLG-GD-0012-V2.1 (System Planning Mitigation Options).

2. DYNAMIC STABILITY ASSESSMENTS OVERVIEW

The dynamics cases are built to be consistent with the regional dynamics database except for the load modeling, which may consist of appropriate load and motor modeling for voltage stability assessments. Dynamic stability assessments will include consideration of the following system load conditions.

1) Summer peak
2) Light load

The dynamic load conditions have the following general applications.

1) **Summer peak** – This load condition is typically used for voltage stability studies to determine whether system disturbances during peak load conditions cause voltage instability. Also, since the performance of wind generators is more closely linked to system voltage performance, summer peak cases should be considered when assessing the performance of wind generation.
2) **Light load** – This load condition is typically used for dynamic stability assessments in order to assess the angular stability of synchronous machines (e.g. fossil fuel generators). Empirically, it is noted that the dynamic performance of synchronous machines is worse in lighter load conditions likely due to lower field excitation current.

Transient and dynamic stability assessments of the planning horizon are generally performed by the System Planning Department to assure adequate avoidance of loss of generator synchronism, prevention of system voltage collapse, and system reactive power resources after a system disturbance based on 20 second simulations.

The transient and dynamic system stability performance criteria to be utilized by ATC for planning purposes shall include the following factors.
(Applicable NERC Standard: TPL-001-4, R2.4, R2.5, and R4)

2.1 Large Disturbance Stability Performance Assessment

1) For generator transient stability, faults will be modeled on the high side bus at generating plants.
2) For generating units with actual “as built” or “field setting” dynamic data, a 0.5 cycle margin will be added to the expected clearing time (ECT) for dynamic Contingency simulations. For generating units with assumed, typical, or proposed dynamic data, a 1.0 cycle margin will be added to the ECT for dynamic Contingency simulations. The ECT margin will only be added to near end protective device for normal clearing faults (i.e. P1, P2, P3, P6 and P7) or it will be only added to the protective device with delayed clearing (i.e. P4 and P5). The total clearing time (ECT + margin) must be equal to or less than the calculated critical clearing time (CCT) from the simulation.

3) Generator transient stability will be demonstrated for at least one key Contingency for each applicable P1 through P7 Contingency[4]. Unacceptable transient stability performance occurs when any of the stability assessment criteria are not met.

A. Angular Stability Assessment

i. Generating unit loses synchronism with the transmission system, unless it is deliberately islanded

ii. Cascading tripping of transmission lines, tripping of transmission transformers or uncontrolled loss of load

iii. Poorly damped angular oscillations where acceptable damping is defined in Section 2.2 below

B. Voltage Stability Assessment

i. Transient stability voltage response at applicable Bulk-Electric System (BES) buses serving load shall recover to at least 80% of nominal voltage within 2 seconds after the initiating event is cleared for all P1-P7 Contingencies

ii. For voltage swings subsequent to fault clearing and the first voltage recovery above 80%, voltage dips at each applicable BES bus serving load for all P1-P7 Contingencies:

a. Shall not dip below 70% of nominal voltage for more than 30 cycles continuous, or

b. Shall not dip below 80% of nominal voltage for more than 2 seconds continuous.

C. Inverter-Based Resources Stability Assessment

Inverter-based resources refer to generating and energy storage resources that are asynchronously connected to the grid and are either completely or partially interfaced with the transmission system through power electronics.

i. An inverter-based resource shall not trip for any studied Planning Events unless it is deliberately islanded. This also applies to single line to ground (SLG) faults for Planning Events that are defined as three phase faults (e.g. certain P1, P3 and P6 events).

ii. An inverter-based resource's active power and reactive power as measured at the machine bus and bus voltage as measured at the Point-of-Interconnection (POI) shall be positively damped and meet one of the following two criteria:

[4] This criterion applies to all BES generating units and generating units required to submit "as-built" Generating Facility modeling data according to their Interconnection Agreement or comparable data as acceptable to ATC. For all other generating units, generator transient stability will be demonstrated for at least one key P1 Contingency only.

a. Time domain analysis indicates a 50% or greater reduction in oscillation magnitude over the last four oscillation periods.
b. Peak-to-peak magnitudes during the last two seconds of the 20 second simulation shall not exceed 3% of their rated values (machine MVA base for active and reactive power and base kV at POI for voltage).

iii. Inverter-based resources shall not re-enter fault ride-through mode more than once in the time period beginning 6 cycles after the fault clears until the end of the 20 second simulation.

iv. Inverter-based resources should be designed and configured to continue current injection (active, reactive, or a combination of current) inside the “No Trip Zone” of the frequency and voltage ride-through curves of the currently effective version of PRC-024 unless a reliability study identifies a system need to cease injecting current. Inverter-based resources should be designed and configured to use momentary cessation only outside the “No Trip Zone” if this helps mitigate potential tripping conditions based on interconnection studies. Any use of momentary cessation should be based on equipment limitations or based on reliability studies identifying a system need. Return from momentary cessation upon voltage recovery to within the continuous operation range should occur as quickly as possible with no intentional time delay while maintaining stability.

v. For any studied Planning Event, the post-fault active power output of the inverter-based resource must recover to at least 90% of the pre-fault active power output within 1 second of the fault clearing. In addition to the Planning Events defined in TPL-001-4, Table 1, as three phase faults (e.g. certain P1, P3, and P6 events), this also applies to single line to ground (SLG) fault versions of these same events.

Exceptions to these criteria (item ii, iii) given within this section may be considered on a case-by-case basis (e.g. for existing inverter-based resources or if NERC provides more specific inverter-based resource performance guidelines before ATC revises these criteria).

4) Where needed system reinforcement cannot be implemented in an appropriate timeframe, then a corrective plan must be established in order to respect System Operating Limits and/or Interconnected Reliability Operating Limits. Where appropriate, corrective plans may include generator redispatch, operating guides, and/or Remedial Action Schemes.

2.2 Angular Oscillation Damping

Well damped angular oscillations need to meet one of the following two criteria.

1) The generator rotor angle peak-to-peak magnitude is within 1.0 degree or less at the end of the 20 second simulation:

2) The generator average damping factor for the last five cycles of the 20 second simulation is 15.0 percent or greater after the switching event.

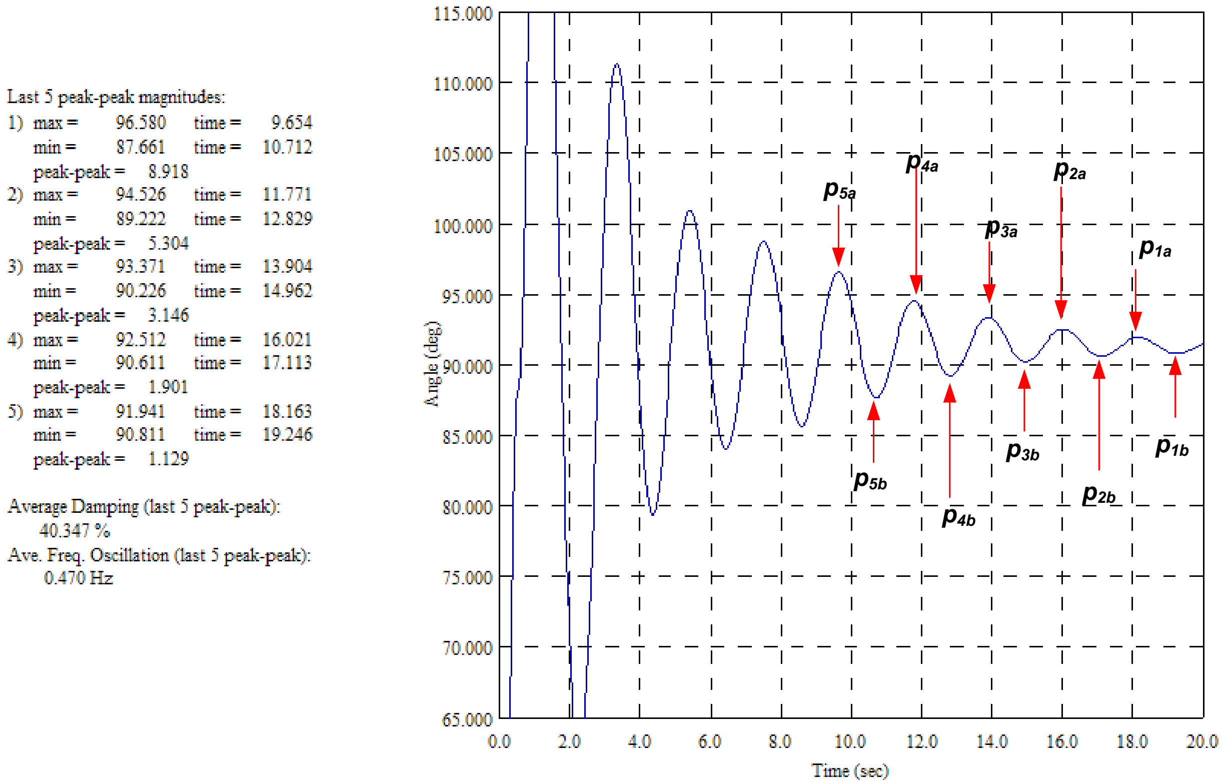
Average Damping Factor (%) = $\left(\frac{d_1 + d_2 + d_3 + d_4}{4}\right) \times 100$

Where:

$d_n = (1 - SPPR_n)$ where $SPPR_n$ (Successive Positive Peak Ratio) is the ratio of the peak-to-peak amplitude of a rotor angle swing (n^{th} cycle back from the 20 second simulation time) to the peak-to-peak amplitude of a rotor angle swing on the previous cycle ($n+1^{th}$ cycle back from the 20 second simulation time).

$$d_4 = 1 - \frac{p_4}{p_5},\ d_3 = 1 - \frac{p_3}{p_4},\ d_2 = 1 - \frac{p_2}{p_3},\ d_1 = 1 - \frac{p_1}{p_2}$$

Example



$p_1 = p_{1a} - p_{1b} = 1.129$

$p_2 = p_{2a} - p_{2b} = 1.901$

$p_3 = p_{3a} - p_{3b} = 3.146$

$p_4 = p_{4a} - p_{4b} = 5.304$

$p_5 = p_{5a} - p_{5b} = 8.918$

$d_1 = 1 - (1.129/1.901) = 0.406102$

$d_2 = 1 - (1.901/3.146) = 0.395741$

$d_3 = 1 - (3.146/5.304) = 0.406863$

$d_4 = 1 - (5.304/8.918) = 0.405248$

Average Damping Ratio = $(d_1+d_2+d_3+d_4) \times 100 / 4 = 40.35\%$

2.3 Extreme Disturbance Events (NERC Standard TPL-001-4 Table 1 Stability Extreme Events)

The NERC Stability Extreme Events that are expected to produce more severe system impacts should be evaluated to determine potential system impacts and vulnerabilities. If widespread Cascading may occur, then an evaluation of possible actions that would reduce the likelihood or mitigate the consequences of the extreme event should be performed.

3. VOLTAGE FLICKER

The criteria for acceptable voltage flicker levels are defined by the requirements of regulatory entities in the states in which ATC owns and operates transmission facilities, IEEE recommended practices and requirements, and the judgment of ATC. The criteria are described below.

The following flicker level criteria are to be observed at minimum nominal system strength with all transmission facilities in service. Minimum nominal system strength shall be defined as the condition produced by the generation that is in service in the Minimum load models, minus any generation that is:

1) Electrically close to the actual or proposed flicker-producing load
2) Could significantly affect flicker levels
3) Could reasonably be expected to be out of service under Minimum load conditions

Although the limits described below are not required to be met during transmission system outages, if these limits are exceeded under outage conditions, the flicker producing load must be operated in a manner that does not adversely affect other loads. Planned outages can be dealt with by coordinating transmission and flicker producing load outages. Because operating restrictions during unplanned outages may be severe, it would be prudent for the owner of the flicker producing load to study the effect of known, critical, or long term outages before they occur, so that remedial actions or operating restrictions can be designed before an outage occurs. During outages, actual, rather than minimum nominal, system strength should be considered.

All ATC buses are required to adhere to the following two criteria.

1) Relative steady state voltage change is typically limited to 3 percent of the nominal voltage for intact system condition simulations. For new projects, it is also typically limited to 5 percent of the nominal voltage under outage conditions. The relative steady state voltage change is the difference in voltage before and after an event, such as capacitor switching, load switching or large motor starting (not including Contingency events). These events should occur at least 10 minutes apart and take less than 0.2 seconds (12 cycles) to go from an initial to a final voltage level.
2) *Planning levels* are to be limited to a short term perception (Pst) of 0.8 and a long term perception (Plt) of 0.6. Pst and Plt are calculated using the calculation methods outlined in IEEE standard 1453-2015.

4. HARMONIC VOLTAGE AND CURRENT DISTORTION

In general, it is the responsibility of ATC to meet harmonic voltage limits and the responsibility of the load customers to meet harmonic current limits. Usually, if harmonic current limits are met, then harmonic voltage limits will also be met. The level of harmonics acceptable on the ATC system is defined by state regulations, IEEE Standard 519-2014 (Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems) and the judgment of ATC. The voltage distortion limits and current distortion limits are specified in the Tables 1-4 below.

The observance of harmonic limits should be verified whenever a harmonic related problem is discovered or a new harmonic producing load with a reasonable possibility of causing harmonic problems is connected to the ATC system. The following process is utilized by

ATC when managing an existing harmonic-related problem or a new harmonic-producing load:

1) *Existing problems* – When a harmonic related problem is found on the ATC system, it is ATC's responsibility to determine the source of the harmonics. If harmonic current limits are violated, the source of the harmonics will be required to decrease their harmonic currents to below the limits. If, after the harmonic current has been reduced to an acceptable level, the harmonic voltage is still causing a problem and above specified levels, it shall be the responsibility of ATC to bring the harmonic voltages within limits. If limits are not violated and there is still a harmonic related problem (an unlikely situation), it is the responsibility of the entity experiencing the problem to harden its equipment to the effect of harmonics or reduce the harmonics at their location. An existing violation of these harmonic limits that is not causing any problems does not necessarily require harmonic mitigation.
2) *New harmonic producing loads* – It is the responsibility of any customer wanting to connect a harmonic producing load to the ATC system to determine if the proposed load will violate the harmonic current limits and, if these limits are violated, to determine and implement steps necessary to reduce the harmonic currents to acceptable levels. If harmonic voltage limits are not met after harmonic current limits have been met, it is the responsibility of ATC to determine if the harmonic voltage distortion will cause any system problems and if they will, it is ATC's responsibility to develop and implement a plan to meet the harmonic voltage limits.

Table 1 – IEEE 519 Voltage Distortion Limits

Bus Voltage at Point of Common Coupling	Individual Voltage Distortion (%)	Total Voltage Distortion (%)
1-kV<V≤69-kV	3.0	5.0
69-kV<V≤161-kV	1.5	2.5
161-kV<V	1.0	1.5

Note 1: These limits should be used as system design values for the "worst case" for normal operation (conditions lasting longer than one hour). For periods lasting less than one hour, these limits may be exceeded by 50 percent.

Note 2: High-voltage systems (>161-kV) can have up to two percent Total Voltage Distortion when caused by a HVDC terminal whose harmonics are attenuated by the time it is tapped by a user.

Table 2 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Between 120-V to 69-kV and All Power Generation Equipment Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order (%)					
	<11	11≤h<17	17≤h<23	23≤h<35	35≤h	TDD
<20	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

I_{SC} = maximum short circuit current at PCC

I_L = maximum demand load current (fundamental frequency component) at PCC

Note 1: Even Harmonics are limited to 25 percent of the odd harmonic limits listed above.

Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the $I_{SC}/I_L<20$ limits listed in this table, regardless of actual I_{SC}/I_L.

Table 3 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Between 69.001-kV and 161-kV Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order (%)					
	<11	11≤h<17	17≤h<23	23≤h<35	35≤h	TDD
<20	2.0	1.0	0.75	0.3	0.15	2.5
20<50	3.5	1.75	1.25	0.5	0.25	4.0
50<100	5.0	2.25	2.0	0.75	0.35	6.0
100<1000	6.0	2.75	2.5	1.0	0.5	7.5
>1000	7.5	3.5	3.0	1.25	0.7	10.0

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25 percent of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the $I_{SC}/I_L<20$ limits listed in this table, regardless of actual I_{SC}/I_L.

Table 4 – IEEE 519 Current Distortion Limits for General Systems with Nominal Voltages Above 161-kV Maximum Harmonic Current Distortion for Odd Harmonics (Percent of I_L)

I_{SC}/I_L	Individual Harmonic Order (%)					
	<11	11≤h<17	17≤h<23	23≤h<35	35≤h	TDD
<50	2.0	1.0	0.75	0.3	0.15	2.5
≥50	3.0	1.5	1.15	0.45	0.22	3.75

I_{SC} = maximum short circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at PCC
Note 1: Even Harmonics are limited to 25 percent of the odd harmonic limits listed above.
Note 2: Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
Note 3: All power generation equipment is limited to the $I_{SC}/I_L<50$ limits listed in this table, regardless of actual I_{SC}/I_L.

5. UNDER-FREQUENCY LOAD SHEDDING

Under-frequency load shedding (UFLS) island identification is based on the following criteria. In general, UFLS is designed to arrest declining frequency after an under frequency event. Island identification is the subdivision of the Bulk Electric System (BES) including the ATC transmission system into sub regions. UFLS analysis falls into two categories; frequency performance and dynamic volts per hertz performance.

5.1 Island Identification

The identification of UFLS islands is based on the NERC reliability standard PRC-006. The UFLS island identification that ATC uses is based on the following four criteria:

1) Actual Historical Island Event

   A UFLS island is identified as a portion of the BES including the ATC transmission system which was an actual historical island event within the past five years.

2) Non-UFLS System Studies

   A UFLS island is identified as a portion of the BES including the ATC transmission system which was determined to be an island through non-UFLS system studies.

3) Relay Scheme or a Remedial Action Scheme

   A UFLS island is identified as a portion of the BES including the ATC transmission system which is planned to detach from the transmission system as a result of the operation of a relay scheme or a Remedial Action Scheme.

4) Large Single Island

   A UFLS island is identified as a single island in the MRO area, the RF area, or the Eastern Interconnection that includes the entire ATC transmission system. The island shall be selected by applying the above criteria and coordinating with the criteria of MISO and PJM to verify that all ATC UFLS schemes meet the PRC-006 standard performance requirements when acting together with or without the programs of the BES.

5.2 Frequency Performance Assessment Criteria

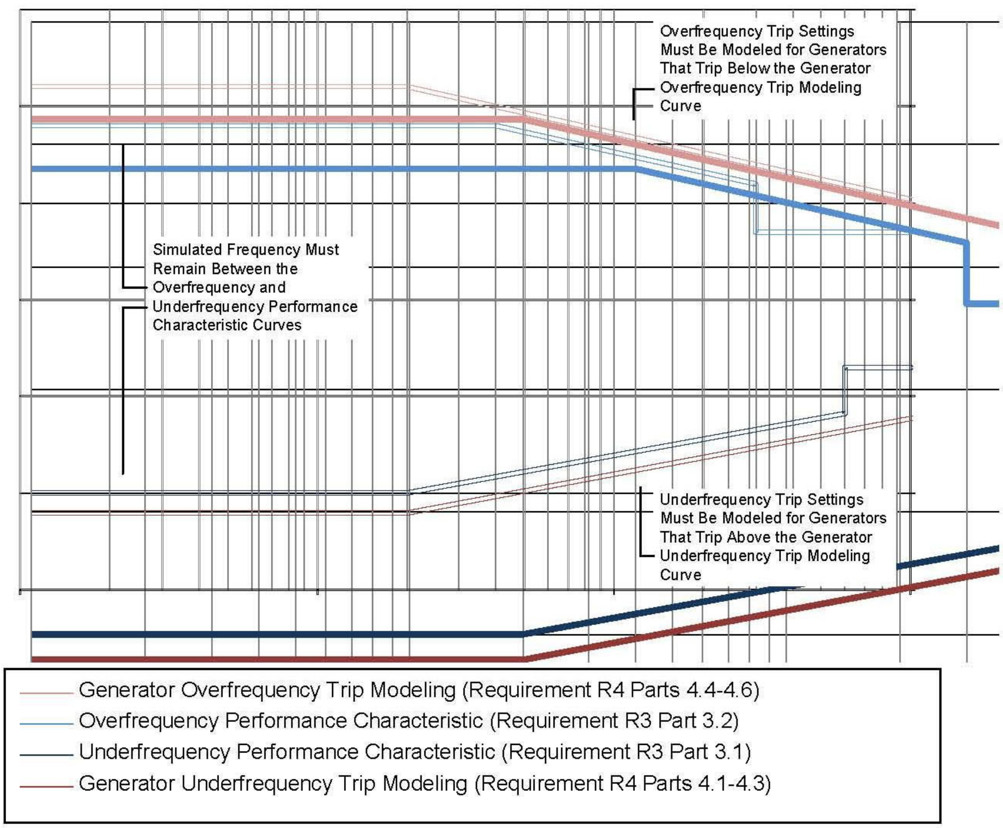
Transient island frequencies shall remain within the Under-frequency and Over-frequency Performance Characteristic Curves in PRC-006 Standard Attachment 1.

5.3 Volts Per Hertz Assessment Criteria

Transient Volts per Hertz values shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus.

PRC-006-1 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz

Figure 2: Performance Characteristic Curves for UFLS Frequency Performance Criteria

6. GENERATING FACILITY POWER FACTOR AND VOLTAGE REGULATION

6.1 Power Factor

Power Factor Requirements for Interconnection Generating Units are as follows. ATC's standard power factor range for synchronous and non-synchronous (e.g., wind turbines, solar) generation is 0.95 leading (when a Generating Facility is consuming reactive power from the transmission system) to 0.95 lagging (when a Generating Facility is supplying reactive power to the transmission system).

As illustrated in a generic example graph below, the Generating Facility must be capable of maintaining ATC's standard power factor range at all power output levels by providing continuous dynamic reactive power at the following locations (i.e. point of measurement):

a) The Point Of Interconnection (POI) for all synchronous generators

b) The high-side of the generator substation for all non-synchronous generators[5]

Figure 3: A Generic Example Graph of Acceptable Power Factor Capability

This power factor requirement applies at all power output levels unless the Generating Facility is physically disconnected from the ATC transmission system. Physically disconnected means an open

[5] FERC Order No. 827, para 34.

- generator step-up transformer high or low-side breaker(s) for a synchronous Generation Facility, or
- generator substation step-up transformer high-side breaker(s) for a non-synchronous Generation Facility.

For synchronous generators, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the POI.

- Dynamic reactive power provided by a synchronous Generating Facility may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the synchronous generator, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses.
- Dynamic leading reactive power provided by a synchronous Generating Facility cannot use inductive losses from generator step-up transformer(s) and generator tie line(s) to meet the leading power factor calculation at POI. A synchronous Generating Facility must be able to meet a 0.95 leading power factor, as measured at the generator terminal (i.e. the low side of the generator step-up transformer).

For non-synchronous generators, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of generator substation step-up transformer.

- Dynamic reactive power provided by a non-synchronous Generating Facility must meet the following requirement from FERC order 827 paragraph 35:
    - "Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses."
- Dynamic leading reactive power provided by a non-synchronous Generating Facility cannot use inductive losses from pad-mount and station step-up transformers and collector system to meet the leading power factor calculation at the high-side of the generator substation. A non-synchronous Generating Facility must be able to meet a leading 0.95 power factor, as measured at the generator terminal (i.e. the low side of the pad-mount transformer).
- Dynamic lagging reactive power provided by a non-synchronous Generating Facility cannot use collector system charging to meet the lagging power factor calculation at the high-side of the generator substation. A non-synchronous Generating Facility must be able to meet a lagging 0.95 power factor, as measured at the generator terminal (i.e. the low side of the pad-mount transformer).
- When the Generating Facility is not generating active power (i.e. zero MW output):

    a. The reactive power injection to the transmission system at the high-side of the generator substation should be zero Mvar. Exceptions for a short transition period during the switching of inverter control modes may be granted on a case by case basis if there is no reliability concern. For example, solar PV facilities may have a transition period during sunrise and sunset periods. The transition period should be minimized by the non-synchronous Generating Facilities as much as possible.

b. When the Generating Facility is physically connected but operating at zero MW and zero Mvar as measured at the high-side of the generator substation, the Generating Facility is not required to control system voltage as specified in Section 6.2 below.

c. The requirements in bullet a and b above are minimum requirements. If a non-synchronous Generating Facility has the capability to provide dynamic voltage control and maintain ATC's voltage schedule as specified in Section 6.2 below when it is at zero MW output, that is acceptable and preferred by ATC.

Static reactive power devices (e.g., capacitors and inductors) can only be used to make up for

- Inductive losses between the generator terminal and the POI for synchronous generators, or
- Inductive losses or collector system charging between the generator terminal and the high side of generator substation for non-synchronous generators.

All other reactive power needed to meet the power factor requirement must be provided by continuous and sustainable dynamic sources. Operation across the entire power factor range must be fully dynamic, variable, and capable of sustained indefinite operation.

Static sources can be switched on or off in the range of seconds and provide reactive power in large discrete blocks. Cap Banks are considered static sources of reactive power.

Dynamic sources can provide variable amounts of reactive power in a few milliseconds. Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), Flexible AC Transmission Systems (FACTS), inverters, and synchronous condensers are all considered dynamic sources of reactive power.

6.2 POI Voltage

The interconnecting generator must be capable of automatically and dynamically maintaining a POI voltage schedule that is specified by the Transmission Operator. Any generator interconnected within the ATC system is expected to maintain a voltage schedule (voltage setpoint) of 1.02 p.u. at its POI, within limits of its reactive capabilities, to facilitate transmission operations reliability under normal system conditions (system intact) and contingency conditions, unless another voltage level is communicated to the generator by the ATC Transmission Operator (cf. NERC Reliability Standard VAR-001).

7. VARIATIONS ON ATC PLANNING CRITERIA

The ATC transmission system consists of assets contributed by entities within the five Balancing Authorities of the Wisconsin-Upper Michigan Systems. Each of the original asset owners planned their system to separate planning criteria, particularly in regard to transient and dynamic performance. Therefore, as ATC has implemented its own planning criteria, portions of the system may require upgrades to meet the more stringent ATC criteria.

This section of the ATC planning criteria describes the philosophy that will be followed for completing projects in a portion of the system identified as deficient with respect to the ATC planning criteria.

Area does not meet the ATC planning criteria performance requirements.

1) Complete projects required for bringing the existing system up to the ATC planning criteria performance requirements with no intentional delay.
2) New generator interconnections are <u>not</u> permitted until the ATC planning criteria are met with the addition of the new generator, if the new generator interconnection aggravates the stability condition [A new generation interconnection is deemed to aggravate the stability performance of an area if a change in scope is required to meet the ATC planning criteria. See NERC Standard FAC-002-1 for new generator interconnections].
3) Depending on the level of risk associated with the deficiency, special operating procedures (restrictions or guides) may be required to mitigate the risk until the projects are completed. If a new generator interconnection is permitted but still negatively influences the stability condition, the operating restriction may follow a "last interconnected, first restricted" approach.
4) Reinforcements to meet ATC Criteria will be reviewed to ensure the risk, cost and benefit are in the best interest of stakeholders. ATC Planning Leadership will have the discretion to determine exceptions to the criteria.

8. DEFINITIONS

8.1 Automatic Model Adjustments

For Planning purposes, automatic model adjustments include switched shunts[6], static var compensators, phase shifters[7], and load tap changers (LTCs)[8].

[6] Most switched shunts have automatic switching or are switched by operators using supervisory control. For the supervisory controlled shunts, automatic adjustment settings are used to approximate expected operator adjustment.

[7] Phase shifters that significantly affect the ATC system are at Lone Rock, Arrowhead and Stinson. Planning assumes Lone Rock and Stinson can adjust, and Arrowhead does not because the automatic adjustment settings are very wide. This is consistent with Operations' understanding.

[8] In Planning's models, LTCs are either modeled as automatic or fixed. Automatic LTCs will adjust when a model is solved, and the fixed LTCs will remain in place. Planning Methodology & Models group maintains a list of which transformer LTCs can automatically switch and models accordingly.

8.2 Extreme Disturbance Events

An extreme disturbance event is one in which any of its component disturbance forces and their interactions with affected systems have dimensions and responses that exceed the known range of variation expected of those parameters.

8.3 Manual – Supervisory Controlled

For Planning purposes, manual supervisory controlled mitigation options include system reconfiguration, HVDC adjustment, and/or appropriate load transfer.

8.4 Manual – Field Switching

Manual field switching is not an available mitigation option to address circuit power flows above applicable ratings or to address bus voltages between 0.8 and 0.9 per unit.

8.5 Maintenance Outage

The temporary operational removal of the Facility from service to perform work on specific components in accordance with a pre-planned operations schedule, such as for a planned annual overhaul, inspections, or testing of specific equipment of the Facility.

8.6 SPS, RAS, and UVLS

These mitigation options include existing Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Under Voltage Load Shedding (UVLS).

The TPL-001-4 standard requires removal of all elements that controls would automatically disconnect for the specific event. If conditions are met to trigger an SPS, RAS, or UVLS, the Contingency analysis must be rerun to include the appropriate option (SPS, RAS, or UVLS) as a mitigation measure. This type of mitigation is only allowed if there is an existing SPS, RAS, or UVLS defined, and the Planner should be aware of when and how to utilize these options appropriately.

8.7 Short-term Steady State

The post-transient period before typical load tap changers and mechanically switched shunts can operate.

8.8 Total Load at Risk

Total Load at Risk is defined as the sum of the following four types of load loss, which are identified in steady state analyses.

Consequential Load Loss (NERC definition)

NERC definition is “All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.” It represents the load that is outaged as a result of automatic fault protection for an event-based Contingency. It excludes load that is immediately restored via automatic switching to adjacent substations.

Interruptible Load Loss

Load that is outaged by other automatic controls for an event-based Contingency based on a documented agreement between ATC and the Load-Serving Entity. The end-use customer must make the load available for curtailment to the Load-Serving Entity via contract or agreement.

Subsequent Cascading Load Loss

Load that is outaged as a result of subsequent element-based outages during the remaining cascading analysis. This type of load loss is a result of either voltage sensitive load tripping when load buses are below 0.8 p.u. or load islanding due to lines/transformers tripping. The 0.8 p.u. load tripping threshold is used as a proxy to simulate the response of voltage sensitive load. The response of voltage sensitive load refers to the tripping of the load due to intrinsic voltage protection mechanisms that manufacturers build into their equipment.

Non-Consequential Load Loss (NERC definition)

NERC definition is “Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.” It represents the non-interruptible load shed that may need to be performed by manual or automatic controls to restore the ATC system to be within emergency limits and the additional load curtailment that may need to be performed by manual or automatic control to restore the ATC system to be within normal limits.

8.9 Uncontrolled Islanding[9]

Islanding is the disconnection of one or more loads and/or generators from the Eastern Interconnection. The resulting island may contain just one load, just one generator or multiple loads and generators. The resulting island may collapse or survive depending on the mix of the load and generation in the island and the automatic controls (e.g. UFLS) present in the island.

Uncontrolled islanding is the disconnection of one or more loads and/or generators from the Eastern Interconnection. It IS NOT caused by either automatic system fault protection in response to the initial fault contingency or system operator manual actions. Uncontrolled islanding IS caused by subsequent (post fault clearing) system conditions, including but not limited to, circuit overloads and low voltages. Circuit overloads can automatically trip lines and transformers. Low bus voltage level can automatically trip generators and loads. The subsequent tripping of lines and/or transformers can result loads and/or generators being islanded. Therefore, uncontrolled islanding can result in the loss of load and/or generation.

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[9] Steady State NERC Category P Events “Interruption of Firm Transmission Service and Non-Consequential Load Loss Assessment” PLG-PRO-0213-V06

8.10 Voltage Stability Flowgate

A transmission facility or transmission element(s) that has been identified as limiting the amount of power that can be reliably transferred over the bulk transmission system due to voltage instability

9. ADMINISTRATION

9.1 Review

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies and new operating procedures, as appropriate. Annually the need for a full review will be evaluated.

9.2 Retention

The previous version of this document will be retained for at least five years after is becomes retired.

10. REVISION HISTORY

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
14	Connie Lunde, et alia	David Smith, Paul Walter	Ron Snead	Primary – split Criteria and Practices into separate documents, added voltage limit text, modified voltage stability margin text; Details – Summary of Planning Criteria V14 and Practices V1 Revisions document
15	Shane Ehster, et alia	David Smith, Paul Walter	Ron Snead	Primary – Addition of UFLS criteria, added low voltage limit text for the P-V nose, revised Category D generator stability requirements, moved Variations on ATC Planning Criteria section from Assessment Practices document
16	Curtis Roe, et alia	David Smith, Paul Walter	Ron Snead	Revised NERC references to TPL-001-4, revised annual review requirement, added criteria summary table, added maintenance plus in P1, and added TTL specifics
16.1	Curtis Roe, et alia	David Smith, Paul Walter	Ron Snead	Errata
17	Curtis Roe, et alia	David Smith, Paul Walter	Andy Dolan	Added post-Contingency voltage deviation criteria, removed post fault voltage recovery threshold, revised the TTL terminology to cascading trip threshold.
18	Curtis Roe, et alia	David Smith, Paul Walter	Andy Dolan	Updated references to IEEE 1453 and 519; and revised the transient response requirement.
19	Curtis Roe, et alia	David Smith, Paul Walter	Andy Dolan	Added non-BES rows to P1.1-P2.5 and P2.1 contingencies in Table A, removed Small Signal Stability criteria, added Section 6 Generating Facility Power Factor, and added Section 2 Variations bullet item #4.
19.1	Chengyue Guo	David Smith, Paul Walter	Andy Dolan	Added clarity around voltage limitations.
19.2	Curtis Roe	Paul Walter	Andy Dolan	Revised power factor limit (new limit 0.95 lagging).
19.3	Chengyue Guo, Damien Sommer, Mike Marz, Bob Krueger, et alia	Paul Walter Adam Manty	Andy Dolan	Added sub-section for “Inverter-Based Resources Stability Assessment”, improved languages in Voltage Stability Assessment criteria for clarification and cleaned up stability simulation time descriptions to be consistent
19.4	David Smith, et alia	Tom Dagenais	Andy Dolan	Added note 7 to the “General Steady State Performance Criteria” Table A, to clarify thermal emergency rating

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
19.5	Chengyue Guo, Damien Sommer, et alia	Paul Walter Adam Manty	Andy Dolan	Enhanced inverter-Based Resources Stability criteria and improved languages in Section 2.1.
20	David Smith	--	Andy Dolan	Changed version from 19.5 to 20 to match TYA year
20.1	Joel Berry Chengyue Guo	Adam Manty Paul Walter	Andy Dolan	Revised the Voltage Stability Margin requirement to 5% on a post-contingent basis. Clarified the application of margins on expected clearing times.
20.2	David Smith	Adam Manty	Andy Dolan	Corrected note numbers for the Table A
21	David Smith et alia	Adam Manty, Paul Walter, Robert Morton, Dale Burmester	Andy Dolan	Removed old footnote 1 related to emergency ratings, particularly in Table A. Specified generators for which stability criteria applies, particularly in Section 2. Replaced SPS with RAS.
21.1	Chengyue Guo Bob Krueger et alia	Paul Walter Adam Manty	Andy Dolan	Added clarity around ATC's generator power factor requirement in Section 6.1
21.2	Chengyue Guo et alia	Paul Walter	Andy Dolan	Added the treatment of a short transition period in bullet a and clarified in bullet c that the requirements in bullet a and b are minimum requirements in Section 6.1 under when the Generating Facility is not generating active power.
22	Jamal Khudai et alia	Paul Walter	Andy Dolan	Rewritten Section 1 “Steady State Criteria and Implementation”, Added Table A Non-Consequential load shed not allowed in-between P6 events Added Section 8 “Definitions”