ATC	Criteria	Department:	System Planning
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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 "NERC Glossary of Terms", any capitalized term herein shall have the meaning set forth in Section 11.

Approved By: Robert J. McKee Digitally signed by Robert J. McKee Date: 2026.09.14 13:07:44 -05'00'	**Prepared By:** Mike Marz, Randy Johanning, Robert Morton, Robert Krueger, et alia

CAUTION: *Any hard copy reproductions of this specification should be verified against the on-line system for current revisions.*

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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[1] unless otherwise noted. The criteria and implementation requirements are summarized in Table A including P0 through P7 Contingencies, L1 Contingencies, and Extreme Events. Criteria and Implementation for Maintenance, Known Outages, and Long Lead Time Equipment is addressed in Note 13.

[1]NERC Bulk Electric System Definition Reference Document Version 3 | August 2018

Table A: Steady State Criteria and Implementation

Category	Event Description [13]	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 and UVLS Allowed[16]	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	Cascading Allowed
				Min	Max (14)											
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
L1[15]	System Intact + Loss of Large Load	NA	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
P2.1	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

Category	Event Description (13)	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 and UVLS Allowed(16)	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	Cascading Allowed
				Min	Max (14)											
			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
P5 (12)	System Intact + Fault (Generator, Transmission Circuit, Transformers, Shunt Devices, Bus Section) + non-redundant component of a Protection System 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
Extreme Events	More severe system impacts	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Yes

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

(2) The steady state voltage shall 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, it should be clarified that load tripping as a mitigation is not acceptable for planning events except where automatic schemes are established for the tripping of load.

(6) For Categories where load curtailment is unacceptable, system design shall 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 1.2 “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.

Category	Event Description (13)	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 and UVLS Allowed(16)	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	Cascading Allowed
				Min	Max (14)											

(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 (current version subject to enforcement)[2]

(12)

a. For P5 events, ATC uses the TPL-001-5 Footnote 13.b exception. A single communications system that is both monitored and reported at a Control Center is not modeled as a valid non-redundant component of a Protection System.

b. For P5 events, ATC uses the TPL-001-5 Footnote 13.c exception. A single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit is not modeled as a valid non-redundant component of a Protection System.

c. Non-BES P5 events with relay and communication system outages are evaluated near generating units.

d. Non-BES P5 events with dc supply and control circuitry outages are not evaluated.

(13) Maintenance outages, combinations of known outages, and long lead time equipment outages are equivalent to P0 with Criteria and Implementation as described in Table A and the latest version of PLG-METH-0002 (ATC Planning Assessment Practices), except with generation redispatch and manual supervisory adjustments allowed in anticipation of valid contingencies.

a. Valid contingencies with maintenance outages are limited to P1 and P2.1 with Criteria and Implementation as described in Table A and the latest version of PLG-METH-0002 (ATC Planning Assessment Practices).

b. Valid contingencies with combinations of known outages are limited to P1 with Criteria and Implementation as described in Table A and the latest version of PLG-METH-0002 (ATC Planning Assessment Practices).

c. Valid contingencies with long lead time equipment outages are limited to P1 and P2 with Criteria and Implementation as described in Table A and the latest version of PLG-METH-0002 (ATC Planning Assessment Practices).

(14) The maximum voltage for all ATC owned equipment at 765 kV and above is 1.05 per unit for all TPL planning events. This includes temporary configurations to energize 765 kV lines. Exceptions for temporary configurations may be made on a case-by-case basis only if a detailed analysis shows that all equipment affected by the line energization has been determined to be able to withstand higher voltages.

(15) L1 contingencies include any ATC defined Large Loads. NERC includes large loads in their extreme event definition, but ATC will evaluate these as shown in Table A.

(16) See section 11

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2 TPL-001Table 1 Footnotes:

TPL-001 Table 1 Footnote 9

An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of generators 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 generators should be considered.

TPL-001 Table 1 Footnote 12

An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

1.1 Cascading Criteria

If Cascading or Uncontrolled Islanding occurs for extreme events with Total Load at Risk exceeding 1,000 MW, then an evaluation of possible actions that would reduce the likelihood or mitigate the consequences of the extreme event shall be performed.

1.2 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 active 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 active power flow that results in the post-Contingency active 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 active power flow that results in the post-Contingency active 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 when steady state analysis indicates a solution failure that is confirmed to be an unstable operating condition (not a numerical instability) and 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 active 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 active 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 active 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 capability 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 1.2-1 depicts an example of the practical implementation of the ATC Steady State Voltage Stability Criteria.

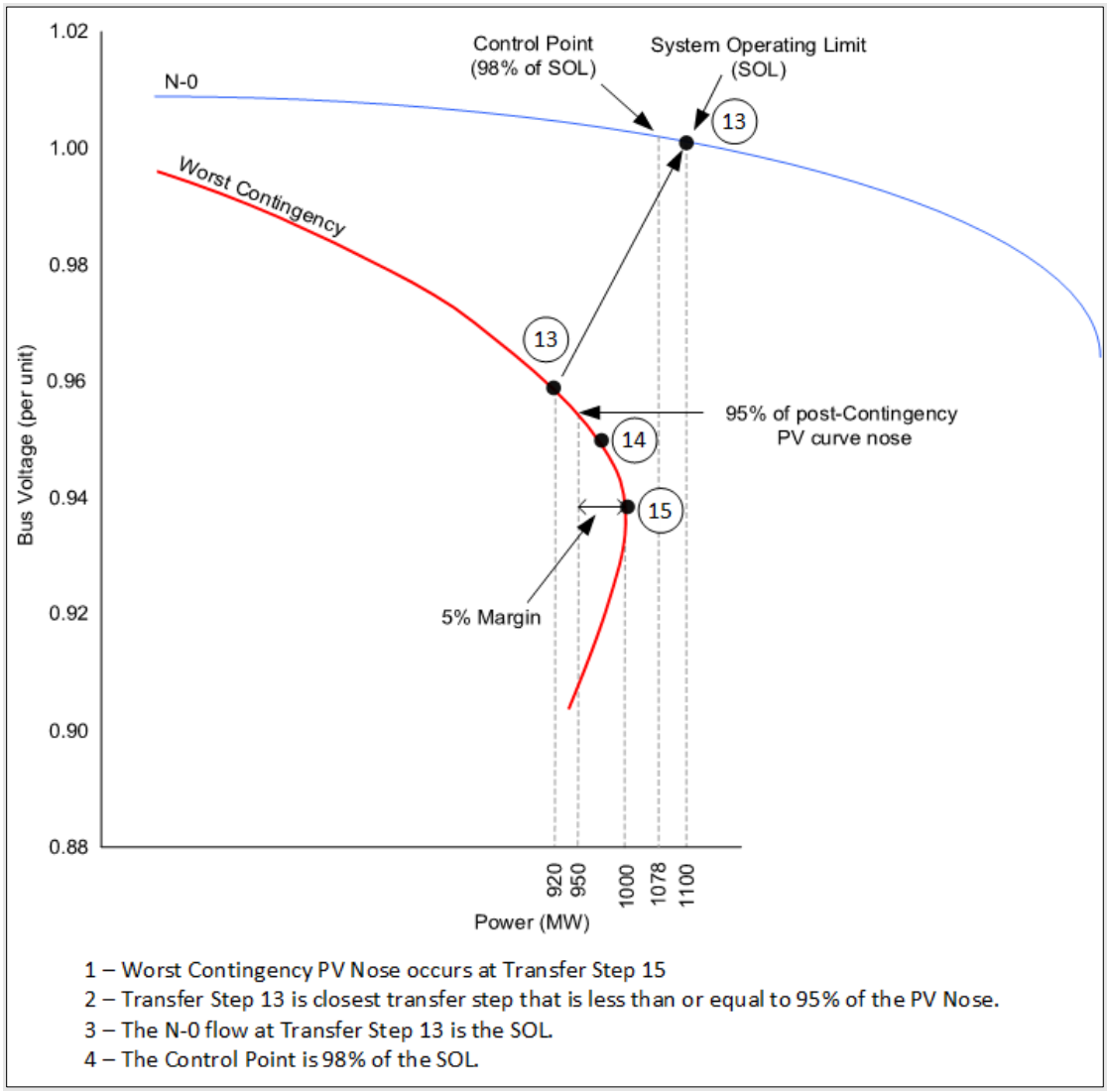


Figure 1.2-1: Practical Implementation of ATC Voltage Stability Criteria

1.3 Generation Redispatch Limitations

For events where generation redispatch is allowed as a mitigation option, redispatch of Hydro is not allowed and redispatch of Nuclear generators is not allowed except for limited exceptions. For Nuclear Generation redispatch exceptions, review the latest version of PLG-GD-0012 (System Planning Mitigation Options). However, redispatch of 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.

2. DYNAMIC STABILITY ASSESSMENTS OVERVIEW

Dynamics cases for MTEP and TYA studies are built to be consistent with the regional dynamics database with loads represented by composite modeling. Transient and dynamic stability assessments of the planning horizon are performed to assure adequate avoidance of loss of generator synchronism, avoidance of non-consequential tripping of inverter-based resources (IBRs), prevention of system voltage collapse, and availability of system reactive power devices after a system disturbance based on simulations of the disturbance for 20 seconds or less after the disturbance. If results are not adequately damped or settled for the studied duration per Section 2.1 and 2.2 below, then simulations must be run for at least 20 seconds to prove compliance with these criteria.

- For applicable MISO Transmission Expansion Plan (MTEP) and ATC studies, dynamic stability assessments will include consideration of the summer peak load and light load conditions to ensure reliability over a range of load levels.
- For generation interconnection (GI) positive-sequence dynamic stability studies, ATC will use the stability model package developed in the applicable MISO generation interconnection study process; refer to ATC Planning Methodology (PLG-METH-0002, current version) for additional dispatch requirements for GI studies. For generation interconnection Electromagnetic Transient (EMT) studies, ATC will select a steady-state model developed in the applicable MISO generation interconnection study process to be the most severe case for system translation into the EMT study model.

For planning dynamic stability assessments, ATC will apply the transient and dynamic system stability performance criteria defined in Sections 2.1 below. All BES and non-BES generators (including generator storage devices), Storage as Transmission Only Asset (SATOA), Dynamic Reactive Power Devices, E-STATCOMs, and Large Loads connected to ATC's system shall be subject to these performance criteria.[3] ATC will also incorporate the factors outlined in Section 2.2 and Section 2.3 into its assessments.

2.1 Large Disturbance Stability Performance Assessment

1) Faults will be modeled at the POI.
2) A 1.0 cycle margin will be added to the expected clearing time (ECT) for dynamic Contingency simulations. Default clearing time margins for all simulations shall be 1.0 cycle but is up to ATC engineering discretion to use a lower margin (e.g., only testing "as-built" or "field setting" with no other system changes nearby, then a 0.5 cycle margin would be allowed). The ECT margin will only be added to Near End

[3] ATC will require BES and non-BES generators going through the MISO and ATC interconnection processes to also meet these criteria; however, non-BES generators studied in MTEP or ATC's TYA that do not have validated models through the MOD-026 process, may be temporarily exempt (i.e., ATC may not develop a mitigation) from meeting this criteria until such time that the generator models have been approved by ATC.

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) TPL-001-5 Footnote 13.a defines one type of a non-redundant component of a Protection System as "A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;" ATC defines comparable Normal Clearing time to be 3 cycles.
4) 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.
5) Transient stability with combinations of known outages will be demonstrated for each applicable P1 Contingency as needed.
6) Transient stability with long lead time equipment outages will be demonstrated for each applicable P1 and P2 Contingency as needed.

2.1.1 Large Disturbance Stability Performance

The following sections must be met for compliance of ATC's Dynamic Performance.

A. Synchronous Unit Angular Stability Assessment

i. The generating unit must not lose synchronism with the transmission system for any planning events, unless it is deliberately islanded.
ii. Cascading tripping of transmission lines, tripping of transmission transformers or uncontrolled loss of load is not allowed.
iii. Poorly damped angular oscillations are not allowed. 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 simulation:
    2) The generator average damping factor for the last five cycles of the simulation is 15.0 percent or greater after the switching event.

The Average Damping Factor is defined as:

[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.

$$\text{Average Damping Factor (\%)} = \left(\frac{d_1+d_2+d_3+d_4}{4}\right) \times 100 \quad \text{[2.1-1]}$$

Where d_1, d_2, d_3 and d_4 are obtained from equation

$$d_n = (1 - SPPR_n) \quad \text{[2.1-2]}$$

Where $SPPR_n$ corresponds to the Successive Positive Peak Ratio) defined as the ratio of the peak-to-peak amplitude of a rotor angle swing (nth cycle back from the end of the simulation) to the peak-to-peak amplitude of a rotor angle swing on the previous cycle (n+1th cycle back from the end of the simulation). As shown in Figure 2.1-1, d_1, d_2, d_3 and d_4 are calculated as follows:

$$d_4 = 1 - \frac{p_4}{p_5},\ d_3 = 1 - \frac{p_3}{p_4},\ d_2 = 1 - \frac{p_2}{p_3},\ d_1 = 1 - \frac{p_1}{p_2} \quad \text{[2.1-3]}$$

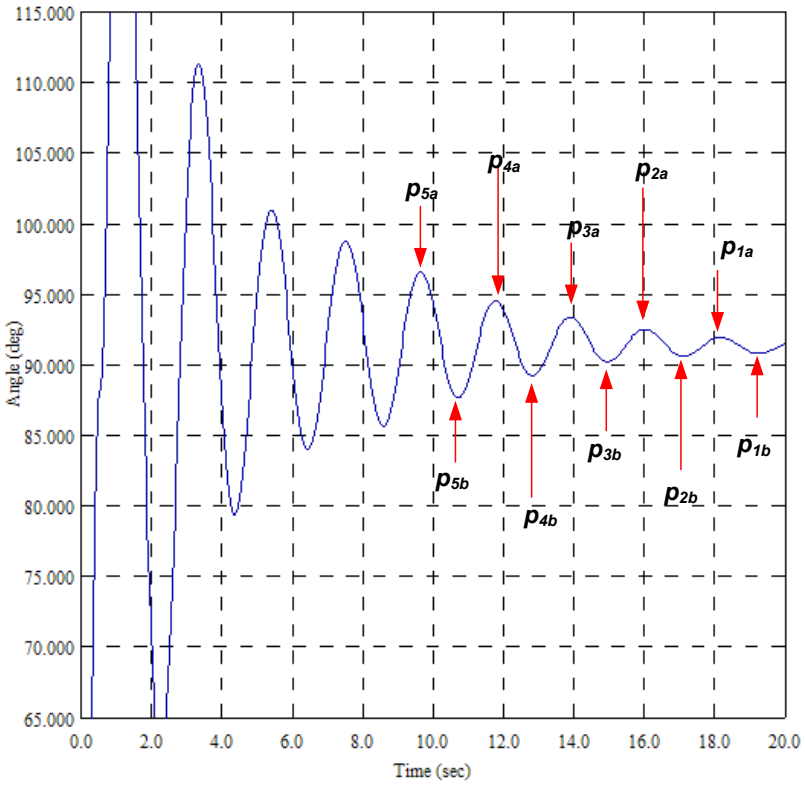
$$d_n = 1 - \frac{p_n}{p_{n+1}} = 1 - \frac{p_{n_a} - p_{n_b}}{p_{n+1_a} - p_{n+1_b}} \quad \text{[2.1-4]}$$

Example

Last 5 peak-peak magnitudes:

1) max = 96.580 time = 9.654
   min = 87.661 time = 10.712
   peak-peak = 8.918
2) max = 94.526 time = 11.771
   min = 89.222 time = 12.829
   peak-peak = 5.304
3) max = 93.371 time = 13.904
   min = 90.226 time = 14.962
   peak-peak = 3.146
4) max = 92.512 time = 16.021
   min = 90.611 time = 17.113
   peak-peak = 1.901
5) max = 91.941 time = 18.163
   min = 90.811 time = 19.246
   peak-peak = 1.129

Average Damping (last 5 peak-peak):
40.347 %
Ave. Freq. Oscillation (last 5 peak-peak):
0.470 Hz



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

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

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

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

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

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

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

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

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

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

Figure 2.1-1: Average Damping Ratio Calculation Example

B. Voltage Stability Assessment at BES Buses Serving Loads

i. Transient stability voltage response at applicable buses shall recover to at least 0.80 per unit within 2 seconds after the initiating event is cleared for all P1 through P7 Contingencies.

ii. For voltage swings after fault clearing and the first voltage recovery above 0.80 per unit, voltage dips at each applicable bus for all P1 through P7 Contingencies:

   a. Shall not dip below 0.70 per unit for more than 30 cycles continuous, or

b. Shall not dip below 0.80 per unit for more than 2 seconds continuously.

iii. Transient stability voltage response at Large Load ATC owned POI buses shall recover to less than 1.10 per unit within 1 second after the initiating event is cleared for all P1 through P7 Contingencies.

C. Inverter-Based Resources Stability Assessment

i. An IBR 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 IBR'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:

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 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. IBRs 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 simulation.

iv. For all P1 through P7 Contingencies the post-fault active power output of the IBR must recover to at least 90% of the pre-fault active power output within 1 second of the fault clearing. The IBR must settle around a single, final setpoint by the end of the simulation and must no longer be increasing or decreasing within criteria ii.b above. In addition to the Contingencies defined in TPL-001, Table 1, as three phase faults (e.g., certain P1, P3, and P6 Contingencies), this also applies to single line to ground (SLG) fault versions of these same contingencies.

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

Where needed system reinforcement cannot be implemented in an appropriate timeframe, then a corrective plan must be established in order to respect SOLs and/or IROLs. Where appropriate, corrective plans may include generator redispatch, operating guides, and/or Remedial Action Schemes (RAS) as approved by ATC.

2.2 Mackinac Area Stability Planning Assumptions

The Mackinac back-to-back HVDC has the capability to control flow from 0 to 200 MW in either direction. Consistent with the original EMT design studies, dynamic and transient EMT studies of the local area are required to model the following HVDC dispatches.

- 60 MW flowing North to South through the Mackinac HVDC device.

- 100 MW flowing South to North through the Mackinac HVDC device with local hydro generators offline.

These dispatches represent the existing Mackinac HVDC operating limits where area stability is required to be maintained. If instability is identified at either (or both) of these dispatches, additional HVDC dispatches may be required to be studied.

Consistent with the original design studies, the Mackinac HVDC is required to ride through (i.e., remain in-service and operate as designed) local P7 contingencies modeled with three phase faults and all planning events regardless of the ride through capabilities of surrounding resources.

2.3 Impacts of Shunt Capacitors to Stability

If any interconnection, material modification, or planning studies show that a planned shunt capacitor on the BES, non-BES, distribution, or as part of any Generating Facilities causes or worsens instability, as defined in Planning Criteria Sections 2.1.A, 2.1.B, 2.1.C, 2.2, and 3.6, during P0-P7 planning events, a mitigation measure shall be developed prior to the Commercial Operation Date (COD) including, but not limited to, plant tuning, installation of Dynamic Reactive Power Device or E-STATCOM installations. Existing shunt capacitor devices that worsen instability or degrade performance will be managed by Operating Guides or through collaborative efforts between ATC and the Generator Owner(s) to tune the plant.

2.4 Extreme Events

The TPL-001 Stability extreme events that are expected to produce more severe system impacts shall be evaluated to determine potential system impacts and vulnerabilities. If Cascading or Uncontrolled Islanding may occur, then an evaluation of possible actions that would reduce the likelihood or mitigate the consequences of the extreme event shall be performed.

3. GENERATOR FACILITY REQUIREMENTS

Generating facility requirements apply to plant facilities that produce real power, including generators and storage devices.

3.1 IBR Reactive Power Design Capability

All new IBRs connecting to ATC shall be designed to have the capability to support voltage by providing dynamic leading and lagging reactive power at all levels of active power output including zero MW. The maximum reactive power design capability in Mvar shall be at least 0.3287 per unit of the IBR nameplate capacity in MW, with this capability available at all levels of active power output. The IBR shall be designed to operate in a voltage support mode that will not be limited by any other IBR facility component.

3.2 Power Factor Minimum Operating Requirements

Power factor requirements within this section refer to operational requirements, IBR design capability requirements are specified in Section 3.1.

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



Figure 3.2-1: 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

1. generator step-up transformer high or low-side breaker(s) for a synchronous Generation Facility, or
2. 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.

3. 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.
4. 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.

5. Dynamic reactive power provided by a non-synchronous Generating Facility must meet the following requirement[5]:
    a. "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."
6. 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).
7. 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

[5] FERC Order No. 827, para. 35.

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).

8. When the Generating Facility is not generating active power (i.e., zero MW output):
    a. The reactive power injection to, or absorption from, 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 3.3 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 3.3 below when it is at zero MW output, that is acceptable and preferred by ATC utilizing the design outlined in Section 3.1.

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

9. inductive losses between the generator terminal and the POI for synchronous generators, or
10. 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.

3.3 POI Voltage

The interconnecting generator must be capable of automatically and dynamically maintaining a POI voltage schedule that is specified by the Transmission Operator,

including energy storage generators in charging mode. Any generator interconnected within the ATC system is expected to maintain a voltage schedule (voltage setpoint) of 1.02 per unit 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).

3.4 IBR Momentary Cessation

IBRs shall 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 or PRC-029 unless a reliability study identifies a system need to cease injecting current. IBRs shall 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 shall 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 shall occur as quickly as possible with no intentional time delay while maintaining stability.

3.5 IBR Power Priority Mode

IBRs shall be designed and configured to use a Q (reactive power) priority for the Power Plant Controller (PPC) and inverter in steady-state and transient operation.

3.6 IBR Performance Requirements

All IBRs connected to ATC shall meet the performance requirements shown in Table 3.6-1 and Table 3.6-2. Table 3.6-1 performance requirements are tested using a non-fault step change and only apply to non-fault events.

Table 3.6-1 Dynamic Active Power-Frequency Performance (1)

Parameter	Description	Performance Requirement
Reaction Time	Time between the step change in frequency and the time when the IBR active power output begins responding to the change (has reached at least 10% of new steady state value).	< 0.5 seconds
Rise Time	Time between the step change in frequency and the time at which the IBR has reached 90% of the new steady-state (target) active power output command.	< 4.0 seconds
Settling Time	Time in which the IBR has entered into, and remains within, the settling band of the new steady-state active power output command.	< 10.0 seconds
Overshoot	Percentage of rated(2) active power output that the IBR can exceed while reaching the settling band.	< 5.0%
Settling Band	Percentage of active power output that the IBR shall settle to within the settling time.	< 2.5% of MW change or < 0.5% of plant rated active power, whichever is higher

(1) This performance requirement is tested in a model using a step increase (non-fault events) in frequency of 0.5% at the POM of the IBR. Plant active power shall reduce by at least 8.8% (based on maximum 5% droop and +/- 0.036 Hz deadband, as defined in Order 842).

(2) Rated active power is the active power of an IBR at the start of a simulation.

Table 3.6-2 Disturbance Reactive Power (or Current)-Voltage Performance

Parameter	Description	Small Disturbance Performance Target (1)	Large Disturbance Performance Target (2)
Reaction Time	Time between the step change in voltage and when the IBR reactive power (or current) output begins responding to the change with no intentional time delay.	< 200 ms	< 16 ms
Rise Time	Time between a step change in voltage and when the reactive power (or current) output has reached 90% of its final value.	< 10 seconds (3)	< 100 ms
Overshoot	Percentage of rated reactive power (or current) output that the IBR can exceed while reaching the settling band(4).	< 5%	< 20% (5)

(1) Small Disturbance (e.g., normal switching-type events, changes in generation and load): For a small step change in voltage at the POM of the IBR (measure reactive power output).

(2) Large Disturbance (e.g., fault-type events): For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response shall meet the above performance specifications.
(3) The maximum Rise Time required may be reduced if studies determine that it is required.
(4) The IBR must settle around a single, final setpoint by the end of a simulation and must not be increasing or decreasing within a 3% margin of the final setpoint.
(5) Overshoot shall not negatively impact the system or nearby devices.

4. INVERTER-BASED RESOURCE EMT MODEL REQUIREMENTS

Any IBRs not subject to MISO's BPM-015 Appendix I IBR Modeling Requirements connecting to ATC must submit an Electromagnetic Transient (EMT) model compatible with the version of PSCAD used by ATC.[6] The EMT model must be able to compile in the version of Fortran used by ATC.[7] The EMT model shall accurately reflect all customer equipment, relevant control and protection systems and settings, and capabilities on the IBR side of the POI.

The following model details must be provided and be clearly observable in the main schematic of the plant model.

- Submission date
- Project Name
- Primary contact information for model related questions
- Secondary contact information for model related questions
- Manufacturer/Vendor
- Model version
- Equipment type (e.g., PV or Wind)
- Equipment version (e.g., Inverter model)
- Documentation or support file(s)[8]
- List of model Files supplied

The model must have control or hardware options which are pertinent to the study accessible to the user[9]; however, when presented to ATC, the model must be configured to match expected site-specific equipment settings. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated, as far

[6] At the time of criteria approval, ATC presently uses PSCAD v4.6.3.

[7] At the time of criteria approval, ATC presently uses Intel(R) Visual Fortran Compiler 18.0.3.210.

[8] EMT model instructional documentation shall be provided and shall match the model version in the main schematic and include instructions for setup and running of the model.

[9] Examples could include protection thresholds, active power recovery ramp rates, frequency or voltage droop settings, voltage control response times, or SSCI damping controllers. All settings must be within realistic bounds in the real hardware. Diagnostic flags to show control mode changes or which protection has been activated (e.g., trip signals) should be visible to aid in analysis.

as they are known. Default parameters are not appropriate unless these will match the configuration in the installed equipment.

Model documentation is required for the inverter and PPC and must provide instruction for setup and running the model, as well as explaining parameters and model configurations. The model documentation must include a clear way to identify the specific settings (including protection settings) and equipment configuration which will be used in any study, such that during commissioning the settings used in the studies can be checked (including recommended range of simulation timesteps). This may be control revision codes, settings files, or a combination of these and other identification measures (e.g., description of trip/operation code signals produced by the model).

The model must also represent the full detailed inner control loops of the power electronics using actual firmware code from the inverter (i.e., a “real code” model). The model cannot use the same approximations classically used in transient stability modeling, and must fully represent all fast inner controls, as implemented in the real equipment.[10] The model also must represent all control features pertinent to the type of study being done (e.g., external voltage controllers, customized PLLs, ride-through controllers, SSCI damping controllers, etc.) and operating modes that require system specific adjustment must be user accessible.

The models must also represent and enable the associated Power Plant Controller (PPC). PPCs must be represented in sufficient detail to accurately represent short term performance, including specific measurement methods, communication delays (including any sample and hold type outputs), transitions into and out of ride-through modes, settable control parameters or options, and any other specific implementation details which may impact plant behavior. Generic PPC representations are not acceptable unless the final PPC controls are designed to exactly match the generic PPC model. If multiple plants are controlled by a common controller, or if the plant includes multiple types of IBRs (e.g., Hybrid BESS/PV) this functionality must be included in the plant control model. If external or multiple voltage control devices (e.g., STATCOM/DVAR, SVC, MSCs) are included in the plant, these shall be coordinated with the PPC to prevent circulating VARs or oscillations. The PPC shall also:

1. Accept external reference variables (e.g., active power setpoint, real and reactive power values for Q control modes, or voltage values (e.g., 1.02 per unit for ATC) for voltage control modes).[11]
2. Have a mechanism to implement a settable voltage droop.
3. Respond to frequency changes by increasing or decreasing its active power as appropriate. This can be done at either the inverter level or via the PPC.[12]

[10] The model must be a full power transistor (e.g., IGBT) representation. The controller source code may be compiled into DLLs or binaries if the source code is unavailable due to confidentiality restrictions.

[11] Model must accept these reference variables for initialization and be capable of changing these reference variables mid-simulation, i.e., dynamic signal references.

[12] If the model cannot respond in this manner, a description of the under/over frequency response capabilities of the actual equipment must be provided by the manufacturer.

4. Initialize to the setpoints specified in the PPC in 5 seconds or less.[13] Active power, reactive power, and RMS voltage shall reach steady state after this initialization time.

The model must include all necessary documentation and a sample implementation test case. The test case must use a single machine infinite bus representation of the system, configured with an appropriate representative Short Circuit Ratio. The model shall contain the modeling of all the facilities from the inverters to Point of Interconnection (POI) including, but not limited to, the facilities listed below. The facilities shall be site specific according to the project design at 60 Hz grid frequency base. The EMT modeling data shall match steady state modeling data.

- Aggregated generator model
- Equivalent pad mount transformer
- Equivalent collector system
- Main step-up transformers
- Generator tie line
- Power plant controller
- Capacitor banks, STATCOM, or any other types of voltage control devices
- AC equivalent source at the POI with an appropriate representative Short Circuit Ratio for the inverter

The model must represent all pertinent electrical and mechanical configurations. This includes any filters, specialized transformers, gearboxes, pitch controllers, or others if they impact electrical performance within the timeframe of the study. Any control or dynamic features of the actual equipment which are not represented or which are approximated, must be clearly identified.

Additionally, all pertinent protection devices and protection settings must be implemented in detail AND enabled for balanced and unbalanced fault conditions. This includes but is not limited to (voltage protections (OV and UV for individual phase and RMS), frequency protections, DC bus voltage protections, converter overcurrent protections, etc.). These must be available as inputs in the model. There must also be an option to disable protection models as needed. All protection settings shall match provided positive sequence dynamic data files.

The model must also:

1. Operate and be accurate with a simulation timestep of 10 µs or greater.
2. Support multiple instances of its own definition in the same simulation case.
3. Not use or rely upon global variables in the PSCAD environment.
4. Include a plant level electrical single line diagram.
5. Not utilize multiple layers in the PSCAD environment, including ‘disabled’ layers.

[13] Model must be capable of initializing itself without external input.

6. Be capable of scaling plant capacity to represent any number of inverters or turbines, either externally by using a scaling transformer or internal scaling; but shall not be using current injection to scale the plant.
7. Be capable of dispatching plant output to values less than nameplate to test plant behavior at various operating points.

The models shall have the following minimum characteristics or functions:

- Instantaneous voltage and current waveforms shall have minimal distortion, and no oscillations observed.
- Trip or block when the terminal voltage rises above 1.3 pu for one second.
- Trip or block when terminal voltage falls below 0.2 pu for one second.
- Capable of riding-through, recovering and meeting ATC's stability criteria from a temporary (no line outage or drop in Short Circuit Ratio), 6-cycle, zero-impedance, three-phase fault at the high side of the station transformer, with an appropriate representative Short Circuit Ratio, measured at the POI, while dispatched at 20% and while dispatched at the maximum active power capability of the plant.

4.1 PSCAD Model Verification Process

For PSCAD models submitted that are not subject to MISO's BPM-015 Appendix I IBR Modeling requirements, ATC requires that all PSCAD plant models submitted to ATC use the ATC test controller component as the system equivalent. The Interconnection Customer (IC) submitting the PSCAD plant model must use the most recent published version of the ATC test controller to complete the ATC PSCAD Model Verification checklist. The ATC PSCAD Model Verification checklist and the ATC test controller component are posted on ATC website (https://www.atcllc.com/customer-engagement/). The checklist must show that the PSCAD plant model meets all ATC PSCAD modeling requirements for ATC to accept the PSCAD plant model.

For PSCAD models submitted that are subject to MISO's BPM-015 Appendix I IBR Modeling requirements, ATC does not have additional PSCAD model verification requirements beyond what is required by MISO.

4.2 As-Built Parameter Verification Process

For PSCAD models submitted that are not subject to MISO's BPM-015 Appendix I IBR Modeling requirements, the As-built Parameter Verification Process shown in Figure 4.1-1 is required to be followed for all IBRs that are required to submit a PSCAD model to ATC. The IC shall update the PSCAD plant model with as-built parameters and submit the as-built model as soon as all plant parameters are finalized (at least 30 days prior to COD). ATC will compare the as-built model with the model studied in the generation interconnection process and decide if there are any stability concerns prior to the plant proceeding to commercial operation.

For PSCAD models submitted that are subject to MISO's BPM-015 Appendix l IBR Modeling requirements, ATC does not have additional as-built PSCAD model verification requirements beyond what is required by MISO.

***CAUTION**: Any hard copy reproductions of this specification should be verified against the on-line system for current revisions.*

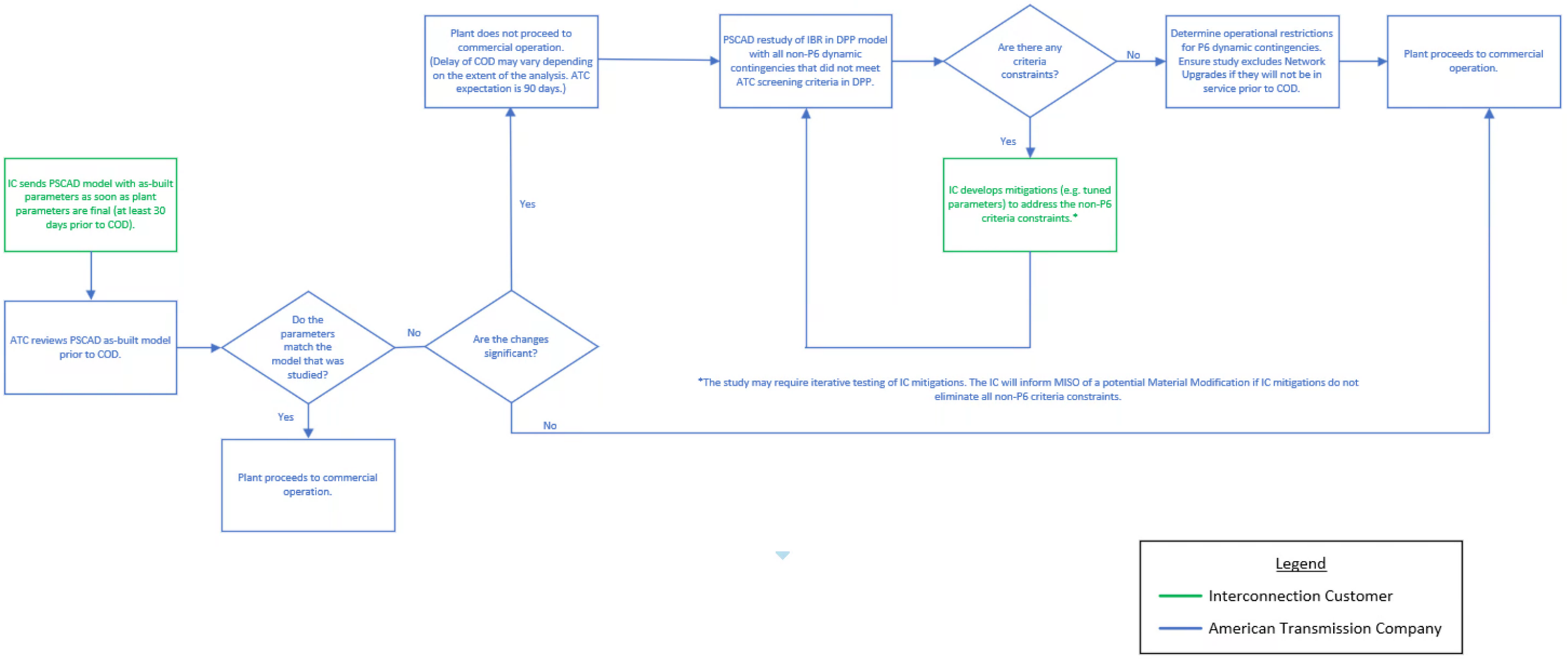


Figure 4.1-1: As-Built Parameter Verification Flowchart

4.3 Post-Commercial Operation Date Model Update Requirements

For PSCAD models submitted that are not subject to MISO's BPM-015 Appendix I IBR Modeling requirements, IBR owners are required to resubmit their PSCAD plant models to ATC as corrections, updates, or modifications are made to their PSCAD plant model that would impact the output, response, or general function of the plant. Model updates shall be submitted to ATC using the ATC Generating Facilities Modification Notification (GFMN) form. See the current version of the ATC GFIG (Generating Facility Interconnection Guide) for additional requirements following commercial operation.

For PSCAD models submitted that are subject to MISO's BPM-015 Appendix I IBR Modeling requirements, ATC does not have additional as-built PSCAD model verification requirements beyond what is required by MISO. The models and verification submitted to MISO shall also be submitted to ATC via the GFMN process at the same time.

5. VOLTAGE FLUCTUATION AND FLICKER

In general, all equipment connected to the ATC system is required to meet these voltage fluctuation and flicker criteria. ATC may allow specific higher fluctuation and flicker levels at specific locations where ATC has determined through experience or analysis that exceeding these requirements will not cause system or customer issues. Additional information on the development and application of these criteria can be found in ATC Guide PLG-GD-0020, "Voltage Fluctuation and Flicker."

Voltage fluctuations include rapid voltage changes (RVC) lasting several cycles before taking seconds to return to a new steady state voltage. RVCs are caused by events such as load changes, motor starting, and transformer energization and are defined as the difference between two voltage levels - one before and one immediately after the event. RVCs, as a function of the number of changes per day or hour and voltage level, shall not exceed the values specified in Table 5-1.

Table 5-1 – Acceptable Voltage Change (%) as a Function of the Number of Changes Per Time Period and Voltage (IEEE 1453-2022, Table 3 Maximum Values)

Number of Changes n	$\Delta V/V_{nominal}$	
	MV	HV/EHV
n ≤ 4 per day	6%	5%
n ≤ 2 per hour and > 4 per day	4%	3%
2 < n ≤ 10 per hour	3%	2.5%

Note: 1 kV < MV ≤ 35 kV, 35 kV < HV ≤ 230 kV, EHV > 230 kV

Capacitor Switching Step Voltage Change Limits. Steady state step voltage changes due to capacitor switching shall not exceed 3% at minimum normal system strength. ATC may allow Relative Voltage Changes due to device switching to exceed 3% when the transmission system is not intact due to either planned or unplanned equipment outages, but this shall not exceed 5%. Other infrequent switching events, such as line energization

or tripping, that usually occur less than once a day, can cause severe voltage variations that shall be evaluated in the planning stage and comply with the limits in Table 5-1.

ATC has three flicker criteria, one general criterion applicable to all cases and two criteria applicable to special cases. 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.

The **General Flicker Criteria** (based on IEEE 1453) is applicable to all cases and uses Pst (short term perception – 10 minutes) and Plt (long term perception – 2 hours) as measured using an IEC standard flickermeter. Different Pst and Plt limits are used for compatibility (all equipment operates as intended) and planning (which includes some margin). A flickermeter calculates the 95% and 99% probability values $P_{st99\%}$, $P_{st95\%}$, $P_{lt99\%}$ and $P_{lt95\%}$, which represent values that are not exceeded 95% and 99% of the time. Compared to the system flicker planning levels in Table 5-2, (1) the 95% probability value shall not exceed the planning level and (2) the 99% probability value may exceed the planning level by a factor (1−1.5) depending on system conditions to be determined by ATC. The limits shown in Table 5-2 apply to an individual customer's emissions at their point of common coupling (PCC).

Table 5-2 – Compatibility and Planning Flicker Limits

	Compatibility Levels	Planning Levels	
	LV ≤ 1 kV	1 kV < MV ≤ 35 kV	HV & EHV > 35 kV
Pst	1.0	0.9	0.8
Plt	0.8	0.7	0.6
Note: LV ≤ 1 kV, 1 kV < MV ≤ 35 kV, 35 kV < HV ≤ 230 kV, EHV > 230 kV			

Single Frequency Flicker. In the unlikely condition that the flicker to be analyzed consists of a single frequency caused by step changes in RMS voltage, the flicker tolerance curve shown in Figure 5-1 can be used to determine if the flicker is acceptable. ATC limits single frequency flicker to below the "borderline of irritation" on Figure 5-1. ATC does not have provisions for a margin or any time for this limit to be exceeded.

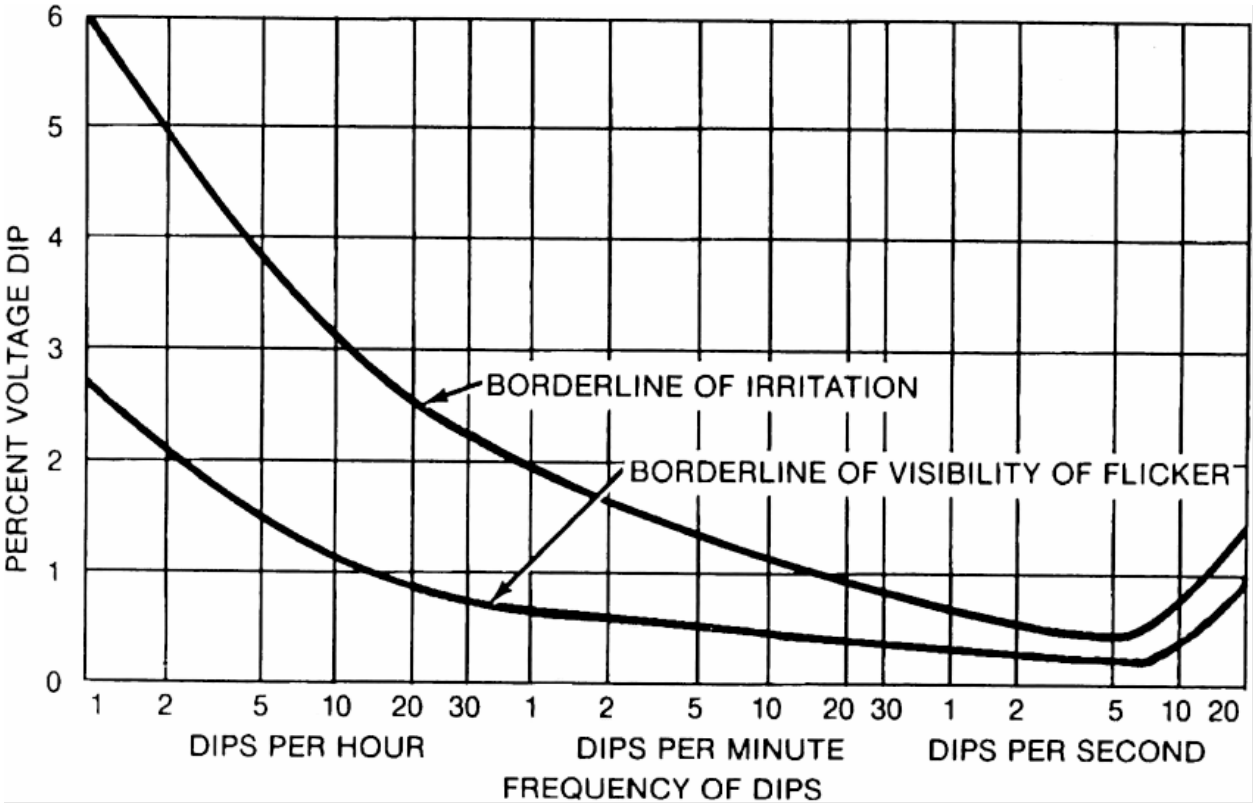


Figure 5-1: Flicker Tolerance Curve from IEEE Standard 1453

Flicker Caused by Interharmonic Voltages below 120 Hz: Interharmonic voltages with frequencies up to 120 Hz can cause flicker and shall be limited to the 95th percentile short time interharmonic voltage values shown in Figure 5-2.

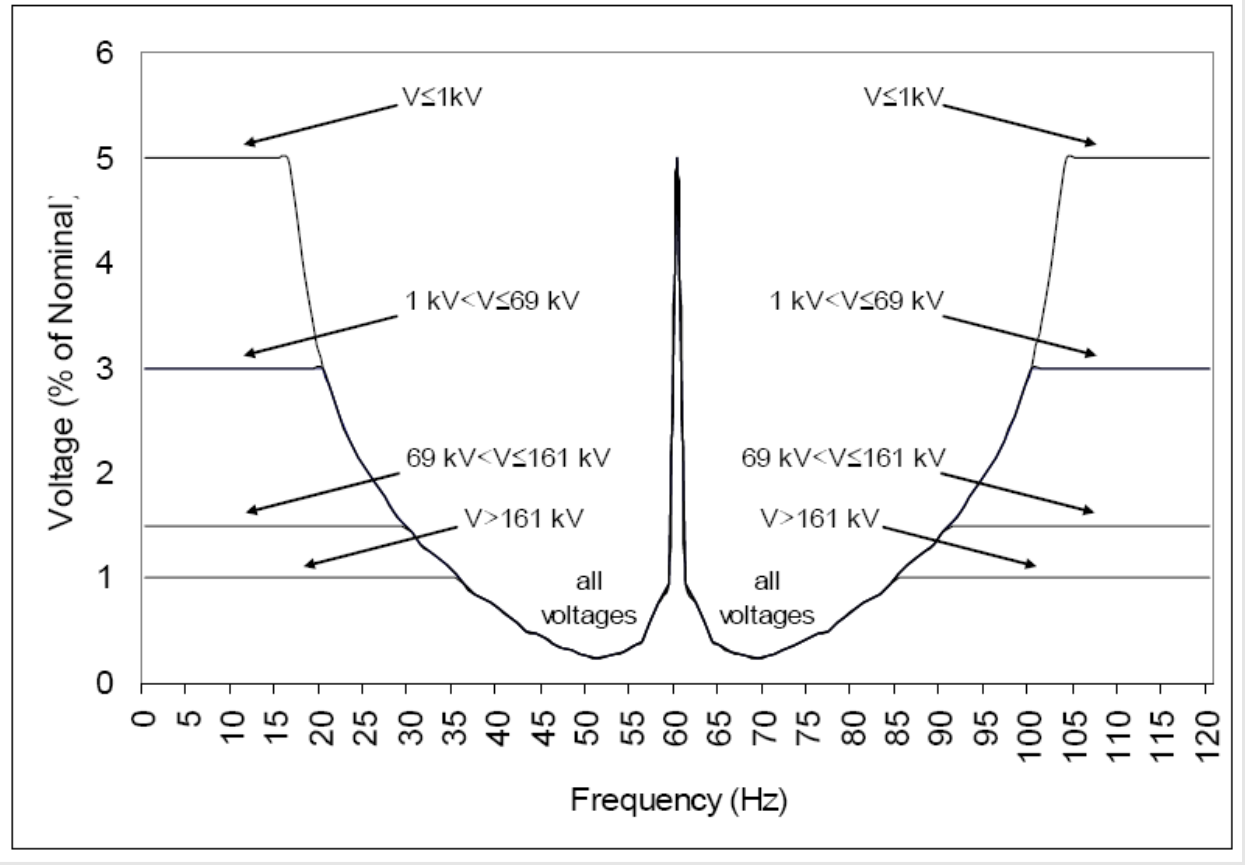


Figure 5-2: Flicker Limits Based on Interharmonic Voltages < 120 Hz (IEEE 1453)

6. HARMONIC AND INTERHARMONIC VOLTAGE AND CURRENT DISTORTION

In general, all equipment connected to the ATC system is required to meet these harmonic criteria. ATC may allow specific higher harmonic levels at specific locations where ATC has determined through experience or analysis that exceeding these requirements will not cause system or customer issues. Harmonic criteria are designed so that in most cases when harmonic current limits are met, harmonic voltage limits will also be met. It is the responsibility of loads to meet harmonic current limits at their PCC and the responsibility of ATC to meet harmonic voltage limits.

These harmonic criteria are based on specific measurement techniques that use the harmonic measurement windows, short and very short time harmonic measurements, and statistical evaluation defined in IEEE 519-2022. Any harmonic meter used to measure harmonics on the ATC system shall specify that they are IEEE 519-2014 compliant. Additional information on these measurements and application techniques can be found in ATC Guide PLG-GD-0019 “Harmonic Distortion” and IEEE-519-2022, “IEEE Standard for Harmonic Control in Electric Power Systems.”

Harmonic Voltage Limits. Table 6-1 lists limits for both Individual Harmonic and Total Harmonic Voltage Distortion (THVD) to be applied when large new harmonic loads are

connected to the system and when harmonic related issues are discovered These limits are applied to line-to-neutral voltages at the Point of Common Coupling (PCC) and reported as the percentage of the rated power frequency voltage. Total Harmonic Distortion is calculated as the square root of the sum of the squares of the individual harmonic distortions (root square sum - RSS). Limits are given for four voltage ranges, with the limits being more restrictive at higher voltage levels.

Table 6-1 – IEEE 519-2022 Harmonic Voltage Distortion Limits

Line-to-neutral voltage harmonics shall be limited as follows (% of rated voltage at PCC):
(1) Daily 99th percentile very short time (3 s) values shall be < 1.5 times Table 6-1 values
(2) Weekly 95th percentile short time (10 min) values shall be < the Table 6-1 values

Bus Voltage at Point of Common Coupling (PCC)	Individual Harmonic Voltage Distortion (%)	Total Harmonic Voltage Distortion (%)
V ≤ 1.0 kV	5.0%	8.0%
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%*
*High-voltage systems (V > 161 kV) can have up to 2.0% THVD where the cause is an HVDC terminal whose effects will have attenuated at points in the network where future users may be connected.		

Current Distortion Limits. Tables 6-2 to 6-4 list limits for both Individual and Total Harmonic Current Distortion to be applied to harmonic producing loads at their Point of Common Coupling (PCC). Both are reported as percentages of the fundamental frequency component of the maximum demand load current (I_L) - the maximum demand during each of the twelve previous months divided by 12. Limits are given for three voltage ranges, with the limits being more restrictive at the higher voltages. These current limits vary with the size of the load (I_L) in relation to system strength (I_{SC}) and harmonic frequency. All synchronous generation, regardless of the I_{SC}/I_L ratio at its PCC, are held to the minimum I_{SC}/I_L limits for their voltage range. Generator installations with primarily IBRs (combined site rated generation ≥10% of the average annual load demand) shall comply with applicable IEEE Standards including 1547 (IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces) and 2800 (IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems) as applicable.

Table 6-2 – Harmonic Current Distortion Limits for Systems Rated 120 V through 69 kV and All Power Generation Equipment

Daily 99th percentile very short time (3 s) harmonic currents shall be < 2.0 times Table 6-2 values.
– Weekly 99th percentile short time (10 min) harmonic currents shall be < 1.5 times Table 6-2 values.
– Weekly 95th percentile short time (10 min) harmonic currents shall be < the Table 6-2 values.

Maximum Harmonic Current Distortion for Individual Odd Harmonics and TDD (% of I_L)[a,b]						
I_{SC}/I_L	$3 \le h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h < 50$	TDD
<20[c]	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%

a. For h ≤ 6, even Harmonics are limited to 50% of the harmonic limits listed above.
b. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
c. All power generation equipment is limited to these values, regardless of ISC/IL where ISC = maximum short circuit current at PCC and IL = maximum demand load current (fundamental frequency component) at PCC

Table 6-3 – Harmonic Current Distortion Limits for Systems Rated > 69 kV to 161 kV

Daily 99th percentile very short time (3 s) harmonic currents shall be < 2.0 times Table 6-3 values.
– Weekly 99th percentile short time (10 min) harmonic currents shall be < 1.5 times Table 6-3 values.
– Weekly 95th percentile short time (10 min) harmonic currents shall be < the Table 6-3 values.

Maximum Harmonic Current Distortion for Individual Odd Harmonics and TDD (% of I_L)[a,b]						
I_{SC}/I_L	$3 \le h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h < 50$	TDD
<20[c]	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%

a. For h ≤ 6, even Harmonics are limited to 50% of the harmonic limits listed above.
b. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
c. All power generation equipment is limited to these values, regardless of ISC/IL where ISC = maximum short circuit current at PCC and IL = maximum demand load current (fundamental frequency component) at PCC

Table 6-4 – Harmonic Current Distortion Limits for Systems Rated > 161 kV

Daily 99th percentile very short time (3 s) harmonic currents shall be < 2.0 times Table 6-4 values.
– Weekly 99th percentile short time (10 min) harmonic currents shall be < 1.5 times Table 6-4 values.
– Weekly 95th percentile short time (10 min) harmonic currents shall be < the Table 6-4 values.

Maximum Harmonic Current Distortion for Individual Odd Harmonics and TDD (% of I_L)[a,b]						
I_{SC}/I_L	$3 \le h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h < 50$	TDD
< 25[c]	1.0%	0.50%	0.38%	0.15%	0.10%	1.5%
25 < 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%

a. For h ≤ 6, even Harmonics are limited to 50% of the harmonic limits listed above.
b. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
c. All power generation equipment is limited these values, regardless of ISC/IL where ISC = maximum short circuit current at PCC and IL = maximum demand load current (fundamental frequency component) at PCC

Recommendations for Increasing Harmonic Current Limits. The limits on certain harmonic currents given in Table 6-2, Table 6-3, and Table 6-4 can be increased by the multiplying factors in Table 6-5 when actions are taken to reduce other harmonic currents. The multipliers in Table 6-5 are applicable when steps are taken to reduce the harmonic orders listed in the first column. Taking the first row as an example, if a 12 pulse rectifier that keeps the 5th and 7th harmonics below 25% of their limits in Tables 6-2, 6-3 and 6-4) is used, all other (non-5th and 7th) harmonic current limits are increased by 40%.

Table 6-5 –Recommended Multipliers for Increases in Harmonic Limits

Harmonic Orders Limited to 25% of Values Given in Tables 6-2 to 6-4	Multiplier
5, 7 (12-pulse rectifier)	1.4
5, 7, 11, 13 (18 pulse rectifier)	1.7
5, 7, 11, 13, 17, 19 (24 pulse rectifier)	2.0
5, 7, 11, 13, 17, 18, 23, 25 (30 pulse rectifier)	2.2

Interharmonic Limits. To prevent interference with Automatic Meter Reading (AMR) systems, ATC limits the Total Interharmonic Voltage Distortion (TIHVD) of all interharmonics below 1000 Hz (i.e. the root sum square of the first 16 interharmonics) to below 0.4%. All connections to the ATC system shall not cause the TIHVD at their point of interconnection to exceed 0.4%.

7. 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.

7.1 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 RAS

   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 RAS.

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.

7.2 Frequency Performance Assessment Criteria

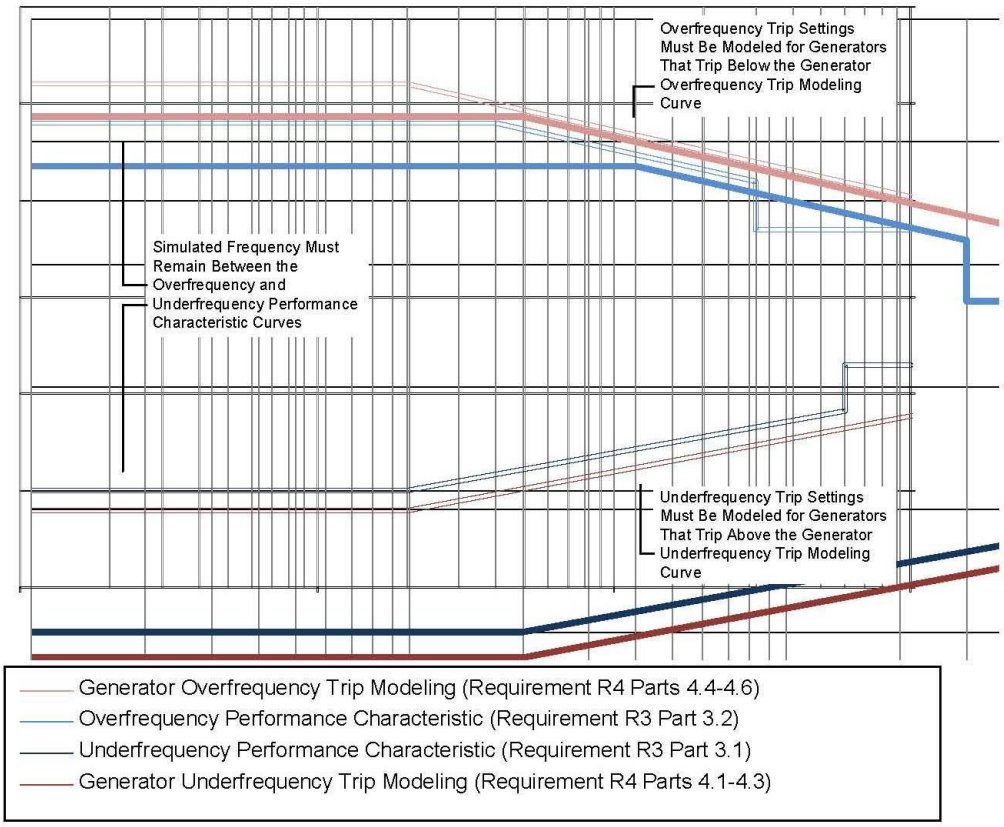
Transient island frequencies shall remain within the Under-frequency and Over-frequency Performance Characteristic Curves in PRC-006 Standard Attachment 1.

7.3 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 7.3-1: Performance Characteristic Curves for UFLS Frequency Performance Criteria

8. EXCEPTIONS TO ATC PLANNING CRITERIA

Under rare circumstances, limited exceptions to these criteria may be considered when warranted by project-specific or study-specific conditions, provided system reliability is maintained. ATC Planning Leadership shall have sole discretion to evaluate and approve any such exceptions.

9. LARGE LOAD INTERCONNECTIONS PERFORMANCE REQUIREMENTS

Please see the ATC Load Interconnection Guide for more information on these criteria. The requirements in Sections 9.1 and 9.2 shall apply during normal, abnormal, and emergency transmission system conditions unless explicitly stated otherwise.

9.1 Load Active Power Oscillations & Ramp Rate Limits

Customer's equipment/facility shall be designed and operated within the maximum allowable variation limit of steady state (continuous load operation) active power oscillations as follows and as measured at the point of interconnection (POI) to the ATC transmission system.

Table 9.1-1: Active Power Oscillation Criteria Limits

Constant	Limit	Unit
ΔP2	25[14]	MW
T1	5	seconds
P3	50	MW
R2	0.5	MW/second (MW/s)

Criterion 1: Repetitive changes in load active power must be < ΔP2 for any period of time < T1 seconds calculated using a sliding time window.

[14] By default, a new interconnection shall limit aggregated power oscillations at the POI to no more than 25 MW. However, if studies or established operating limits in the vicinity of the POI indicate a more restrictive oscillation amount, the lower limit shall apply.

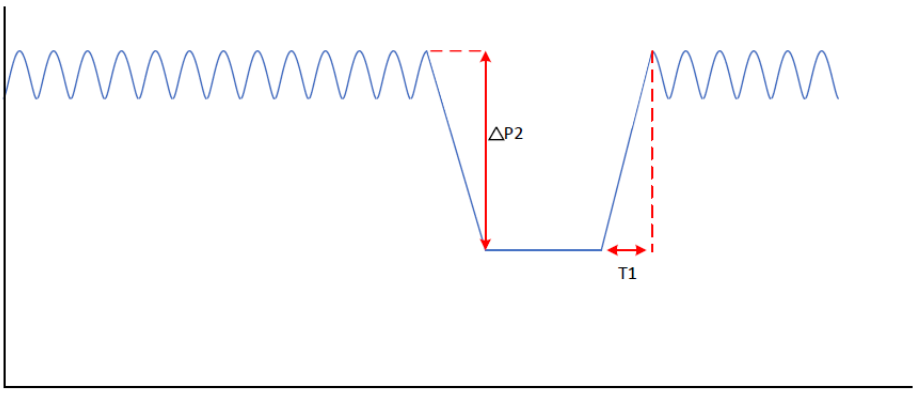


Figure 9.1-1: Active Power Criterion for ΔP2 and T1, Example 1

For example, for T1 = 5 seconds, all sine waves of frequency 0.1 Hz or higher with a magnitude greater than ΔP2 are unacceptable. Frequencies less than 0.1 Hz with magnitudes greater than ΔP2 may be acceptable if other criteria are not exceeded.

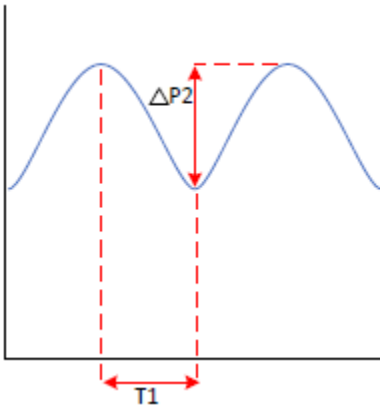


Figure 9.1-2: Active Power Criterion for ΔP2 and T1, Example 2

Step changes or square waves at any frequency are unacceptable if the step is larger than ΔP2.

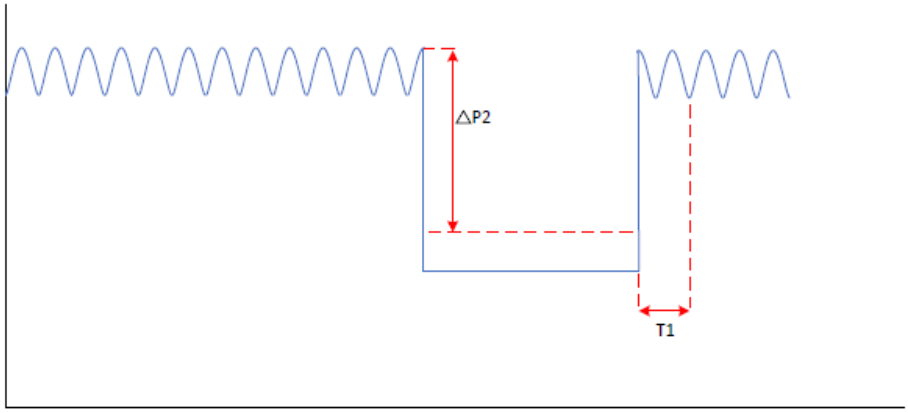


Figure 9.1-3: Active Power Criterion for ΔP2 and T1, Example 3

ΔP2 and T1 are chosen to (1) prevent damage to system equipment and (2) maintain acceptable system voltage and frequency.

Criterion 2: Any change (increase or decrease) in active power > P3 MW shall be limited to < R2 MW/s.

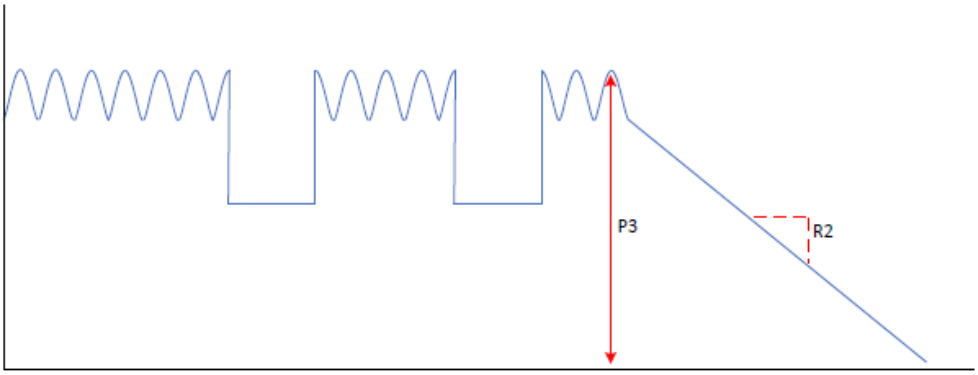


Figure 9.1-4: Active Power Criterion for P3 and R2 Example

This criterion is designed to address resource management, reserves, scheduling, real-time contingency analysis, and other operator concerns associated with starting or stopping large processes where the facility is trying to achieve a new continuous operating state. P3 and R2 are chosen to allow operators to react and voltage and frequency control resources to be brought in service. Criterion 2 should be measured in MW/s and applied for any 1 second average.

9.2 Voltage Ride Through

The interconnection customer shall ensure that the load rides through the voltages below without tripping due to voltage excursions within the Voltage Tolerance Envelope.

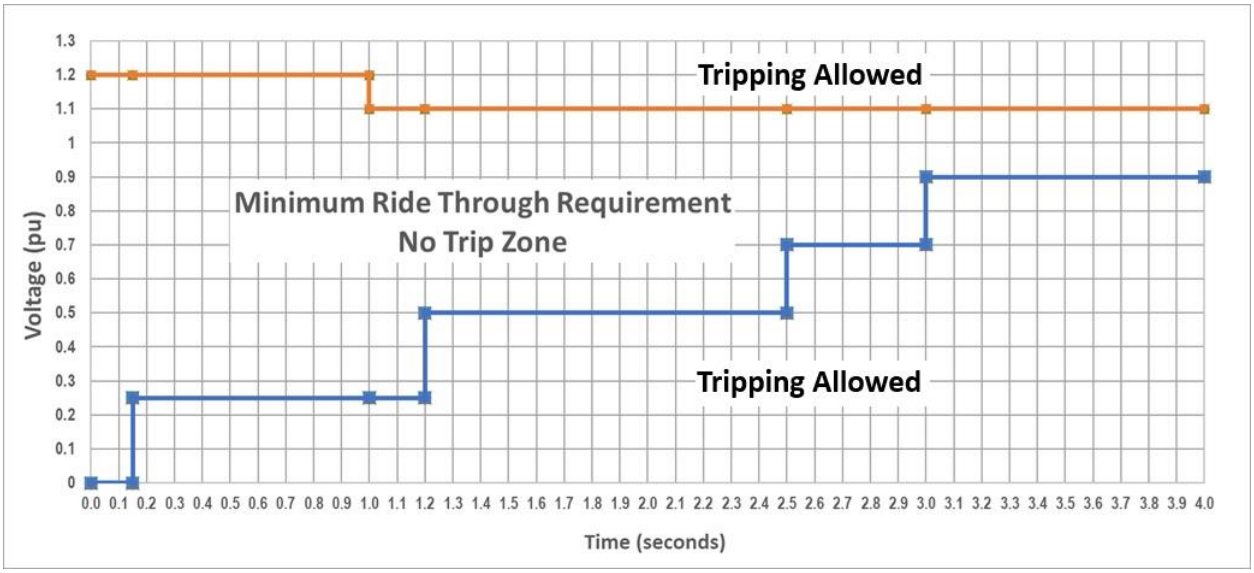


Figure 9.2-1: Voltage Ride Through Curve for Large Loads

Table 9.2-1: Voltage Tolerance Envelope defining voltage limits and time thresholds for load ride-through

POI Voltage (pu)	Minimum ride-through time (s)
V > 1.20	May ride-through or trip
V > 1.10	1.00
V ≥ 0.90 & V ≤ 1.10	Continuous
V < 0.90	3.00
V < 0.70	2.50
V < 0.50	1.20
V < 0.25	0.15
Note 1: Load must ride through 3 voltage excursion events within 10 seconds. Note 2: POI Voltage is at the connection point to the ATC transmission system. For ride-through, the relevant voltage is the lowest (in the case of undervoltage) or highest (in the case of overvoltage) magnitude fundamental frequency phasor component of the applicable voltages at the POI relative to the nominal voltage. Instantaneous phase voltages may exceed these levels.	

Note 3: Load shall not trip for instantaneous transients due to normal system events such as faults, energization or switching.

10. REMEDIAL ACTION SCHEMES (RAS)

ATC-owned RAS may be used as an interim solution to mitigate transmission constraints pending the completion of planned network upgrades to meet NERC standards and ATC planning criteria. All RAS installations for which ATC has a direct compliance obligation shall be limited to no more than ten years after which a system improvement must be in-service to permit retirement of the RAS. Because RAS is intended only as an interim measure, it shall not be relied upon as a long-term solution, including in, but not limited to MISO Generation Interconnection studies and ATC load interconnection studies.

Customer-owned or customer-initiated RAS installations shall not cause ATC to have a direct compliance obligation.

11. DEFINITIONS

11.1 Automatic Model Adjustments

For Planning purposes, automatic model adjustments include switched shunts[15], static var compensators, phase shifters[16], and load tap changers (LTCs)[17].

11.2 Dynamic Reactive Power Devices

Dynamic Reactive Power Devices adjust reactive power output automatically in real-time over a continuous range within a specified voltage bandwidth in response to grid voltage changes. These devices operate to maintain a set point voltage or operate in a voltage droop mode. Many Dynamic Reactive Power Devices, particularly those employing power electronics, can respond within electrical cycles using fast-acting controls. Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), other Flexible AC Transmission Systems (FACTS), inverters, and synchronous condensers are all Dynamic Reactive Power Devices.

[15] 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.

[16] 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.

[17] 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.

11.3 Known Outage

The combination of all planned outages (scheduled and/or known) with schedules overlapping on a single date as described in MISO Business Practice Manual 020 *Transmission Planning* section 4.3.6 *Consideration of Planned Outages in the Near-Term Transmission Planning Horizon*.

11.4 Large Load(s)

Loads that serve a single end use customer/deliver point that are greater or equal to 200 MW.

11.5 Long Lead Time Equipment Outage

Outage of equipment that could take one year or more to replace.

11.6 Manual – Supervisory Controlled

Includes system reconfiguration, HVDC adjustment, and/or appropriate load transfer.

11.7 Manual – Field Switching

Manual operation of field switches outside of the control center for system reconfiguration or load transfer.

11.8 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.

11.9 Near End

The protective device physically closest to the electrical fault.

11.10 RAS and UVLS

These mitigation options include existing RAS, and Under Voltage Load Shedding (UVLS).

The TPL-001 standard requires removal of all elements that controls would automatically disconnect for the specific event. If conditions are met to trigger a RAS or UVLS, the Contingency analysis must be rerun to include the appropriate option (RAS or UVLS) as a mitigation measure.

11.11 Short Circuit Ratio

The short-circuit MVA capacity at the IBR POI divided by the maximum active power capacity of the IBR.

11.12 Short-term Steady State

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

11.13 Static Reactive Power Devices

Static Reactive Power Devices provide constant reactive power output at nominal voltage, and their capability varies with the square of the voltage. These devices are switched in or out of service based on system conditions. Switching action can be manual or automatic, but these devices provide constant reactive power to the grid once connected. Shunt capacitors and shunt inductors are Static Reactive Power Devices.

11.14 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)

The 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.

Non-Consequential Load Loss (NERC definition)

The 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.

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 per unit or load islanding due to lines/transformers tripping. The 0.8 per unit 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.

11.15 Uncontrolled Islanding

Islanding is the disconnection of one or more loads and/or generators from the BES and Non-BES. 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 BES and Non-BES. 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 voltages can automatically trip generators and loads. The subsequent tripping of lines and/or transformers can result in loads and/or generators being islanded. Therefore, Uncontrolled Islanding can result in the loss of load and/or generation.

11.16 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.

12. ADMINISTRATION

12.1 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. This document will be reviewed and evaluated at least annually.

12.2 Retention

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

12.3 References

This criteria relies on the material from other sources that ATC maintains. These other sources contain additional non-performance, design criteria and operational requirements outside of these performance criteria. These include but are not limited to the following documents:

- ATC Transmission Planning Assessment Practices
- ATC Load Interconnection Guide
- ATC Generating Facility Interconnection Guide
- ATC Transmission Interconnection Guide
- ATC TPL-001 Contingencies Rationale

13. 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 3 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
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.

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
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 3.2
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 3.2 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 9 "Definitions"
22.1	Jamal Khudai, Joel Berry, Mike Marz, Stephanie Schmidt, Randy Johanning, et alia	Paul Walter	Tom Dagenais	TPL-001-5 compatibility related edits i.e. P5 Added known outage and long lead time equipment Added Resource Facility Requirements Section 3 Added IBR EMT Model Requirements Section 4 Updated Voltage Fluctuation and Flicker Section 5 and Harmonic Voltage and Current Distortion Section 6
22.2	Damien Sommer	Paul Walter	Tom Dagenais	IBR Model Verification Process Section 4
22.3	Damien Sommer, Chengyue Guo, Xiangyang Zhou Randy Johanning Joel Berry, et alia	Paul Walter Adam Manty	Tom Dagenais	Clarified on how positive-sequence dynamic models and EMT models are used in different processes in Section 2 Added Section 2.3 Impacts of Shunt Capacitors to Stability Added IBR EMT model submittal deadline in generation interconnection study process in Section 4. Streamlined the existing PSCAD As-built Parameter Verification Process (Section 4)
22.4	Joel Berry, Randy Johanning, Xiangyang Zhou, Josh Tellier, Mike Marz, et alia	Paul Walter Adam Manty	Tom Dagenais	Clarified study requirements for damping criteria Updated cascading criteria verbiage Added Section 4.3 Post-COD Model Update Requirements Update numerous "should" / "shall" verbiage Added Table A footnote 13 verbiage to reference PLG-METH-0002 Updated Table 4 footnote 5 verbiage. Added BESS to 3.3 POI Voltage section requiring them to maintain POI voltage schedule in charging mode. Updates and clarifications to Section 5 and 6.

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
22.5	Damien Sommer, Joel Berry, Josh Tellier, Mike Marz, Xiangyang Zhou	Paul Walter Adam Manty	Tom Dagenais	Added Table A footnote 14 verbiage which specifies Vmax for 765 kV facilities Added Section 2.3 Mackinac Area Planning Requirements
25	Mike Marz, Randy Johanning, Robert Morton, Robert Krueger	Adam Manty Joey Cheng	Tom Dagenais	Added new section 9 for Large Load Interconnection Requirements, moved Definitions to section 10; small consistency edits
26	Randy Johanning, Joel Berry, Lance Letellier, et alia	Adam Manty, Joey Cheng	Robert McKee	Added new event L1 & corresponding footnote to Table A Added and revised language for section 2 on application of dynamic criteria Revised language on IBR dynamic performance requirements Added new section 2.1.1 B iii for Large Load voltage recovery Removed majority of section 8, Exceptions to ATC Planning Criteria Added new section 1010 on Remedial Action Schemes (RAS)Remedial Action Schemes (RAS) Many general edits for readability, clarity, & consistency