AMERICAN TRANSMISSION COMPANY®	**Criteria**	Department:	System Planning and Strategic Projects
		Document No:	**PLG-CR-0001-V15**
Title: Transmission System Planning Criteria		Issue Date:	August 12, 2013
		Previous Date:	September 27, 2012

SCOPE

This document describes ATC's system planning criteria to plan, design, build and operate its transmission system in a safe, reliable and economic manner to meet the needs of its customers while maintaining compliance with NERC standards. This criteria applies to the ATC transmission system operated at 69-kV and above.

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.

Approved By: Ron Snead Signed original on file	**Prepared By: Shane Ehster, et alia**

1. System Performance Criteria....3
  1.1 Steady State Assessments Overview....3
    1.1.1. Normal Intact Conditions (NERC Category A)....4
    1.1.2. Loss of Single Element Conditions (NERC Category B)....4
    1.1.3. Loss of Multiple Element Conditions (NERC Category C)....6
    1.1.4. Extreme Disturbance Conditions (NERC Category D)....6
    1.1.5. Planning Horizon Steady State Voltage Stability....7
  1.2 Dynamic Stability Assessments Overview....7
    1.2.1 Transient and Dynamic Stability Performance Assessment....8
    1.2.2 Large Disturbance Stability Performance Assessment....8
    1.2.3 Small Disturbance Performance Assessment....10
  1.3 Voltage Flicker....11
  1.4 Harmonic Voltage and Current Distortion....12
  1.5 Under-Frequency Load Shedding....15
    1.5.1 Island Identification....15
    1.5.2 Frequency Performance Assessment Criteria....16
    1.5.3 Volts Per Hertz Assessment Criteria....16
2. Variations on ATC Planning Criteria....18
3. Administration....19
  3.1 Review....19
  3.2 Retention....19
4. Revision History....19

1. SYSTEM PERFORMANCE CRITERIA

System performance over a ten year planning horizon will be assessed at least annually. Such assessments will involve steady state simulations and, as appropriate, dynamic simulations.

1.1 Steady State Assessments Overview

Steady state assessments include the consideration of the following system load conditions:

1) Summer peak
2) Summer 90/10 proxy peak
3) Summer shoulder peak
4) Winter peak
5) Fall/spring off-peak
6) Light load
7) Minimum load

At a minimum, two of the first three load conditions or similar models will be assessed in all long-range planning studies. The last four load conditions may be considered when more detailed analyses are being conducted of specific alternatives developed to solve a particular problem. The specific criterion associated with each of the load conditions above is provided in Section 9, Load Forecasting Criteria.

General application of the steady state cases:

1) **Summer peak** - Used to determine summer peak load serving and regional supply limitations, including voltage security assessments.
2) **Summer 90/10 proxy peak** – Used considering the NERC Category B (loss of single element) analysis to help us determine whether extreme weather conditions may require unusual measures to meet unexpected load. The 90/10 proxy forecast will be used to help prioritize and stage projects but it will not necessarily be used as the sole reason to justify projects or required in service dates.
3) **Summer shoulder peak** – Used to evaluate contingencies where transmission equipment may be intentionally outaged (e.g. maintenance duration of more than 6 months) at intermediate load levels in addition to assessing system biases or high system imports into the ATC foot print.
4) **Winter peak** – Used to determine winter peak load serving limitations.
5) **Fall/spring off-peak** – Used to evaluate contingencies where transmission equipment may be intentionally outaged (e.g. maintenance duration more than 6 months) at intermediate load levels to identify seasonal regional transfer impacts.
6) **Light load** –Used to study the possibility of high voltages on the power system, impact of capacitor switching, and potential equipment overloads near base load power plants due to reduced local demand at light load levels. The light load case represents many more hours in the year than the minimum load model.
7) **Minimum load** – Used to review the expected voltage range at distribution interconnection points and for determination of adequate voltage control at minimum

load levels. Typically the highest bus voltages will occur with an intact transmission system during minimum load conditions

Steady state performance assessments incorporating Operating Guides are done to identify potential transmission system vulnerabilities over a reasonable range of future scenarios. The steady state system performance criteria to be utilized by ATC for its assessments shall include:

1.1.1. Normal Intact Conditions (NERC Category A)

No transmission element (BES and 69-kV transmission circuits, transformers, etc.) should experience voltage levels outside of applicable voltage limits or loading in excess of its applicable thermal ratings for NERC Category A conditions. This criterion should apply for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-001-1, R1)

1) The normal voltage limit range is typically 95 percent to 105 percent of nominal voltage for NERC Category A conditions. Such measurements shall be made at the high side of transmission-to-distribution transformers. Voltage levels outside of this range will be considered, if they are acceptable to the affected transmission customer. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001-2). All voltage limits should be met with the net generator reactive power limited to 90 percent of the reported maximum reactive power capability.
   (Applicable NERC Standards: TPL-001-1, R1)
2) The steady state voltage as noted in section 1.1.5 below should be stable at all ATC buses for normal intact system configurations and for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
   (Applicable NERC Standard: TPL-001-1, R1)

1.1.2. Loss of Single Element Conditions (NERC Category B)

No transmission element should experience voltage levels outside of applicable voltage limits or loading in excess of its applicable thermal emergency ratings for applicable NERC Category B contingencies. This criterion should be applied for a reasonably broad range of forecasted system demands and associated generation dispatch conditions. Load curtailment may not be utilized in planning studies for overload relief. Field switching may not be considered as acceptable measures for achieving immediate overload relief for breaker-to-breaker contingencies. For restoration after breaker-to-breaker contingencies, field switching, Load Tap Changer (LTC) adjustments, Operating Guides and/or generator redispatch may be considered as acceptable measures to bring element loading levels below appropriate limits.

1) System design should ensure that loading can be adjusted to observe a reliable state within 30 minutes or any Interconnection Reliability Operating Limit Tv[1] (IROL Tv), whichever is less. Temporary excursions above the applicable thermal emergency ratings are acceptable if a Special Protection System (SPS) will reduce loadings automatically (i.e. no manual intervention) to acceptable loading levels in the applicable timeframe. The acceptable loading levels after SPS operation cannot exceed the applicable thermal emergency ratings. The applicable timeframe is determined by the type of limitation that will occur if left unmitigated (e.g., clearance limitation may take several minutes whereas exceeding a relay trip setting may result in an essentially instantaneous trip).
(Applicable NERC Standard: TPL-002-1, R1)

2) Under applicable NERC Category B contingencies, the temporary acceptable voltage level must be within the applicable voltage limits. The acceptable temporary voltage range is typically 90 percent to 110 percent of the system nominal voltage. Voltage levels outside of this range will be considered, if they are acceptable to the affected transmission customer. Voltage levels more restrictive than this range will be considered to address specific equipment limitations. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001-2). Load shedding or field switching are not acceptable measures for achieving immediate voltage restoration for breaker-to-breaker contingencies. However, for full or partial restoration of load after the event, field switching, LTC adjustments, Operating Guides and/or generator redispatch may be considered as acceptable measures to bring voltage levels within appropriate limits. <u>The applicable voltage limits should be met with the net generator reactive power limited to 95 percent of the maximum reactive power capability</u>.

3) System design should ensure that voltage levels outside of any IROL can be restored to achieve a reliable state within 30 minutes or any IROL Tv, whichever is less. These voltage limits should be met with the net generator reactive power limited to 95 percent of the applicable maximum reactive power capability. Temporary voltage excursions outside the range of applicable high and low voltage limits are acceptable if a Special Protection System (SPS) or control of shunt compensation will automatically (i.e. no operator intervention) restore system voltage to temporary acceptable voltage levels within the applicable timeframe. The applicable timeframe will be situation dependent and may need to be reviewed with Asset Planning & Engineering.
(Applicable NERC Standard: TPL-002-1, R1)

4) The steady state voltage should be stable at all ATC buses for applicable NERC Category B contingencies for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-002-1, R1)

---

[1] The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection IROL Tv shall be less than or equal to 30 minutes (from NERC Glossary of Terms)

5) For assessments conducted using applicable Midwest Reliability Organization (MRO) and ReliabilityFirst Corporation (RFC) region-wide firm load and interchange levels (i.e. no market or non-firm system bias), generator real power output should not be limited under NERC Category B contingency conditions. A lower level of transmission service will be considered if requested by a transmission customer.

1.1.3. Loss of Multiple Element Conditions (NERC Category C)

1) No transmission element should experience loading in excess of its applicable thermal emergency ratings for applicable NERC Category C contingencies. This criterion should be applied for a reasonably broad range of forecasted system demands and associated generation dispatch conditions. Overload relief methods may include supervisory controlled or automatic switching of circuits, generation redispatch, or firm service curtailments, as well as minimal planned load shedding. The transmission element loading should be reduced to within the normal thermal ratings within the timeframe of the applicable ratings.
(Applicable NERC Standard: TPL-003-1, R1)
2) Under applicable NERC Category C contingencies, the temporary acceptable voltage level must be within the applicable voltage limits. The acceptable temporary voltage range is typically 90 percent to 110 percent of the system nominal voltage. Voltage levels outside of this range will be considered, if they are acceptable to the affected transmission customer. Voltage levels more restrictive than this range will be considered to address specific equipment limitations. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001-2). Methods of restoration to normal voltage range may include supervisory control of the following: capacitor banks, LTCs, generating unit voltage regulation, generation redispatch, line switching or firm service curtailments. Minimal planned load shedding may also be used for voltage restoration. The applicable voltage limits should be met with the net generator reactive power limited to 95 percent of the applicable maximum reactive power capability. For Category C contingencies, consideration may be given to operating procedures that are designed to shed a minimum amount of load.
(Applicable NERC Standard: TPL-003-1, R1)
3) The steady state voltage should be stable at all ATC buses for applicable NERC Category C contingencies for a reasonably broad range of forecasted system demands and associated generation dispatch conditions.
(Applicable NERC Standard: TPL-003-1, R1)

1.1.4. Extreme Disturbance Conditions (NERC Category D)

1) The MRO/RFC Extreme Disturbance Criteria and NERC Category D criteria should be used to assess system performance compared to the applicable voltage limits and thermal ratings. The disturbance or contingency criteria may include examining loss of all circuits on a right-of-way or loss of an entire substation, including generation at that substation. These criteria should be used to determine system vulnerabilities, but may

not necessarily dictate that potential problems identified need to be remedied with system modifications.
(Applicable NERC Standard: TPL-004-1, R1)

1.1.5. Planning Horizon Steady State Voltage Stability

1) The nose of the steady state bus P-V curve should be at or below the applicable bus voltage limit as coordinated with the applicable Planning Coordinator and/or by any applicable Transmission Owner(s) (e.g., the MWEX limitation of 95 percent of nominal voltage at the Arrowhead 230 kV bus) to assure adequate system voltage stability and reactive power resources for NERC Category A, B, and C events. Different values may be appropriate for areas of the system that contain fast acting reactive power devices (e.g., FACTS devices). If additional voltage stability limitations are discovered on the ATC system, then further analysis will be conducted to determine the appropriate course of action based on the probability and impact of the situation.

2) The steady state operating point at all ATC buses should be at least 10 percent away from the nose of the bus P-V curve and above the applicable low voltage limit to assure adequate system voltage stability and reactive power resources for NERC Category A, B and C events. The pre-contingency voltage stability margin should be adequate to avoid voltage instability for the most severe applicable contingency. This 10 percent voltage stability margin is chosen to reflect uncertainties in load forecasting and modeling, as well as to provide a reasonable reliability margin. Exceptions to the 10 percent margin requirement may be granted if there are feasible system adjustments which can reliably restore the 10 percent margin post contingent within 30 minutes.

   [Note that dynamic voltage stability must be assessed to determine whether voltage instability (collapse) may occur during the transition from acceptable steady state pre-contingent (Category A) voltage stability to acceptable steady state post-contingent (Category B or C) voltage stability.]

3) Steady state voltage stability assessments are performed on a selective basis using engineering judgment, when ATC bus voltages are found to be at or below the low voltage limit at multiple buses in a common geographic area when performing other steady state analyses over a broad range of forecasted system demands and associated generation dispatch conditions. Otherwise, acceptable steady state voltage stability is assumed to exist.

4) System design should ensure that exceeding any steady state voltage IROL can be mitigated within 30 minutes or any IROL Tv, whichever is less. Temporary excursions above the applicable voltage stability limit are acceptable if a Special Protection System (SPS) will automatically (i.e. no manual intervention) return the system to an acceptable stability condition in an acceptable timeframe.

1.2 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

General applications of the dynamics cases:

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.

1.2.1 Transient and Dynamic Stability Performance Assessment

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 within 20 seconds after a system disturbance.

The transient and dynamic system stability performance criteria to be utilized by ATC for planning purposes shall include the following factors.

1.2.2 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, add a 0.5 cycle margin to the expected clearing time (ECT) for dynamic contingency simulations. For generating units with assumed, typical, or proposed dynamic data, add a 1.0 cycle margin to the ECT for dynamic contingency simulations. 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 NERC Category B contingency. These contingencies will typically be sustained three-phase faults of a single generator, transmission line, or transmission transformer with normal fault clearing.
(Applicable NERC Standards: TPL-002-1, R1)

4) Generator transient stability will be demonstrated for at least one key contingency for each applicable NERC Category C contingency. These contingencies will typically be three-phase faults of single elements with prior outage of a generator, line or transformer with normal clearing; single line-to-ground faults on a transmission bus or

breaker with normal clearing; single line-to-ground faults on two transmission lines on a common structure with normal clearing; or single line-to-ground faults on a single generator, transmission line, transmission transformer or transmission bus section with delayed clearing.
(Applicable NERC Standards: TPL-003-1, R1)

5) Generator transient stability will be reviewed for any NERC Category D contingencies that are judged to be potentially critical to transmission system adequacy and security (i.e., loss of system stability, widespread cascading outages, and/or uncontrolled system separation).
(Applicable NERC Standards: TPL-004-1, R1)

6) Unacceptable system transient stability performance for NERC Categories analyzed as a part of the Planning Criteria includes the conditions described below. Unacceptable system transient stability performance occurs when any of the following stability assessment criteria are not met. Corrective plans may include system reinforcements or establishing appropriate System Operating Limits (SOL) or Interconnected Reliability Operating Limits (IROL). Where needed system reinforcement cannot be implemented in an appropriate timeframe, then an SOL or IROL must be established.

   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 1.2.3 below

   B. Voltage Stability Assessment

   i. Voltage recovery within 70 percent and 120 percent of nominal 2 cycles following the clearing of a disturbance[2].

   ii. Voltage recovery within 80 percent and 120 percent of nominal for between 2.0 and 20 seconds following the clearing of a disturbance.

      a. Voltage instability (collapse) at any time after a disturbance [100 percent constant current modeling for real power load and 100 percent constant impedance modeling for reactive power load may be used in areas where the steady state operating point is at least 10 percent away from the nose of the P-V curve, otherwise appropriate induction motor modeling should be used for the voltage stability assessment.]
      (Applicable NERC Standard: 002-1, R1, TPL-003-1, R1)

---

[2] Motor terminal voltage recommendations from Carson Taylor paper

1.2.3 Small Disturbance Performance Assessment

The small disturbance (e.g. switching) stability performance criteria to be utilized by ATC will include:

1) Unacceptable small disturbance performance consists of a response beyond the limits described below. Unacceptable small disturbance performance indicates that a System Operating Limit (SOL) or an Interconnected Reliability Operating Limit (IROL) exists for the Planning Horizon where improvements cannot be implemented in an appropriate timeframe.
2) With all generating units at their prescribed base case (normally full) real power output, all units will exhibit well damped angular oscillations [as defined below] and acceptable power swings in response to a (non-fault) loss of a generator, transmission circuit, or transmission transformer.
(Applicable NERC Standard: TPL-002-1, R1)
3) With all generating units at their prescribed base case (normally maximum) real power output, all units will exhibit well damped angular oscillations [as defined below] and acceptable power swings in response to a (non-fault) loss of any two transmission circuits on a common structure.

   Note: 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 20 seconds after the switching event:
   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.

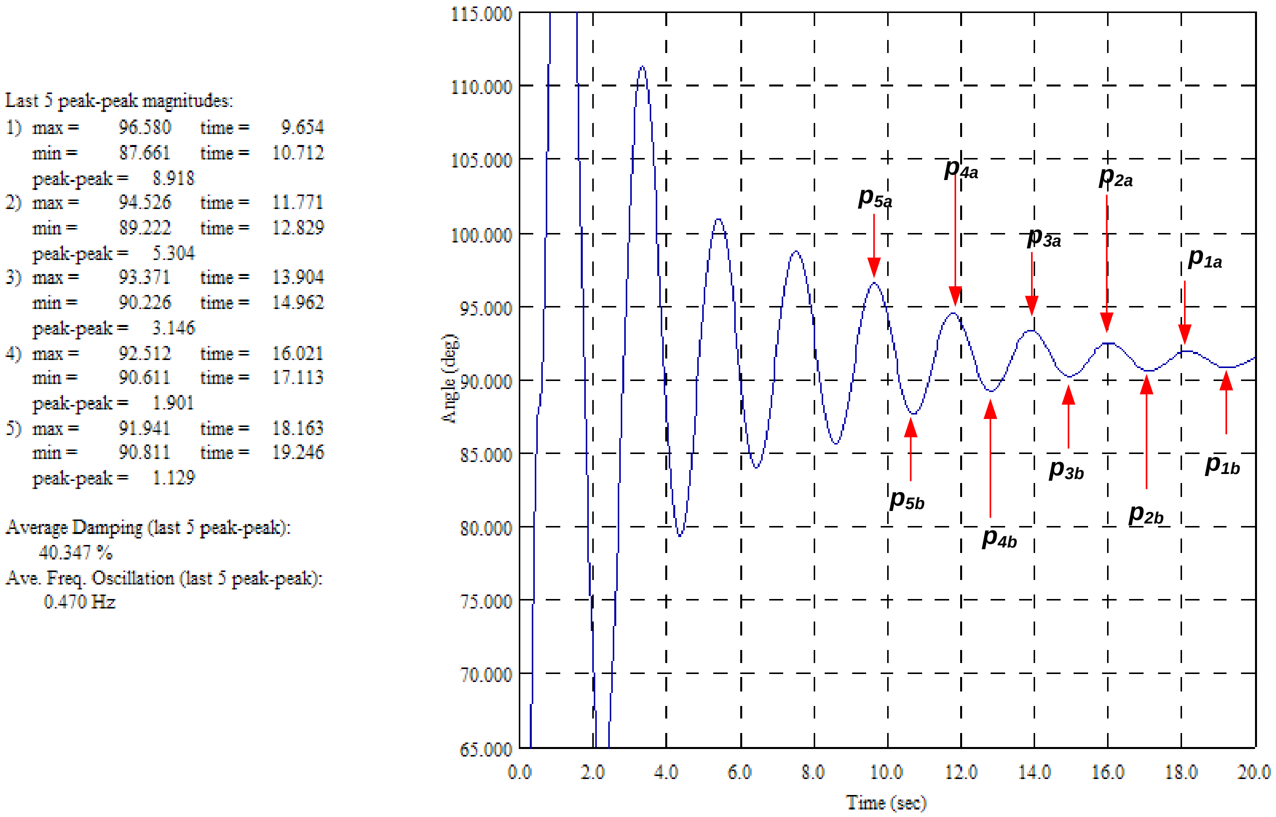
   Average Damping Factor (%) = $\left(\frac{d_1 + d_2 + d_3 + d_4}{4}\right) \times 100$

   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



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

1.3 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 50 percent peak load case 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 light system 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 three 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 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. 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) *Single frequency flicker* is to be below the applicable flicker curves described in Table A.1 of IEEE 1453-2004 “Recommended Practice of Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems.” Single frequency flicker is created by voltage affecting events that occur at a regular interval and superimpose a single frequency waveform between 0.001 and 24 Hz on the fundamental frequency 60 Hz voltage waveform. Depending on frequency (the human eye is most sensitive to frequencies in the 5 to12 Hz range) sub-synchronous frequencies with magnitudes from 0.35 percent to 8 percent can cause irritable flicker. ATC uses the flicker curve in IEEE Standard 1453-2004 (Table A.1) to determine the acceptability of single frequency flicker.

3) *Multiple frequency flicker* is 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 1453-2004. These limits can be exceeded 1 percent of the time with a minimum assessment period of one week. Multiple frequency flicker has the same frequency range as single frequency flicker, but is more complex to analyze, especially when flicker magnitudes and frequencies change over time. Multiple frequency flicker is best analyzed using a flicker meter.

1.4 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 519-1992 (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 (%)
69-kV and below	3.0%	5.0%
69.001-kV through 161-kV	1.5%	2.5%
161.001-kV and above	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%.

Note 2: High-voltage systems (>161-kV) can have up to 2% 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% 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% 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% 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.

1.5 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.

1.5.1 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. (*Applicable NERC Standard:* PRC-006-1 R.2.1)

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. (*Applicable NERC Standard:* PRC-006-1 R.2.1)

3) Relay Scheme or a Special Protection System

   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 special protection system (*Applicable NERC Standard:* PRC-006-1 R.2.2)

4) Large Single Island

   A UFLS island is identified as a single island in the MRO area, the RFC 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-006-1 standard performance requirements when acting together with or without the programs of the BES.
(*Applicable NERC Standard:* PRC-006-1 R.2.3)

1.5.2 Frequency Performance Assessment Criteria

Transient island frequencies shall remain within the Under-frequency and Over-frequency Performance Characteristic Curves in PRC-006-1 Standard Attachment 1. The Performance Characteristic Curves are shown in Figure 1.5.2.

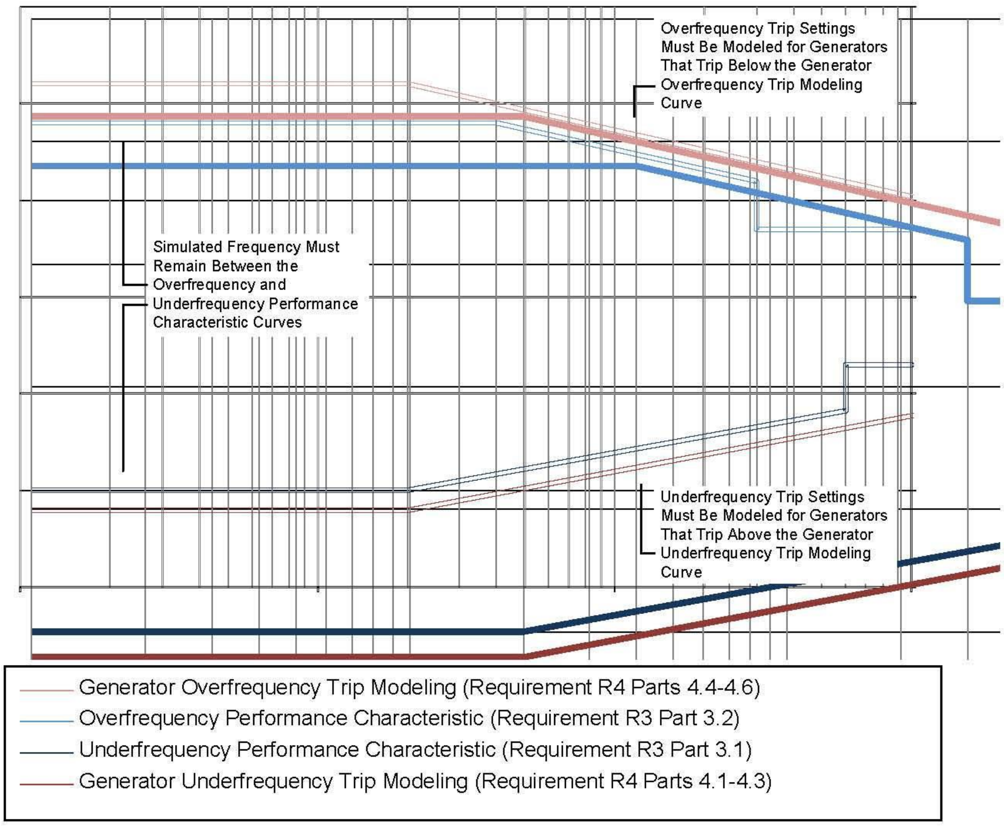
1.5.3 Volts Per Hertz Assessment Criteria

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 [per PRC-006-1, R3.3].

Figure 1.5.2 – Performance Characteristic Curves for UFLS Frequency Performance Criteria

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

2. 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.

1. Area does not meet NERC Standards TPL-001-1, -002-1 or -003-1 with respect to stability.
    a. Complete projects required for bringing the existing system up to NERC Standards TPL-001-1, -002-1 or -003-1 performance requirements with no intentional delay.
    b. New generator interconnections are not permitted until the NERC standards 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 NERC Standards TPL-001-1, -002-1 or -003-1. See NERC Standard FAC-002-1 for new generator interconnections].
    c. 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.

2. Area meets NERC Standards TPL-001-1, -002-1 or -003-1 but not ATC criteria with respect to stability.
    a. Normal schedule for projects required for bringing the existing system into compliance with ATC criteria.
    b. New generator interconnections are permitted as long as the system continues to meet the NERC Standards TPL-001-1, -002-1 or -003-1. If the new generator interconnection causes the system to be unable to meet the performance requirements of these NERC standards, 1.b above applies.
    c. Operating procedures will not be required in the interim period while the projects to meet ATC criteria are being constructed.

3. Area meets ATC planning criteria for existing system but a new generator interconnection causes a violation of:
    a. ATC planning criteria – New generator interconnection is not permitted until ATC criteria are met with the addition of the new generator.

b. NERC Standards TPL-001-1, -002-1 or -003-1 under FAC-002-1 – New generator interconnection is not permitted until both NERC standards and ATC criteria are met.

3. ADMINISTRATION

3.1 Review

This document will be reviewed annually.

3.2 Retention

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

4. REVISION HISTORY

Revision	Author(s)	Manager(s)	V.P.(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