AMEREN's
(On Behalf of Its Transmission Owning Affiliates, Including Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois)
TRANSMISSION PLANNING
CRITERIA AND GUIDELINES

Document Approvals			
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1.0 INTRODUCTION

This document contains the Ameren Transmission Planning criteria and guidelines. The Ameren Transmission Planning Department is responsible for planning the development of the Ameren bulk power system facilities, 100 kV and above, on behalf of its transmission owning affiliates, including Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois. These criteria address customer expectations, and compliance with NERC reliability standards, SERC regional criteria, applicable state regulations, and public policy requirements.

There is a definite distinction between criteria and guidelines as used in this document. Criteria have had specific management approval and are unconditional, for they are the principles by which a reliable Ameren transmission system is planned. A guideline is of lesser importance and subject to engineering judgment. A guideline may reflect generally accepted practice, normal procedure, or a general philosophy to be applied depending on the particular circumstances in a specific case.

Deterministic tests of a limited number of system conditions require the application of engineering judgment to evaluate the complex multi-variable problems involved in planning analysis. Sensitivity analyses, reliability margins, and adequacy assessments are used in conjunction with the criteria and guidelines to plan a robust transmission system.

Though a project may be identified as a result of this document's application, project timing may be dependent on several factors including regulatory restrictions, management directives, contractual relations with others, and/or socio-environmental considerations.

These criteria and guidelines have evolved over a number of years, and reflect considerable planning and operating experience for the Ameren transmission system. Ameren Transmission Planning criteria are subject to change at any time at Ameren's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, operational issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

While the following criteria and guidelines provide a framework for planning the Ameren transmission system, it must be recognized that the system that exists at any point in time will likely be different from planned system conditions due to variations in dispatch, facility outages, market activity, environmental factors, etc.

2.0 RELIABILITY CRITERIA AND GUIDELINES

The measure of successful transmission system planning is the attainment of a system that provides dependable service at a reasonable cost over a long period of years, and in the process of its growth and development, acquires no significant weakness that stands in the way of substantially greater growth or utilization. Each individual piece of system equipment must be selected so as to meet probable future demands; even more importantly, the basic system pattern must be such that it can grow without causing the obsolescence or the major rebuilding of facilities already installed.

2.1 NERC Reliability Standards and SERC Regional Criteria

Ameren intends to comply with all NERC Reliability Standards. Ameren's transmission planning criteria and guidelines, at a minimum, are intended to provide full compliance with the NERC Planning Standards, as they pertain to transmission system planning.

SERC regional criteria are detailed regional criteria and guidelines describing the process to be used at the regional level to be compliant with the NERC Reliability Standards.

2.2 Ameren Planning Criteria and NERC Reliability Standards

2.2.1 NERC Reliability Standard TPL Planning Events

Short-term emergency ratings may be required to cover post-contingency conditions until system adjustments can be made to mitigate any overloads or low system voltages, and particularly for planning events involving the outage of multiple facilities (P2, P3, P6, or P7). Such adjustments would include generation redispatch, transmission switching, shedding of load, or transfer of load at the subtransmission level. Transmission upgrades or other mitigation may need to be initiated or advanced if the expected short-term emergency ratings cannot cover the expected post-contingency loadings, or if the proposed mitigation cannot be accomplished within the time duration of the short-term emergency rating. Refer to Ameren's FAC-008 procedure document for short-term emergency rating information.

2.2.2 Specific Cases Where Ameren Transmission Planning Criteria Exceed Performance Requirements of NERC Reliability Standard TPL-001-4

In several instances, Ameren Transmission Planning Criteria exceed the performance requirements of NERC TPL Standards. These specific cases are listed below:

1. Following N-2 (or N-1-1) contingency events involving two circuits that are nominally rated at 345 kV or higher (Planning Events P6-1-1 and P7), no interruption of Firm Transmission Service or loss of Non-Consequential Load will be permitted, except to those generators that have only two outlet lines that would be involved in the contingency event. In general, no system adjustments will be allowed between transmission circuit contingencies; however, when a contingency outages a line that terminates at a ring bus, either manual or SCADA controlled restoration of the ring bus following the first contingency (open line disconnects or open loops), would be allowed, and all facilities would be operated within applicable ratings.

2. For NERC Planning Events P2-2, P2-3, P2-4 and P4-P7, no NERC cascading shall occur and Total Load at Risk shall be limited to 300 MW. (Note exception for EHV facilities in item 1.) *The 300 MW level for loss of load for more than 15 minutes due to equipment failures represents the threshold of a NERC reportable event under NERC Standard EOP-004 and also the threshold for the DOE Energy Emergency Incident and Disturbance Reporting Requirement per Form EIA-417.* Load restoration via manual transfers (to reduce the magnitude of the load loss) shall *not* be considered when determining if the 300 MW threshold will be exceeded.

3. For NERC Planning Events P3-1 through P3-5, no System adjustments would be allowed except for increased generation to provide the replacement power for the outaged generators. The Ameren transmission system should be planned to handle a variety of generation dispatch scenarios and should not be dependent on a particular set of generation dispatch patterns to mitigate thermal overloads or low voltage conditions.

4. An entire peaking plant or intermittent plant should be considered as a single generator for NERC Planning Events P1-1, and P3-1 through P3-5. No System adjustments would be allowed except for increased generation to provide the replacement power for the outaged plants. The Ameren transmission system should be planned to handle a variety of generation dispatch scenarios and should not be dependent on peaking plants or intermittent resources to mitigate thermal overloads or low voltage conditions. Osage hydro generation should be considered as a peaking plant for the purposes of planning the Ameren transmission system, recognizing that the Osage units can provide some reactive support while operating as synchronous condensers.

5. Double-line-to-ground faults would be utilized instead of single-line-to-ground faults for NERC Planning Events P2-2, P2-3, P4-1, P4-2, P4-3, P4-5, P5-1, P5-2, P5-3 and P5-5.

6. For all NERC Planning Events relevant to Callaway Plant, three-phase faults would be utilized per the Callaway NPIR.

2.2.3 Use of Remedial Action Schemes or Operating Guides/Procedures to Meet Reliability Standards

Remedial Action Schemes (RAS) or Operating Guides/Procedures may be used as an interim solution to alleviate steady state transmission constraints pending the completion of planned and committed network upgrades to meet national and regional standards and Ameren transmission planning criteria. RAS may be considered, on an interim basis, as generation plants can often be constructed and operational before the necessary transmission facilities can be upgraded to allow network resource (NR) status or resolution of injection-related transmission constraints to allow energy resource (ER) status. Remedial Action Schemes may be utilized on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events as detailed in in section 2.4.7.

2.3 Transmission Interconnection Planning

2.3.1 New AC Transmission Interconnections

Consistent with FAC-001 and FAC-002 requirements, all new Transmission Interconnections and Material modifications of existing Transmission facilities are addressed in the Ameren document "Transmission Facility Interconnection Procedures" posted on OASIS.

2.3.2 Incremental Import Capability Criteria and Guidelines

2.3.2.1 Criteria for Incremental Import Capability Related to Generation Reserve

Unless a level of import capability requirement for generation reserves is otherwise specified by RRO or RTO requirements, a minimum simultaneous (meaning from multiple cardinal directions at the same time) incremental import capability (First Contingency Incremental Transfer Capability = FCITC) of the largest plant on the Ameren system or 2000 MW, whichever is larger, as limited by an Ameren transmission element would be used as a proxy to maintain transmission capability related to generation reserves in the Ameren Missouri or Ameren Illinois footprint. Note that valid limits to the transfers tested would consist of those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists.

2.3.2.2 Guidelines for Voltage Constrained Maximum Simultaneous Incremental Import Capability for St. Louis Metro Area

Voltage constrained maximum simultaneous incremental import capability is an assessment of the adequacy of reactive resources in the St. Louis Metro area[1]. The basis of this assessment is the coincident outage of multiple generating units within roughly 100 miles of the St. Louis Metro area with all transmission facilities in service. Simultaneous incremental import capability simulation is performed so as to identify and prioritize locations for reactive compensation and/or system upgrades. Ameren's maximum simultaneous import capability shall be considered adequate if there are neither significant facility overloads, nor any metropolitan area subtransmission substation with 34.5 kV and 69 kV voltages below 95% of nominal.

For simulating this test, the coincident outage of any seven generating units within 100 miles of the St. Louis Metro area should be considered, with system loads based on the Ameren corporate load forecast.

Additional considerations for this test should include the coincident outage of a transmission facility and any five generating units within 100 miles of the St. Louis Metro area.

2.3.2.3 Guidelines for Nonsimultaneous Incremental Import Capability Testing

The Ameren transmission system is tested for nonsimultaneous transfer capability for imports (First Contingency Incremental Transfer Capability = FCITC) from all cardinal directions when sourcing from generally a single direction (north, south, east or west) at a time. An incremental import capability level of approximately 1200 MW, as limited by an Ameren transmission element, would be used as a proxy for each of the Ameren Illinois and Ameren Missouri systems. Valid limits are facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists. Powerflow simulations would be run to confirm that the area voltages would be acceptable to support the levels of transfer identified in the linear analysis.

Typically, values of nonsimultaneous incremental import capability into Ameren Illinois or Ameren Missouri from each cardinal direction in excess of 1200 MW would be considered as adequate. Values less than or equal to approximately 2/3 of the "Adequate" levels would be considered as less than adequate, and would require further review of the constraints for possible mitigation.

2.3.2.4 Guidelines for Nonsimultaneous Incremental Import Capability in

[1] St. Louis Metro area includes St. Louis City, St. Louis County, Jefferson, Franklin, and St. Charles Counties in Missouri, and Madison, St. Clair, and Monroe Counties in Illinois.

Regional Studies

Ameren transfer capabilities are also determined in SERC and MISO regional studies, in which Ameren transmission planning engineers are participants. Linear analysis methods are used to calculate transfer capabilities, with AC power flow solutions used to confirm that the area voltages would be acceptable to support the transfer levels identified. Valid limits are facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists.

Ameren reviews the adequacy of the nonsimultaneous import FCITC due to the need to address variations in local and regional generation dispatch, net scheduled interchange, and uncertainties in the powerflow models associated with them. Less than adequate transfer capability may limit Ameren's options to import power from specific directions during both economic and emergency conditions. Economic considerations may require higher import capabilities than stated here for reliability purposes.

The above magnitudes of transfer capability reflect the requirements of the transmission system to supply the Ameren customer load with the desired reliability levels for a variety of system operating conditions considering:

1. The geographic location of the Ameren, Ameren Illinois, and Ameren Missouri systems and its electrical connections in the Eastern Interconnection,
2. The existing capability of the Ameren, Ameren Illinois, and Ameren Missouri systems and its interconnections to supply the Ameren customer load during first contingency conditions,
3. The response of the Ameren transmission system to system transfers, including those not involving Ameren,
4. The magnitude and economics of available generation in the Midwest,
5. The increased utilization of the transmission system for economic benefits, to maintain adequate generation reserve levels, to defer capacity additions, and/or to reduce fossil fuel emissions, and
6. The impact of simultaneous power transfers and other actions on day-to-day system operation.
7. Transmission service reservations impacting Ameren facilities.

Operating guides, procedures which may or may not involve operator intervention to alleviate the loading on a particular transmission facility, including generation redispatch and transmission switching may be used to enhance transfer capability between areas.

2.3.2.5 Subsystem Guidelines

To test the capabilities of the Ameren transmission system, different combinations of sink points should be selected for development of import subsystems. These import subsystems should, at a minimum, reflect generating units in close proximity and within the same relative geographic areas, such as Ameren Illinois, Ameren Missouri, or the St. Louis metropolitan area. The import subsystem participation file can also include the largest unit at each base-load plant in the Missouri and Illinois sides of the Ameren footprint. Other import subsystems can be developed based on fuel type, specific rail carrier or type of transportation, specific gas pipeline supply, system voltage, or other common concern. The status of generating units on interfaces should also be considered, including units in neighboring powerflow control areas electrically close to the Ameren system (e.g. Kincaid, Thomas Hill, New Madrid, Powerton, Gibson, etc.) to determine the impacts on import capability.

Source subsystem definitions should consider combinations of increased generation or decreased loads in powerflow control areas outside of the Ameren footprint. Control areas inside as well as outside of the MISO footprint should be considered for these exporting areas. System transfers from all cardinal directions should be considered.

2.4 Generation or HVDC Connection and Outlet Transmission Criteria

The planning of generation outlet transmission follows "General Transmission Planning Criteria", plus additional criteria for certain specific items such as stability considerations and high-speed reclosing of EHV circuits.

Consistent with FAC-001 and FAC-002 requirements, new Generator Interconnections and Material Modifications to existing generation facilities are addressed in the Ameren document "Generation Connection Procedures Requirements" posted on OASIS.

Material changes to existing generator interconnections shall trigger a review of system performance by Transmission Planning, as required by standard FAC-002. Such facility changes would include the following items:

1. Any change in nameplate MVA capability of generators or GSU transformers.
2. Any change in net MW or net Mvar capability of generators.
3. Any change to impedances of generator windings or GSU transformers.
4. Any change to generator, exciter, governor, or stabilizer model types or model parameters.
5. Any changes to generator/turbine inertia constants.
6. Any purchases of spare equipment, including GSU transformers, exciters, or other major electrical equipment planned to be installed on a short notice.

Studies would include a review of steady-state, short-circuit, and dynamics system performance under both normal and contingency conditions as necessary to ensure system reliability. Study assumptions, system performance, alternatives considered, and coordinated recommendations will be documented for review by the entities involved.

Requests for connecting generating equipment to the Ameren transmission system are handled by the Midcontinent Independent System Operator (MISO) via Attachment X to the MISO Tariff.

The MISO process includes application of a Transmission Owner's Local Planning Criteria. As this applies to Ameren transmission facilities, Ameren's Local Planning Criteria are stated in this document.

The new generator will be responsible to pay for system upgrades to mitigate overloads related to tests specified by the Ameren Planning Criteria when:

1) The overload was not identified for mitigation by the non-Ameren Planning Criteria tests performed as part of the generator connection request; and,
2) The new generator has a 3% TDF on the limiting element, or when the new generator increases the amount of the flow by more than 5% of the limiting facility's rating. (Appropriate seasonal normal rating used for non-outage condition, and Long Term Emergency rating used for a contingency.)

When applying the Ameren import capability criteria and guidelines found in sections 2.3, the new generator would be responsible for system improvements required to mitigate limitations to transfer capability for those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists, and for which a 200 MW or greater reduction in transfer capability would result.

2.4.1 Generator and HVDC terminals Power Factor

As a minimum criterion, all synchronous generators are required to have minimum capability of 95% leading and lagging net power factor at the point of interconnection.

Newly interconnecting non-synchronous generators will be required to design their Generating Facilities to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation. At that point, the non-synchronous generator must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis.

Owners of HVDC transmission lines connected to the Ameren transmission system would be required to inject or absorb reactive power (+/- 95% power factor at AC high voltage connection at the converter station at all real power levels).

2.4.2 Plant Bus Configuration Criteria

For future generation connections to Ameren's transmission system with a voltage above 100 kV, the following minimum criteria apply as indicated in the table below. These criteria are consistent with past planning philosophy that provides the highest reliability configurations on the 345 kV system and highly reliable circuit arrangements at 230 kV, 161 kV and 138 kV. These configurations are consistent with Ameren design criteria and permit Ameren to maintain contiguous ownership of the transmission system. Note: Ameren is converting its 230 kV system to 345 kV, so plants should not connect at 230 kV unless they can convert to 345 kV as needed.

Connection Type	Configurations Allowed	Ownership
345 kV	Ring Bus Breaker-and-a-Half	Ameren owns all substation facilities at the connection point (network facilities). Ameren or IPP may own the lead line(s) connecting the IPP facility and Ameren substation (interconnection facilities).
161 kV or 138 kV	Ring Bus Breaker-and-a-Half Straight Bus	Same as above Note that a Straight Bus connection would only be permitted at an existing substation at Ameren's sole discretion.
230 kV	Ring Bus Breaker-and-a-Half	Ameren is converting its 230 kV system to 345 kV, so plants should not connect at 230 kV unless they can convert to 345 kV as needed.

Prior to 1980, AmerenMO had designed the plant connection at 345 kV at Labadie and Rush Island Plants via a straight bus arrangement. Because of the difficulties encountered (typically space requirements) in converting the straight bus style of connection, it is not intended to retroactively apply the current design configuration requirements to the existing plants, even for planned future generation connections at these facilities.

2.4.3 Plant Outlet Transmission Line Outage Criteria

Plant outlet transmission is considered adequate when, with the plant at full rated output, and with other generation in electrical proximity to the plant under study which contributes in an additive manner to the critical circuit loading dispatched so as to maximize facility loading such that the outage of any plant outlet circuit or other valid local single contingency does not result in the loading of any circuit above its emergency rating, and there are no transmission system voltages below values specified in section 3.1.

2.4.4 Steady-State Stability Criteria

Plant outlet transmission is considered adequate, from the standpoint of steady-state stability, when it will pass both of the following simulated tests:

1. With the plant at full real power output and lagging power factor (unit is providing Vars), with an outage of any one of the transmission outlet circuits, all generating units at the plant should remain stable in the steady-state.

2. With the plant at full real power output and lagging power factor (unit is providing Vars), with an outage of transmission outlet circuits on a common tower, all generating units at the plant should remain stable in the steady-state.

If the Test #2 listed above is not met, use of operating guides including reduced generation at the plant may be considered for a limited time until a committed reinforcement is implemented. Dynamic models representing winter peak load conditions should be used for the stability analysis, as the loads in these models provide less damping than the load in summer peak models and fewer generating units are available to provide synchronizing power.

Small signal analysis would show satisfactorily damped post-disturbance response with damping ratios of 3% or higher with modeled excitation system parameters based on field-tested data. Otherwise, damping ratios of 5% or greater would demonstrate satisfactory damping.

2.4.5 Guidelines for Determination of Generator Underexcitation Limits

A generator's underexcitation limit consists of operating points at which the generator is on the verge of losing synchronism with the remainder of the system. For a particular real power output, this occurs when the generator's excitation is gradually decreased so that the generator voltage behind the saturated synchronous reactance leads the Thevenin equivalent system voltage by 90°. Usually the generator is underexcited (absorbing reactive power) at this absolute underexcitation limit.

To allow for possible generator governor action in response to system disturbances, an appropriate margin is selected. Typically, these margins would be 3% of the generator capability with automatic voltage regulating equipment in-service, 5% for a non-continuous acting voltage regulator in-service, or 10% of the generator capability if automatic voltage regulating equipment is assumed to be out-of-service or is not present. Calculation of this minimum excitation limit for various real power output levels for a particular generator yields minimum excitation values which would result in the generator reaching its absolute minimum excitation limit should the generator governor call for an increase in generator real power output.

Typically, light load system conditions are used as a basis to determine minimum generator excitation limits, with the strongest source (outlet line) assumed out-of-service at the plant under study.

2.4.6 High-Speed Reclosing of the 345 kV Circuits Criteria

High-speed reclosing after the tripping of 345 kV circuits terminating at power plants is not allowed. The reason for this criterion is to reduce the probability of torsional oscillations causing damage to the shafts of the turbine-generators, in accordance with manufacturer's recommendations.

When required hot-bus dead-line reclosing of these EHV circuits is to be delayed by a minimum of ten seconds.

2.4.7 Transient Stability and Circuit Breaker Clearing Times Criteria

Plant outlet transmission is considered adequate, from the standpoint of transient stability, when

Contingency Test	Contingency Event Description and Outcome	Corresponding NERC Reliability Standard and Contingency Category
1.	With all lines in service, the plant and remainder of the system shall remain stable and ride-through when a sustained three-phase fault on any outlet facility is cleared in primary clearing time.	TPL-001-4 Planning Event P1-2
2.	With all lines in service, the plant and the remainder of the system shall remain stable and ride-through when sustained single-line-to-ground faults on any two circuits of a multiple circuit tower line is cleared in primary clearing time.	TPL-001-4 Planning Event P7
3.	With one outlet facility out of service, the plant and the remainder of the system shall remain stable and ride-through when a sustained three-phase fault on any of the remaining facilities is cleared in	TPL-001-4 Planning Event P6-1-1

	primary clearing time.	
4.	With all lines in service, the system and the remainder of the plant units shall remain stable and ride-through when a sustained double-line-to- ground (2-L-G) fault* on any Ameren 345, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker or relay-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker" (except Bus-tie breaker).	TPL-001-4 Planning Events P4-1, P4-2, P4-3, P4-5 P5-1, P5-2, P5-3 and P5-5 Also covers Planning Events P2-2 and P2-3 as a breaker failure for a line fault would result in the clearing of a straight bus or the adjacent facility in a ring bus or breaker and a half arrangement.

*: Callaway Plant shall meet the three-phase fault test as outlet for this plant was designed for three-phase faults. Note that Ameren's general use of 2-L-G fault conditions with delayed clearing (breaker-failure) conditions is more stringent than the consideration of single-line-to-ground (S-L-G) fault conditions as specified in NERC Reliability Standard TPL-001-4.

Simulations and Other Considerations

a) Consistent with Table 1 Planning Event P5, the impact of loss of system protection should be investigated for those locations where back-up protection systems on plant outlet lines are significantly slower than primary relaying schemes. Double-line-to-ground fault conditions should be tested assuming primary protection scheme failures that would result in breaker clearing times that are greater than the clearing time associated with the breaker failure protection scheme. This testing is generally required because of older system protection schemes associated with older power plants or substations. (See item 4 above.)

b) Dynamic models representing winter peak load conditions should be used for plant stability analysis, as the loads in these models provide less damping than the load in summer peak models and fewer generating units are available to provide synchronizing power. Winter peak output (MW and Mvar) of the generating unit(s) shall be considered. For power plants located in or near the St. Louis metro area or the Peoria area where there are high concentrations of residential air-conditioning load, the modeling of summer peak load conditions, with dynamic load behavior, should be considered for the stability analysis. Off-peak or minimum load system conditions with pumpedstorage hydro units operating in pump mode should also be considered for the stability analysis.

c) Plant voltages will be modeled at the low end of their scheduled voltage range.

d) The transient stability Tests 2, 3, and 4 above are considered a double-contingency test. The "stuck breaker" is considered one of the contingencies in test 4.

e) Any of the Tests 1, 2, 3, or 4 for outlet of new generation shall not in any way degrade existing stability limits including critical clearing times of any of the nearby plants. All oscillations must exhibit acceptable damping.

f) The term "stable" in above Tests 1 through 4 means the generating unit(s) which remain connected to the system following fault clearing remain in synchronism. All oscillations must exhibit acceptable damping.

g) Plant outlet transmission configuration resulting in no outlet transmission for Test 3 or 4 or both shall require installation of out-of-step-protection on generators, and shall not in any way degrade existing stability limits including critical clearing times of any of the nearby plants or result in system instability.

h) In Test 4 for the "stuck breaker" simulation, a due consideration shall be given to down-grading of the initiating double-line-to ground fault (three phase fault for Callaway) to a single-line-to ground fault if the associated breakers are equipped with the independent pole operated (IPO) mechanism.

i) For the non-peaking units at plants connected to the 345 kV system, light load system conditions shall also be considered. Due consideration should be given to breakers equipped with independent pole operated (IPO) mechanisms.

j) For Test 3 above, a planned reduction in generation associated with the out-of-service outlet line may be considered to maintain plant stability.

k) Use of Remedial Action Schemes (RAS) shall not be allowed for Tests 1 or 2. If RAS is used to meet Test 3 or 4 above, it shall meet the requirements of the NERC Reliability Standards and/or SERC regional criteria. Remedial Action Schemes may be utilized on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events related to Tests 3 or 4 above.

l) The transient stability Tests 1, 2, 3, and 4 above are also applicable to inverter-based resource generating facilities.

m) Ameren reserves the right to evaluate the stability of any generating units connected to the Ameren transmission system, including those owned by retail customers. If it is determined that such generation would cause a material detriment to the transmission system or other nearby generation, then such generators would be required to make modifications such that it would be capable of meeting Ameren's criteria with respect to transient stability performance.

n) Ameren checks the damping with the Power System Stabilizer circuit out-of-service which may result in operating guides.

2.4.8 Transient Stability Fault Scenario Selection

As a guide to selection of fault conditions for development of a portfolio of transient stability simulations for assessment of the transmission system, the following should be considered:

a) The most severe fault for selected Planning Events P1 through P7 or Extreme Event contingencies should be simulated for each power plant on the Ameren system which has units on-line in the stability power flow model being used. Typically, the element that is selected for fault simulation has the longest clearing time, is the strongest source to the system, or results in the greatest number of facilities being removed from service. Close-in faults are usually the most severe from a generator perspective but slow-clearing remote faults should also be given consideration for study. Often the fault selection is based on the knowledge gained from performing a plant stability study which is updated when major changes at the plant or on the nearby system occur.

b) At a minimum, the most severe fault for selected Planning Event P1 through P7 or Extreme Event contingencies should be simulated at each substation or switchyard on the Ameren system with three or more 345 kV lines connected. Typically, the element that is faulted has the longest clearing time or results in the greatest number of facilities being removed from service.

c) At a minimum, the most severe fault for selected Planning Event P1 through P7 or Extreme Event contingencies should be simulated at each substation or switchyard on the Ameren system with 8 or more networked 161 or 138 kV lines. Typically, the element that is faulted has the longest clearing time or results in the greatest number of facilities being removed from service.

d) The most severe fault for selected Planning Event P1 through P7 or Extreme Event contingencies should be simulated for each substation on the Ameren system that serves more than 300 MW of customer load. Typically, the element that is faulted is a transformer or lead line serving the substation in order to determine the impact of losing the load on the stability of the transmission system.

e) Faults that historically have been known to present stability issues on the Ameren or nearby transmission systems should be simulated until upgrades are implemented to completely resolve these issues. These fault simulations are based on the historical events and circumstances that led to the stability concerns, and could include relay misoperations as part of the events.

f) All faults required to meet the Clinton and Callaway NPOA agreements should be simulated. These faults scenarios are prescribed in the NPOA agreements.

The portfolio of transient stability scenarios would be expanded over time to include progressively more than the most severe contingency events at any given location.

2.4.9 Synchronous Generator Out-of-Step Protection

To provide protection for generating equipment should synchronism be lost following a contingency event, new generators to be connected to the Ameren transmission system with capacity of 100 MW or more, would be required to have out-of-step protection installed.

2.4.10 Inverter Based Resources (Wind Farm, Solar Farm, Battery Storage Facility, and HVDC facilities)

An inverter-based resource (IBR), consisting of a wind farm, solar farm, or battery storage facility, shall meet all the requirements specified in FERC Order 661A. All inverter-based resources must conform to Clause 7.2 of the IEEE 2800 standard to meet the Voltage Ride Through requirements and must conform to Clause 7.3 of the IEEE 2800 standard to meet the Frequency Ride Through requirements. Inverter based resources should also meet power quality requirements as specified in section 3.6 Harmonics. The general procedure for performing an assessment of an inverter-based facility is covered in the Ameren document “Guide to Inverter Based Resource Interconnection Studies”, dated February 5, 2019.

All inverter-based resources must conform to Clause 10 of the IEEE 2800 to meet the Modeling Requirements. Generation Interconnecting customers with inverter-based resources can only obtain commercial status when the models in Clause 10 of IEEE 2800 are submitted to Ameren Transmission Planning and these models must include the Electromagnetic Transient (EMT) models in PSCAD software format.

All inverter-based resource must install a Phaser Measurement Unit (PMU) to verify Inverter Based Resource (IBR) performance during system disturbances in addition to ensuring compliance with FERC Orders 827 and 842.

2.5 Generation Retirement

Ameren reserves the right to make upgrades to the transmission in anticipation of future generation retirement. Future generator retirements include publicly announced generator retirements as well as generators that may terminate operations due to current or future environmental requirements at the state or federal level including but not limited carbon or other pollutant emission limitations. With respect to regulated assets, such generator retirement dates may be included in an IRP, while other pending and future retirement events could be identified in an attachment Y, or attachment Y2 study, or otherwise publicly disclosed such as in a Securities and Exchange Commission filing. Regardless of the source of the announcement, from a transmission perspective, Ameren believes it appropriate to properly plan for such retirements. Accordingly, upgrades to the system will include replacing the rated Mvar of the retired unit(s) up to the retiring unit(s) Short Term Emergency Mvar[2] output. The Mvar may be located at the retired unit(s) location or at different locations throughout the transmission system. Ameren also will make needed transmission upgrades to meet NERC TPL standards and Ameren Planning Criteria.

2.6 Short Circuit Criteria

The interrupting requirements of all Ameren circuit breakers must remain within circuit breaker interrupting capabilities considering the impacts of asymmetry, reclosing (where allowed), and actual system operating voltage for the appropriate type of circuit breaker in the field (breakers rated on a total current basis or symmetrical current basis). The maximum short circuit current to be interrupted for both new and existing circuit breakers is calculated.

Circuit breakers with fault duties in excess of interrupting capabilities are candidates for immediate replacement or other acceptable mitigation alternative that meets power flow, relay coordination, and system stability requirements. Such mitigation may include the opening of bus-tie circuit breakers.

2.6.1 Ultimate Fault Current determination:

Ameren considers the impact of possible future projects when determining ultimate fault levels. The following criteria is used to specify the required interrupting capability of breakers for facility additions or modifications.

[2] Short Term Emergency Mvar output will be 1.6 times the rated Mvar of the generator. The rated Mvar of the generator is received via MOD-32 and is in the powerflow model as Qmax and Qmin.

Near future maximum fault current (assuming additional transformation and synchronous generation with GIA)	Ultimate fault (kA)
< 18 kA	25 kA
< 35 kA	40 kA
< 45 kA	50 kA
>= 45 kA	63 kA

2.6.2 Identification of a Weak System

Using the weighed short circuit formula as defined by IEEE standard P2800, a short circuit ratio less than 3 indicates potential problems for inverter-based resources. An inverter based resource that connects at that location would be required to have PSCAD analysis performed. The weighted short circuit is

$$WSCR_{MVA} = \frac{\sum_i^N SCMVA_i * P_{RMVA_i}}{(\sum_I^N P_{RMVA_i})^2}$$

$SCMVA_i$ is the short circuit MVA at bus i. P_{RMVA_i} is the MVA output of the non-synchronous generator(s) connected at bus i. N is the number of interacting units in the area.

2.7 Nuclear Plants and Transmission Operator Agreements

In accordance with NERC Standard NUC-001, All Nuclear Plants with a Nuclear Plant Interconnection Requirement (NPIR) with Ameren shall have an NPOA which includes rights and responsibilities of each party. This agreement includes rights and responsibilities of the Transmission Planning Department to evaluate the transmission system's ability to support plant needs from voltage levels, short circuit, and stability considerations. These needs are to be considered along with other criteria and guidelines contained in this document in developing overall transmission plans.

Ameren will enter into any appropriate agreements with the Transmission Provider and nuclear plant regarding study requirements.

2.8 System Conditions and Modeling Assumptions

System conditions that are assumed to be in effect when the criteria are tested can have a great influence on the results obtained. Detailed information on system conditions and modeling assumptions for developing power flow and stability models for testing Ameren's transmission system performance are found in the Ameren MOD-32 Procedures.

2.8.1 System Study Criteria

For transient stability study work, a progressively unbounded list of facilities which are reported with out-of-step conditions following clearing of a fault would be an indication of an unbounded cascading condition. In addition, generator frequency relay models are included, which would act to trip generators offline should a severe over- or underfrequency event occur.

2.8.2 Cascading Criteria

Total Load at Risk in excess of 1500 MW or loss of 4000 MW of generation would also be a proxy for cascading conditions. Note that load disconnected temporarily by customer-owned protection systems (e.g., residential air-conditioners with reciprocating compressors) should not be considered as an indication of cascading.

2.8.3 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.

1) Consequential Load Loss (NERC definition) = "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."

2) Interruptible load (NERC definition) = "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment."

3) Subsequent cascading load loss = Load that is outaged as a result of subsequent element-based outages during the remaining cascading tier analysis. This type of load loss is a result of either voltage sensitive load tripping when load buses are below 0.89 p.u. or load islanding due to lines/transformers tripping. The 0.89 p.u. load tripping threshold is used as a proxy to simulate the response of voltage sensitive load. The response of voltage sensitive load refers to the tripping of the load due to intrinsic voltage protection mechanisms that manufacturers build into their equipment.

4) Non-Consequential Load Loss (NERC definition) = "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."

Cascading (NERC Definition) = "The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

In the Ameren area, widespread transmission planning load loss is the potential loss of 1500 MW or more of Total Load at Risk.

2.9 Load Connection and Power Factor

Consistent with FAC-001 and FAC-002 requirements, Requirements for the Connection of Customer Load to the Ameren Transmission System are addressed in the Ameren document "End-User Connection Requirements to Ameren's Transmission System" posted on OASIS.

2.9.1 Material Modifications to End-User Facilities Require Study

Material changes to existing end-user interconnections shall trigger a review of system performance by Transmission Planning, as required by standard FAC-002. Such facility changes would include the following items:

1. Any change in nameplate MVA capability of transmission connected transformers.
2. Any change to impedances of transmission connected transformers.
3. Any line extension from the existing interconnection to supply system load or to connect a generator.
4. Any increase in load magnitude (MW, Mvar, or MVA) by 10% or more.

Studies would include a review of steady-state, short-circuit, and dynamics system performance under both normal and contingency conditions as necessary to ensure system reliability. Study assumptions, system performance, alternatives considered, and coordinated recommendations will be documented for review by the entities involved.

3.0 VOLTAGE CRITERIA

Voltage criteria are used to assess the transmission system reliability during assumed normal and contingency conditions. The transmission system response to various contingencies, whether steady state or transient conditions, must be assessed on the basis of these and other criteria. These criteria are presented below and are used by the transmission planning engineers to determine the level of reliability of the transmission system. Depending on the type of analysis being performed, steady state or transient, most or all of the following voltage criteria are used to determine the reliability of the transmission system through the use of computer simulations. The voltage limits and criteria used in planning the Ameren transmission system are presented below. These voltage limits are also used by transmission system operators to ensure that the transmission system is operated in a safe and reliable manner.

3.1 Transmission Voltage Levels and Limits

	Normal Condition (P0)		Post Contingency Condition Steady State (P1-P7)		
Nominal voltage	**Minimum (p.u.)**	**Maximum (p.u.)**	**Minimum (p.u.)**	**Maximum(p.u.)**	**Deviation (%)**
345 kV	0.95	1.05 see note 1	0.95 See note 2	1.075	8% of Nominal see note 3
230 kV, 161 kV, 138 kV	0.95	1.05 see note 1	0.93 See note 2	1.075	8% of Nominal see note 3

NOTES and EXCEPTIONS TO ABOVE CRITERIA

Note 1: Operation in the range 105% to 107.5% of nominal would be permitted on a case-by-case basis, as allowed by ANSI guides, Ameren standards, or manufacturer's exception.
Note 2: Under single (line, transformer, or generator) contingencies, voltages below 95 percent of nominal are used as a screening tool to flag the need for further analysis. Voltages below this threshold would initiate further analysis and/or discussion with the Distribution System Planning groups to ensure that adequate distribution voltages would be provided for these conditions. Minimum voltage limits would apply at the point of delivery. When performing GMD studies, minimum voltage will be as specified in section 3.8.
Note 3: Post-contingency scenarios where the transmission voltage change is greater than 8% of nominal, when compared to pre-contingency conditions, and the resulting

transmission voltage is below the minimum allowed post-contingency voltage, will be investigated to determine what actions, if any, are required to avoid wide-spread outages.
For single customers supplied from the transmission system, the following minimum voltage limits would apply at the point of delivery: • Normal Conditions (all facilities in service): 92% • Single Contingency Conditions: 90%. These limits are in line with governing tariffs in both Missouri and Illinois.
Exceptions to the above voltage criteria would apply to the Callaway and Clinton 345 kV switchyards, as defined in the Nuclear Plant Interconnection Requirements (NPIR) document for these facilities. For Callaway, the required 345 kV bus voltage limits are 372.6 kV (108.0%) to 329.8 kV (95.6%), but the desired upper limit is 362.5 (105.0%). For Clinton, the required 345 kV bus voltage limits are 362.25 kV (105.0%) to 327.75 kV (95.0%). Bus voltages outside of these NPIR limits would require mitigation
Exceptions to the above voltage criteria would apply to the Clinton 138 kV ERAT bus, as defined in the Nuclear Plant Interconnection Requirements (NPIR) document for this facility. The Clinton 138 kV voltage limits are 144.9 kV (105.0%) to 129.72 kV (94.0%). Bus voltages outside of these NPIR limits would require mitigation.

3.2 Potential voltage collapse

In the course of study work, should post-contingency transmission voltages in a general area drop to 90% of nominal or below, closer examination is warranted to determine whether voltage collapse for such contingency conditions is likely. Distribution bus voltages less than or equal to 90% would indicate possible motor stalling (considering voltage drop of 5-7% on distribution feeders). Transmission voltages of 85% is the level at which a voltage collapse is essentially assured. Situations which show transmission voltages in the range of 86% -89% in a steady state analysis carry significant risk for voltage collapse. When performing a detailed study of an area that may be exposed to voltage collapse, distribution line capacitors should be modeled as a separate element from distribution reactive load. Transformer LTC's should be locked at the pre-contingency position when evaluating exposure to voltage collapse, as the collapse would likely occur before the LTCs would begin to operate. When investigating potential voltage collapse in a load pocket, consideration should be given to using 90/10 forecast load or non-coincident local area load levels.

3.3 Transient Voltage Recovery

Following the clearing of a fault resulting from single or multiple contingency events (Planning Events P1- P7), transmission voltages should return to 80% of nominal or greater within two seconds and 90 % of nominal or greater within ten seconds unless the system becomes radial following the outage of multiple contingencies. This criterion would not be applicable to remote or isolated sections of the transmission system, or to portions of Ameren's transmission system that are supplied primarily via another company's facilities.

Means of addressing transient voltage recovery issues would include additional reactive supply provided by capacitor banks or static reactive sources (SVC, STATCOM, Synchronous Condenser, or future technology), or additional transmission facilities connecting to the affected portion of the transmission system. The particular solution pursued would depend on the specific area and size of the affected portion of the transmission system, and whether static or dynamic reactive resources would be deemed necessary to address the particular deficit.

3.4 Application of Shunt Reactors

Shunt reactors would be considered for installation to maintain EHV steady-state transmission voltages at or below 107.5% of nominal, and particularly for the retirement of large power generators connected to the EHV transmission system.

Reactors will be installed on buses if possible. To avoid encountering damage to breakers due to trapped charge and the delayed voltage zero crossing phenomenon, the utilization of pre-insertion resistors or modification to the switching scheme will be considered. If installed on a line, the reactor will be tripped off prior to line reclosing.

3.5 Voltage Fluctuation due to Capacitor or Reactor Switching

Based on IEEE Standard 1453 and 519 and consistent with Good Utility Practice, when installing new shunt reactive devices steady state voltage fluctuation resulting from capacitor or reactor switching would be limited to a maximum of 3.3% of nominal on the transmission system under normal system conditions. The test for this criterion will be conducted via steady state load flow analysis with automatic controlling devices such as switched shunts, load tap changing transformers ("LTC") and phase shifting transformers ("PARS") locked. Dynamic VAR devices such as STATCOMs and SVCs should be allowed to control voltage during these simulations. Transient simulations may be required to ensure equipment will be sized to avoid harmonic resonance." Single contingency conditions will be evaluated for capacitor switching voltage fluctuation considering the outage of the strongest area source element or facility (largest contributor of short circuit current). Ameren has established a guideline for single contingency conditions, that steady state voltage fluctuation resulting from capacitor or reactor switching should be limited to a maximum of 5% of nominal on the transmission system.

3.6 Harmonics

All generation and load connections to the Ameren system should conform to IEEE Standard 519 with respect to voltage distortion. These limits restrict individual harmonic distortion limits to 1.5% between 69 kV and 161 kV, and 1.0% at 161 kV and above, with Total Harmonic Distortion limited to 2.5% between 69 kV and 161 kV, and 1.5% at 161 kV and above.

3.7 Voltage and Reactive Control

A generating plant or HVDC terminal should maintain either a specified voltage or reactive power schedule in accordance with NERC Reliability Standards VAR-001-5 and VAR-002-4.1.

3.8 Transmission Steady-State Voltage Criteria for GMD Events

3.8.1 Voltage Criteria for the Benchmark GMD Events

Acceptable Ameren transmission steady-state voltage criteria for NERC defined benchmark GMD events shall be when all Ameren transmission bus voltages are within the range 0.90 – 1.075 p.u. (NERC Standard TPL-007-4 R3). This voltage range would be used to gauge Ameren system performance in GMD Vulnerability Assessments of the Near-Term Transmission Planning Horizon considering both peak load and off-peak load conditions (NERC Standard TPL-007-4 R4).

3.8.2 Voltage Criteria for the Supplemental Event

Acceptable Ameren transmission steady-state voltage criteria for NERC defined supplemental GMD events shall be when all Ameren transmission bus voltages are within the range 0.90 – 1.075 p.u. (NERC Standard TPL-007-4 R3). This voltage range would be used to gauge Ameren system performance in GMD Vulnerability Assessments of the Near-Term Transmission Planning Horizon considering both peak load and off-peak load conditions (NERC Standard TPL-007-4 R8).

3.9 Transmission Line and Substation Equipment Short-Term Overvoltage Capability

Typical and switching overvoltage capability for transmission lines are as shown in the table below. The steady-state maximum voltage limit would be 107.5% of nominal, with overvoltage capability due to switching of three times the maximum steady-state voltage.

Nominal System Line-to-Line Voltage	138 kV	161 kV	230 kV	345 kV
Maximum System Line-to-Ground Voltage (Nominal Voltage/1.732) x 1.075)	86 kV	100 kV	143 kV	214 kV
Switching Overvoltage Requirement (Maximum System Line-to-Ground x 3)	258 kV	300 kV	429 kV	642 kV

Transmission line insulator string flashover characteristics for porcelain suspension insulators are based on the number of insulators in a given string, and are as follows:

Number of Insulators	6	7	8	9	10	11	12	13	14	15	16	17	18
Low Frequency Flashover Wet (kV)	240	280	320	360	400	440	480	520	560	600	640	680	720

On a short-term basis (up to 10 second duration), substation equipment would be able to withstand 110% of nominal voltage.

4.0 THERMAL CRITERIA

4.1 Ratings methodology

Ameren's methodology for determining Facility Ratings is found in the Ameren FAC-008 Procedures document.

4.2 Application of Normal ratings

No facility may exceed its normal rating in the pre-contingency state following the occurrence of any operating condition in category P0 of the NERC Reliability Standard TPL-001-4 addressing Transmission System Planning Performance Requirements.

4.3 Application of Emergency ratings

No facility may exceed its applicable emergency rating in the post-contingency state following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard TPL-001-4 addressing Transmission System Planning Performance Requirements.

4.4 Proposal of new projects

In consideration of uncertainty and tolerance margins in the planning process, new projects or facility upgrade may be proposed if the projected loading exceeds 95% of the applicable rating.

4.5 Steady State Cascading determination

As a proxy for cascading conditions in steady-state study work, facilities with loadings of 120% of emergency rating or greater should be considered to have tripped offline. As the lines would be tripped in the powerflow simulations, a growing number of facilities loaded above 120% of the emergency rating would indicate cascading, and particularly if the overloads extend beyond Ameren boundaries to neighboring transmission systems.

5.0 LIST OF REFERENCED DOCUMENTS

5.1 North American Electric Reliability Corporation (NERC) Reliability Standards.

5.2 Federal Energy Regulatory Commission (FERC) Order 661-A “Interconnection for Wind Energy”, Issued December 12, 2005

5.3 Federal Energy Regulatory Commission (FERC) Order 827 "Reactive Power Requirements for Non-Synchronous Generation", Issued June 16, 2016

5.4 Ameren Documents

5.4.1 Transmission Facility Interconnection Procedures

5.4.2 End-User Connection Procedures

5.4.3 Generator Connection Procedures

5.4.4 Ameren FAC-008 procedure document: Ameren Facility Rating Criteria and Methodologies for Developing Transmission Facility Ratings

5.4.5 Ameren TPL-001 procedure document: TPL-ADM-0010-TP

5.4.6 Ameren TPL-007 procedure document: TPL-ADM-0070-TP

5.4.7 Ameren MOD-32 procedure document: MOD-ADM-0320-TP

5.4.8 Ameren VAR-001 procedure document: NOP-N16-7 Voltage and Reactive Control.doc

5.5 MISO Documents

5.5.1 MISO Tariff: Attachment X- GENERATOR INTERCONNECTION PROCEDURES (GIP)