

AMERICAN ELECTRIC POWER – 2011 FILING

**FERC FORM 715 – ANNUAL TRANSMISSION PLANNING
AND EVALUATION REPORT**

**PART 4 – TRANSMISSION PLANNING RELIABILITY CRITERIA
EASTERN AEP**

Attached is a document entitled "The American Electric Power System Transmission Planning Criteria and Assessment Practices Eastern AEP". This document provides the criteria to test and assess the strength of AEP's transmission system to meet its load responsibility, including power transfers with other systems (including activity within PJM) as well as to move bulk power between and among other electric systems. This document, in conjunction with the documents submitted under Part 5, provides a description of transmission planning criteria and assessment practices for the AEP System.

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THE AMERICAN ELECTRIC POWER SYSTEM

**TRANSMISSION PLANNING CRITERIA
AND ASSESSMENT PRACTICES**

EASTERN AEP

East Transmission Planning
Transmission Asset Strategy & Planning
American Electric Power Service Corporation
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Introduction

Electric utilities, such as AEP, meet their obligation to supply electricity demanded by their customers with a high degree of reliability through the carefully planned development of electric generating sources, transmission, and distribution systems. The reliable supply of electricity involves two elements – adequacy and security. "Adequacy" relates to the production and delivery of electric power and energy in the quantity and quality that the customer requires. For example, sufficient power must be provided at acceptable voltage levels and frequency to match the customers' equipment specifications. "Security" relates to the ability to produce and deliver power whenever the customer needs it. Credible contingencies, such as the sudden outage of transmission facilities, should not result in uncontrollable power interruptions over a wide area. Planning a reliable transmission system requires the application of fundamental principles and the establishment of criteria, which balance adequacy and security against the cost to provide them.

The eastern AEP transmission system was developed over many decades. In the early days of the utility industry, power plants were small and located near load centers. Consequently, transmission distances between the generation resources and the ultimate consumer were comparatively short and the amounts of power delivered were small. As the demand for electricity increased, larger power plants were designed and built further from the load centers to exploit economies of scale, and greater amounts of power had to be transmitted over longer distances. This led to the development of higher voltage, higher capacity transmission facilities.

As utilities developed in their respective geographic areas, the establishment of interconnecting transmission facilities between adjacent systems became attractive as a means to provide mutual support during emergencies and to avoid constructing duplicate facilities. The high transmission voltages have enabled power systems to interconnect on a broad scale. Interconnections allow utilities to support each other during forced or scheduled generation and transmission outages, to buy and sell power for reasons of economy and thereby enhance reliable and economic operation. On the other hand, each interconnected system is unavoidably impacted by events on neighboring systems, requiring coordinated planning and operating practices among neighboring systems and regions. Facility outages and variations in generation dispatch within one system will affect power flow patterns in neighboring systems. Consequently, cascading outages that affect widespread areas are possible. The highly interconnected nature of electric utilities has made it necessary that system planning criteria evolve to recognize these interrelated consequences of interconnected operation.

This document describes the criteria that AEP uses for planning a reliable transmission system to meet its customers' needs at the lowest cost. The first section describes the principles underlying the planning criteria and discusses the planning process. The following three sections provide details of modeling assumptions, performance expectations, and testing criteria, respectively, for AEP's bulk transmission system and area transmission system.

AEP's eastern bulk transmission system, which consists of an extensive network of extra high voltage (EHV) facilities generally operating at 345 kV and above, delivers power from generating plants to major load centers and connects load centers together to form an integrated network. The area

transmission system, which consists of high voltage (HV) facilities operating at 230 kV, 161 kV, 138 kV and 115 kV and lower voltage sub-transmission (Sub-T) facilities (from 23 kV to 88 kV), moves power within the major load centers and delivers it to distribution centers and major customers. The EHV and HV facilities connect the AEP System to neighboring companies. Even though AEP's eastern bulk and area transmission systems are planned and operated on a totally integrated basis, the planning criteria of each differ because of separate and distinct functions that each of these systems are intended to serve.

The AEP transmission facilities are divided into the following three performance categories:

- **EHV Facilities:**
Transmission lines rated 765 kV, 500 kV, and 345 kV, and transformers with secondary voltages at or above 345 kV, are considered Extra High Voltage (EHV) facilities, and are referred to as “EHV facilities” in this document. These facilities are also part of the Bulk Electric System (BES).
- **HV Facilities:**
Transmission lines rated 230 kV, 161 kV, and 138 kV, and transformers with secondary voltages above 100 kV but below 345 kV, are considered High Voltage (HV) facilities, and are referred to as “HV facilities” in this document. These facilities are also part of the BES.
- **Sub-T Facilities:**
Transmission lines rated below 100 kV, and transformers with secondary voltages below 100 kV are considered sub-transmission (Sub-T) facilities, and are referred to as “Sub-T facilities” in this document. These facilities are not part of the BES.

1. UNDERLYING PRINCIPLES AND PLANNING PROCESS

1.1 Underlying Principles

Although planning is essential in any industry, it is critical for electric utilities due to the characteristics of an electric power system: the inherent need to respond instantaneously to the electric power demand of customers (load); the heavy financial investment and long service lives of its facilities; the long lead and construction times to add facilities; and the social and economic importance of a reliable power supply. AEP has adopted fundamental planning principles as the basis for specific reliability criteria. Briefly, these principles state that a properly designed transmission system should provide a good distribution of power flows by avoiding excessive geographic concentrations of generating sources or transmission paths. A transmission system should have ample margin to allow for contingencies so as to avoid uncontrolled, area-wide power interruptions and also provide flexibility to deal with the uncertainties inherent in making long range forecasts. Interconnection capabilities between systems should be maintained commensurate with the amount of system load and the size of the individual generating units connected to the transmission system. Station switching arrangements, relay protection, and system controls should be adequate to maximize the use of the transmission system and minimize interruptions; and to provide flexibility for scheduling required maintenance as well as facilitating the restoration of outaged facilities while always, and most importantly, insuring the safety of the general public and our employees.

It is impossible to anticipate or test all possible contingencies that could adversely affect the eastern AEP transmission system because of the large number of individual elements that comprise the system and the fact that power flows, and load levels are continually changing. Therefore, the planning criteria and related contingency tests outlined in this report do not represent an exhaustive set of system operating conditions, transfer levels, and specific contingencies; instead, they constitute an effective and practical means to stress the eastern AEP transmission system, testing its ability to survive the entire spectrum of possible contingencies and identifying potential weaknesses and problems.

The AEP criteria described herein are compatible with: 1) the North American Electric Reliability Corporation (NERC) Reliability Standards; 2) the ReliabilityFirst Corporation (RFC) Standards, 3) PJM Planning and Operating Manuals, and 4) other external documents. A listing of those external documents is provided in Appendix A. The application of the NERC and RFC criteria to any particular utility system, including AEP, must be adapted to the specific characteristics of that utility. Each utility's transmission system is configured in a way that is specific to the geographic region it serves as well as the electrical facilities that are installed to meet these requirements. There are also various ways of achieving reliability objectives. Therefore, differences can exist among the specific planning criteria employed by various systems. Compatibility among different systems' criteria and guidelines are achieved, however, by adopting fundamentally sound planning principles and practices.

This report presents an overview of AEP's eastern transmission planning criteria and assessment practices. Specific application of these criteria and practices on a case-by-case basis must employ sound engineering judgment. The transmission planner conducting each study should always evaluate

these criteria and apply them in such a manner to account for special considerations applicable to the area under study.

Due to inherent uncertainties associated with forecasts of loads, new technological developments, equipment costs, and changing social, economic, and political conditions, it is prudent to develop long range plans of transmission system expansion/modification based on a range of assumed scenarios. Sensitivity analysis is also useful in making these judgments. By their very nature, long-range plans must be reevaluated and modified periodically to reflect the persistent changes in the variety of factors that influence future system performance. While current planning criteria are inherently deterministic, qualitative distinctions about the likelihood of various scenarios and contingencies are recognized.

More likely events require higher levels of system performance; lower system performance standards (greater negative impacts) are acceptable for events that are less likely to happen. Deterministic reliability criteria that are sufficiently stringent to ferret out potential system problems may also result in specific design consequences, which are impractical or too expensive in relation to the benefits realized or the risks mitigated. In these cases, prudent exceptions to the criteria can be made, or other less expensive control schemes employed.

1.2 Planning Process

The planning process, as carried out in the eastern AEP area, provides the focus for establishing an appropriate level of system reliability. The planning process includes seasonal assessments of system performance; near-term facility addition studies; and long-term strategic planning. The planning process typically begins with a deterministic appraisal of transmission system performance. When such appraisals identify potential problems, detailed studies are conducted to evaluate the severity of the problem and to develop an optimal plan to remove or mitigate the deficiency.

Seasonal assessments, also referred to as operational planning assessments, have a horizon of up to one year. These appraisals verify that the transmission system, as planned and built based on long term predictions and assumptions, is adequate to meet the actual requirements that emerge for the approaching peak load periods. Delays in transmission reinforcements, and changing power flow patterns or performance expectations, also influence the need for short-term appraisals. These appraisals also provide an early warning of future system reinforcement needs. Operational planning appraisals are conducted in a manner similar to facility planning appraisals. The major difference is that problems identified in these assessments typically cannot be corrected by transmission reinforcements due to insufficient lead time. Therefore, problems identified by these studies are addressed by deriving indices for system operators to monitor system performance and establishing operating procedures to mitigate any transmission problems detected by the operators during real time operation.

Near-term (1 to 5 years) and long-term (more than 5 years) facility planning appraisals analyze anticipated system conditions within the specified time periods. Near-term and long-term planning of the transmission system allows adequate time to identify emerging trends and anticipated system

deficiencies and then to plan and build needed transmission reinforcements, including time for potentially lengthy regulatory approval processes.

Near and long term facility planning studies are conducted for both the bulk transmission system and the area transmission system in accordance with their respective testing criteria and performance expectations. These studies are conducted externally by PJM transmission planners from a regional perspective and internally by AEP transmission planners from a local perspective, and are supplemented by information generally available from neighboring electric utilities. In addition, joint planning studies involving one or more neighboring systems and/or the appropriate Regional Transmission Organization(s) are carried out to assess and enhance the transmission interfaces between AEP and its neighbors through the coordination of operating procedures, development of new interconnection facilities, and/or coordinated transmission enhancements within each system.

AEP's eastern Transmission Planning organization continues to receive requests through PJM from merchant generation and transmission developers for interconnection of new facilities to the eastern AEP transmission system. PJM assesses the impact of these requests on the AEP bulk transmission system. The PJM studies are supplemented by studies conducted by AEP transmission planners. The integration of new merchant projects into the AEP transmission system is conducted based on the same planning principles as for any other transmission facilities.

In addition, seasonal, near-term and long-term appraisal studies, limited to assessing regional and inter-regional transmission system performance, are conducted jointly with neighboring utilities as part of PJM, RFC and Eastern Interconnection Reliability Assessment Group (ERAG) agreements. These joint appraisals focus on measuring the strength of the interconnected network and on assuring coordination of facility planning and operational planning efforts. Where such assessments uncover deficiencies, the specific findings are referred to the appropriate company or companies to develop solutions as part of their normal planning processes.

This document does not directly address regional and interregional appraisal criteria except to note that AEP's criteria comply with those in the NERC and RFC Reliability Standards. Also, AEP uses regional and interregional transfer capability measures that are consistent with the NERC and RFC definitions, to assess the strength of its transmission system. AEP is an active participant in many regional and interregional study groups and has made significant contributions to the development of regional and interregional criteria, including the NERC and RFC Reliability Standards.

2. KEY MODELING ASSUMPTIONS

The computer models used in transmission planning studies necessarily differ widely in dimensions and details to suit the scope of each study. Power flow models are developed to represent system operation during highly stressed periods such as peak load conditions and heavy power transfers that simulate emergency and opportunity power transactions. System dynamics and short circuit computer models are also used, depending on the specific analysis, to complement the power flow models. Using these computer models, transmission system performance is assessed by simulating disturbances to identify system strengths and weaknesses. In general, the following assumptions are used in conducting various types of transmission planning studies.

System active power (MW) loads are often represented at extreme weather, peak, off-peak, and/or light load levels depending upon the type of analysis being conducted. The load levels for studies of the EHV and HV systems are based on the forecasts of diversified peak demand (developed for transmission analysis purposes) provided by AEP's Fundamental Analysis and Economic Forecasting function. These forecasts include both the loads of full requirements customers and customers taking transmission service within the AEP Transmission Zone of PJM. For studies of the sub-transmission system, load levels are based on peak demands of individual load areas.

Facility planning studies usually simulate performance during peak load periods because this is the condition that produces the most heavily loaded transmission conditions. There are exceptions due to: 1) pumped storage hydro characteristics, and 2) the fact that the heaviest power transactions often occur at load levels 80-90% of peak. Sensitivity analyses are conducted to investigate the impact of load growth forecasts on the expansion/modification plans being considered. For most internal and some external studies of the eastern AEP transmission system, sub-transmission facilities are modeled in detail, in order to capture the effects of shunt capacitors, LTC transformers, and the hydro-electric generators that are connected to the sub-transmission system. Broader regional and interregional studies and assessments, such as those conducted by RFC, ERAG, and NERC, generally include detailed models only at the 138 kV and higher voltage levels, with the sub-transmission facilities represented through appropriate equivalents.

Reactive power (MVar) loads are based on the measured power factor for each load area. It is assumed that reactive correction will be provided as load increases in the future to maintain that power factor. Where future system assessments indicate a need for additional power factor correction, appropriate reinforcements are proposed to meet AEP's design goal that each voltage level is not a reactive burden to its source system. When the impacts of extreme weather forecasts are assessed on the transmission system, the power factor of the incremental load (above the base forecast load) is modeled at 80% because it is assumed that power factor correction is not provided for load that exceeds the forecast.

Power transfer levels modeled in base cases for analysis of the AEP transmission system vary from one study to another depending on the particular focus of the study. The ERAG Multi-Regional Modeling Working Group (MMWG) power flow base cases generally model only committed firm energy commitments. The Reliability *First* base cases, which are derivatives of the ERAG base cases,

are modified to include additional recently experienced power transfer biases. AEP's base cases, which are derived from these regional models and those developed by PJM, may require further updates and detail. Often high levels of transfers are simulated to reflect parallel flow conditions reflecting recent experience and in order to assure that probable system bottlenecks are identified.

Generators are normally dispatched to simulate economic operation (lower cost generation 'loaded' first followed by higher cost units) to meet the load demand for system conditions being studied. Most generators will be modeled at or near full output for peak load conditions while some units may be at minimum levels for light load conditions depending upon generation market assumptions. In addition, for operational planning studies, the generation dispatch reflects scheduled generation maintenance related outages. In some cases, the generation dispatch may be adjusted to more accurately reflect other constraints or typical dispatch levels of the units. Pumped storage units are dispatched in the pumping, generating, or condensing mode, depending on modeled system load level and other typical operating constraints such as generating unit minimum output levels appropriate for the modeled conditions. Emergency dispatch models may also be used to simulate actions taken to relieve transmission constraints or to simulate a response to an extreme condition. In the absence of specific information, non-utility generators are modeled in the same manner as utility generation for transmission study purposes.

Base cases model all transmission facilities in service except for known scheduled maintenance, long term construction outages, or long-term forced outages. These known outages are normally only reflected in operational planning studies. Because it is impractical and unnecessary to represent all interconnected systems in detail, the type of planning study dictates the extent of the interconnected network representation. Thus, an interconnection study involving the bulk transfer of power between two power systems not only would require sufficient detail of the bulk transmission in each participating system but also would include sufficient detail and/or equivalent representation of other interconnected systems to assure proper analysis of critical elements.

Sufficient modeling of neighboring systems is essential in any study of the AEP bulk transmission system. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the ERAG MMWG power flow library, the PJM base cases, or the neighboring company itself. In general, sufficient detail is retained to adequately assess all outages and changes in generation dispatch, which are contemplated in the particular study. Other areas are usually reduced to a mathematical equivalent.

With the power flow base cases described above, the study engineer develops scenarios that are surrogates for a wide range of possible conditions. Numerous facility outages and power transfers occur daily in the interconnected network. It would be impractical to simulate all such possible conditions in planning studies. In order to establish a manageable set of base case scenarios, historical data and experience are employed. Although history is not a perfect indicator of the future, it provides valuable information to benchmark the base case models. For future power flow base cases, further adjustments are made to reflect forecasted load levels, expected facility changes, and projected power transfers, as well as emerging trends that will affect historical power flow patterns.

Power flow models described above are the most frequently used models for transmission planning studies. Transient stability and short circuit studies are also used to evaluate the system performance during and immediately following fault conditions on the transmission system. The network configurations used in the power flow models also provide a starting point for transient stability and short circuit studies. In addition, for transient stability studies, additional impedance and electromechanical detail of generators and their controls are included. Three-phase models of the power system are employed to study single-phase switching and other unbalanced operating configurations.

3. PERFORMANCE STANDARDS

Performance standards provide the basis for determining whether system response to contingency analysis is acceptable. Depending on the nature of the study, one or more of the following five types of performance standards will be applied: thermal, voltage, relay, stability, and short circuit.

In general, system response to contingencies evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

3.1 Thermal Limits

Thermal ratings define transmission facility loading limits. Normal ratings are generally based upon no abnormal loss of facility life or equipment damage. Emergency ratings accept some loss of life or strength, over a defined time limit for operation at the rated loading level. The thermal rating for a transmission line is defined by the most limiting element, be it a conductor capability, sag clearance, or terminal equipment rating. When a line is terminated with multiple circuit breakers, as in a ring bus or "breaker and a half" configuration, it is assumed that the line flow splits equally through the terminal equipment unless one breaker is open. Ratings in power flow simulations normally assume all breakers are in service.

Most thermal ratings are defined in amperes. However, transmission planning studies use ratings expressed in MVA, based on the ampere rating at nominal voltage. When voltages during testing deviate considerably from nominal, the MVA loading is adjusted for the voltage deviation from nominal to permit an appropriate comparison to the MVA rating.

3.2 Voltage Limits

Voltages at transmission stations should be within the values listed in Table 1 in subsection 4.1 to reduce the risk of system collapse and/or equipment problems. In addition, voltages at generating stations below minimum acceptable levels established for each station must be avoided to prevent tripping of the generating units. High voltage limits are specific for particular pieces of equipment, but are typically 105% of nominal.

Relay trip settings, selected primarily for fault conditions, could be reached in some cases during contingency loading conditions or transient power swings. These relay trip settings are evaluated in operational planning studies, as well as longer term studies, to determine whether adjustments are needed. If it is not practical to revise the setting, subsequent planning studies must recognize that the line could trip due to the resultant contingency loading condition. Facilities that must comply with NERC Reliability Standard PRC-023 requirements have relay limits set at least 150% above the highest seasonal (emergency) Facility Ratings, for the available defined loading duration nearest 4 hours.

3.4 Stability Limits

Stability limits can be of several types and are characteristic of any power system. These include steady-state, transient, and oscillatory stability limits. More than one type of limit may impact power system operation, but often only one type of limit is most constraining.

The steady-state stability limit (P_{MAX} in Figure 3.1) is the point at which no more power can flow through a system without precipitating a voltage collapse. This limit is often related to heavily loaded systems where even small perturbations, such as the normal adjustment of generator output to match load, could cause system collapse. Steady-state stability limits are typically evaluated using power vs. voltage (PV) curves or power vs. angle curves, for individual lines or transmission interfaces. In planning studies, a loadability limit is defined, which includes a safety margin of 5-10% below the theoretical maximum power flow.

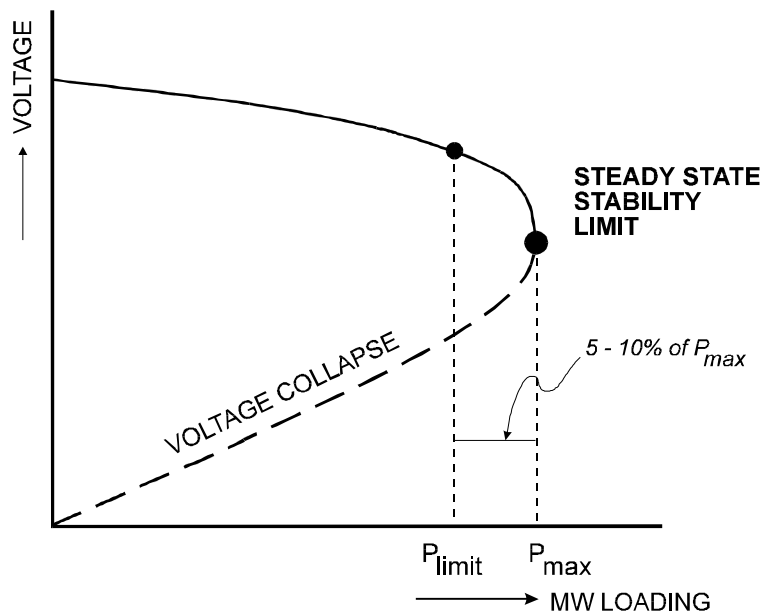


Figure 3.1

Transient stability refers to the ability of a power system to remain in synchronism following a disturbance, such as a short circuit. Facilities must be planned and operated so that all generating units remain stable through the transient period regardless of the plant's output level prior to the disturbance. Also, transient voltage dips at generating stations below established minimum acceptable levels, and for significant durations, must be avoided to prevent tripping of the auxiliary loads, which in turn, could trip generating units.

Oscillatory stability refers to the ability of a power system to damp out electromechanical oscillations (or power swings) in the 0.1-3.0 Hz range. Oscillatory modes within this range inherently exist on any power system. Oscillatory instability is manifested in terms of sustained or growing oscillations in various electrical quantities observable at power plants and on the transmission system, following a disturbance, or a routine network operation such as load ramping. These oscillations must be suppressed within seconds to prevent potential equipment tripping and damage. The oscillatory instability limit is defined as the power level beyond which one or more generators or groups of generators continue to exhibit one or more sustained modes of oscillation beyond a reasonable time limit. Generally, this limit is not dependent on the size of the disturbance or the period of the mode. Any sustained or growing oscillation that persists beyond a reasonable time period indicates that the stability limit has been exceeded and represents unacceptable performance.

3.5 Short Circuit Limits

Short circuit limits are also an important aspect of system performance, since the extremely high, short duration currents that accompany system faults will impose considerable stresses on network elements. Circuit breakers must be capable of interrupting the anticipated fault currents in the shortest possible time. Failure to interrupt these currents may lead to catastrophic equipment damage and endanger human life. Short circuit levels increase as network reinforcements are implemented or new generating units are added to the system. Therefore, short circuit levels must be reviewed periodically so that inadequate equipment can be replaced or upgraded, or a mitigation procedure developed.

AEP steady state planning criteria requires that no bus voltage on AEP system shall exceed 1.05 per unit under system normal or contingency conditions. This voltage limit takes into consideration the equipment capabilities on AEP system. Short circuit assessment is performed assuming 1.05 per unit voltage at all the AEP system buses. This is a conservative approach but accounts for a wide range of system conditions. Circuit breakers at or near a generator plant shall be analyzed differently based on the scheduled voltage at the generator bus. This exception only applies to generator plants already in operation with established scheduled voltages.

4. TRANSMISSION TESTING AND PERFORMANCE CRITERIA

4.1 Steady State Testing Criteria

The planning process for AEP’s transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the BES, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance. Each type of performance requirement is described in the following discussion. Table 1 below documents the performance criteria for all transmission facilities under normal and contingency conditions.

Table 1

NERC Contingency Category	Transmission Facilities		
	EHV Facilities	HV Facilities	Sub-T Facilities
A – System Normal	<p><u>Thermal:</u> No facility may exceed its normal rating.</p> <p><u>Voltage:</u> All station voltages must stay between 1.05 per unit and 0.95 per unit.</p>		
B1 – Single Generator	<u>Thermal:</u> No facility may exceed its normal rating.	<u>Thermal:</u> No facility may exceed its emergency rating.	
B2 – Single Line	<u>Voltage:</u> All station voltages must stay between 1.05 per unit and 0.92 per unit. A voltage change from system normal of 8% or greater is not acceptable at any station.		
B3 – Single Transformer			
C1 – Bus C2 – Breaker Failure C5 – Double Circuit Tower	<u>Thermal:</u> No facility may exceed its emergency rating.		<u>Note:</u> Not planned for this Category of contingencies.
	<u>Voltage:</u> All station voltages must stay between 1.05 per unit and 0.92 per unit. A voltage change from system normal of 8% or greater is not acceptable at any station.		

<p>C3 – Two Category B Contingencies (one Category B contingency followed by another Category B contingency)</p>	<p><u>Thermal:</u> No facility may exceed its emergency rating.</p> <p><u>Voltage:</u> All station voltages must stay between 1.05 per unit and 0.92 per unit. A voltage change from system normal of 8% or greater is not acceptable at any station.</p> <p><u>Manual System Adjustments After First Contingency:</u> Not acceptable for transmission facilities supplying major load centers (as defined below).</p>	<p><u>Note:</u> Not planned for this Category of contingencies.</p>
<p>D6 – Loss of Tower Line with 3 or More Circuits</p> <p>D7 – Loss of All Transmission Lines on Same Right of Way</p> <p>D8 – Loss of Substation</p> <p>D9 – Loss of Switching Station</p> <p>D10 – Loss of All Generating Units at a Station</p>	<p><u>Note:</u> Performance is evaluated for risks and consequences. Issues identified may not be mitigated, but may be used to screen viable solutions to resolve violations from Category B and C contingencies.</p>	<p><u>Note:</u> Not planned for this Category of contingencies.</p>

Major Load Centers: Considering the location and strength of the eastern AEP transmission system, it is subjected to a wide variety of power flow patterns. In some instances, these conditions result from economic power transfers between neighboring systems which are outside the control of AEP or PJM system operators. It is not possible to ensure that effective system readjustments will be available to address all of the credible outages that are identified in the planning study. This is of particular concern for major load centers where the impact of a blackout is too severe to allow reliance on manual system adjustments. Therefore, AEP does not allow the use of manual system adjustments after the first contingency in anticipation of the next contingency as a viable mitigation tool for planning the transmission system supporting major load centers. A major load center is

defined as an area with significant demand that is dependent on the bulk transmission system. In the eastern AEP footprint, the following areas are considered major load centers:

- Columbus Metropolitan Area
- Fort Wayne Metropolitan Area
- Eastern Appalachian Power Company Service Territory
- Central Appalachian Power Company Service Territory

Special Protection Schemes (SPS): An SPS may be implemented as an interim measure to prevent propagation of cascading outages across the transmission network and thus mitigate the possibility of a large scale blackout. Interim use of an SPS is intended to provide sufficient time for implementation of a permanent solution.

4.1.1 Single and Double Contingencies

Single contingencies include the forced outage of generating units, transmission circuits, transformers, and/or other equipment. In general, a single contingency is defined as the outage of any one of these facilities. Due to the interconnected nature of power systems, testing includes outages of facilities in neighboring systems. A single facility is defined by the arrangement of automatic protective devices. Generally, double circuit tower outages, breaker failures, station outages, common right-of-way outages, and other common mode failures have substantially lower probabilities of occurrence than the outage of a single transmission facility and are, therefore, not considered single contingencies.

Double contingencies, being a more severe test of system performance, are used as a surrogate for the significant uncertainties that are inherent in the planning process. A double contingency can be defined as an outage of any two facilities.

For facility planning purposes, contingencies result from scheduled maintenance and/or forced outages. Double outages are generally viewed as separate events that overlap in time. Each contingency is tested with the system load level, generation dispatch, generating unit outages, and transfer conditions, which would be most severe, but still credible, for that particular contingency.

Single and double contingencies are tested with firm import and export transactions, third party transfers, and the expected level of opportunity transfers (or expected generation market activity) as a base condition. The import scenarios assessed assume planned imports plus an additional level of imports necessary to assure that the load expectation for the eastern AEP transmission system will be no greater than one day in ten years. Furthermore, since the availability of off system resources is uncertain, the transmission system must be capable of importing these resources across a limited number of interfaces when these resources are not available from one or more directions. Sensitivity studies are also normally conducted for a range of opportunity transfers and generation dispatches as well as extreme weather conditions. The various types of sensitivity analyses performed are discussed in subsection 4.3.

Operational planning studies consider up to two key outages in effect prior to the next (third) contingency. It is assumed that all operator adjustments required for the prior outages have been implemented. Uncertainties such as generation availability and dispatch, load forecast error and load diversity are also considered. The number of prior outages depends on the strength of the transmission system and the number of variables to be considered in developing effective operating guidelines. Clearly, as the number of concurrent contingencies increases, it will become increasingly difficult to meet the required performance limits (see Section 3), even with special operating procedures.

The number of outages actually occurring on the system can exceed the number assumed for study purposes. Operational planning engineers evaluate those conditions, as needed.

4.1.2 Extreme Contingencies

The more severe reliability assessment criteria required in the NERC Reliability Standards (Category D contingencies) are primarily intended to assess the risks for uncontrolled area-wide cascading outages under adverse but credible conditions. AEP, as a member of *ReliabilityFirst*, plans and operates its bulk transmission system to meet the criteria. However, new facilities would not be committed on the basis of local overloads or voltage depressions following the more severe multiple contingencies unless those resultant conditions were expected to lead to widespread, uncontrolled outages.

In operational planning studies, the purpose of studying multiple contingencies and/or high levels of power transfers is to evaluate the strength of the system. Where conditions are identified that could result in significant equipment damage, uncontrolled area-wide power interruptions, or danger to human life, IROL operating procedures will be developed, if possible, to mitigate the adverse effects. It is accepted that the defined performance limits could be exceeded on a localized basis during the more severe multiple contingencies, and that there could be equipment damage, increased loss of equipment life, or limited loss of customer load. Normally, operating procedures to mitigate uncontrolled area-wide power interruptions are only used on an interim basis until facility additions can be put in place to restore acceptable reliability levels.

In carrying out operational or facility planning studies, it is recognized that there are many protective and special controls on the system that must operate properly when an event occurs. These controls include but are not limited to: protective relays, circuit breakers, breaker failure schemes, quick reactor or capacitor switching, rapid generating unit runback, automatic motor operated disconnects, and emergency generator tripping. The misoperation of any of these controls may result in equipment damage, but should not result in widespread power interruptions or danger to human life.

4.2 Stability Testing Criteria

Stability testing covers the entire range of power system dynamics from "first swing" transient stability to longer term oscillatory and steady-state stability. This testing is an essential complement to the steady-state analysis embodied in the power flow testing described above.

Maintaining power plant transient stability is essential because loss of synchronism (or instability) of a generating unit or an entire generating plant can lead to equipment damage and severe power system transient swings. Instability may further compound a disturbance by causing the tripping of the unstable generators and possibly other equipment. When simulating system contingencies affecting power plant stability, various types of fault and network conditions are analyzed in accordance with the transient stability disturbance testing criteria outlined in Appendix B.

The Appendix B transient stability disturbance testing criteria specifies the disturbance events for which stable operation is required of all transmission and EHV connected generation. The stability testing criteria appropriate for sub-transmission and distribution connected generation is determined on a case-by-case basis and may be less stringent as long as instability may be shown not to adversely affect the bulk transmission system. In cases where the bulk system is not adversely affected and the speed of sub-transmission or distribution system protection is inadequate to prevent instability for normally cleared faults, out-of-step tripping would be required to prevent adverse affects on the sub-transmission or distribution systems.

Steady state and oscillatory stability performance problems may be initiated by a wide variety of contingencies or operating conditions on the transmission network. Appendix B network disturbances are similarly applied when testing for steady state and oscillatory instability and these criteria are sufficient for detecting these types of instability. The measures of acceptable performance for each type of stability performance problem are discussed in Section 3.4.

AEP generally carries out simulations corresponding to the A through E set of criteria in Appendix B for facility planning studies. For operational planning studies, the F and G criteria, in addition to the A-E set, are applied, especially when a long-term facility outage is anticipated. Testing of more severe disturbances than those of Appendix B may be performed to evaluate the strength of the transmission system and to assess potential for cascading outages. Examples of such testing include common-failure mode disturbances such as double circuit tower faults or bus faults that result in the outage of multiple facilities at a location.

The disconnection of generation due to a disturbance is distinct from instability. Instability refers to loss of synchronism or pole slipping when the generation remains physically connected. Disconnection results in generator overspeed followed by turbine shutdown in response to protective relay action. Systems are planned such that disconnection does not occur for single contingencies. Disconnection may occur during Appendix B disturbance scenarios involving the outage of more than one transmission element, or common-failure mode disturbances such as bus outages, as a consequence of isolating faulted facilities or other system design considerations. Disconnection under these circumstances is considered to be acceptable whereas instability is not.

4.3 Sensitivity Scenarios Testing Criteria

In addition to testing base case conditions, as described in the preceding sections, uncertainty inherent in the system planning process warrants that variations from the assumptions underlying the base case models also be evaluated. The particular sensitivities examined may vary from area to area, depending on the characteristics of both the portion of the AEP transmission system which is the focus of study, and its (AEP or non-AEP) neighbors. In this regard, the individual study area considered may be one or more of the AEP Transmission Regions (Fort Wayne, Columbus, or Roanoke). The thermal rating and voltage limits defined in Table 1 must be adhered to for the sensitivity assessments of AEP transmission system performance as well. In addition to the particular sensitivity scenarios described below, sensitivity of other system conditions are also considered, including but not limited to changes in system load such as shoulder peak load, light load, extreme (e.g., one in ten years) load, or local area load conditions, different generation dispatch scenarios, and system conditions reflecting historical operating experience.

4.3.1 Power Transfers

Power transfers of at least 4000 MW across the AEP transmission system, both with and against the normal flow bias, are simulated to assess the performance of the BES. The geographic span of the eastern AEP transmission facilities results in connection points between areas that may experience conditions substantially different from those projected for the peak load period. Past events that have produced different patterns of sustained (weeks or months) flows have included drought, flood, fuel supply disruptions, and regulatory restrictions affecting similar generating units.

4.3.2 Potential Generation Retirements or Unavailability of Generation

A significant portion of the generation fleet in the U.S. entered service 30 years ago or more, and even newer units may be exposed to early retirement if changing regulations, such as environmental regulations, render their continued operation uneconomical. Robust transmission requires years to study and develop. On the other hand, the PJM tariff requires that retiring generators only provide 90-days notice before they retire. Therefore, the potential retirement of generating units in or adjacent to the study area based on credible information available in the public domain is analyzed to determine the potential impact on AEP transmission system performance.

4.3.3 Potential Generation Development

In areas with significant intermittent generation (wind, solar) connected to the BES or requesting interconnection, sensitivity analyses include simulations with high generation output (100% of seasonal installed nameplate) in or near the study area, concurrent with 85% of the projected peak load. The following generation dispatch scenarios are considered:

- a) All the intermittent generation connected to the BES or requesting interconnection is

dispatched to neighboring areas. The neighboring areas are chosen so as to reflect a stressed condition on the AEP transmission system.

- b) 20% of all intermittent generation connected to the BES or requesting interconnection is dispatched to replace existing generation in the AEP footprint while the remainder is dispatched to neighboring areas. At no time are any base load units dispatched to less than their minimum generating capabilities. The neighboring areas are chosen so as to reflect a stressed condition on the AEP transmission system.
- c) 50% of all intermittent generation connected to the BES or requesting interconnection is dispatched to replace existing generation in the AEP footprint while the remainder is dispatched to neighboring areas. At no time are any base load units dispatched to less than their minimum generating capabilities. The neighboring areas are chosen so as to reflect a stressed condition on the AEP transmission system.

4.3.4 Energy Storage Facilities

Several portions of the eastern AEP transmission system are affected by large storage facilities. To properly plan the transmission system, operation of BES connected Energy Storage facilities in the charging mode, at 85% of projected peak load and during light load conditions, is assessed.

APPENDIX A

External Documents that Relate to AEP's Transmission Planning Criteria and Assessment Practices

1. NERC Reliability Standards *
2. NERC "Transfer Capability – A Reference Document" *

* NERC website: www.nerc.com

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APPENDIX B

AEP TRANSIENT STABILITY DISTURBANCE TESTING CRITERIA

<u>PREFault CONDITION</u>	<u>765 KV PLANTS</u>	<u>345 KV PLANTS</u>	<u>138 KV PLANTS</u>
All Transmission Facilities in Service	1A Permanent single line-to-ground (SLG) fault with 1 ϕ breaker failure. Fault cleared by backup breakers.	2A Permanent SLG fault with 1 ϕ breaker failure. Fault cleared by backup breakers.	3A Permanent SLG fault with 3 ϕ breaker failure. Fault cleared by backup breakers.
	1B Permanent SLG fault cleared by primary breakers. 3 ϕ fault developed following HSR. Fault cleared by primary breakers.	2B Permanent 3 ϕ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3B Permanent 3 ϕ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1C 3 ϕ line opening without fault.	2C 3 ϕ line opening without fault.	3C 3 ϕ line opening without fault.
One Transmission Facility Out of Service	1D Permanent SLG fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	2D Permanent 3 ϕ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3D Permanent 3 ϕ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1E 3 ϕ line opening without fault.	2E 3 ϕ line opening without fault.	3E 3 ϕ line opening without fault.
Two Transmission Facilities Out of Service	1F Temporary SLG fault with successful HSR, if applicable.	2F Temporary 3 ϕ fault with successful HSR, if applicable.	3F Temporary 3 ϕ fault with successful HSR, if applicable.
	1G 3 ϕ line opening without fault.	2G 3 ϕ line opening without fault.	3G 3 ϕ line opening without fault.