Kansas City Power & Light Company

BULK ELECTRIC SYSTEM PLANNING CRITERIA

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1.0 Introduction

The primary purpose of the Company's (inclusive of Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO)) bulk electric system is to supply our customers with economic and reliable electrical energy. To achieve this objective Transmission Planning has developed minimum planning criteria, which provides the basis for the design and operating criteria of the Company's bulk electric system. This Criteria presents the characteristics of a well-planned bulk power electric system, describes the basis for model testing and lists the reliability and adequacy tests to be used to evaluate the performance of the Company's bulk electric system. Reliable operation of the Company's interconnected bulk electric system requires that the system comply with these Criteria. The Company's Bulk Electric System Planning Criteria meets or exceeds all North American Electric Reliability Corporation (NERC) Reliability Standards and Southwest Power Pool (SPP) Transmission Planning Criteria.

Prior to July 2008, GMO was known as Aquila. With the acquisition of Aquila by Great Plains Energy (parent of KCP&L), these Criteria now applies to the former Aquila Missouri electric service territory. In this document "KCP&L" is inclusive of both KCP&L and GMO service areas. "GMO" will be used to refer to items only applying to KCP&L Greater Missouri Operations Company.

KCP&L is a member of the SPP Regional Transmission Organization (RTO). SPP is one of the eight regional reliability council members of NERC. SPP performs the requirements of a Reliability Coordinator and Planning Coordinator function for KCP&L. KCP&L performs the requirements of a Transmission Operator and Transmission Planner function. The SPP Criteria is revised on an on-going basis as needed to incorporate the policies, standards, and principles by which the coordinated planning and operation of the interconnected electric system is achieved.

In February 2005, the NERC Board of Trustees adopted Version 0 of the new NERC Reliability Standards with an effective date for implementation of April 1, 2005. These new Reliability Standards define the reliability requirements for planning and operating the North American bulk electric system. They were developed from the previous NERC Operating Policies and Planning Standards into a form that would fit the NERC Reliability Functional Model of the electric utility industry.

In 2006, the Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization (ERO), approved a base set of 83 reliability standards, and required NERC to develop a Compliance Monitoring and Enforcement Program (CMEP). In April 2007, FERC approved delegation agreements between NERC and eight (8) regional entities (RE), including SPP, responsible to perform the delegated reliability compliance and monitoring functions.

The original set of approved Reliability Standards included four standards on Transmission Planning (TPL) with many requirements and sub-requirements on transmission system performance and regional reliability assessments. These TPL standards are applicable to the Planning Authority and Transmission Planner functions of the NERC Reliability Functional Model.

In 2013, FERC approved a new Transmission Planning Reliability Standard, TPL-001-4, while simultaneously retiring the previous four standards. This standard establishes transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probably contingencies. It is applicable to the Planning Coordinator and Transmission Planner functions.

2.0 KCP&L Transmission Planning

The interconnected transmission system should be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. Electric systems must be planned to withstand contingencies and maintenance outages. Extreme event contingencies, which measure the robustness of the electric systems, should be evaluated for risks and consequences. The NERC Reliability Standards define specific transmission planning requirements that provide reliability for the bulk interconnected electric system. SPP provides coordinated regional transmission planning requirements to promote reliability through its Criteria Section 3, “Regional Transmission Planning”, and related Attachment O, “Coordinated Planning Procedures”, in the SPP Open Access Transmission Tariff (OATT).

It is the policy of KCP&L to maintain as high an interconnection capability with adjoining systems as is economically prudent. These interconnections with adjoining systems shall be designed such that KCP&L will remain interconnected following all of the more probable transmission and generation outage contingencies as described in the NERC Reliability Standards found in Table 1 of TPL-001-4. It is recognized that emergencies that occur in adjoining systems can affect KCP&L, just as the emergencies within KCP&L can affect adjoining systems. Therefore, joint studies will be made on a regular basis to investigate various system emergencies that can occur and their effects on the various systems involved. In this way, the effectiveness of existing and planned interconnections will be periodically measured and the design of the system periodically updated so that the interconnection capability and reliability will be maintained. In these activities KCP&L will perform the requirements of the Transmission Planner function as defined in the NERC Reliability Functional Model.

Transmission planning criteria for the KCP&L electric system shall at a minimum conform to the NERC Reliability Standards and SPP Transmission Planning Criteria Section 3 and meet the following:

- **a.** Excessive concentration of power being carried on any single transmission circuit, multi-circuit transmission line, or right-of-way, as well as through any one transmission station shall be avoided.
- **b.** Adequate transmission capability shall be maintained to provide for intra-regional, inter-regional and trans-regional power flows under normal and more probable contingency conditions as defined in Table 1 of the NERC Reliability Standards.
- **c.** Switching arrangements shall be utilized that permit effective maintenance of equipment without excessive risk to the electric system.
- **d.** Switching arrangements and associated protective relay systems shall be utilized that do not limit the capability of a transmission path to the extent of causing excessive risk to the electric system.
- **e.** Sufficient reactive capacity shall be planned within the KCP&L electric system at appropriate places to maintain transmission system voltages

within plus or minus 5% under normal and within plus 5% or minus 10% for contingency conditions, for all busses. Certain transmission busses such as, Northeast, Bull Creek, and Osawatomie require higher voltage levels to provide for successful starting of combustion turbines located there. At those busses KCP&L will maintain additional reactive resources to meet the individual bus voltage requirements.

f. KCP&L electric transmission facilities shall be rated, as a minimum, in accordance with KCP&L Transmission Facility Rating Methodology document. KCP&L uses 90 degrees C as the conductor temperature for normal transmission line ratings for ACSR conductors.

The strategy for transmission planning at KCP&L is driven primarily by two main goals. The first goal is compliance with reliability standards at the national (NERC/FERC), regional (SPP) and local (KCP&L) levels. The second goal is to provide transmission capacity for existing and new loads and existing and new electric supply resources.

Transmission planning for reliability standards compliance is performed for all planning horizons; operational (real time to 1year in future), near term (1 to 5 years in future), and long term (5 to 10 years in future). It generally involves the analysis of the transmission system under various operating conditions, the identification of any reliability standard violations, and the development of plans or actions to mitigate each violation.

Transmission planning for capacity expansion to serve loads and new supply resources are performed for both the near term and long term planning horizons. Transmission planning must interface with the planning performed by the Distribution Provider and Resource Planner functions of the NERC Reliability Functional Model. The Distribution Provider provides input on the size and location of loads to the transmission planning process. The Resource Planner provides the size and locations of future resources through the SPP process. Long term transmission planning is performed to develop an overall plan for expansion of the transmission system. This would include the approximate capacity and location of transmission assets required for future operations. Near term transmission planning is performed to refine portions of the long-term transmission plan on localized areas and provide more definition of required transmission assets.

Another part of transmission expansion is driven by transmission service requests and generation interconnection requests made to SPP as the RTO. KCP&L participates in SPP’s transmission system planning process to assess the ability of the transmission system to provide these requested services in the near and long term planning horizons. This includes development of plans or new transmission asset additions that will be required to meet reliability standards if the requested services are granted.

2.1 Transmission Contingency Analysis

The KCP&L transmission system shall be planned and constructed so that the contingencies as set forth in these Criteria will meet the applicable NERC Reliability Standards for Table 1 of TPL-001-4 and SPP Transmission Planning Criteria and their applicable requirements and measurements.

Table 1 was developed to thoroughly search out the most severe, credible contingencies for study, creating the assurance that the many possible contingencies not studied are less severe. It lists the normal and contingency conditions under which the electric transmission system is to be analyzed. It also lists the limits or impacts that the transmission system can sustain and still meet an acceptable performance level.

2.1.1 Base Case Analysis

KCP&L will support and participate in the SPP Model Development Working group (MDWG) development and verification of base case transmission system models. KCP&L base case models will maintain at least the following attributes:

- System facilities shall be modeled to reflect normal operating conditions and limits
- Line and equipment loading shall be within normal rating limits.
- Voltage levels shall be maintained within plus or minus 5% of nominal voltage
- All customer electrical demands shall be supplied, and all contracted firm (non-recallable reserved) transfers shall be maintained.
- Stability (dynamic and steady state) of the network shall be maintained.
- Cascading outages shall not occur.

2.1.2 Loss of Single Component Analysis

KCP&L will perform single contingency studies under the following conditions:

- Initiating incident results in a single element out of service.
- Line and equipment loadings shall be within emergency rating limits.
- Voltage levels shall be maintained within plus 5% or minus 10% of nominal voltage for all busses.
- No loss of customer electric demand (except as allowed through Attachment 1 of TPL-001-4).
- No curtailment of contracted firm (non-recallable reserved) transfers shall be required.
- Stability (angular and voltage) of the network shall be maintained.
- Cascading outages shall not occur.

2.1.3 Loss of Two or More Transmission Components

KCP&L will perform contingency studies under the following conditions:

- Initiating incident may result in two or more (multiple) components out of service including common right-of-way and common structure circuits.
- Line and equipment loadings shall be within emergency thermal rating limits.
- Voltage levels shall be maintained within plus 5% or minus 10% of nominal voltage for all busses.
- Stability (angular and voltage) of the network shall be maintained.
- Planned outages of customer demand or generation (as noted in Table 1 of TPL-001-4) may occur.
- Contracted firm (non-recallable reserved) transfers may be curtailed.
- Cascading outages shall not occur.

2.1.4 Extreme Contingency Events

KCP&L will perform contingency studies where extreme contingency events could lead to uncontrolled cascading outages or system instability. KCP&L shall document the measures and procedures to mitigate or eliminate the extent and effects of those events.

2.2 Required Studies

KCP&L participates in all SPP coordinated planning studies and performs internal load flow, transient stability and voltage stability studies to meet NERC Reliability Standards compliance.

These studies will consider all contingencies applicable to the appropriate NERC Table 1 of TPL-001-4, Category P1 through P7 events.

Annually, KCP&L will perform summer and winter peak operating studies for the upcoming seasons. Intermediate range studies covering the two to five year planning horizons to address both intra- and interregional reliability will be performed as needed. A 10-year expansion planning study will be conducted no less than biannually.

2.3 Additional Study Requirements

2.3.1 Power Flow – Cascading Events

As a proxy for cascading conditions, transmission facilities found to be loaded at 120% of the emergency rating (Rate B) or greater should be tripped offline. The removal of ten or more transmission branches will serve to indicate cascading.

Similarly, bus voltages exceeding 70% to 120% nominal following an event should be tripped offline. The removal of five or more transmission buses will serve to indicate cascading.

2.3.2 Voltage Stability

For voltage stability studies, stability shall be maintained under single and multiple contingencies throughout the KCP&L area. The performance and voltage stability criteria listed below will be followed:

- Critical voltage (voltage at bottom of V-Q curve) and reactive power margin should be sufficient such that stability is ensured following the loss of nearby reactive power sources and
- Reactive capacity shall be sufficient to ensure that transmission system voltage is maintained within plus 5% or minus 10% of nominal for single contingencies.

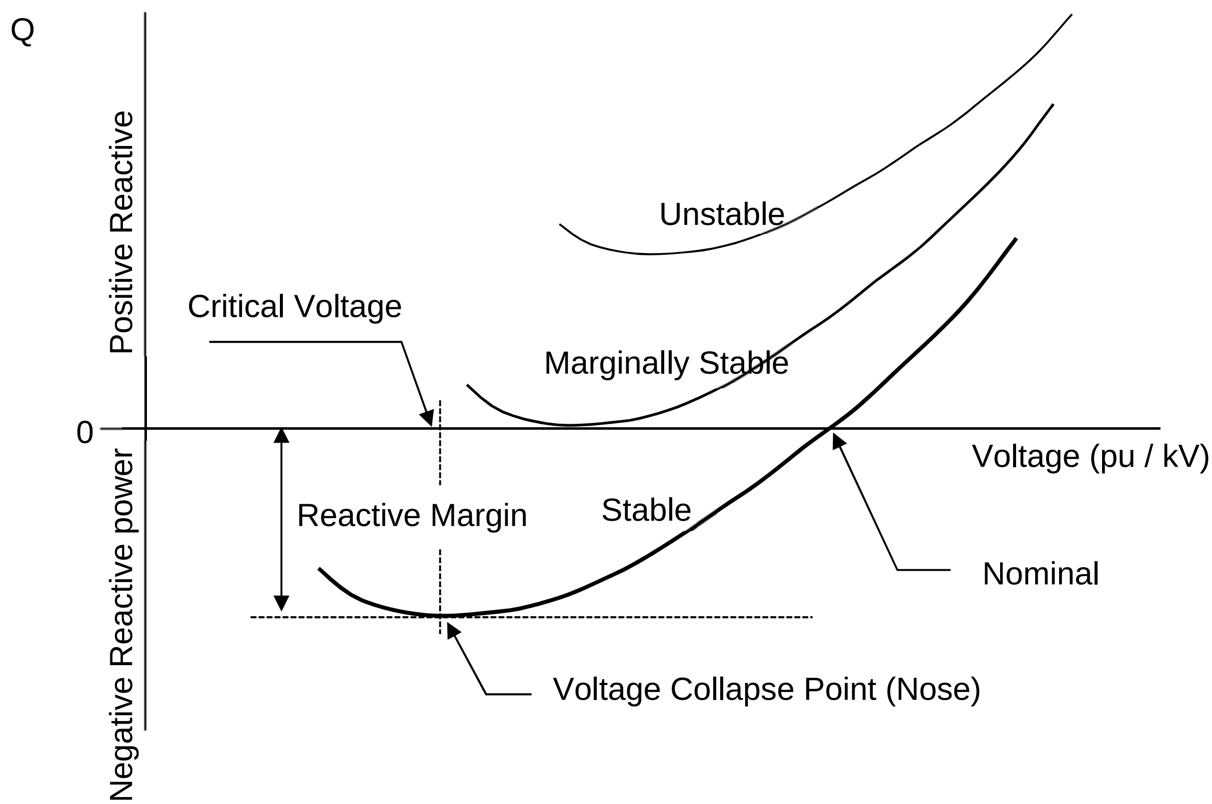

Figure 1: V-Q Curve

2.3.3 Transient Stability

For transient stability studies, generator rotor angle and transient voltage stability shall be maintained between KCP&L and neighboring systems following the loss of an electric network component and associated equipment tripped by the protection scheme following a line-to-ground fault, a three-phase fault, or a breaker open resulting in an open-ended transmission line. For faults, normal and stuck breaker clearing times shown in Table 1 will be used to assess stability; backup clearing times will be used as needed per the TPL-001-4 standard. Breaker clearing times are derived in Table 2, Table 3, and

Table 4 per the KCP&L System Protection group. Times in Table 1 are rounded up to the nearest quarter-cycle due to limitations in simulation software.

To develop the clearing times in Table 2 through Table 4, the KCP&L System Protection group evaluated the entire KCP&L system and provided the slowest clearing times for normal clearing, stuck breaker clearing, and backup clearing. Most KCP&L equipment utilizes faster clearing.

Table 1 Simulated 345 kV and 161 kV Breaker Clearing Times used in Simulations

Nominal Equipment Voltage (kV)	Normal Clearing Time	Stuck Breaker Clearing Time	Backup Clearing Time
161	7.25 cycles (0.120833 s)	21.0 cycles (0.350 s)	35.25 cycles (0.5875 s)
345	4.25 cycles (0.070833 s)	11.0 cycles (0.183 s)	5.0 cycles (0.083 s)

Table 2: Normal Clearing Time Derivation

Nominal Equipment Voltage (kV)	Longest Primary Pickup Setting (cycles)	Communications Delay (cycles)	Breaker Clearing Time (cycles)	Total Clearing Time (cycles)
161	2.0	1.2	4.0	7.2
345	1.5	0.6	2.0	4.1

Table 3: Stuck Breaker Clearing Time Derivation

Nominal Equipment Voltage (kV)	Longest Primary Pickup Setting (cycles)	Communications Delay (cycles)	Breaker Clearing Time (cycles)	Total Clearing Time (cycles)
161	2.0	15.0	4.0	21.0
345	1.5	7.5	2.0	11.0

Table 4: Backup Clearing Time Derivation

Nominal Equipment Voltage (kV)	Longest Backup Pickup Setting (cycles)	Communications Delay (cycles)	Breaker Clearing Time (cycles)	Total Clearing Time (cycles)
161	31.2	0.0	4.0	35.2
345	1.5	1.5	2.0	5.0

For normal clearing time, the worst-case scenario is an internal breaker fault. Such a fault would be detected by the primary relaying and be communicated to adjacent breakers. Worst-case normal clearing times (including the delay for communication time) are used for TPL-001-4 P0 through P3, P6, and P7 events.

For stuck breaker clearing time, the fault is detected by the appropriate relay(s) and normal clearing time passes. When the relay detects that a trip signal was sent but the fault was not cleared, an instantaneous trip signal is communicated to the adjacent relays. Worst-case stuck breaker clearing times are used for TPL-001-4 P4 and Extreme events. For most extreme events, the stuck breaker time is the longest that should be used.

For backup clearing time, the only 100 kV and above elements on KCP&Ls system that does not have redundant relaying is a subset of bus differential relays.

The clearing time for 345 kV is a great deal faster than that for the 161 kV system because the 345 kV system uses communication-assisted tripping on both the primary and backup relaying which allow faster detection and slightly slower-than-normal clearing in the event of a relay failure. The 161 kV system has communication on the primary relaying only which causes its backup relaying depend on Zone 2 clearing by distant relays. Backup clearing should only be used for those system elements which do not have redundant relays for TPL-001-4 P5 and Extreme events.

2.3.3.1 Transient Stability Performance Requirements

Transient stability analysis results will be evaluated using the SPP Disturbance Performance Criteria to identify events that may potentially cause "system instability and uncontrolled separation". The SPP Criteria uses two components to define stability: generator rotor angle damping and transient voltage recovery. Machine Rotor Angles shall exhibit well damped angular oscillations (as shown in Figure 2) and acceptable power swings following a disturbance on the Bulk Electric System. Any time after a disturbance is cleared bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit (shown in Figure 3).

Transient Voltage Recovery

Following the clearing of a fault, if any KCP&L or first-tier neighbor bus voltage is unable to recover to 0.75 per-unit within 0.05 seconds (3 cycles; primary recovery) or 0.9 per-unit within 2.5 seconds (150 cycles; secondary recovery), the initiating event will be considered potentially unstable. The primary criterion was chosen to help catch potential Fault Induced Delayed Voltage Recovery (FIDVR) events which may cause small single-phase motors to stall if voltages do not recover quickly and cause further voltage recovery issues. The secondary voltage recovery criterion was selected to help screen for issues which may require load shedding or cause tripping of generation.

Transient Voltage Dip

Following the clearing of a fault, if any KCP&L or first-tier neighbor bus voltage recovers to 0.9 per-unit or higher then drops below 0.9 per-unit for 0.25 seconds (15 cycles), the initiating event will be considered potentially unstable. This criterion was chosen to help flag areas of the system where initial voltage recovery is sufficient but sagging voltages may indicate deteriorating system stability.

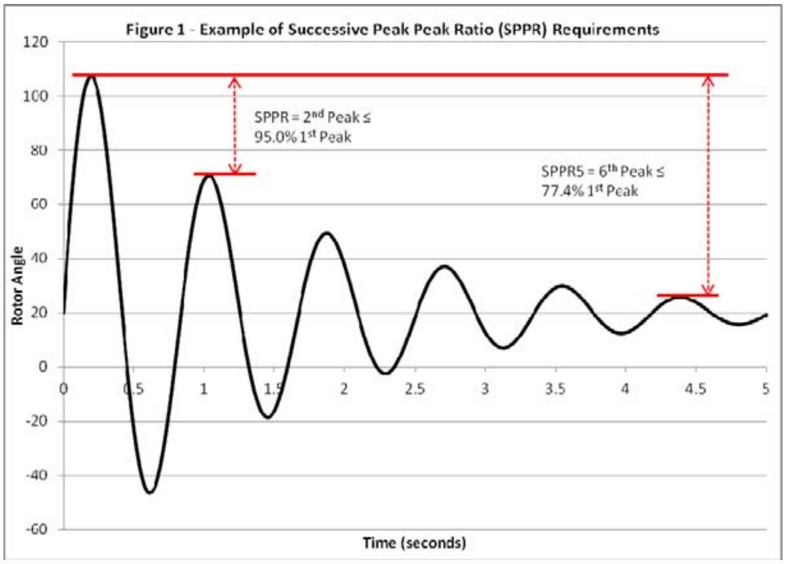

Figure 2: Example of Successive Positive Peak Ratio (SPPR) Requirements

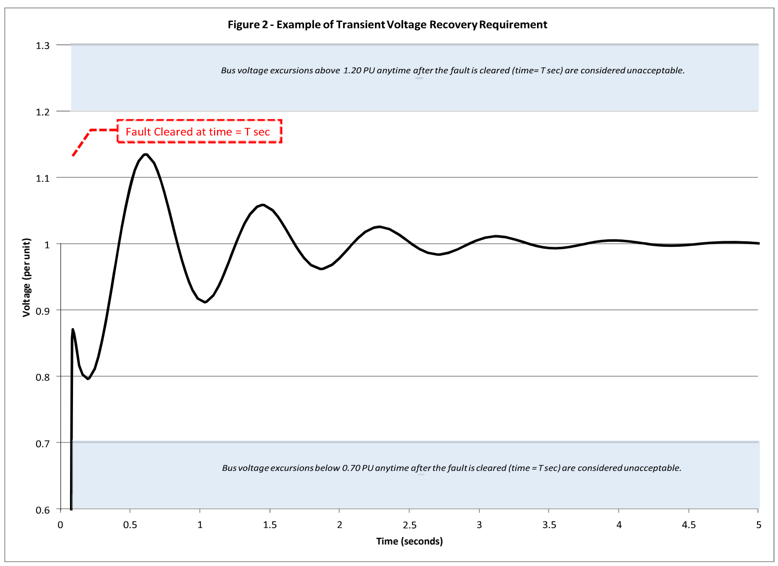

Figure 3: Example of Transient Voltage Recovery Requirements

2.3.3.3 Cascading Event Requirements

KCP&L uses several thresholds to determine if an event may potentially cause cascading. If an event causes facilities other than those specified by the protection scheme (or otherwise prescribed by the event definition) to trip and it meets one of the criteria thresholds, the event will be marked as potentially cascading and must be reviewed by an engineer. The criteria are defined as follows:

Number of Additional Bus Trips

Additional bus trips refer to buses which are not tripped as part of the protection scheme in order to clear a specified fault.

- TPL P1 events are not allowed to trip any additional buses

- TPL P2-P7 events are allowed to trip a generator and associated facilities only if that generator is tripped to clear the fault
- TPL Extreme and Other events allow up to 5 additional buses to be tripped before the event is considered potentially cascading

Number of Additional Branch Trips

Additional branch trips refer to branches which are not tripped as part of the protection scheme in order to clear a specified fault.

- TPL P1 events are not allowed to trip any additional branches
- TPL P2-P7 events are allowed to trip a generator and associated facilities only if that generator is tripped to clear the fault
- TPL Extreme and Other events allow up to 10 additional branches to be tripped before the event is considered potentially cascading

Number of Additional Generator Trips

If more than eight additional generators trip, an event will be considered potentially cascading.

Amount of Generation Tripped

If a MW amount equaling or greater than KCP&Ls largest generating plant trips offline, an event will be considered potentially cascading.

Average Rate of Decline (ROD) for Generation

Cascading may occur even if one of the previous generator criteria are not met. Therefore, it is desirable to determine an average rate at which generation can trip before it requires further investigation. The allowable average amount of generation which can be tripped by a certain number of generators is obtained using the following formula (assuming the maximum number of generator trips has not been recorded):

Equation 1: Maximum Allowed Average Amount of Generation which can be tripped

$$Max\ Average\ Gen.Trip\ Amount\ (MW) = \frac{Maximum\ Allowed\ Generation\ Trip\ \ (MW)}{Number\ of\ Generators\ Tripped}$$

The average amount must include only generation tripped as a result of out-of-step or angular stability conditions (not as prescribed by the event) and is the MW amount of generation tripped divided by the number of generators tripped. If the average value calculated is greater than the maximum average determined using Equation 1, the event should be flagged as potentially cascading. This limit is shown graphically in Figure 4 assuming the maximum allowable generation trip is 1700 MW.

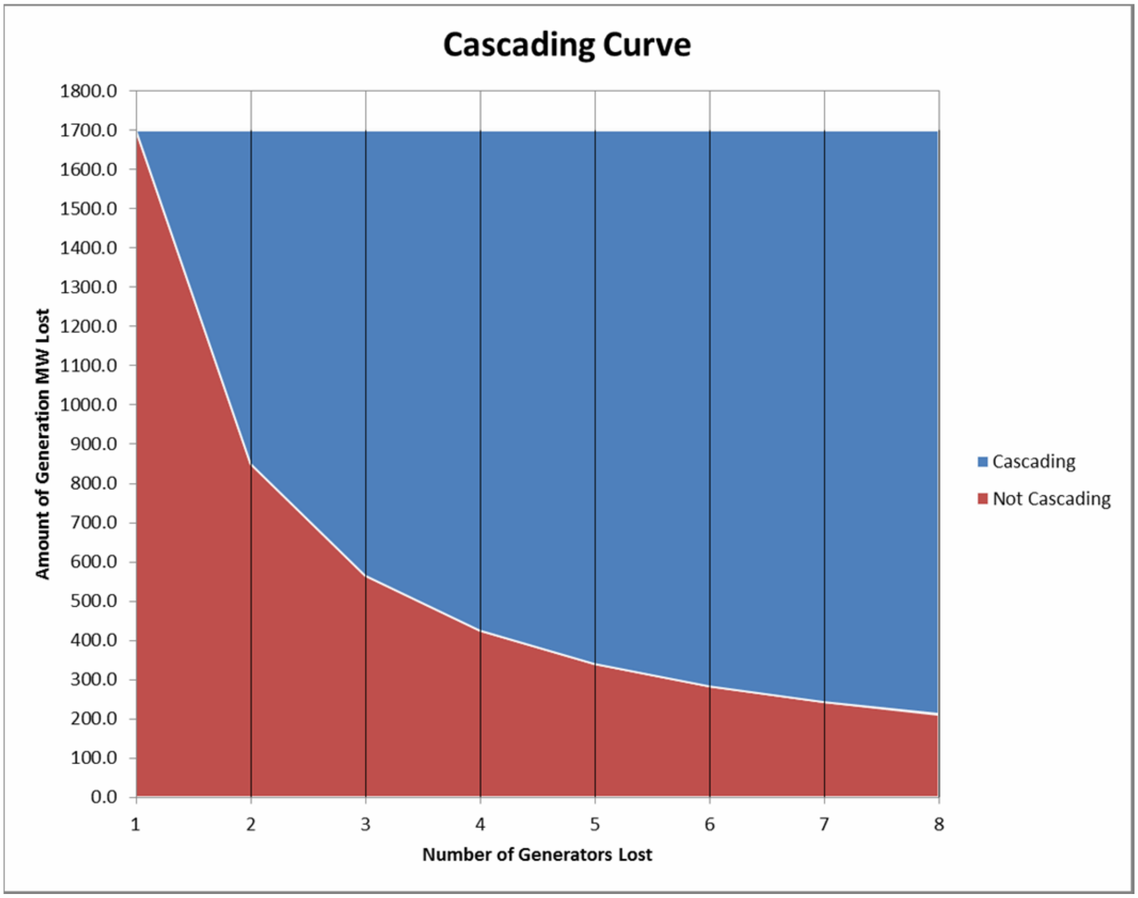

Figure 4: Graphical Representation of Maximum Average Generation Trip assuming a 1700 MW Maximum

Amount of Load

If 10 percent or more of the online KCP&L load is shed, an event will be considered potentially cascading.

Voltage Thresholds

As a proxy for cascading conditions, KCP&L will screen KCP&L and Tier-1 neighbor buses for voltage magnitudes exceeding the range of 120% - 70% of nominal at the end of a transient stability simulation. Such bus voltages may indicate sever voltage issues and delayed system recovery which could lead to potential system cascading and/or uncontrolled separation.

Thermal Loading Thresholds

As a proxy for cascading conditions, KCP&L will screen KCP&L and Tier-1 neighbor transmission lines and power transformers at the end of the transient stability simulation for facilities loaded at or above 120% of the emergency thermal limit (Rate B). Such facilities may indicate severe system conditions and delayed recovery which could lead to potential system cascading and/or uncontrolled separation.

Crashed Simulations

If a simulation crashes it will be regarded as potentially cascading and will be reviewed to determine why it crashed and if the event may cause cascading.

Discovery of a Potentially Cascading Event

Upon discovery of a potentially cascading event, Transmission Planning will review the event in greater detail to determine if it is a legitimate concern. This analysis may include but is not limited to:

- Checking the simulated event against switching one-lines to determine event accuracy
- Contacting system protection to determine that the clearing times used in the simulation were accurate for the prescribed event
- Rerunning the simulation for a longer period of time (e.g., 30 seconds)
- Checking modeled KCP&L load and generation dispatch
- Reviewing system topology for modeling errors

If the detailed analysis determines the event was simulated properly and the system is modeled correctly, the event should be considered cascading. The following actions may be taken to mitigate the issues:

1. Revise breaker clearing times
2. Consider revising generator governor/exciter settings
3. Consider revising generator protection settings
4. Consider adding a power system stabilizer to one or several units
5. Consider EHV transmission projects at or near affected generator stations
6. Consider adding additional generation in the affected area

2.4 Transmission Planning for Serving New Customer Load

Distribution Planning Engineering has traditionally planned for serving existing and new load additions on the KCP&L distribution systems (<69kV). This includes deciding when new transmission sources are needed to meet increased demand on the distribution system due to overloaded distribution facilities or inadequate distribution voltage profiles. These new substations are incorporated into KCP&L's transmission expansion plan by optimizing the existing transmission system network or expanding the system into these areas.

Historically KCP&L has provided new transmission sources for the distribution system by either inserting new load serving substations in existing transmission lines when possible or building new transmission lines to connect the new substations. In areas where expansion of the 34kV system is no longer the prudent solution, converting these 34kV loads to 12kV requires new 161/12kV substations.

Inserting new substations in existing lines was done for reasons of economics and site requirements. This practice has led to transmission lines with numerous two terminal load serving substations along their length. Operational and reliability problems can arise from this practice when the amount of total load served by these substations exceeds the capability of the transmission lines serving them with the outage of one end of the line. To avoid these problems KCP&L has established the following planning criteria for the number of two-terminal substations between source substations and building the second transmission line into a radial substation:

- During normal or contingency conditions, when the amount of connected load-serving transformer capacity on a transmission path serving only two terminal substations exceeds the normal rating of any of the transmission lines between the source substations or when the third two-terminal substation is added between source substations, a third transmission source shall be required that connects into one of the two-terminal substations. However, the installation of this new line is dependent on site, availability of right-of-way and environmental considerations.
- A second transmission source shall be required for a radial substation when the radial substation load cannot be served from backup distribution sources for the outage of the radial transmission line. The timing of this new transmission line is also dependent on site, availability of right-of-way and environmental considerations.

At the time of the acquisition of Aquila, the GMO system was reviewed to determine if it met the requirements of section 2.4 of the Criteria. There were areas of the GMO system identified that did not meet the requirements of section 2.4. Plans will be developed in the future to bring those areas into accord with these Criteria, subject to siting, availability of right-of-way and environmental considerations.

3.0 Monitoring Transmission System Performance

An important part of transmission planning is monitoring transmission system performance. This includes monitoring the performance of sections – Line, Transformer, Switchgear, and Substations within the transmission system and benchmarking the overall performance of the KCP&L transmission system against past performance. To accomplish this effort KCP&L's Transmission Planning has an inter-departmental work group which analyzes transmission outages on a monthly basis. This group produces an annual report entitled KCP&L Transmission System Reliability Indices Report.

3.1 Transmission Reliability Indices

Five Transmission Reliability Indices have been established to monitor Transmission System performance: (1) Frequency of Outages - $\textbf{SAIFI}_{\textbf{T}}$,

(2) Duration of Outages – $\textbf{SAIDI}_{\textbf{T}}$, (3) Transmission System Availability - $\textbf{Availability}_{\textbf{T}}$,
(4) Forced Outages per Hundred-line Mile Year - **FOHMY**, and

(5) Transmission Minutes of Load Unserved - **TMLU**. These indices provide quantitative measures of transmission system reliability annually. All of the above reliability indices are based on only automatic forced outages in the transmission system for 69kV, 161kV, 230kV, and 345kV facilities. Transmission reliability indices are evaluated monthly, quarterly, and annually to monitor transmission system performance and are used to recommend corrective measures to maintain and/or improve transmission system reliability. Transmission outages are broadly classified by Transmission Availability Data System (TADS) cause codes. All transmission outages are recorded including those due to Major Event Days (MED). Some outages may be excluded if they meet the following exclusion criteria to provide comparability and meaningful results for transmission reliability improvement analysis and recommendations.

Exclusion Criteria:
IEEE 1366 MED's plus storm days preceding/following a MED, if the impact was significant. All Class II storms were included, provided they did not exceed the Institute of Electrical and Electronics Engineers (IEEE) 1366 Tmed level.

The IEEE 1366-2003 outlines a statistically based threshold based on a company's own daily outage data (up to 5 immediately preceding years). This threshold (labeled Tmed, for Threshold – major event day) is labeled a MED, or Major Event Day. The IEEE 1366-2003 is a Distribution Reliability Criteria standard.

4.0 Calculation of Available Transfer Capability

The calculation of Available Transfer Capability (ATC) is a very complex and dynamic procedure. KCP&L realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. A key element of NERC's ATC principles is "Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATC's of the interconnected transmission network". Therefore, KCP&L will follow SPP guidelines and methodology as outlined in Section 4.0 of SPP Criteria.

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners (i.e. KCP&L). This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes.

The SPP utilizes a "constrained element" approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed "flowgates", used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of Section 4 of the *Criteria* based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP By-laws at the first practical opportunity.

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as pre-determined limiting constraints to power transfer. The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within SPP Criteria 4.

Determination of ATC via Flowgates adheres to the following approach:

- Establishes a network representation (power flow model).
- Identifies potential limits to transfer (thermal, voltage, stability, contract).
- Determines response factors of identified limits relative to transfer directions (Transfer Distribution Factor - TDF).
- Determines impacts of existing commitments (Firm, Non-Firm)
- Applies margins (Transmission Reliability Margin - TRM, Capacity Benefit Margin - CBM, a & b multipliers).
- Determines maximum transfer capabilities allowed by limits and applied margins (ATC, Firm ATC, and Non-Firm ATC).

4.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short-Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests.

Daily and Weekly ATC is calculated on a daily basis and posted at the time of run. SPP will also provide control area/balancing areas (CA/BA) to CA/BA path conversions to any individual providers needing that information to administer their own tariff. Hourly calculations are done hourly for anywhere from 12 to 36 hours ahead depending on time of day. SPP has a firm-scheduling deadline at 12:00 noon, day prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. Then, SPP calculates hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again.

4.2 Use of the KCP&L Open Access Transmission Tariff

SPP functions as KCP&L's Transmission Service Provider under the SPP OATT. Grandfathered transmission service schedules that used the KCP&L Open Access Transmission Tariff have been converted to the SPP OATT.

New requests for transmission service must be arranged through the Southwest Power Pool.

5.0 Protective Relaying

Protective relaying, communications and instrumentation play an important role in maintaining the reliability of the bulk electric system. Protective Relay Systems (PRS) requirements shall be taken into account during the planning and design of generation, transmission and substation configurations. If configurations are proposed that require PRS that do not conform to SPP criteria or to accept IEEE/ANSI practices, then the entities affected shall negotiate a solution. The principles for planning additions in these categories are set forth in SPP Criteria.

- **a.** The bulk power protective relay system design shall have as its objective rapid clearing of all faults, with no fault permitted to remain uncleared despite the failure of any single protective system component. To accomplish this, transmission protection systems shall be installed as specified in the SPP Transmission Protection Systems Criteria 7.2.
- **b.** Transmission Operators shall maintain communications systems to their generating stations, operation centers and to neighboring utilities, which shall provide adequate communication in the event of failure of any one element of the systems. In general, such communication systems should not be susceptible to failure during an interruption of the A.C. power supply in any part or all of their areas.
- **c.** Loading on the bulk electric system shall be monitored continually to insure that operation is within safe limits.
- **d.** Suitable instrumentation, and/or other devices, shall be installed to measure appropriate quantities at key points in the electric system with appropriate automatic alarms.
- **e.** Fault recording devices as described in SPP Criteria 7.1 shall be installed at appropriate points within KCP&L so that outages and short circuits can be analyzed and protective relay performance studied. In addition, Disturbance Monitoring Equipment shall be provided to meet SPP Criteria 7.1 so those system disturbances may be analyzed.
- **f.** Underfrequency Load Shedding (UFLS) equipment shall be installed pursuant to SPP Criteria 7.3 for the purpose of maintaining a stable operating frequency.
- **g.** Given the requirements of SPP Criteria 7.6, Automatic Restoration of Load schemes may be installed by KCP&L to expedite load restoration. These systems shall be coordinated with all other schemes such as system protection, Underfrequency Load Shedding, Undervoltage Load Shedding, and Generation Control and Protection. These systems shall operate only after underfrequency and/or undervoltage events.
- **h.** Generation Control and Protection schemes shall be designed pursuant to SPP Criteria 7.7 to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect generator equipment from damage.

6.0 System Restoration

NERC Reliability Standard EOP-005 deals with system restoration. A blackout is a condition where a major portion or all of an electrical network is de-energized resulting in loss of electric supply to a portion or all of that network's customer demand. Blackouts will generally take place under two typical scenarios:

- Dynamic instability, and
- Steady-state overloads and/or voltage collapse.

Blackouts are possible at all loading levels and all times in the year. Changing generation patterns, scheduled transmission outages, off-peak loadings resulting from operations of pumped storage units, storms, and rapid weather changes among other reasons can all lead to blackouts. Systems must always be alert to changing parameters that have the potential for blackouts.

Actions required for system restoration include identifying resources that will likely be needed during restoration, determining their relationship with each other, and training personnel in their proper application. Actual testing of the use of these strategies is seldom practical. Simulation testing of restoration plan elements or the overall plan is essential preparation toward readiness for implementation on short notice.

From a planning standpoint, it is critical that any overall system restoration plans include adequate generating units with system blackstart capability. It is also important that adequate facilities are planned for the interconnected transmission systems to accommodate the special requirements of system restoration plans such as switching and sectionalizing strategies, station batteries for dc loads, coordination with under-frequency and undervoltage load shedding programs and Regional or area load restoration plans, and facilities for adequate communications.

KCP&L has developed its' own specific plans to deal with Capacity and Energy Emergency, Load Shedding Emergency, and Transmission System Emergency.

6.1 Blackstart Capability

Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration. These initiating generators are referred to as system blackstart generators. They must be able to self-start without any source of off-site electric power and maintain adequate voltage and frequency while energizing isolated transmission facilities and auxiliary loads of other generators. Generators that can safely reject load down to their auxiliary load are another form of blackstart generator that can aid system restoration.

From a planning perspective, a system blackstart capability plan is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional system restoration plans.

In the event that the KCP&L Load Shedding Emergency Procedures are unsuccessful in reducing customer load to maintain system voltage and frequency, KCP&L may be faced with a situation where generating units are isolated serving only its own auxiliaries or units are not on line and all customer loads has been interrupted. Interruption of service may encompass the KCP&L service territory or possibly the entire region and many utilities. A KCP&L System Restoration Plan has been developed to systematically restore generation and customer load to the KCP&L service territory (including GMO). Detailed generating unit startup procedures and transmission switching instructions can be found in the KCP&L System Restoration Plan.

6.2 System Restoration Simulation

Requirement R6 of NERC Reliability Standard EOP-005-2 is stated below.

> **R6.** Each Transmission Operator shall verify through analysis of actual events, steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify:
>
> > **R6.1.** The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.
> > **R6.2.** The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.
> > **R6.3.** The capability of generating resources required to control voltages and frequency within acceptable operating limits.

KCP&L Transmission Planning performs dynamic and steady state system restoration simulation studies using the PSSE power flow model every five years at a minimum. These simulation studies verify that the KCP&L Blackstart Resources are capable to meet the real and reactive power requirements along the primary transmission restoration path and the dynamic capability to supply initial loads. Study results also verify the location and magnitude of loads, and the capability of generating resources required to control voltages and frequency within acceptable operating limits.

Document Version History

The following table documents changes to this document and its predecessors.

Date	Document	Description
3-15-16	2016 KCP&L Planning Criteria.pdf	Minor formatting changes; added clarity to breaker clearing times; added cascading criteria for load flow and transient stability; split "study requirements" into "required studies" and "additional requirements"
3-15-15	2015 KCP&L Planning Criteria.pdf	Reviewed and updated document to reflect new TPL standard and disturbance performance criteria.
3-13-12	2012 KCP&L Planning Criteria.pdf	Removed Section 5 of Bulk Electric System Planning Criteria to its own document. Reviewed and updated entire document as necessary.
3-21-11	2011 KCP&L Planning Criteria.pdf	Reviewed and updated Bulk Electric System Planning Criteria.
3-1-10	2010 KCP&L Planning Criteria.pdf	Reviewed and updated Bulk Electric System Planning Criteria; included addition of section 5.1.9 clarifying rating of substation infrastructure facilities.
4-1-09	2009 KCP&L Planning Criteria.pdf	Reviewed and updated Bulk Electric System Planning Criteria.
4-1-08	2008 KCP&L Planning Criteria.doc	Reviewed and updated Bulk Electric System Planning Criteria.
4-1-06	2006 KCP&L Planning Criteria.doc	Reviewed and updated Bulk Electric System Planning Criteria.
4-1-03	FINAL 2003 KCPLcriteria.doc	Reviewed and updated Bulk Electric System Planning Criteria.
4-1-02	Final 2002 KCPLcriteria.doc	Reviewed and updated Bulk Electric System Planning Criteria.
4-1-01	FINAL 2001 KCPLcriteria	Reviewed and updated Bulk Electric System Planning Criteria.
4-1-98	FINAL1998 KCPLcriteria	Reviewed and updated Bulk Electric System Planning Criteria.