VOLUME 4.5:

TRANSMISSION AND DISTRIBUTION ANALYSIS

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.045

CASE NO. EO-2012-0323

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22.045 Transmission and Distribution Analysis

VOLUME 4.5: TRANSMISSION AND DISTRIBUTION ANALYSIS

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

SECTION 1: AQEQUACY OF THE TRANSMISSION AND DISTRIBUTION NETWORKS

(1) The electric utility shall describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that—

1.1 OPPORTUNITIES TO REDUCE TRANSMISSION POWER AND ENERGY LOSSES

(A) Reduce transmission power and energy losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040(3). The utility shall assess the age, condition, and efficiency level of existing transmission and distribution facilities and shall analyze the feasibility and cost-effectiveness of transmission and distribution network loss-reduction measures. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution systems, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options;

Electrical losses in a transmission line are primarily dependent on the specific characteristics of the line (conductor type, line length, etc.) and the amount of power flowing (I^2R) on the transmission line. KCP&L uses 161 kV transmission lines (approximately 1000 miles) for the majority of its load serving substations. Most of KCP&L's existing 161 kV transmission lines use a single 1192 ACSR conductor per phase on H-frame wood structures. This design provides a normal line rating of 293 Mva and an emergency rating of 334 Mva for summer conditions. For increased transmission capability and lower line losses, KCP&L Transmission Engineering recommended using a line design with two, 1192 ACSR conductors per phase on H-frame wood or steel structures. This design provides a normal line rating of 586 Mva and an emergency rating of 668 Mva for summer conditions. Adding the additional conductor per phase reduces the line's electrical resistance by half and results in reduced transmission losses. Transmission Engineering estimated the cost to rebuild a single conductor per phase line to a two conductor per phase line at $746,400 per mile.

In order to "analyze the feasibility and cost-effectiveness of transmission network loss-reduction measures", KCP&L Transmission Planning staff analyzed the costs and loss reductions associated with rebuilding five of KCP&L's most heavily loaded 161kV transmission lines. This analysis involved calculating new impedances values for the five transmission lines converted from single 1192 conductor to bundled 1192 conductors and performing a loadflow analysis to determine the level of loss reduction for the rebuilt lines. Results of this analysis for 2012 summer peak conditions are shown in Table 1, below.

Table 1: Cost Analysis for 161kV Transmission Line Loss Reduction

TRANSMISSION LINES		2012 SP Flow	LINE IMPEDENCE			LINE	
FROM	TO	MW	R	X	B	MILE	
			1192 ACSR CONDUCTOR				
CRAIG 5	LENEXAN5	175.6	0.00100	0.00840	0.00460	2.95	
MARTCTY5	STHTOWN5	138.7	0.00339	0.02230	0.01170	7.76	
WGARDNR5	MOONLT 5	162.2	0.00200	0.01610	0.00890	5.77	
OLATHE 5	SWITZER5	162.4	0.00150	0.01210	0.00640	4.24	
GRNWOOD5	LENEXAN5	149.5	0.00130	0.01110	0.00150	3.89	
			TOTAL KCP&L LOSSES AT PEAK LOAD				69.9
			1192 BUNDLED CONDUCTOR				
CRAIG 5	LENEXAN5	245.4	0.00050	0.00420	0.00620	2.95	
MARTCTY5	STHTOWN5	175.3	0.00170	0.01115	0.01630	7.76	
WGARDNR5	MOONLT 5	182.8	0.00100	0.00805	0.01212	5.77	
OLATHE 5	SWITZER5	177.7	0.00075	0.00605	0.00890	4.24	
GRNWOOD5	LENEXAN5	230.3	0.00065	0.00555	0.00817	3.89	
			TOTAL KCP&L LOSSES AT PEAK LOAD				68.8
MW LOSS REDUCTION using 1192 BD conductor in KCP&L							1.10
TOTAL LINE MILES							24.6
TOTAL COST TO RECONDUCTOR/REBUILD AT $746,400 PER MILE							$18,368,904
AVERAGE COST OF LOSS REDUCTION					$/KW		$16,699

The average cost of loss reduction for these five transmission lines is $16,699/kw. This is approximately five times the average $/kw construction cost of Iatan 2. Clearly transmission loss reduction is not cost effective for KCP&L when compared to the cost of construction for new supply side resources. This is mainly due to the fact that KCP&L already has a relatively low loss transmission system.

The KCP&L transmission system is a relatively low loss network due to good line design, concentration of load, and the distribution of its generation resources throughout its service territory. As shown in Table 2, KCP&L’s projected transmission loss as a percent of peak load served for 2012 summer peak load conditions is only 2.0%. The comparative value for the rest of the Southwest Power Pool (SPP) is 2.4%.

Table 2: SPP 2012 Transmission Losses by Area

AREA	Load Mw	Loss Mw	% Loss
502	2586.6	65.0	2.5%
503	495.0	6.1	1.2%
504	228.0	0.1	0.0%
515	902.9	29.2	3.2%
520	10343.4	252.2	2.4%
523	931.5	23.8	2.6%
524	5716.4	134.2	2.3%
525	1446.3	49.6	3.4%
526	5778.9	185.0	3.2%
527	753.7	3.6	0.5%
531	357.1	7.5	2.1%
534	1140.1	37.4	3.3%
536	5866.1	126.8	2.2%
540	1937.8	32.8	1.7%
KCP&L	***3475.8***	***69.9***	**2.0%**
542	551.5	3.7	0.7%
544	1156.9	39.5	3.4%
545	303.7	2.8	0.9%
546	785.5	10.7	1.4%
SPP	44757.2	1080.2	2.4%

1.1.1 DISTRIBUTION SYSTEM OVERVIEW

The various KCP&L planning groups (Supply, Transmission, and Distribution) assimilates a broad set of engineering inputs to determine how the company will invest in improving the respective systems to meet ongoing load growth, system reliability, operational efficiency and asset optimization needs. The Distribution Planning group analyzes data, identifies patterns, develops electrical models representative of the KCP&L distribution system, and performs studies to understand and prioritize system improvement needs.

Generally, the inner urban core is experiencing widespread deterioration of its underground systems, while maintaining a high utilization of its distribution assets and a high density of high-profile customers. The primary driver for investment in this area addresses the risk to reliability for high-profile customers by installing replacement or contingency infrastructure. The distribution system over many decades has been built to have no more capacity than is required to serve local loads, and any changes require lumpy capacity improvements. These types of problems have been categorized as condition and/or contingency, and specific recognizable projects like Troost Substation and the Twelfth Street Duct Bank Reconstruction are good examples of this type of investment.

In contrast are the suburban areas of the KCP&L system, where new development of open land requires the build-out of the distribution system. The highest load growth is seen on the fringe, demanding investments to serve new emerging electrical loads – largely a capacity issue. Circuits must be tied together more effectively to allow for contingency switching and disperse the load across a larger number of circuits, all the while expanding substation breaker positions for these new circuits. Many investments like this have been made in recent years, especially around Tiffany Springs, Cedar Creek, and Riley Substations.

The rural areas have the most widespread infrastructure components and have the fewest or most limited emergency ties, where any load manipulation can cause large disturbances to customers' voltage. Distribution Planning carefully examines these systems to assure customer voltages are within tolerance, a process which demands high-quality mapping and device load data. With so many widespread components, acquiring data has become one of the greatest challenges in these areas. One specific project initiated to address rural voltage issues is the Adrian 25kV Substation project, in the Belton service territory.

The risks to the distribution system's reliability are likely greater than imagined, but this is primarily because with such a huge system it is difficult to know about all problems all at once. The Distribution Planning group is tasked with elevating the highest priority and highest-risk projects to a point where investments are made earlier than those with lower priorities and risk profiles. Many years of constant review have provided the group with a robust set of criteria within which these problems are evaluated, and even today process improvements are being made to further analyze how well to build out the distribution system to assure cost-effectiveness.

Furthermore, the Long-Term Planning component handled by Distribution Planning assures strategic long-term investments are made. Solutions are selected based upon how well they fit into an area-plan, not only the cost-effectiveness for the immediate need. Between the robust planning criteria and the strategic long-term vision, Distribution Planning will continue to construct the distribution system capable of serving tomorrow's needs by making appropriate investments when they are needed.

In the inner-urban core of Kansas City, the long-term vision involves installing replacement substations in new locations to strategically phase-out deteriorated underground components, a great improvement to reliability and area capacity. Beyond life of service components could then be abandoned, removed, or rebuilt, but in the end the company would have a new distribution system better suited to reliably serve the Kansas City of 2010 and flexible enough to serve well into the future. The Troost, Charlotte, and Truman Road Substation projects have all been budgeted in the five-year plan and will continue to have components critical to the Long-Term strategy over the next twenty years.

On the suburban fringe, Distribution Planning plots out growth patterns to identify substation sites well ahead of the need. On the Northern edge of the Metro Area, several substation sites have already been purchased in anticipation of future load growth. Within the 20-year plan, nine separate new substations or substation expansions will accommodate growth as Kansas City sprawls outward. Distribution Planning constantly reviews the build-out of the distribution system on the suburban fringe as development in Kansas City continues this march North, South, and East of the current Metro Area.

The rural areas of the service territory are envisioned to one day have entirely remotely-received load and condition data – a completely automated system. Today, load information is difficult to obtain, due to inaccurate watt-var charts or costly field load checks during peak periods. Strategic and timely decisions can better be made with abundant characteristic data for the components being studied. Efforts are underway to systematically bring all rural components up to metro-area data acquisition standards.

As KCP&L builds toward its own future here in Kansas City, it is the goal of Distribution Planning to assure that every investment optimizes capital spend and balances risk, meets current and future needs, and is built strategically when and where they are needed. Many tools and a great deal of information is processed and analyzed to develop these strategic plans. While budgets may expand or contract over time, with enough planning and follow-through, the distribution system will eventually appear the way Distribution Planning envisions.

1.1.2 ANNUAL SCOPE OF WORK

Throughout each year, Distribution Planning prepares a number of system studies to determine weaknesses or risks to reliability and to assess the overall adequacy of our distribution system. Some of the studies are used in other areas of the company, possibly reporting to FERC. The majority of the work focuses on increasing reliability and prioritizing work based upon cost, scope, impact, and effectiveness. This work is centered around four (4) specific areas which include capacity, contingency, voltage and condition. The table below illustrates the various deliverables associated with each focus area:

Table 3: Distribution Planning - Annual Scope of Work

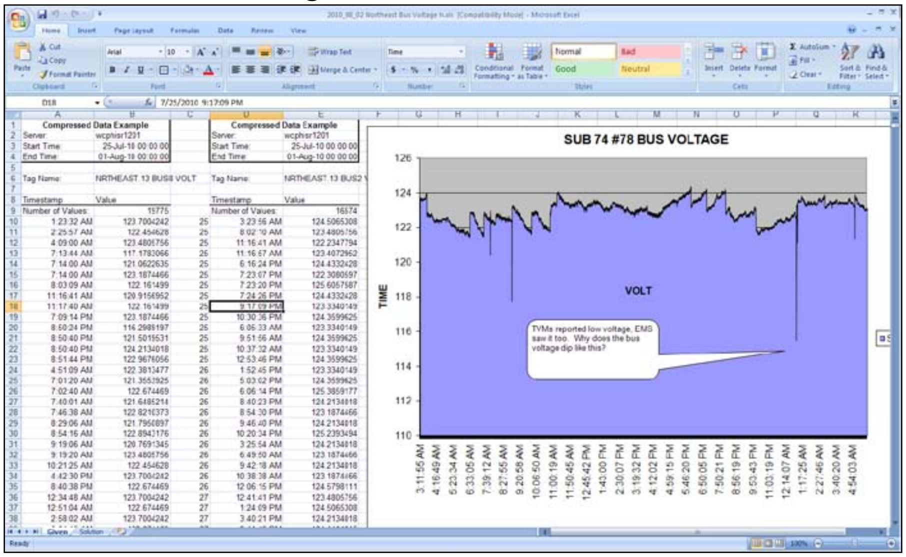
Category	Study Name	Deliverable
Capacity	Load Preservation 5 Yr. System Expansion – Load Device Weather Adjustment 20 Year Forecast Circuit Rating Study	Black Start Plan Budgetary Recommendations Distribution Load Book Forecasted Substation Loads Circuit Rating utilized for Operational Guidance
Contingency	5 Yr. System Expansion – contingency N-1 Circuit Contingency Study N-1 Transformer Contingency Study	Budgetary Recommendations Circuit Contingency Plan Transformer Contingency Plan
Voltage & Losses	Phase Balancing Voltage Drop Studies System Efficiency Studies Capacitor Studies Voltage Regulation Studies	Load-Swap Recommendations DVC Operational Guidance System Loss Studies Capacitor Installations Substation Tap Settings
Condition	Worst Performing Circuits Circuit Review Short Circuit Studies Other Reviews	Budgetary Recommendations Budgetary Recommendations Customer-Required Special Studies

To complete this identified scope of work, KCP&L Planning Engineers utilize a variety of tools that make use of the device loads and system schematics as input. There are several tools currently in use at KCP&L to collect and process this information.

PI/Network Manager

During the summer of 2010, the new Network Manager Energy Management (SCADA) system was placed in-service. With this ABB product KCP&L also acquired at PI Historian data archive, which now contains device loads and other historical system characteristics. Once all system components are merged into the new system, the PI Historian will be the primary archive for engineers to find and extract load and voltage history. The figure below provides a snapshot of PI Historian.

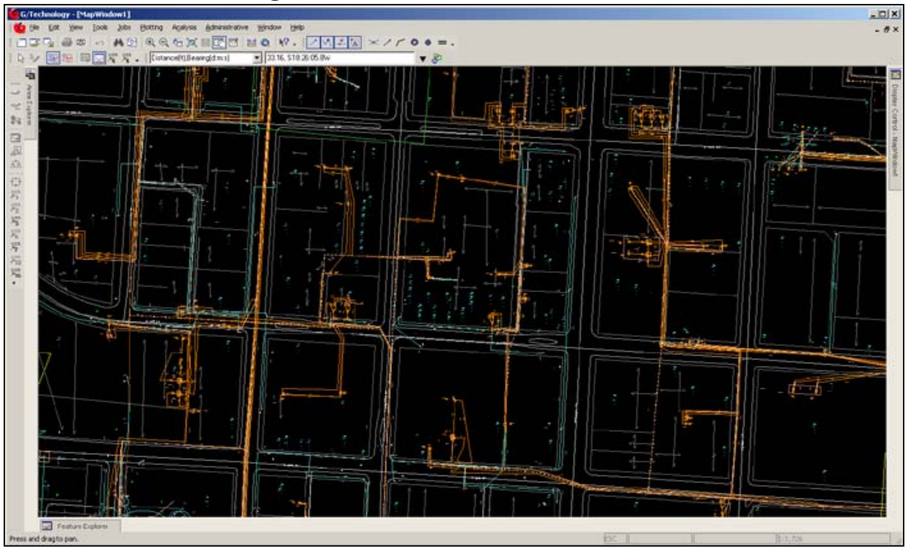
Figure 1: PI Screenshot



<u>GTechnology</u>

The software mapping tool used by Distribution Planning engineers is called GTech. The KCP&L distribution system G.I.S. database is viewed and extracted from GTech, where engineers acquire model data for use in SynerGEE. Device characteristics and connectivity drive load-flow models in use by Distribution Planners. The figure below provides a snapshot of G/Tech.

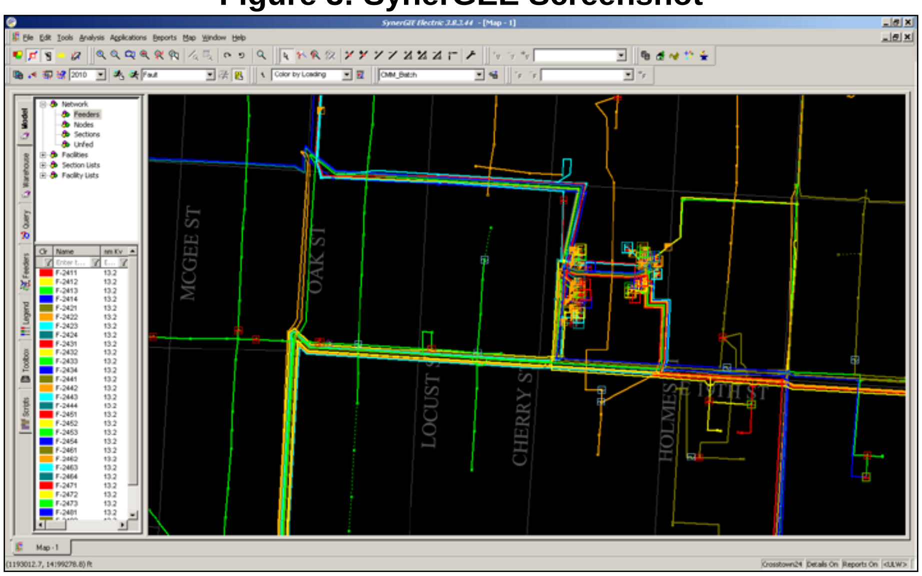
Figure 2: G/Tech Screenshot



<u>SynerGEE</u>

A multipurpose tool primarily used by engineers to analyze load flow characteristics of distribution feeders. Distribution Planning is also responsible for providing fault current information to customer's electrical contractors when performing arc-flash studies, a process which requires the use of SynerGEE. The figure below provides a snapshot of the SyngerGee software program.

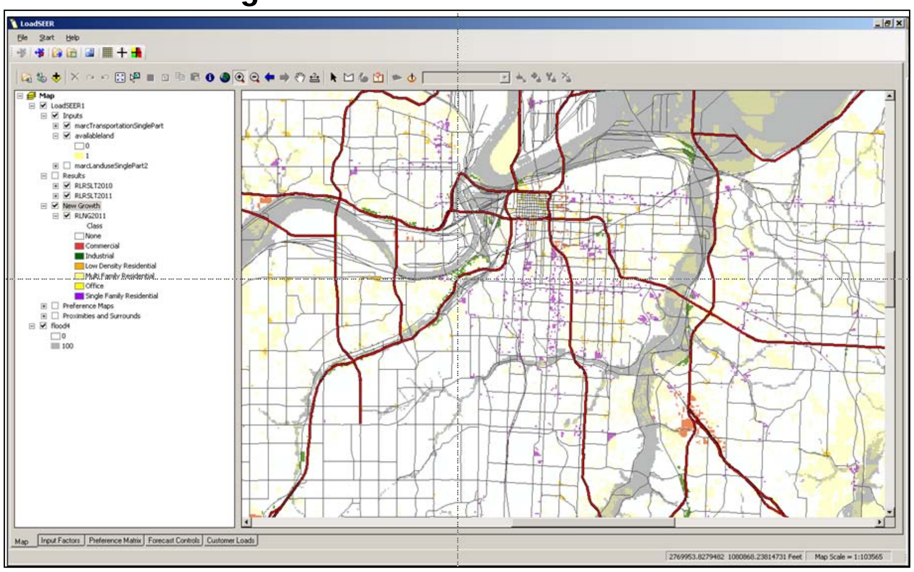
Figure 3: SynerGEE Screenshot



LoadSEER

The software Distribution Planning uses to forecast long-term load growth and its location in the Greater Metro Area is called LoadSEER. Geo-spatial maps of the six-county metropolitan area have been developed with the help of MARC, and are used for LoadSEER's cellular automata method of forecasting future development locations.

Figure 4: LoadSEER Screenshot



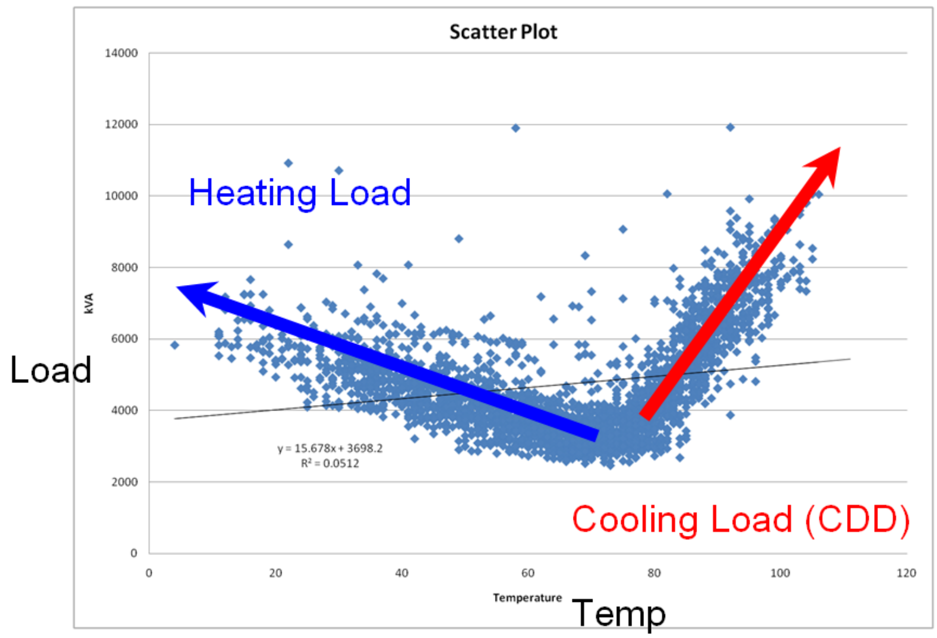
1.1.2.1 Capacity Planning

Device loads, such as substation transformer and distribution circuit loads are collected annually from a number of remote-sensing sources and are weather-adjusted to determine the effects of temperature (heating & cooling). This load data is compared to previous years' loads and device maximum loading to determine how the load is changing over time and if any component is overloaded in need of an upgrade. These types of problems are given a higher priority than others to assure continued reliability.

1.1.2.1.1 Device Weather Adjustment

The whole system improvement process begins with Device Weather Adjustment. There are a number of ways engineering monitors and records the loads experienced across the distribution system, and however this is done, load data is gathered and tabulated. The daily peak demand is then compared with the daily high temperature (for Winter, the daily low temperature), and a comparison is made using an excel scatter-plot with a linear-regression best-fit line.

Figure 5: Example of Weather-Adjustment Scatter Plot



Distribution Planning cleanses the data using filters to assure outlying data points (abnormal behaviors) are omitted from the study. What results is a linear equation, where the variable 'x' refers to the temperature. For 'x', Distribution Planning inserts 100 degrees Fahrenheit, the chosen planning temperature at KCP&L. This then yields a weather-adjusted peak demand, which is utilized throughout the rest of the planning process.

Figure 6: Example Scatter Plot after data filtered to show collating loads

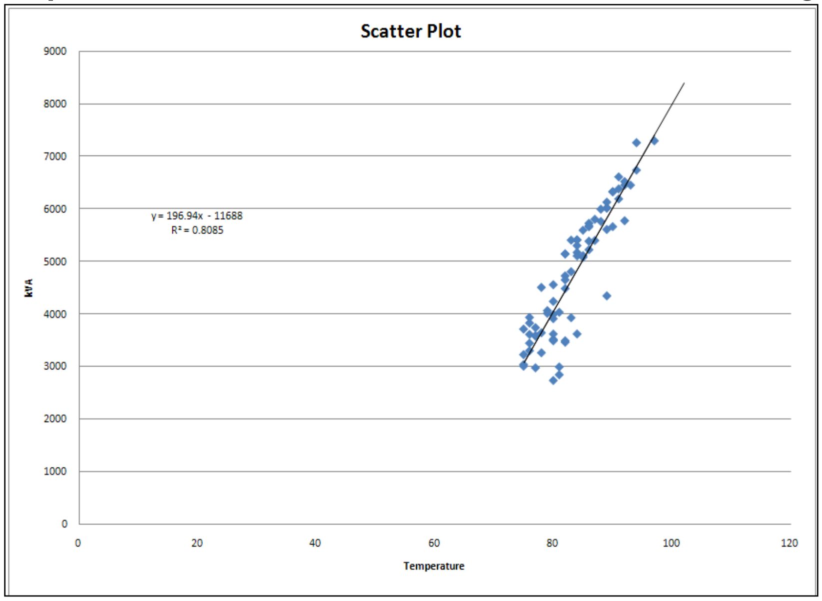
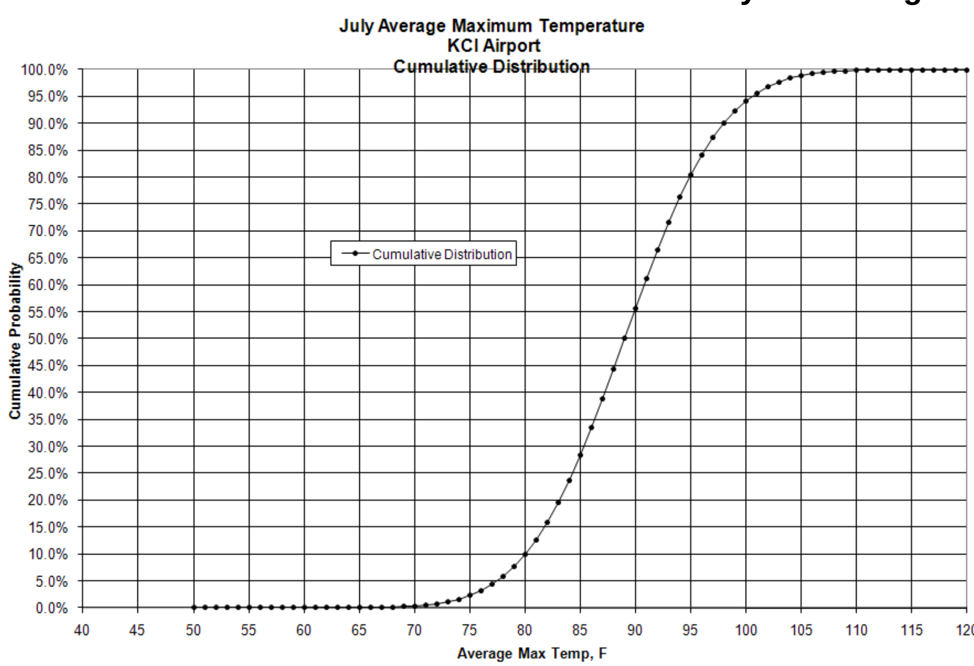


Figure 7: Cumulitive Distribution Plot - 95% certainty at 100 degrees F



For load driven higher by increasing temperatures, the chart above shows at what temperature the Kansas City Area tops out. Temperatures above 105 degrees Fahrenheit are almost nonexistent historically and statistically. For Kansas City, the 95% mark (5% of the time temperature runs hotter) is 100 degrees F. For Distribution Planning, taking 5% risk means planning to a weather-adjusted temperature of 100 degrees F.

One hundred degrees Fahrenheit planning temperature was chosen for several reasons. First, Corporate Planning uses 100 degrees for their studies, and Distribution Planning felt it appropriate to match their criteria for distribution expansion projects. Second, 100 degrees represents a five percent risk, meaning there is a five percent chance in any given year the temperature will exceed 100 degrees on at least one day, sending system loads beyond designed capacity. Third, 100 degrees best-matched the previous design criteria in terms of system improvement dollars needed in a given year.

1.1.2.1.2 Circuit Rating Study

Armed with weather-adjusted loads, Distribution Planning can produce ratings for each circuit. Again, this study is done in several different ways depending on the configuration and style of the distribution components being looked at. The most complex of these studies deals with underground feeder cables within duct bank, which de-rate each other by mutual heating. Whatever the case may be, Distribution Planning uses weather-adjusted loads to determine capacity ‘choke-points’ in order to rate the circuit. These ratings are provided to operations to set alarms, and become an integral part of the N-1 Contingency Study. These ratings are also compared with native device loads to determine where normal-load capacity expansions are needed, leading to budget recommendations.

Figure 8: Screenshot from Cable De-rating Program

Description Duct Bank from M.H. 2312 East to M.H. 2313

Rows	6	*# of Positions*	
Columns	2	10	
Ambient	22		
Earth Rho	90		

Position	*Circuit*	*load factor*	*running load*	*vertical*	*horiz.*	*Nom Ckt Voltage*	*Duct Type*	*Cable Type*
1	1561	0.67	204	77.8	5.6	13	4.5"-Fibre	1-400 KCM-3C PILC
2	7472	0.67	35	77.8	12.9	13	4.5"-Fibre	1-400 KCM-3C PILC
3	1574	0.67	201	70.5	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
4	1511	0.67	123	70.5	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
5	1743	0.67	185	63.2	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
7	1567	0.67	109	55.9	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
9	7432	0.67	228	48.6	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
10	1522	0.67	178	48.6	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC
11	1523	0.67	180	41.3	5.6	13	4.5"-Fibre	1-750 KCM-3C PILC
12	1512	0.67	195	41.3	12.9	13	4.5"-Fibre	1-750 KCM-3C PILC

Circuit	*Load (A)*	*Oper. Temp.*	*Norm. Amp.*	*Norm. MVA*	*Emerg. Amp.*	*Emerg. MVA*
1561	204	50.6	380	8.68	428	9.78
7472	35	37.8	369	8.44	418	9.55
1574	201	45.1	522	11.93	575	13.15
1511	123	40.6	520	11.88	575	13.15
1743	185	44.0	522	11.94	575	13.15
1567	109	40.3	522	11.93	575	13.15
7432	228	45.7	536	12.26	575	13.15
1522	178	42.4	533	12.19	575	13.15
1523	180	41.0	544	12.44	575	13.15
1512	195	41.7	546	12.47	575	13.15

1.1.2.1.3 Spatial Electric Load Forecast Study (Electric Vehicle Study)

KCP&L with the help of Integral Analytics, Inc. (IA) conducted a rigorous electric vehicle impact study and a long-range spatial load forecast study. The study details long-range substation load growth due to increases in employment, population, and estimates the future adoption of electric vehicles at different penetration levels for the entire KCP&L service territory. The study intent was to help distribution planners identify future capacity constrained areas due to future electric vehicle load additions and to proactively plan for distribution expansion work before system loading became an issue.

Electric vehicles present a significantly large end use load to the distribution system. To study the potential distribution impact of vehicle electrification, one must understand the customer key drivers of adoption. Therefore, IA designed a discrete choice survey and recruited 113 KCP&L residential customers randomly to participate in a discrete choice survey online. The survey results were processed and unique electric vehicle adoption and charging behavior segments were developed. The segmentation was applied to the KCP&L customer base with demographic information pulled from the Experian database. A probability of adoption score was assigned to each KCP&L customer based on the segmentation analysis. The scoring identified the customers most likely to purchase electric vehicles. Finally, the customers were mapped spatially in LoadSEER 2010 to geographically locate potential electric vehicle customer clusters at different penetration levels in the KCP&L service territory.

The worst case scenario of 100 percent of new vehicles sold in the KCP&L service territory are electric vehicles show, on average, the load will increase by 2,500 kilowatts per substation over the next 20 years. Therefore, residential electric vehicle charging at the local or neighborhood levels will resemble normal load growth. KCP&L annually reviews distribution feeder capabilities and implements necessary upgrades to meet the electricity requirements. KCP&L does not anticipate substation loading issues. However, KCP&L does anticipate localized loading issues at the distribution line transformer level providing service to a cluster of customer who all adopt EV. Localized distribution line transformer loading can be easily resolved by upgrading the size of the transformer.

The electric vehicle impact study provides distribution planning a 20 year forecast of future loading by substation for different electric vehicle penetration scenarios. The scenario based planning methodology has allowed distribution planning to understand the impact of electric vehicles in the KCP&L service territory at the substation level. The electric vehicle study did highlight a few potential loading issues but overall the impact of electric vehicles on the distribution networks will to be very minimal over the next 20 years. Appendix 4.5.A contains a complete copy of the “Spatial Electric Load Forecast Study”.

1.1.2.2 Contingency Planning

Contingency Planning is similar to Capacity Planning in its view of loads compared to device capacity, but deals in an N-1 contingency setting. KCP&L designs its system to withstand a failure of any one component at a given time. It is the responsibility of Distribution Planning Engineers to determine system weaknesses which do not comply with this and to make the necessary changes to allow emergency switching to restore power without overloading backup devices. These issues have a secondary priority in the budgetary process.

1.1.2.2.1 N-1 Contingency

The annual contingency study will provide the earliest indication of system improvement needs. It is more likely wire upgrades will be needed in the case of feeder or transformer loss, rather than there being simply too much native load on a single feeder or substation transformer. For Distribution Planning, the N-1 Contingency Study is a very systematic and complex process due to the magnitude of the individual distribution system circuit components. SynerGEE is the primary software tool in use to determine the load flow across a circuit. Distribution Planners break apart circuits into segments of load, and establish switching orders for restoration in the case of a feeder or substation transformer loss. SynerGEE, using G.I.S. models exported from GTech and weather-adjusted load data, actually determines how that load is spread across the circuit by taking a third input from the C.I.S. – metered customer load data. The SynerGEE CMM Module allows Distribution Planning to allocate feeder breaker weather-adjusted load on a given feeder based upon how it appears by its metered customer load, which is typically measured in kWh.

Three very complex inputs into one N-1 Contingency Study using a highly-technical software program yields effective results determining where system improvement is needed. By using the model to rearrange the configuration of circuitry using SynerGEE, Distribution Planning can detect where mapping errors exist, where low voltage can be problematic, and where wire sizes can limit how the distribution system is operated. Contingency Planning is an intensely complex process taking significant engineering time in order to determine system weaknesses for a given planning year. The study is completed every year for every distribution feeder and for the loss of every substation transformer.

These weaknesses, once identified, are further analyzed to determine with impact to system reliability and are ranked against each other correspondingly. Ultimately, this ranking, energy efficiency impacts, reliability and customer impact risks, and the project cost determine whether a system improvement is constructed or not. Distribution Planning therefore must not only identify the weakness, but provide some budgetary estimation and project description. It also becomes the responsibility of Distribution Planning to thoroughly communicate why a project exists throughout the company, until it becomes part of the approved budget and is handed-off to a design engineer for sponsorship.

1.1.2.3 Distribution Voltage

At the customer-end of any given line, distribution voltage must be maintained within specific tolerances. It is the responsibility of Distribution Planning to assure system-level issues do not adversely affect the voltage received by KCP&L customers. To do this, G.I.S. models are used in a load-flow program called SynerGEE to simulate voltage levels in the field. In addition to supplying adequate voltage levels to our customers, is maintaining an efficient low-loss distribution system. Several examples of this are the annual load balancing efforts and capacitor studies to optimize voltage levels and reduce system losses.

1.1.2.3.1 Loss Studies

Another method of analyzing overall system efficiency is through the performance of system loss studies. These are done periodically and the information gathered is used by Planning Engineering as well as in rate case filings. The most recent system loss study was performed by Siemens in February of 2006. A complete copy of this study, “Kansas City Power and Light Electric System Loss Analysis”, can be found in Appendix 4.5.B.

1.1.2.3.2 KCP&L Green Circuits Analysis

Another example of KCP&L’s efforts to improve overall circuit efficiency and reduce system losses was a recent study commissioned by KCP&L and completed by EPRI (Electric Power Research Institute). This study analyzed various loss reduction options such as phase balancing, capacitor controls, re-conductoring, and/or voltage optimization. The information gathered by this study has been used by Planning Engineeing to optimize their approach to circuit construction, configuration and operation. A complete copy of this study, “KCP&L Green Circuits Analysis Study”, can be found in Appendix 4,5.C.

1.1.2.3.3 Transformer Efficiency Analysis

Currently, KCP&L purchases transformers based on the Total Ownership Cost (TOC), which includes the transformer purchase price as well as the cost of the no-load and load-losses associated with each transformer, capitalized over a 30 year expected transformer life. As of 2010, all KCP&L transformers were purchased utilizing the Department of Engergy (DOE) transformer efficiency standards, which has enabled KCP&L to optimize the TOC of all transformers over a 30 year period. The table at the top of the following page contains the DOE Efficiency ratings and covers all transformer sizes currently utilized by KCP&L. Efficiencies are calculated at 50% of the transformers name plate rated load.

Table 4: Department of Energy (DOE) - Transformer Effieciency Ratings

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.62	15	98.36
15	98.76	30	98.62
25	98.91	45	98.76
37.5	99.01	75	98.91
50	99.08	112.5	99.01
75	99.17	150	99.08
100	99.23	225	99.17
167	99.25	300	99.23
250	99.32	500	99.25
333	99.36	750	99.32
500	99.42	1000	99.36
667	99.46	1500	99.42
833	99.49	2000	99.46
		2500	99.49

1.1.2.4 Condition

Another important focus area for Planning Engineering deals with component conditions and their affect on reliability as it relates to capacity, contingency, voltage and overall system efficiency. Ongoing strategic planning to maintain reliability must account for device degradation over time, and planning engineers look for cost-effective replacement or maintenance opportunities where they coincide with capacity expansion plans. By working with the Asset Management group to determine the best course of action, these replacements in some cases are combined into Distribution Planning's capacity expansion projects – an increase in project scope from the normal course of action. System expansion to replace degraded system components can be a more cost-effective solution than the “run-to-failure” strategy.

1.1.2.4.1 URD Cable Replacement Programs

Currently, there are two cable replacement programs in existence at KCP&L: 1) Proactive Cable Replacement, and 2) Reactive Cable Replacement.

The proactive cable replacement program requires an analysis of the entire underground lateral after the second fault on a cable section or a number of faults correlated by region, cable age, or other attributes among different cables. The focus is to research the adjacent cables on the same lateral of a failed direct buried cable and to replace all those cables that have similar characteristics as the failed cables if the failure rate and number of customers of the lateral would warrant it. This provides a targeted proactive cable replacement before failure, eliminating high-risk cables before they fail.

The reactive cable replacement program requires replacement of a cable when it has failed two or more times. The current policy of the reactive URD replacement program is to replace any direct buried cable after its second failure with cable in conduit. A section of cable receives a priority which is a function of the number of customers affected by the cable outage, the duration of the outage, the vintage of the cable, the number of failures of cable, the time elapsed from the most recent failure, and the number of outages that the lateral has experienced in past 12-months.

The activity for these programs is as follows. 2011 shows the current status of issued and completed jobs through October 1, 2011.

Table 5: 2011 Cable Program Costs

	2009	2010	2011
Reactive Segments	38	58	110
Reactive Cost	$ 943,902	$ 1,213,365	$ 1,381,478
Proactive Segments	44	47	0
Proactive Cost	$ 584,383	$ 601,333	$ -

1.1.2.4.2 Cable Injection Program

In addition to cable replacement, cable injection proactively addresses high-risk cables. Cable injection techniques prolong the cable's life and improve reliability. Injection can be performed on cables that have faulted, but as with proactive replacement, the goal is to prevent failures from happening in the first place. Injection contractors provide a minimum warranty of 20 years, with the option to upgrade to as much as 40 years with better injection fluids. Cable injection companies are used by KCPL to perform these activities.

1.1.2.4.3 Inventory Assessment

The Inventory Assessment process is a distribution mapping project for the purpose of combining two mapping systems and improve the physical accuracy of the current electrical system to new digital county land base maps, and capture new GPS coordinates of those facilities. Additionally, we conducted a condition assessment on each component of those electrical facilities, and assess their physical conditions and labeled them with a priority code 1, 2, 3, or 4. Each priority code is a measurement of severity and importance from 1 to 4. This prioritization process control is a communication tool utilized by our field personnel to fix the most important components. Table 6 is an indication to the quantity of GIS data corrections we have completed for KCP&L and KCP&L GMO areas, and Table 7 shows the distances poles were moved graphically to match GIS locations taken in the field. Table 6 assessment statistics captures all of the overhead facilities for Kansas City Power and Light Missouri and Kansas electrical facilities.

Table 6: KCP&L and GMO Areas GIS Data Accuracy

	KCP&L DSIA	Lee's Summit	Blue Springs	Belton	St Joseph 85% Comp	CIA Totals
Poles Delivered (Pole Single)	323,686	32,382	23,378	24,071	48,390	128,221
Database Accuracy						
Electric Features Added	251,758	72,493	51,611	62,304	17,561	203,969
Attributes Reviewed	26,582,927	3,638,343	2,163,380	1,887,857	3,296,143	10,985,723
Attributes Added	2,100,812	785,141	497,903	608,585	129,865	2,021,494
Attributes Corrected	9,281,990	1,394,263	989,603	938,121	1,304,447	4,626,434
Original Database Accuracy	65.08%	61.68%	54.26%	50.31%	60.43%	57.89%

Table 7: KCP&L and GMO Areas GIS Graphical Accuracy

	KCP&L Rural	KCP&L Metro	Lee's Summit	Blue Springs	Belton	St Joseph 85% Comp
Poles Delivered	118,548	205,138	32,382	23,378	24,071	48,390
Graphical Accuracy (pole relocation)						
1 – 20 Foot Shift	6,208	20,417	1,818	2,023	1,172	10,246
21 – 100 Foot Shift	50,193	46,122	8,515	7,742	5,876	21,073
101 – 400 Foot Shift	32,137	10,337	4,563	3,816	3,100	4,060
> 401 Foot Shift	3,925	637	1,049	560	956	193
> 20 Foot Shift	73%	28%	44%	52%	41%	52%
Original GIS Graphical Accuracy	27%	72%	56%	48%	59%	48%
Underground Structures Delivered	NA	NA	18,999	16,977	10,038	6,539
Graphical Accuracy (UG relocation)						
1 – 20 Foot Shift	NA	NA	1,738	1,824	897	464
21 – 100 Foot Shift	NA	NA	7,825	7,764	5,016	2,832
101 – 400 Foot Shift	NA	NA	1,327	1,485	850	524
> 401 Foot Shift	NA	NA	412	199	175	33
> 20 Foot Shift	NA	NA	50%	56%	60%	52%
Original GIS Graphical Accuracy	NA	NA	50%	44%	40%	48%

The efficiencies gains include better visual control of our facilities maintenance programs. There were two separate mapping systems combined to one complete mapping system. Each structure has a UFLID

(Unique Field Label Identity) which makes it easier to direct crews and shorten travel distances. And, we captured additional attributes not originally added to the maps.

Table 8 below has assessment statistics on overhead facilities in the Kansas City Power and Light territories. The table represents a partial review of those components needing attention. Total assessment quantity for each column is separated by counts and percents of the total discovered by locations. This information is centralized in one software package unique to KCP&L.

Table 8: KCP&L Missouri and Kansas Assessment Statistics

Inspection Type	Total	Northland	F&M	Dodson	South District	East District	Southland
Total Assessment Records	586,856 (2.1 per site)	108,179 (2.8 per site)	90,698 (2.1 per site)	143,341 (2.3 per site)	147,534 (1.9 per site)	77,308 (1.8 per site)	19,796 (1.5 per site)
Insulator Brown/Broken	244,829 (42%)	42,154 (39%)	40,111 (44%)	75,128 (52%)	50,291 (34%)	33,980 (44%)	3,165 (16%)
Insulator Aluminum Cap	56,371 (9%)	9,258 (9%)	10,324 (11%)	16,892 (12%)	12,780 (8%)	4,694 (6%)	2,423 (14%)
Un-insulated Jumper	55,781 (9%)	6,987 (6%)	6,057 (7%)	7,921 (6%)	27,622 (19%)	5,314 (7%)	1,880 (10%)
Cutout – Joslyn	46,162 (8%)	7,702 (7%)	7,777 (9%)	14,608 (10%)	10,053 (7%)	4,123 (5%)	1,899 (10%)
Conductor Splices	33,896 (6%)	23,777 (22%)	8,520 (9%)	505 (0.03%)	610 (0.01%)	402 (0.01%)	82 (0.01%)
All others	149,817 (26%)	18,301 (17%)	17,909 (20%)	28,287 (20%)	46,178 (32%)	28,795 (38%)	10,347 (50%)

1.1.2.4.4 Worst Performing Circuit Analysis

The inventory assessment projects have given Kansas City Power and Light an advantage that we can employ with worst performing circuit analysis. Annually, we identify worst performing circuits from States requirements criteria and develop reliability plans and make repairs. The performance of circuits vary significantly and no two of them have identical problems to fix. We use the assessment data to be included in our analysis of those worst performing circuits.

Table 9 illustrates the impact of addressing worst performing circuit issues. In the table CI is defined as customers interrupted and CMI customer minutes interrupted. Those statistical numbers, found in Table 9, are the difference in CI and CMI saved by utilizing the condition assessments and conducting root cause analysis on each of the worst performing circuits. There are approximately 70 WPC's under review each year that covers Missouri and Kansas's regulatory rules.

Table 9: CI and CMI Data

Annual CI and CMI Saved		
Years	Customer Interrupted Saved	Customer Minutes Interrupted Saved
2008	94,766	7,199,849
2009	86,939	7,674,498
2010	107,449	8,834,313

1.2 ASSESSMENT OF INTERCONNECTING NEW FACILITIES

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;

KCP&L Transmission Planning must meet interconnection needs of transmission customers for connection to and use of the KCP&L transmission system. The Interconnection procedures are covered within the Federal Energy Regulatory Commission (FERC) approved transmission tariff provisions where customers are provided detailed transmission studies and interconnection estimates for connecting to and using KCP&L's transmission system.

An example of such is the review of potential sites for addition of a new KCP&L 600 MW combined cycle gas fired power plant. This process included review of brown field (existing) and green field (new) sites within or near the KCP&L and GMO service territories. KCP&L 161 kV transmission lines are generally not adequate to provide firm transmission for a 600 MW generation resource unless multiple (2+) transmission lines are available for generation outlet. KCP&L 345 kV transmission lines can generally provide firm transmission for a 600 MW generation resource if there is available transmission capacity.

The KCP&L Combined Cycle Plant Siting Study identified seven potential sites for addition of a 600 MW generation resource. Transmission Planning provided a range of transmission costs for each site and identified potential transmission limitations.

Any KCP&L generation resource addition that would impact transmission level (>60 kV) flows would have to proceed through the SPP Generation Interconnection process before it could be interconnected to the transmission system. The resource addition would also have to be included in the SPP Aggregate Facility Study process to obtain firm transmission service for delivery of generation to load.

1.3 ASSESSMENT OF TRANSMISSION UPGRADES FOR POWER PURCHASES

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040(3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of preliminary supply-side candidate resource options; and

KCP&L is member of the Southwest Power Pool (SPP) a Regional Transmission Organization (RTO), mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. As a North American Electric Reliability Corporation (NERC) Regional Entity, SPP oversees enforcement and development of reliability standards. SPP has members in nine states. As a member of SPP, KCP&L participates in the regional transmission expansion plan processes of the RTO. Two recent expansion plan processes conducted by SPP are the Balanced Portfolio (June 2009) and the Priority Projects (April 2010).

The Balanced Portfolio is an SPP strategic initiative to develop a grouping of economic based regional transmission upgrades that benefit the SPP region while allocating the cost of the upgrades regionally. Projects in the Balanced

Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources. SPP analyzed the benefits and costs of the Balanced Portfolio and established that these projects provided a region-wide per-customer average benefit of $1.66/month with a corresponding cost of $0.88/month. The Balanced Portfolio included a total of seven transmission projects with an estimated engineering and construction cost of approximately $700 million (initial estimate). Two of these projects are within the KCP&L service territory. They are the Iatan-Nashua 345 kV line (~$54 million) and the Swissvale-Stilwell tap at West Gardner (~$2 million).

In the Priority Projects plan, SPP sought to identify, evaluate, and recommend transmission projects that would improve regional production costs, reduce grid congestion, enable large-scale renewable resources (primarily wind), improve the Generation Interconnection and Aggregate Facility Study processes, and better integrate SPP’s east and west regions. A total of six transmission projects with an estimated cost of $1.1 billion were selected for construction in the Priority Projects process providing a variety of benefits to the region. One of the projects included is a GMO project as the Nebraska City-Maryville-Sibley 345 kV transmission line. These Priority Projects achieve the strategic goals of reducing transmission congestion, improving the Aggregate Facility Study process by creating additional transfer capability and increasing the ability to transfer power in an eastward direction for the majority of the transmission paths between SPP’s western and eastern areas.

The costs for the Balanced Portfolio and Priority Projects will be allocated on a regional basis by specific allocation methods whether or not KCP&L makes any resource additions. For this reason, KCP&L's share of the allocated costs for Balanced Portfolio and Priority Projects were not reflected in the analysis of preliminary supply-side candidate resource options.

The preferred resource plan for KCP&L includes additional wind and solar generation resources. The solar resources are relatively small amounts of generation and are assumed to be interconnected at the distribution voltage levels. For this reason there is no associated transmission interconnection or upgrade costs for these solar generation resources. The wind resources included in the preferred resource plan are assumed to be remotely located in western Kansas and will utilize regional transmission capacity and transmission service to deliver their output to KCP&L loads. Any new generation resources would have to apply for interconnection through the SPP generator interconnection process and apply for transmission service in the SPP Aggregate Study process.

1.4 ASSESSMENT OF TRANSMISSION OR DISTRIBUTION IMPROVEMENTS WITH RESPECT TO COST EFFECTIVENESS OF DSM OR SUPPLY-SIDE RESOURCES

(D) Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the analyses of each resource option.

1.4.1 CAPACITOR AUTOMATION EFFORTS

KCP&L, an industry leader in Distribution Automation (DA), began its automation initiatives in the early 1990's by deploying several hundred automated capacitors in the metropolitan area using the CellNet fixed network communication system also used for the automated meter reading system (AMR) at that time.

Since the early 1990's, KCP&L has worked with Sensus (formerly Telemetric) to develop automated capacitor controls with integrated GPRS radios for use throughout the KCP&L service territory. This technology simply uses radios that leverage the commercial cell coverage infrastructure while also providing secure communications and technology applications for KCP&L users. This added technology is particularly cost effective and successful in rural areas where KCP&L to date has not deployed the fixed network or other automated meter reading communication infrastructure technology. KCP&L has been able to quickly deploy automated capacitors in areas in the Aquila acquisition.

The business case for automated capacitors includes:

- Upgrade existing capacitors with controls with new technical features
    - Voltage Override
    - Neutral Sensing
    - Limiting number of switching operations per day
    - Ability to change setpoints remotely
    - Ability to obtain power quality data for improved customer service
- Optimizing utilization of these existing capacitor banks
- Enhancing safety for KCP&L workers
    - Five minute time delay in control for a close after an open
    - One minute timer for close after faceplate control operation
- Reduced O&M
    - Limiting number of capacitor patrols due to real time data
    - Limiting number of customer voltage complaints
    - Extending life of existing capacitor switches

- Improved Distribution and Transmission Power Factor
    - o Enhance System Stability
    - o Enhance system volt/VAr response
    - o Increase system efficiency

Below is a list of automated capacitors now installed on the KCP&L system:

Legacy KCP&L System Automated Capacitors Counts:

- Automated Capacitor Controls for Switched Banks.........1028
- Automated Monitoring of Fixed Banks 482
- Subtotal...1608

KCP&L GMO Automated Capacitors Counts:

- Automated Capacitor Controls for Switched Banks.......... 169
- Automated Monitoring of Fixed Banks 4
- Subtotal.. 179

1.4.2 <u>34 KV SWITCH AUTOMATION PROGRAM</u>

Over the past five years, KCP&L has installed 88 automated reclosers on their 34-kV overhead distribution lines. These circuits are very lengthy (up to 25 miles long) and feed 34:12-kV substations and also 34-kV loads directly (such as municipalities and private substations).

KCP&L uses Sensus integrated hardware and software solutions and KCP&L's Energy Management System (EMS). This includes the following Sensus products and applications: the Remote Telemetric Module (RTM radio), the PowerVista Internet application, and SCADA X-Change. The Sensus RTM is integrated into the Cooper Form 6 recloser control for use in the Cooper NOVA recloser. The NOVA recloser uses vacuum bottles and solid dielectric insulation to increase safety for KCP&L linemen. KCP&L dispatchers use this technology to perform planned and emergency switching to quickly restore service to 34-kV customers.

The business case behind this program is as follows:

- Reduce Outage Time
- Reduce Customer Minute Interruptions
- Use remote control commands to support planned switching
- Use information from reclosers to augment engineering studies

Here are the installed totals for these 34-kV Automated Reclosers:

- Legacy KCP&L Areas 53
- Legacy Aquila Areas 35
- Total Now Installed.......................88

Attached are five figures showing actual results from this project in the East and South Districts where 53 automated reclosers are installed in legacy KCP&L areas:

Figure 9: South District Customer Minutes Interrupted (CMI)

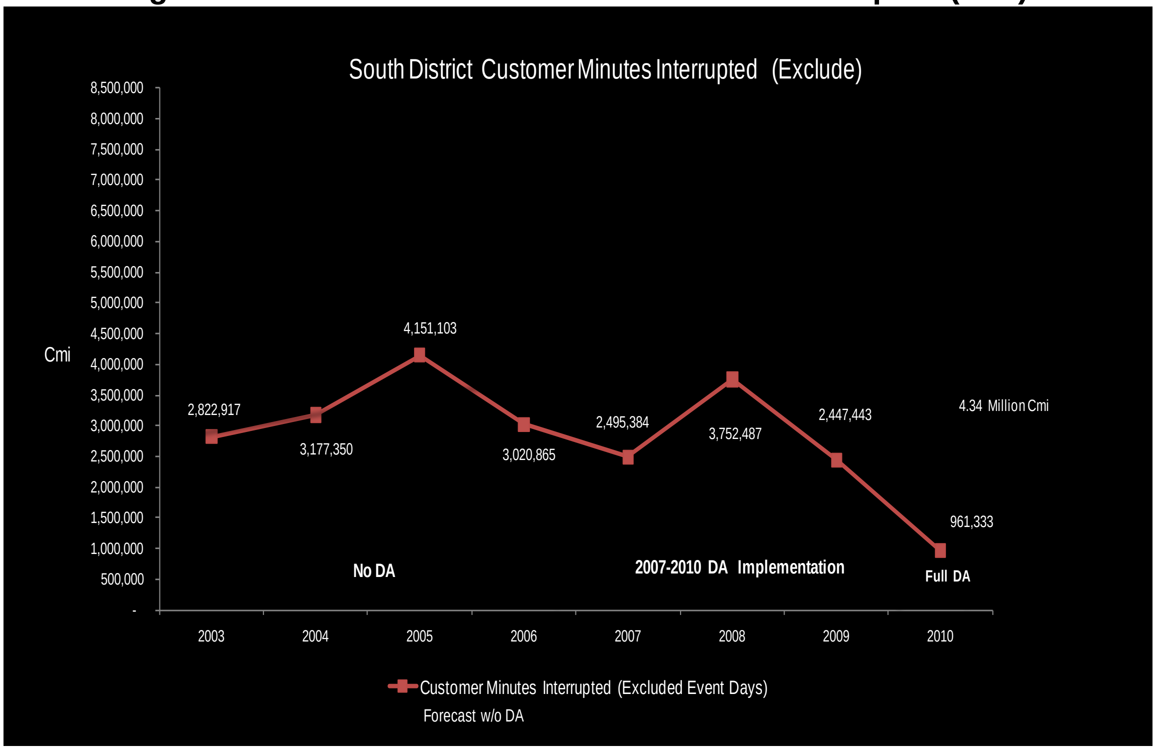


Figure 10: South District Customer Average Interruption Duration Index (CAIDI)

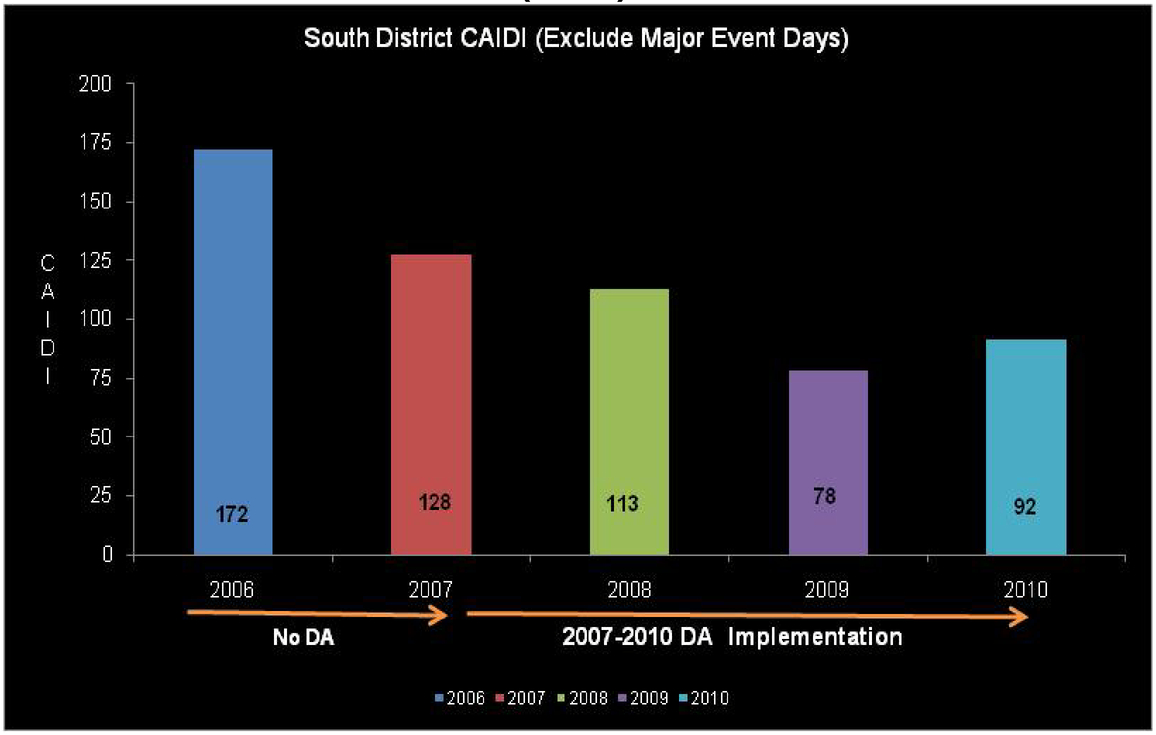


Figure 11: South District Customer Minutes Interrupted - DA Projections

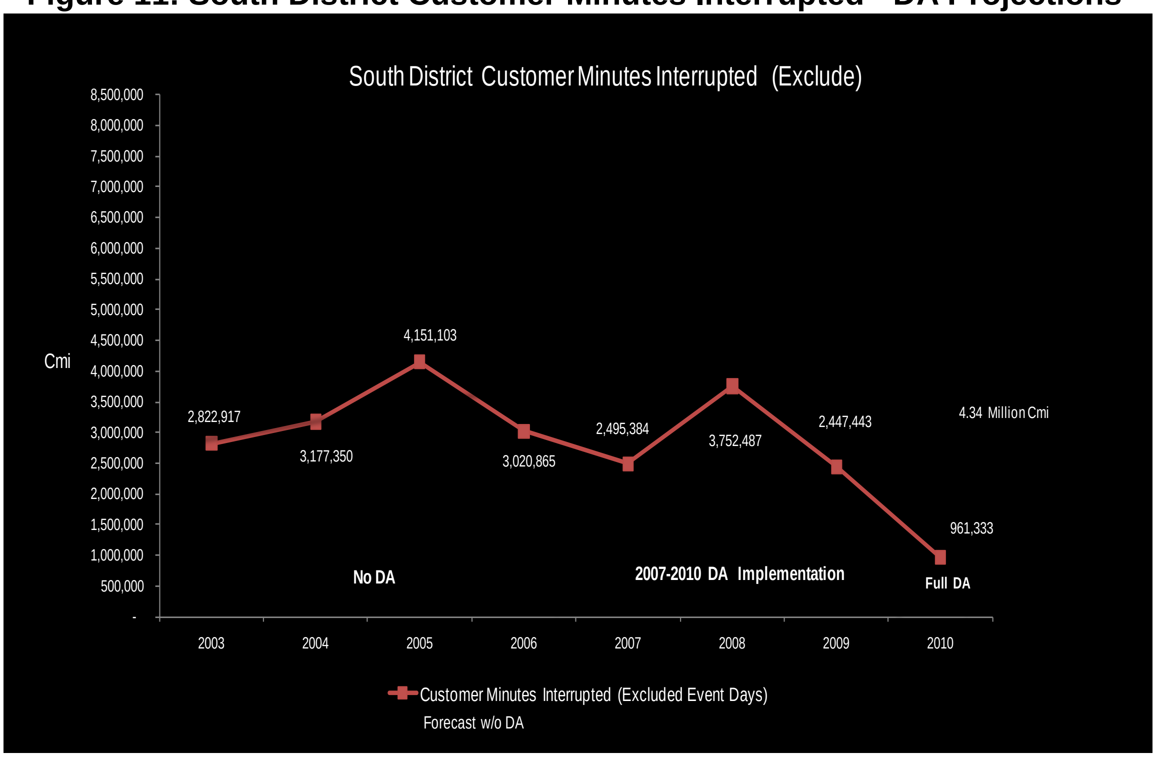


Figure 12: East District Customer Average Interruption Duration Index (CAIDI)

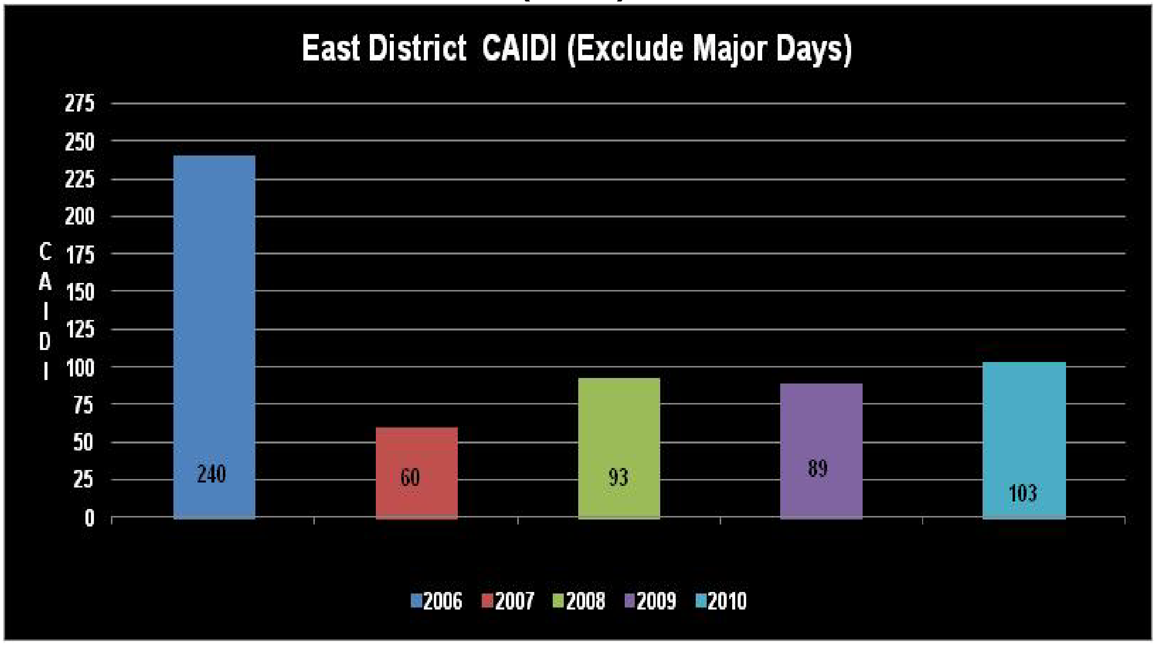
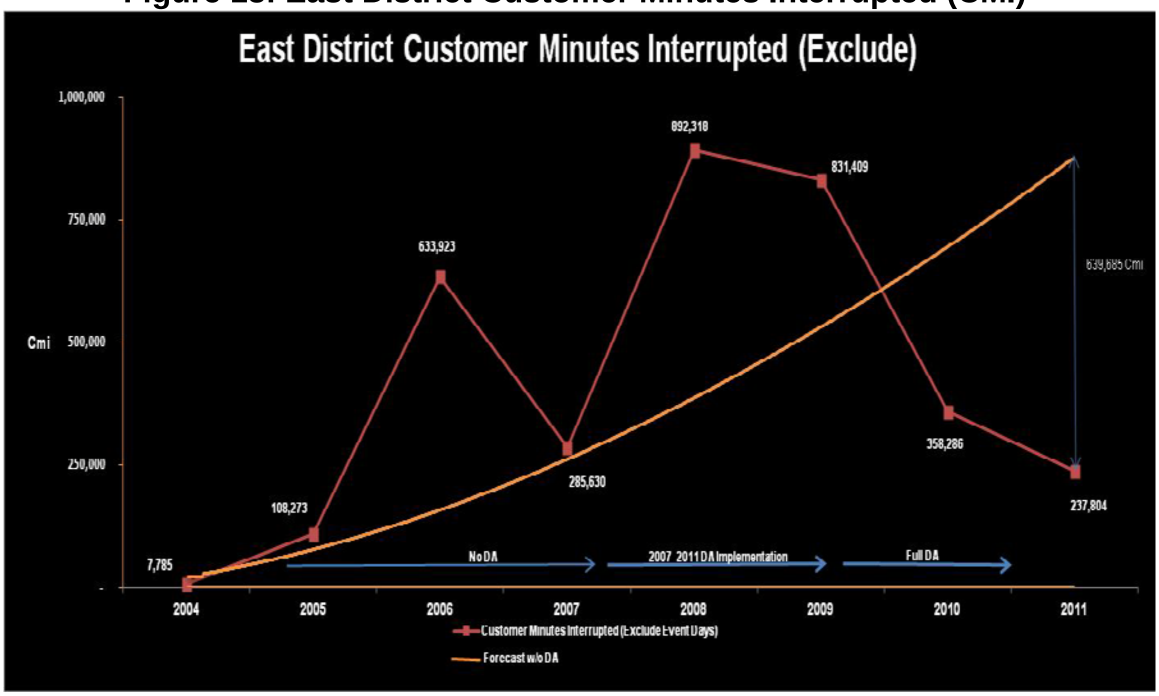


Figure 13: East District Customer Minutes Interrupted (CMI)



1.4.3 UNDERGROUND NETWORK AUTOMATION

In 2004 and 2005, KCP&L was beginning to experience some outages to customers served by the Downtown Network. In addition, underground cable splicers were reporting extraordinary number of network protector operations on the Plaza Underground network grid. Problems continued to escalate in the downtown area. Several large buildings lost service during the work day and occupants needed to evacuate tall buildings through stair wells.

A KCP&L underground crew escaped injury after closing a network protector manually inside the vault. A 480-volt phase to phase fault resulted that vaporized the inside of this network protector. KCP&L executives called upon the Distribution Automation team to find ways to mitigate these concerns.

A business case was prepared to accomplish the following:

- Reduce number of customer outages on the Network
- Extend life of network protectors by additional sensors
- Extend life of network protectors and transformers by using live data
- Improve KCP&L worker safety by mitigation of manual switching
- Monitor network protector closed status to ensure balanced loading
- Use control to monitor equipment malfunctions
- Use monitoring to ensure protectors are operating in the automatic mode

The project was done using Intelligent Electronic Devices (IEDs) from Electronic Technologies Incorporated (ETI). ETI, KCP&L and Telemetric worked together to design a waterproof enclosure that mounted high in the vault to facilitate radio coverage. The RTM solution, Power Vista, SCADA X-change were used to send remote commands and retrieve valuable data from the ETI relays.

As a result of this project, KCP&L changed operating procedures to minimize the number of switching operations seen at the Network protectors on the Plaza Network Grid. In addition, dispatchers used remote control through the RTM to eliminate the need for underground cable splicers to perform manual switching inside the vault.

Underground network protector equipment malfunction is now quickly reported. Crews take the needed parts to the specific job site to make prompt repairs. Prompt restoration of transformers extends the service life of the grid transformers by limiting the amount of thermal overloading and overload duration.

To date, there has not been an outage to customers served from the underground network since Underground Network was deployed at KCP&L in 2006 through 2007. Sensors have successfully reported numerous issues: protectors accidentally left blocked, protectors with equipment malfunction, network protectors with moisture inside the protector, overloaded network transformers. All these issues were promptly discovered and resolved before any equipment was damaged. For example, a building contractor placed a load of plywood sheets over a vault that compromised the ventilation and caused a transformer to quickly become hot. Top oil temperature alarms successfully reported this problem that was also promptly resolved.

Here is a list of installed Automated Network Protectors at KCP&L

- East Grid 27
- West Grid 13
- Plaza Grid 29
- Spot Networks..............................48
- Total 117

1.4.4 DYNAMIC VOLTAGE CONTROL

KCP&L also has been a pioneer in demand reduction from voltage reduction during peak summer loading. KCP&L already had a progressive capacitor automation system in place. This became the foundation for another successful KCP&L distribution automation project called Dynamic Voltage Control (DVC).

The business case for this project is as follows:

- MW Demand reduction from controlled voltage reduction
- Better substation voltage regulation

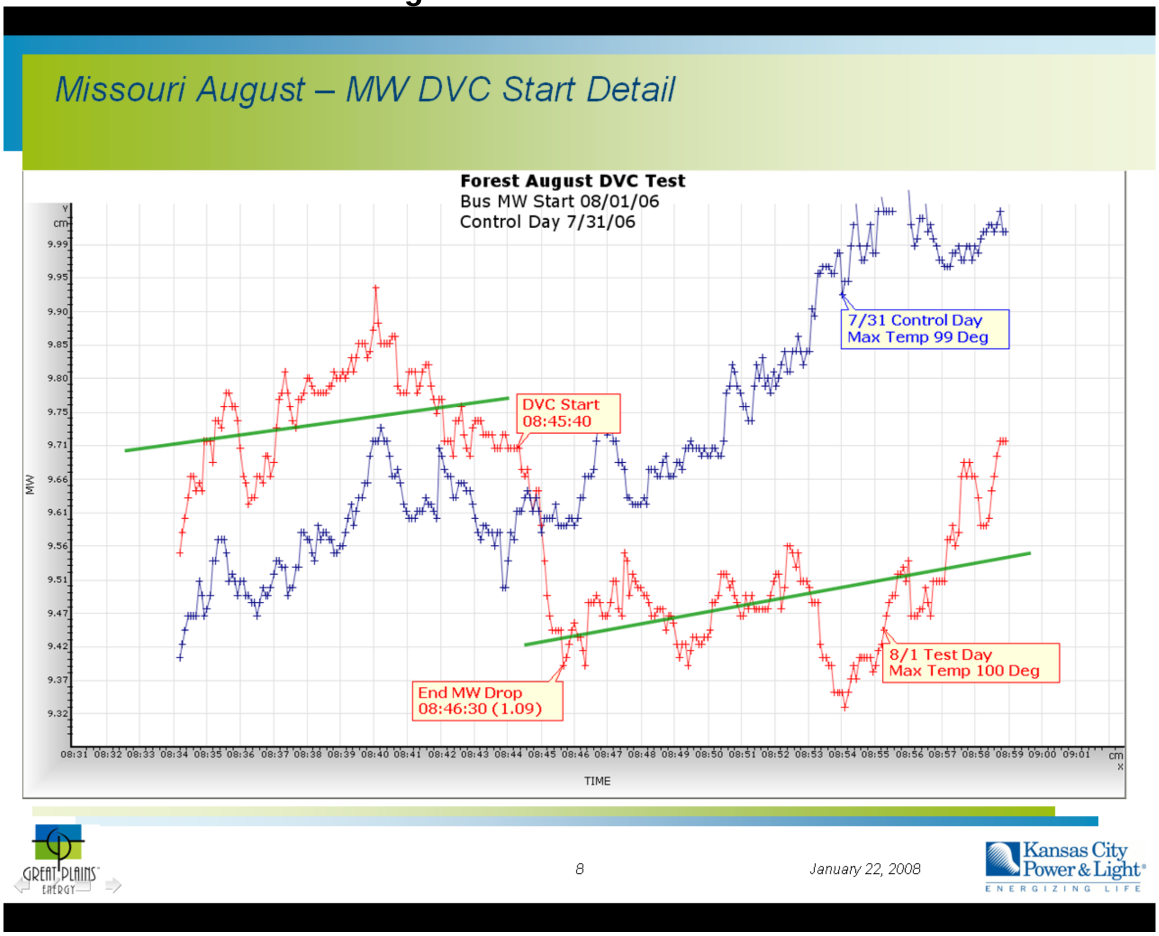
- Improved process for load tap changer setpoints
- Integration of substation load tap changer and distribution capacitors by settings and practical application versus complex feedback loops
- Remote control of load tap changer for planned switching
- Provide Remote setpoint changes for authorized users
- Release MVAr in support of transmission and distribution system

The project involved replacing electromechanical and non-communicating load tap changer controls with electronic load tap changer controls that use DNP protocol. This intelligent electronic device (IED) streams DNP messaging into a remote terminal unit (RTU). KCP&L developed EMS screens and applications to support remote setpoint changes as well as the ability to see the actual settings values.

KCP&L installed this system on 203 substation buses on legacy KCP&L substations prior to the Aquila acquisition. KCP&L dispatchers now use the system to successfully accomplish all the desired tasks shown above. KCP&L performed various tests on the use of DVC to reduce demand on system peak. Below is a test on August 1, 2006 showing the interaction between voltage reduction and the resulting demand reduction. For KCP&L, distribution system studies show a reduction of 0.92% MW reduction for each 1.0% voltage reduction upon system peak. This results in nearly 50 MW reduction on the KCP&L system peak for the 203 substation buses on legacy KCP&L system.

Furthermore, KCP&L studies showed that near 30 MVAr was released on the system during voltage reduction control during peak loading. Finally, KCP&L distribution operations noted the number of customer voltage complaints during peak loading and throughout the year actually decreased due to the combination of improved voltage regulation at the substation plus the enhanced voltage support from the automated capacitors on the distribution system.

Figure 14: DVC Test Detail



SECTION 2: AVOIDED TRANSMISSION AND DISTRIBUTION COST

(2) Avoided Transmission and Distribution Cost. The utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

The KCP&L transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

2.1 IMPACT OF DSM ON DISTRIBUTION EXPANSION

First, Marketing Intelligence established the Demand Response MW that would be enabled on the KCP&L system as a whole based on four different funding levels – 1%, 0.75%, 0.5%, and 0%. These funding levels are listed in-terms of the annual increase in DSM as a percentage of the Legacy-KCP&L system peak; e.g. if KCP&L has a 4000MW peak and DSM is funded at 1%, KCP&L would expect to obtain 40MW (1% of 4000MW) in a given year.

Next, Distribution Planning Engineers shared the planned system expansion projects based upon 100F weather-adjusted demands. These are system expansions which have a high-confidence level of need, and in most cases have become a part of the capital budget. It is these known projects which KCP&L intends to spend capital dollars on which should be targeted for deferral by demand response measures, rather than currently hypothetical needs which may or may not actually initiate a construction project.

The first assumption made has to do with targeting. KCP&L is assuming the example 1% DSM obtained in a given year can be (and will be) targeted to delay load-growth driven projects. This means all the DSM obtained in a given year is targeted within an area fed by just one or a few substations, a geographic area defined by Distribution Planning Engineers.

The second assumption made deals with the dollars deferred. Substation expansion projects not yet designed were assigned a budgetary value of $1.5MM for 30MVA transformer/switchgear, and $750K for switchgear only (where transformer capacity already exists). These are the only two project types considered in the study; circuit expansions have a wide variety of costs associated with them and are less predictable as compared to substation expansion projects.

The third assumption concerns the operability of the DSM program(s). In the past, DSM at KCP&L (MPower) was called upon to meet the needs of KCP&L generating facilities. These needs did not always coincide with the peaking-hours of substation transformers, or were not called upon frequently enough to provide certainty an expansion project could still be deferred. It has been assumed the new DSM program(s) will functionally replace a new substation transformer. This means the new DSM program(s) may be called upon over a wider range of dates and times, and for a longer period of time than the MPower program was designed for.

A final assumption is KCP&L will expand substations in 30MVA blocks only. This is the currently KCP&L standard substation transformer capacity, even though many times the full-capacity is not needed at the time of installation.

Another consideration taken during the study has to do with the geographic areas and reasons the distribution system is being expanded. Targeted DSM is unlikely to be able to delay the need to expand substations on the fringe of metro-area growth, so those projects were separated from the ones which dealt with capacity issues in completely established areas. Areas with significant “green space” will likely expand as these areas cannot be as effectively targeted for DSM due to the fact they contain large areas that remain undeveloped. Therefore, the areas targeted for DSM for the purpose of calculating avoided costs are for “Established-Areas Only”. According to Distribution Planning’s budgeted and planned expansion projects, approximately 60 MVA of new capacity is needed in the next 20 years within established areas, to meet the needs of redevelopment where distribution facilities already exist. Substations with low to modest growth in established areas represent the most likely candidates for a targeted DSM effort.

Three projects make up the “Established-Areas Only” component of the study, totaling 60 MVA and $3.75 MM over 20 years. These three projects are called Claycomo, Gladstone, and Chouteau.

In 2015, Claycomo is budgeted for a switchgear addition, primarily driven by a large industrial expansion project and nearby growth. Since most of the loads fed by Claycomo are located in a well-established area, there is a higher probability DSM programs would be able to delay the need to expand.

Gladstone Substation feeds a primarily residential area, but the area served and all surrounding areas are completely established. For many years loads on this substation have crept up to its design capacity, so there is a good chance a targeted DSM program would be effective to defer an expansion there in 2017.

In 2018, Chouteau Substation is listed for possible expansion. This project is located near I-435 and Front Street in Kansas City, MO, in an area which has some open space available for new development. The vast majority of the substations’ load is located in the surrounding light-industry area, which has great potential for deferral resultant from a DSM program. Recent economic conditions have impacted the growth trend for the Choteau expansion in a negative manner, as load growth for Chouteau Substation is very modest, making it an excellent candidate for targeted DSM efforts.

Based upon the predicted acquisition of DSM megawatts for each funding level and the projected need for expansion in these established areas, it can be assumed a targeted 30MVA block of DSM can defer a substation expansion outside the study timeframe (20 years). In the case of the 1% DSM scenario for established areas, the DSM megawatts obtained are sufficient to functionally eliminate the three planned expansion projects, if targeted appropriately. Below in Table 10 is the avoided capacity cost.

Table 10: Avoided Capacity Cost **Highly Confidential**

[redacted]

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SECTION 3: ANALYSIS OF TRANSMISSION NETWORK PERTAINENT TO A RESOURCE ACQUISITION STRATEGY

(3) Transmission Analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.

3.1 TRANSMISSION ASSESSMENTS

(A) The utility shall provide, and describe and document, its—

3.1.1 TRANSMISSION ASSESSMENT FOR CONGESTION UPGRADES

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

In 2009, the SPP Board of Directors approved a new Integrated Transmission Planning (ITP) process that will determine the transmission needed to maintain electric reliability and provide near- and long-term economic benefits to the SPP RTO region, which includes all or parts of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Successful implementation of the ITP will result in a list of transmission expansion projects and completion dates that facilitate the creation of a reliable, robust, flexible, and cost-effective transmission network that improves access to the region’s diverse resources, including its vast potential for renewable energy. Significant wind energy development is taking place in parts of Oklahoma, Kansas, Nebraska, and Texas.

The ITP is an iterative three-year process that includes a 20-Year, 10-Year, and Near-Term Assessment. The 20-Year Assessment evaluates the high voltage transmission (345 kV +) needs over a 20 year study period to meet load growth and other future scenarios and potential developments. The first iteration of the 20-Year Assessment (ITP20), conducted in 2010, included an examination of high voltage transmission needs while taking into account state renewable energy targets. The transmission needs were studied both with and without a potential 20% federal renewable energy standard (RES), and a potential carbon tax. The renewable energy generation in a 20-year future without a federal RES was 10.6 GW, and the renewable energy generation in a future with a federal RES was 16.5 GW. The SPP Board of Directors voted to approve the ITP20 Report on January 25, 2011. The cost of the plan was estimated at $1.8 billion through the construction of 1,494 miles of 345 kV lines along with 11 various - 345 kV step-down transformers.

The 10-Year Assessment is a value-based planning approach that analyzes the transmission system over a 10-year horizon. Economic and reliability analyses are utilized to identify 100 kV and above solutions for issues identified on the 69 kV and above system, as well as issues identified by the 20-Year Assessment appropriate for the 10-Year Assessment. The first iteration of the 10-Year Assessment (ITP10) was conducted in 2011, with the final report issued in January 2012. This study, like the 20-Year Assessment, examines transmission needs while taking into account state renewable energy targets and a potential 20% federal RES. The renewable energy generation in a 10-year future without a federal RES is 10.0 GW, and the renewable energy generation in a 10-year future with a federal RES is 14.0 GW. The recommended 2012 ITP10 portfolio was estimated at $1.5 billion engineering and construction cost and includes projects needed to meet potential reliability, economic, and policy requirements. Within this portfolio, economic projects, estimated at $206 million engineering and construction cost with a total estimated net present value revenue requirement of $302 million, are expected to provide net benefits of approximately $596 million over the life of the projects under a Future 1 scenario containing 10 GW of wind capacity. Project need dates were identified as early as 2014 and as late as 2022. Several projects were identified for ATP status and one project for NTC status. The remaining projects were identified to receive Conditional Notification to Construct (CNTC) letters. KCP&L did not receive any transmission projects as a result of the ITP10 study.

The Near-Term Assessment of the ITP evaluates transmission system reliability in the near-term planning horizon. The Assessment will identify potential problems using NERC Reliability Standards, SPP Criteria, and local planning criteria. Mitigation plans are developed to meet regional reliability needs and identify necessary reliability upgrades for all voltage levels for approval and construction. The first iteration of the Near-Term Assessment (ITPNT) was conducted in 2011, with the final report issued in January 2012. SPP performed reliability analyses identifying potential bulk power system problems. These findings were presented to Transmission Owners and stakeholders to solicit transmission solutions. Also considered were transmission options from other SPP studies, such as the Aggregate Study and Generation Interconnection processes. From the resulting list of potential solutions, staff identified the best regional solutions for potential reliability violations. Staff presented these solutions for member and stakeholder review at SPP's July and September 2011 planning summits. Through this process, SPP developed a final list of 69 kV and above solutions necessary to ensure the reliability in the SPP region in the near-term. Engineering and Construction (E&C) cost estimates for new and modified reliability projects needed in the years 2012-2017, totaled $251 million. This is in addition to the upgrades previously approved by the Board and does not include $190 million in upgrades with active Notification to Construct (NTC) that need to be withdrawn.

The ITP process has been a fundamental change in the way in which transmission planning occurs in the SPP region. This new process, with its iterative nature and wide range of planning periods, helps to ensure robust planning, lowest cost solutions and a reliable bulk electric grid for the region. It also strengthens the balance between future needs of the system with an ever-changing grid topology, load growth, generation resources, energy policy and planning criteria.

3.1.2 TRANSMISSION ASSESSMENT FOR ADVANCE TECHNOLOGIES

2. Assessment of transmission upgrades to incorporate advanced technologies;

KCP&L currently makes use of four advanced technologies in its transmission system; Real Time Line Rating, Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire.

KCP&L currently uses a commercial application, based upon actual conductor tension, to provide real time line ratings for two of the more critically loaded 345 kV transmission lines. Basing the ratings upon a direct measurement of the actual conductor tension is the most direct method currently available to establish real time (dynamic) conductor ratings, and using the conductor tension captures all of the local conditions that affect the conductor tension and current carrying capacity. The real time line ratings are provided not only to our Transmission System Operators but also to the SPP Reliability Coordinator. This equipment allows transmission lines to carry more power when conditions are favorable and reduce transmission congestion.

KCP&L uses a hybrid steel and wood H-Frame structures for both single and double circuit applications. Using steel poles, provides easier installation due to their lower weights compared to other materials, and the use of wood X-bracing provides a cost effective option to conventional steel bracing and allows us to use established stock materials. Steel replacement arms and bracing for both 161 and 345 kV H-Frame structures are used to reduce construction and maintenance costs. Each assembly is rated for helicopter installation weight not to exceed 800 pounds per lift. This layout allows the use of smaller helicopters for both energized and normal maintenance change out work.

KCP&L is using solid dielectric cables at 161 kV for specific applications at power plants where limited space made conventional bus or overhead circuit installations impractical or impossible. The cable design is based on 230 kV cable specifications with insulation levels for 161 kV operation.

KCP&L currently uses optical ground wire (OPGW) for most or all of new shield wire installations. This gives not only superior lightning performance, due to the lower resistance of the OPGW compared to conventional galvanized steel strand shield wires, but also provides a high capacity path for internal communications and system protection functions. The standard OPGW options provide either 48 or 72 single mode fibers per shield wire.

3.1.3 AVOIDED TRANSMISSION COST ESTIMATE

3. Estimate of avoided transmission costs;22.045 Transmission and Distribution Analysis,

The KCP&L transmission projects included in the SPP regional planning processes for reliability improvement or economic benefits would not be impacted by the implementation of DSM programs. Therefore, the only avoided cost for transmission facilities are the transmission equipment additions associated with distribution facility expansions.

3.1.4 REGIONAL TRANSMISSION UPGRADE ESTIMATE

4. Estimate of the portion and amount of costs of proposed regional transmission upgrades that would be allocated to the utility, and if such costs may differ due to plans for the construction of facilities by an affiliate of the utility instead of the utility itself, then an estimate, by upgrade, of this cost difference;

Table 11 below shows the SPP projected annual transmission revenue requirement allocated to KCP&L for regional transmission upgrades.

Table 11: SPP Projected ATRR Allocated to KCP&L

YEAR	ANNUAL TRANSMISSION REVENUE REQUIREMENT ALLOCATED TO KCP&L
2012	$ 20,961,204
2013	$ 25,490,041
2014	$ 39,353,440
2015	$ 43,584,966
2016	$ 43,259,270
2017	$ 44,038,700
2018	$ 44,594,567
2019	$ 43,418,143
2020	$ 42,198,523
2021	$ 40,848,096
2022	$ 39,497,663

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

Separate filings with the Commission, apart from this IRP filing, are planned for later this year to further detail the benefits related to development of regional transmission projects through Transource.

3.1.5 REVENUE CREDITS ESTIMATE

5. Estimate of any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

Estimated Transmission Service revenue that KCP&L will receive is based on the amounts included in FERC account 456100.

Table 12 below shows historical and projected amounts for account 456100 for 2009-2022. The revenue credit process for future regional transmission upgrades has not been fully developed by SPP at this time and is not included in these projections.

Table 12: KCP&L Transmission Service Revenues from SPP

YEAR	TS REVENUE	BASIS
2009	$10,192,837	actual
2010	$12,350,369	actual
2011	$10,819,580	forecast
2012	$10,804,687	budget
2013	$10,804,687	budget
2014	$11,130,389	budget
2015	$11,130,389	budget
2016	$11,130,389	projected
2017	$11,130,389	projected
2018	$11,130,389	projected
2019	$11,130,389	projected
2020	$11,130,389	projected
2021	$11,130,389	projected
2022	$11,130,389	projected

3.1.6 TIMING OF NEEDED RESOURCES ESTIMATE

6. Estimate of the timing of needed transmission and distribution resources and any transmission resources being planned by the RTO primarily for economic reasons that may impact the alternative resource plans of the utility.

The SPP Balanced Portfolio of regional transmission projects included two projects in the KCP&L service territory. The Swissvale – Stilwell 345 kV tap at West Gardner and the Iatan – Nashua 345 kV line are primarily economic-based transmission projects. The expected in-service date for Swissvale – Stilwell 345 kV tap at West Gardner is 6/1/2012. The expected in-service date for Iatan – Nashua 345 kV is 6/1/2015. These projects were identified within the SPP transmission planning process to reduce transmission congestion and provide regional production costs and trade benefits. They will have minimal impact on KCP&L alternative resource plans.

3.2 USE OF RTO TRANSMISSION EXPANSION PLAN

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in subsection (3)(A) if all of the following conditions are satisfied:

See response to Section 3.1.1 above for description of SPP RTO transmission expansion planning processes.

3.2.1 UTILITY PARTICIPATION IN RTO TRANSMISSION PLAN

1. The utility actively participates in the development of the RTO transmission plan;

KCP&L actively participates in the development of SPP transmission expansion plans through a number of related activities. These include participation in the Model Development Working Group (MDWG), the Transmission Working Group (TWG), and regional transmission expansion workshops

Participation in the MDWG involves reviewing and updating the transmission planning models used for regional transmission expansion analysis. This includes adding KCP&L transmission projects into the planning models and providing a substation level load forecast for the seasonal and future years planning models. The expected generation dispatch required to meet KCP&L load requirements is also included in these models. These models form the basis for the reliability analysis needed to identify future transmission projects to maintain reliable service and reduce transmission congestion.

The Transmission Working Group (TWG) is responsible for planning criteria to evaluate transmission additions, seasonal Available Transfer Capability (ATC) calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations. The TWG works with individual transmission owners on issues of coordinated planning and North American Electric Reliability Corporation (NERC) and SPP compliance. The

TWG coordinates the calculation of the ATC for commerce maintaining regional reliability, while ensuring study procedures and criteria are updated to meet the regional needs of SPP, in cooperation with governing regulatory entities. The TWG is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. The TWG works closely with the Economic Studies Working Group (ESWG) to develop the scope documents used to direct the analysis and studies performed for the ITP process.

SPP hosts three to four ITP workshops annually to get stakeholder input to the transmission planning process and provide analysis results for stakeholder review. The workshops allow SPP stakeholders to provide input on assumptions for economic analysis and propose transmission projects to reduce congestion and improve reliability. KCP&L reviews transmission projects in its area and proposes alternatives that may provide better benefit or requests restudy for projects that it believes are not required. In other instances KCP&L was able to offer an operating guide to mitigate a transmission problem and avoid new transmission construction.

3.2.2 ANNUAL REVIEW OF RTO EXPANSION PLANS

2. The utility reviews the RTO transmission overall expansion plans each year to assess whether the RTO transmission expansion plans, in the judgment of the utility decision makers, are in the interests of the utility's Missouri customers;

KCP&L reviews transmission projects in its area and proposes alternatives that may provide better benefit or requests restudy for projects that it believes are not required. In other instances KCP&L is able to offer an operating guide to mitigate a transmission problem and avoid or delay new transmission construction.

3.2.3 ANNUAL REVIEW OF SERVICE TERRITORY EXPANSION PLAN

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO

transmission expansion plans pertaining to projects that are partially- or fully-driven by economic considerations (i.e., projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

KCP&L reviews transmission plans and projects within its service territory that develop through the SPP RTO transmission expansion plan. Many are zonal projects providing additional obligations to serve or meet specific planning and bulk electric reliability criteria.

For region-wide project sets such as the SPP Balanced Portfolio, projects meet a wide range of needs including reduced production costs, reduced congestion, reduced system losses and base reliability needs. For example, in the case of the Iatan-Nashua 345kV project in KCP&L's territory, it is a project that will significantly reduce congestion of a major regional flowgate near the Kansas City-north area and directly relieves growing limitations on the ability to dispatch KCP&L's new Iatan 2 generating unit. The Iatan – Nashua project also provides approximately 8 Mw of loss reduction for the KCP&L and GMO transmission system at peak load conditions. Iatan – Nashua also eliminates two flowgates; one on the KCP&L – Westar boundary and one on the GMO – KCP&L boundary.

3.2.4 DOCUMENTATION AND DESCRIPTION OF ANNUAL REVIEW OF RTO OVERALL AND UTILITY-SPECIFIC EXPANSION PLANS

4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans; and

KCP&L reviews transmission projects in its area and proposes alternatives that may provide better benefit or requests restudy for projects that it believes are not required. KCP&L planning personnel participate throughout the year within the planning process providing insight and review of the transmission plans. In some instances KCP&L may be able to offer an operating guide to mitigate a transmission problem and avoid or delay new transmission construction. Also, KCP&L personnel participate in the overall approval of RTO expansion plans through the SPP approval process within the Markets and Operation Policy Committee and Members Committee.

3.2.5 <u>AFFILIATE BUILD TRANSMISSION PROJECT DISCUSSION</u>

5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially- or fully-driven by economic considerations, then the utility shall explain why such affiliate built transmission is in the best interest of the utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate-built transmission is in the interest of the utility's Missouri customers.

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

Separate filings with the Commission, apart from this IRP filing, are planned for later this year to further detail the benefits related to development of regional transmission projects through Transource.

3.3 RTO EXPANSION PLAN INFORMATION

(C) The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

The following SPP regional transmission planning reports are provided as attachments to this report.

2009 Balanced Portfolio - Final Approved Report.pdf (Appendix 4.5 - 3.3A)

Priority Projects Phase II Final Report - 4-27-10.pdf (Appendix 4.5 - 3.3B)

ITP20_Report_01-26-11.pdf (Appendix 4.5 - 3.3C)

20120131 2012 ITP10 Report.pdf (Appendix 4.5 - 3.3D)

2012 ITPNT Report_Board Approved.pdf (Appendix 4.5 - 3.3E)

2012 STEP Report.pdf (Appendix 4.5 - 3.3F)

The Balanced Portfolio and Priority Projects reports are described in Section 1.3 above. The ITP20, ITP10, ITPNT reports are the first cycle of SPP's new Integrated Transmission Planning process as described in Section 3.1.1 above. The 2012 SPP Transmission Expansion Plan (STEP) summarizes 2011 activities that impact future development of the SPP transmission grid. Seven distinct areas of transmission planning are discussed in this report, each of which are critical to meeting mandates of either the 2011 SPP Strategic Plan or the nine planning principles in FERC Order 890. These areas are Integrated Transmission Planning, Tariff Studies, Sub-regional and Local Area Planning, Transmission Congestion and Top Flowgates, Interregional Coordination, Project Tracking, and Public Policy Impacts.

3.4 TRANSMISSION UPGRADES REPORT

(D) The utility shall provide a report for consideration in 4 CSR 240-22.040(3) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

3.4.1 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION WITHIN RTO

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint; 22.045 (3) (D) 1.

It is not possible to provide a specific list of transmission upgrades needed to physically interconnect a generation resource within the SPP footprint. Any generation interconnection request within the SPP must proceed through the generation interconnection process as defined by the SPP transmission tariff. That process will examine the specific location proposed for generator interconnection and develop the necessary transmission upgrades needed at that location.

Generally speaking, generator interconnections for green field sites will require a three breaker ring bus substation for interconnection to the existing transmission system. Estimated costs for the interconnecting substation are in the range of $8-10 million at 345kV and $3-5 million at 161kV. Costs for interconnection of new generation resources at existing substations are generally significantly less due to the availability of existing substation infrastructure.

3.4.2 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT WITHIN RTO

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including requirements for firm transmission service from the point of delivery to the utility's load and requirements for financial transmission rights from a point of delivery within the RTO to the utility's load;

In the SPP, requests for firm transmission service are processed through the Aggregate Facility Study (AFS) process. The AFS process is performed three times per year by collectively analyzing specific transmission service requests, including those associated with generation interconnection requests, across the entire SPP footprint. These service reservations are modeled based on control area to control area transfers. The transmission system is assessed with these potential service requests and, where needed, transmission improvements are identified that would enable the service to occur without standard or criteria violations. All transmission customers are allocated cost responsibility for portions of the various upgrades needed to deliver all of the transmission service requests. Transmission customers may decline to pay their portion of the allocated cost and drop out of the study process. Study analysis is repeated on the reduced set of transmission service requests. This is an iterative process until a final set of transmission service requests for those customers remaining in the process has been reached. The remaining transmission customers with service requests in the process agree to the projects needed to deliver the remaining transmission service and share the resulting upgrade costs. Those remaining upgrade projects are included in the next SPP transmission expansion plan process.

Because of the iterative nature of the Aggregate Facility Study process it is not possible to identify specific transmission upgrades needed to deliver energy from a resource in the RTO footprint to KCP&L until the process for a specific transmission service request has been completed.

3.4.3 TRANSMISSION UPGRADES REPORT – PHYSICAL INTERCONNECTION OUTSIDE RTO

3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;

It is not possible to develop a list of specific upgrades needed to interconnect a generation resource located outside the SPP without actually making a generation interconnection request at a specific location.

3.4.4 TRANSMISSION UPGRADES REPORT – DELIVERABILITY ENHANCEMENT OUTSIDE RTO

4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including requirements for firm transmission service to a point of delivery within the RTO footprint and requirements for financial transmission rights to a point of delivery within the RTO footprint;

It is not possible to develop a list of specific upgrades needed to deliver capacity and energy from a generation resource located outside the SPP without actually making a generation interconnection request and an associated transmission service request at a specific location.

3.4.5 TRANSMISSION UPGRADES REPORT – ESTIMATE OF TOTAL COST

5. The estimated total cost of each transmission upgrade; and

A list of KCP&L transmission projects included in the 2012 SPP Transmission Expansion Plan (STEP) is shown below in Table 13.

Table 13: KCP&L Transmission Upgrades 2012 SPP STEP

TRANSMISSION PROJECT	COST ESTIMATE	TYPE	DATE
West Gardner 345kV bus cut-in to Swissvale-Stillwell 345 kV line	$2,171,096	Balanced Portfolio	06/01/12
Loma Vista East limit is 600/5 CT ratio; reset to 1200/5	$190,860	ITP	06/01/12
Must upgrade Stilwell terminal equipment to 2000 amps	$150,000	transmission service	06/01/12
Rebuild 4.2 mile Olathe - Switzer 161kV line.	$2,963,000	zonal - sponsored	06/01/13
Rebuild 3 mile Overland Park - Merriam 161kV line.	$1,518,750	zonal - sponsored	12/31/14
New Cedar Niles-Clare 161 kV Line & Clare substation	$3,756,500	zonal - sponsored	06/01/15
Tap Hawthorn - St. Joseph 345 kV at Nashua. New 345 kV line Iatan to Nashua.	$49,824,000	Balanced Portfolio	06/01/15
Install new 345/161 kV transformer at Nashua	$4,620,000	Balanced Portfolio	06/01/15
New Waldron 161 kV sub cut-in	$1,632,300	zonal - sponsored	06/01/16
Build new 71 mile 345kV line Iatan-Jeffery Energy Center & associated equip	$79,875,000	ITP	01/01/30

Total estimated construction cost for these transmission upgrades is $146,701,506.

3.4.6 TRANSMISSION UPGRADES REPORT – COST ESTIMATES

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

A list of KCP&L transmission projects included in the 2012 SPP STEP and the portion of their estimated cost allocated to KCP&L is shown below in Table 14.

Table 14: Transmission Upgrade Cost Allocated to KCP&L

TRANSMISSION PROJECT	COST ESTIMATE	% ALLOCATED TO KCP&L	KCP&L $
West Gardner 345kV bus cut-in to Swissvale-Stillwell 345 kV line	$2,171,096	TBD	TBD
Loma Vista East limit is 600/5 CT ratio; reset to 1200/5	$190,860	66.7	$127,304
Must upgrade Stilwell terminal equipment to 2000 amps	$150,000	0	$0
Rebuild 4.2 mile Olathe - Switzer 161kV line.	$2,963,000	100	$2,963,000
Rebuild 3 mile Overland Park - Merriam 161kV line.	$1,518,750	100	$1,518,750
New Cedar Niles-Clare 161 kV Line & Clare substation	$3,756,500	100	$3,756,500
Tap Hawthorn - St. Joseph 345 kV at Nashua. New 345 kV line Iatan to Nashua.	$49,824,000	TBD	TBD
Install new 345/161 kV transformer at Nashua	$4,620,000	TBD	TBD
New Waldron 161 kV sub cut-in	$1,632,300	100	$1,632,300
Build new 71 mile 345kV line Iatan-Jeffery Energy Center & associated equip	$79,875,000	8.3	$6,629,625

The cost allocation between SPP members for Balanced Portfolio projects has not been determined at this time. A primary feature of the Balanced Portfolio cost allocation is to provide all SPP members a benefit/cost ratio of at least 1.0 and thus there will be revenue transfers in order to keep members at or above that threshold.

SECTION 4: ADVANCED TECHNOLOGY ANALYSIS

(4) Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies.

4.1 TRANSMISSION UPGRADES FOR ADVANCED TRANSMISSION TECHNOLOGIES

(A) The utility shall develop, and describe and document, plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in paragraphs (3)(B)1. Through (3)(B)3. are satisfied.

KCP&L will use advanced technologies such as Hybrid Structure Design, Solid Dielectric Cables, and Fiber Optic Shield Wire where applicable in transmission upgrades included in the SPP regional transmission expansion plan.

4.2 DISTRIBUTION UPGRADES FOR ADVANCED DISTRIBUTION TECHNOLOGIES

(B) The utility shall develop, and describe and document, plans for distribution network upgrades as necessary to optimize its investment in advanced distribution technologies.

KCP&L has not established a program to invest in distribution network upgrades to optimize it's investments in advanced distribution technologies. Instead, KCP&L deploys advanced distribution technologies selectively to the network where they are the most economical alternative to maintain the desired level of operational performance, reliability, and power quality.

The previous discussion, in Section 1.4 of this document, discusses how KCP&L plans distribution network upgrades, many of which incorporate the deployment of the previously established advanced grid technologies described in Section 4.6.2.2.

4.3 OPTIMIZATION OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of—

4.3.1 OPTIMIZATION OF INVESTMENT – TOTAL COSTS AND BENEFITS

1. ***Total costs and benefits, including:***

4.3.1.1 Distribution Analysis

KCP&L has not yet performed a comprehensive analysis to optimize investments in advanced distribution technologies pursuant to 4 CSR 240-22.045(4)(C).

As described in Section 4.6.2.2, KCP&L developed a DRAFT SmartGrid Vision, Architecture, and Road Map discussion document in 2008 as a potential guide to future KCP&L investments in advanced distribution technologies. The document produced was a technology road map focused on the deployment of the advanced distribution technologies needed to implement the SmartGrid functions as described in Title XIII of the Energy Independence and Security Act of 2007 (EISA).

With the passage of the American Recovery and Reinvestment Act of 2009 (ARRA) in February 2009, it became apparent that the SmartGrid deployments outlined in the draft road map may be too aggressive and possibly limiting from a technical point of view. The architecture, on which the plan was developed, was based on prior EPRI Intelligrid research. It was unclear, to what extent, the NIST SmartGrid Interoperability Framework initiative funded by ARRA may change our future SmartGrid architecture design and technology selections.

With technology architecture uncertainties and overly aggressive schedule of the ARRA funded SmartGrid Investment Grants (3 years), KCP&L management decided to focus on pursuing a DOE SmartGrid Demonstration Grant. The scope of the SmartGrid Demonstration Project proposed by KCP&L and selected by the DOE for a 50% matching grant is further described in Appendix 4.5.D, "KCP&L SmartGrid Vision, Architecture, & Road Map". KCP&L is using our SmartGrid Demonstration project to:

- Define, implement & test a number of advanced distribution technologies and a Smart Grid system architecture based on the evolving NIST Smart Grid Interoperability Framework and Standards.
- Define and document the requirements of the various SmartGrid function, technologies, and systems for potential future deployment company wide.
- Test, measure, analyze, and document the benefits of the various SmartGrid functions, technologies, systems, and grid operating practices.

Upon completion of the SmartGrid Demonstration Project KCP&L plans to use the finding of the project to develop a well founded SmartGrid Vision, Architecture, and Road Map that will provide framework for evaluating the feasibility of and guiding the implementation of advanced distribution grid technologies and become an integral component of future IRP filings.

In developing these filings, KCP&L will perform a comprehensive analysis to optimize investments in advanced distribution that incorporates the following analyses.

- Total costs and benefits, including:
- Costs of the advanced grid investments;

- Costs of the non-advanced grid investments;
- Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and
- Reduced supply-side production costs;
- Cost effectiveness, including:
- The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;
- The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and
- Additional non-monetary factors considered by the utility;
- Societal benefit, including:
- More consumer power choices;
- Improved utilization of existing resources;
- Opportunity to reduce cost in response to price signals;
- Opportunity to reduce environmental impact in response to environmental signals;
- Any other factors identified by the utility; and
- Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240- 22.080(5).

4.3.2 OPTIMIZATION OF INVESTMENT – COST OF ADVANCED GRID INVESTMENTS

A. Costs of the advanced grid investments;

4.3.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.3 OPTIMIZATION OF INVESTMENT – COST OF NON-ADVANCED GRID INVESTMENTS

B. Costs of the non-advanced grid investments;

4.3.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.4 OPTIMIZATION OF INVESTMENT – REDUCTION OF RESOURCE COSTS

C. Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and

4.3.4.1 Distribution

Refer to comments in Section 4.3.1.1

4.3.5 OPTIMIZATION OF INVESTMENT – REDUCTION OF SUPPLY-SIDE COSTS

D. Reduced supply-side production costs;

4.3.5.1 Distribution

Refer to comments in Section 4.3.1.1

4.4 COST EFFECTIVENESS OF INVESTMENT IN ADVANCED TRANSMISSION AND DISTRIBUTION TECHNOLOGIES

2. Cost effectiveness, including

4.4.1 COST EFFECTIVENESS – INCREMENTAL COSTS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

A. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.2 COST EFFECTIVENESS – INCREMENTAL BENEFITS ADVANCED GRID TECHNOLOGIES VS NON-ADVANCED GRID TECHNOLOGIES

B. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and

4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.3 OPTIMIZATION OF INVESTMENT – NON-MONETARY FACTORS

C. Additional non-monetary factors considered by the utility;

4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4 OPTIMIZATION OF INVESTMENT – SOCIETAL BENEFIT

3. Societal benefit, including:

4.4.4.1 Societal Benefit – Consumer Choice

A. More consumer power choices;

4.4.4.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.2 Societal Benefit – Existing Resource Improvement

B. Improved utilization of existing resources;

4.4.4.2.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.3 Societal Benefit – Price Signal Cost Reduction

C. Opportunity to reduce cost in response to price signals;

4.4.4.3.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.4.4 Societal Benefit –

D. Opportunity to reduce environmental impact in response to environmental signals; Environmental Impact

4.4.4.4.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.5 OPTIMIZATION OF INVESTMENT – OTHER UTILITY-IDENTIFIED FACTORS

4. Any other factors identified by the utility; and

4.4.5.1.1 Distribution

Refer to comments in Section 4.3.1.1

4.4.6 <u>OPTIMIZATION OF INVESTMENT –OTHER NON-UTILITY IDENTIFIED FACTORS</u>

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240-22.080(5).

4.4.6.1.1 <u>Distribution</u>

Refer to comments in Section 4.3.1.1

4.5 <u>NON-ADVANCED TRANSMISSION AND DISTRIBUTION INCLUSION</u>

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing, the utility shall—

4.5.1 <u>NON-ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED ANALYSIS</u>

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. The utility may rely on a generic analysis as long as it verifies its applicability; and

4.5.1.1 <u>Distribution</u>

KCP&L is not proposing any new non-advanced distribution grid technologies or programs in this triennial IRP compliance filing.

KCP&L understands that prior to including new non-advanced distribution grid technologies in future IRP filings, KCP&L will conduct, describe, and document an analysis which demonstrates that investment in each non-advanced distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. KCP&L further understands that we may present a generic analysis as long as we verify its applicability;

4.5.2 NON-ADVANCED TRANSMISSION AND DISTRIBUTION ANALYSIS DOCUMENTATION

2. Describe and document the analysis.

4.5.2.1 Distribution

Refer to comments in Section 4.5.1.1

4.6 ADVANCED TRANSMISSION AND DISTRIBUTION REQUIRED COST-BENEFIT ANALYSIS

(E) The utility shall develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:

4.6.1.1 Distribution

KCP&L is not proposing any new advanced distribution grid technologies or programs in this triennial IRP compliance filing.

KCP&L understands that prior to including new advanced distribution grid technology in future IRP filings, KCP&L will develop, describe, and document the cost benefit analysis for implementation of the advanced grid technology.

As stated earlier in Section 4.3.1.2, upon completion of the SmartGrid Demonstration Project KCP&L plans to use the finding of the project to develop a well founded SmartGrid Vision, Architecture, and Road Map that will provide framework for evaluating the feasibility of and guiding the implementation of advanced distribution grid technologies.

In developing the SmartGrid Road Map, KCP&L will use the build and Impact metrics from our project and other DOE and EPRI SmartGrid demonstration projects to perform a cost/benefit analysis of each of the advanced distribution grid technologies considered for the road map.

4.6.2 ADVANCED GRID TECHNOLOGIES UTILITY'S EFFORTS DESCRIPTION

1. A description of the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

4.6.2.1 Distribution

Historical Advanced Grid Technology Deployments

The distribution grid in place at KCP&L today is substantially "smart" having benefited from decades of power engineering expertise. The existing systems already execute a variety of sophisticated system operations and protection functions. In addition it should be noted that what is now termed "smart grid" has been under development by the KCP&L and the industry for many years. Much of the automation has been accomplished through incremental applications of technology. The following sections describe many of the advanced distribution technologies that have and are currently being implemented at KCP&L. The previous response to section 22.045 (1)(D) describe how KCP&L applies these previously adopted advanced grid technologies to improve the operation of the distribution network.

DA – A 1993-1999 Strategic Initiative

In 1993, Kansas City Power & Light Company (KCP&L) management established an internal, interdivisional, multi-disciplined team to develop definitions, economic evaluations, recommendation plans for Distribution Automation (DA) at KCP&L. The team's purpose was to determine the feasibility of consolidating numerous existing, but independent, automation efforts that were undergoing evaluation throughout the company. Consequently, KCP&L management consolidated multiple DA efforts into one project and between 1995 and 1999 the following components of the DA vision were implemented.

- **AMR -** Automated Meter Reading**.** KCP&L implemented the first utility wide 1-way AMR system in the industry automating over 90% of all customer meters..
- **ACD/VRU** – Automatic Call Director with Voice Response Unit. Provides improved call handling capability for the Call Center and will provide a direct transfer of Outage Calls to the Outage Management System (OMS)
- **DFMS-AMFM/GIS** – Automated Mapping/Facilities Management/ Geographic Information System. Provides the functionality to support the mapping, record keeping and operation of the electrical system via a fully connected and geographically related model. KCP&L entered into data sharing agreements with 7 city and county entities to obtain the most accurate land base information available on which it's hard copy facility maps were digitized
- **DFMS-WMS –** Work Management System. Provides for automated job planning and management of resources.
- **DFMS-EAS –** Engineering Analysis System. Provides the functionality for analysis of the distribution systems electrical performance and plans for the necessary construction and maintenance of the system***.***
- **DFMS-TRS** Trouble Reporting System. Provides functionality to support the day-to-day trouble call tracking, outage analysis, and service restoration of the electrical distribution system. This system is now referred to as the OMS (Outage Management System).
- **DFMS-LDA -** Line Device Automation. Device Automation was initially limited to Capacitor Automation. Over 600 line capacitors have been automated and routinely maintain the urban circuits at nearly unity power factor.

Leveraging the DA Investment

Having successfully implemented the systems initiated by the DA Initiative, KCP&L identified, cost justified, and implemented a series of projects that leveraged the system implementations establishing greater process integration, operational savings and improved operational performance for customers. Many of these projects included first of its kind technology deployments within the utility industry.

- **AMFM/GIS Upgrade**. KCP&L became the first utility to port our vendors AMFM/GIS system from their production legacy CAD-RDBMS platform to a fully RDBMS platform.
- **AMFM/GIS to WMS Integration.** - Integration automated the population of GIS attributes based on the WMS compatible units. This functionality established the foundation for an eventual integrated graphic design function.
- **WMS Expanded to Maintenance Work. -** Use of the WMS was expanded from design-construction jobs to high volume maintenance and construction service orders, automating and streamlining those processes.
- **Account Link WEB portal integrated AMR and CIS –** The AccountLink customer web portal was established and daily AMR read information was made available to customers
- **AMR integrated with OMS**. AMR outage (last gasp) alerts and AMR meter ‘pings’ were implemented to improve outage and trouble response.
- **ORS dashboard integrated with OMS. -** Implemented the Outage Records System, an OMS data mining and management dashboard provides real time summary and overview of outage statistics. This system provides the real-time “Outage Watch” map on the KCP&L web page, www.kcpl.com.
- **MWFM Integrated with AMFM/GIS, OMS, and CIS** - Implemented the Mobile Work Force Management system which automated the field processing of Trouble, Outage, and CIS Meter Service Orders.

Comprehensive Energy Plan – 2004-2009

An element of the KCP&L plan involved infrastructure improvements to strengthen the overall reliability of our system and network. Our plan included the following programs involving distribution facilities to incorporate new advanced technologies for faster diagnosis and repair of service interruptions.

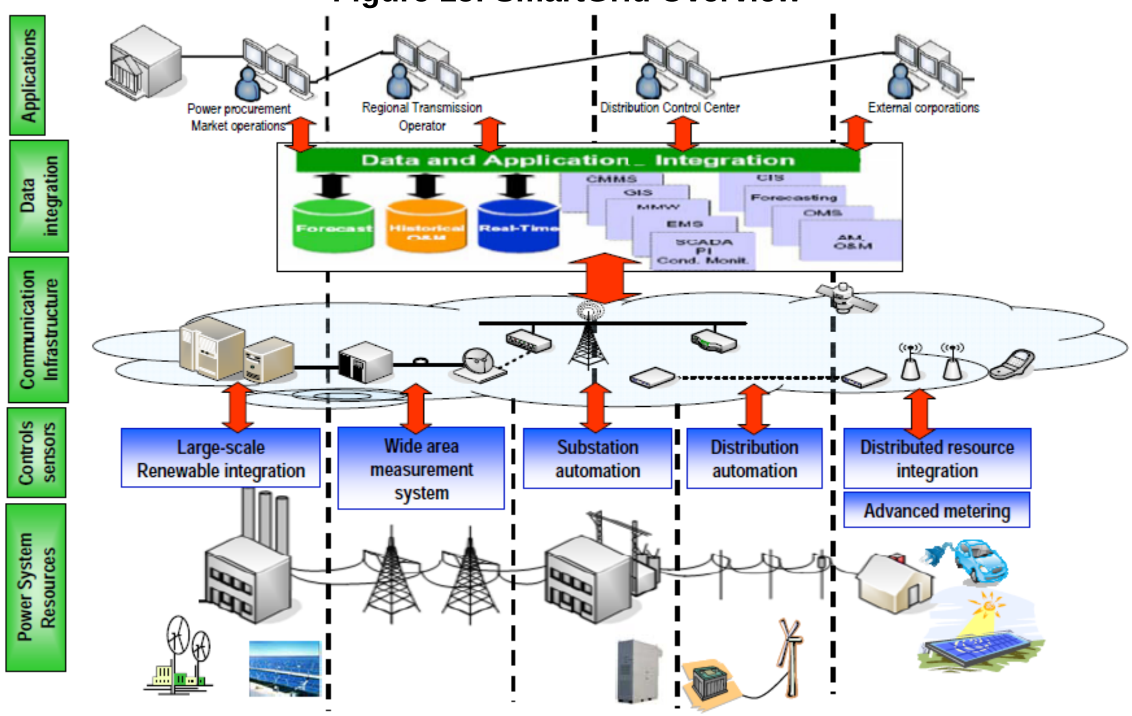
- **Distribution System Inventory Verification Program.** This program involves conducting a full overhead distribution system field inventory to verify and augment existing distribution asset information at the component level. The program for the combined KCPL & KCP&L GMO service territories was completed in 2011.
- **Network Automation.** The Network Automation Project involves monitoring of KCP&L's underground (UG) secondary networks. Automation of the network alerts engineers, dispatchers, and the underground workers to abnormal situations that can potentially cascade into larger problems if left unchecked.
- **"Integrated Circuit of the Future".** The "Integrated Circuit of the Future" project involved the field installation and testing of various distribution automation technologies to evaluate the feasibility of larger scale deployment on the KCP&L's distribution grid.
- **50 C.O. Relay Automation.** The 50 C.O. Automation Project involves remote enabling or disabling of the distribution feeder over-current relays in substations. The ability to turn the relays off under fair weather conditions result in a forty to fifty percent reduction in momentary outages–greatly improving reliability and customer quality-of-service. When turned on during storms, this system allows reclosing to save fuses and reduce outages.
- **Dynamic Voltage Control (DVC).** The program allows operators to reduce the substation voltage a predetermined amount for demand reduction (DR). As a result of successful testing of the DVC system on the Integrated Circuit of the Future, KCP&L accelerated implementation of the DVC system to all 203 metro Kansas City substation buses resulting in an estimated 60MW of peak demand reduction.
- **34-kV Switching Device Automation and Fault Indication.** Project involves installation of automated switching devices and fault indicators.

KCP&L's "SmartGrid Initiative"

The term "Smart Grid" represents a long-term vision for the electric grid, constructed with advanced transmission and distribution technologies, that is highly automated with a tremendous amount of self-operations; distributed generation, and direct customer management of their electrical consumption.

Since 2001, EPRI has managed a collaborative research, development, and demonstration (RD&D) process that has accelerated the industry's migration towards the concept of the Smart Grid. KCP&L has been an active funder and participant in this RD&D effort.

Figure 15: SmartGrid Overview



The illustration above was developed by EPRI to depict the high level of IT applications and communications integration with the grid that will be required to create the envisioned SmartGrid and create the delivery system of the future. In December 2007, Congress passed and the President approved, Title XIII of the Energy Independence and Security

Act of 2007 (EISA). EISA defines the characteristics and functions of the Smart Grid and provided the legislative support for DOE's smart grid activities and reinforced its role in leading and coordinating national grid modernization efforts.

In 2007 KCP&L management established an internal Smart Grid Department to develop strategies and plans to implement Smart Grid concepts and technologies within KCP&L to transform legacy electric grid into a electric grid of the future or "Smart Grid". While developing the Smart Grid will include many incremental enhancements to the existing KCP&L electric power infrastructure, these changes need to occur at a faster pace, be more tightly integrated, and be accompanied by the implementation of transformational technologies.

To meet these requirements, KCP&L desired to shift gears and explore fully integrating dispersed systems including visions of dynamic new customer systems applications, improved system automation and control as well as the potential accommodation of significantly more renewable resources. To that end, the Smart Grid Department staff began developing a SmartGrid Vision, Architecture and Road Map document.

Most utilities are developing a similar vision for an ultimate Smart Grid but will take different paths and time-lines in their respective Smart Grid deployments. These paths will be influenced by regulatory and business drivers and the mix of technologies that a company has currently installed.

The KCP&L SmartGrid Department leveraged EPRI's extensive work in developing a smart grid vision and architecture in developing those sections of the DRAFT SmartGrid Vision, Architecture and Road Map.

Developing the Road Map

In developing this SmartGrid Roadmap, the SmartGrid staff studied several SmartGrid pilot projects and their respective road map documents.

Many of these are focused on AMI and selling SmartGrid as a means of empowering consumers to lower their usage and correspondingly their utility bills. While this may ultimately be the case, with KCP&L's historically low rates, we did not believe our customer are ready to embrace these load shifting initiatives on a large scale. KCP&L's customers continue to be more focused on cost, reliability and quality of service issues.

The benefits of the SmartGrid are multifaceted and interdependent and the costs to implement it will be considerable. It is important that we 'get it right' and maximize the benefits we obtain as we make the grid smarter and add functions and capabilities. From a regulatory perspective it is also important that the costs associated with the technology rollout be borne by those consumers who receive the benefits. In our analysis, we have concluded that we should not focus immediately on the end-user interactions; rather we should begin on the operational side first. If we focus on the distribution grid operations and AMI, we can streamline operations, thus reducing costs, and gain more control of the grid, thus increasing reliability.

<u>Road Map Principles</u>

The SmartGrid Department developed the following principles to guide the development of the SmartGrid Road Map

- Support strategic and short-term business drivers.
- There is no SmartGrid silver bullet technology. SmartGrid projects should implement technology that comply with the defined architecture and provide the greatest operational benefits.
- Leverage the Federal Smart Grid demonstration project and investment grant funding authorized by the Energy Independence and Security Act of 2007 (EISA)..
- 10 year time-line (2009-2018) to deploy existing and emerging SmartGrid technologies

- In 2020 the SmartGrid infrastructure should be able to support advanced grid technologies and potential customer programs deployed across the grid.
- Initial priority should be on projects that that deploy SmartGrid enabling technologies and leverage existing AMR and DA competencies. AMI is considered an enabling technology.
- Consumer facing programs should be preceded with a consumer education program and a well structured pilot of the technology to evaluate consumer participation and benefits.
- The Road Map should be reviewed periodically as business drivers change; revisions made to the Architecture; or new capabilities or opportunities emerge in the industry.

<u>The DRAFT SmartGrid Road Map</u>

Focusing on SmartGrid infrastructure technologies and components that would provide near term utility operational benefits while leveraging the potential EISA established potential funding; the SmartGrid staff developed an initial draft road map with the following components, for discussion purposes, as a plan for implementing the vision and functionality of KCP&L's SmartGrid.

- EISA Demonstration Grant Projects
  - KC SmartGrid Pilot
  - Battery Pilot
- EISA Investment Grant Projects
  - WAN – Extend to GMO & KCPL District Subs
  - AMI – GMO Districts
  - DA - GMO & KCPL Districts Subs
  - D-SCADA - GMO & KCPL District Subs
  - DMS - GMO & KCPL Districts
- KCPL Metro AMR & Grid Control Upgrades
  - WAN – Extend WAN to all L Metro Subs
  - AMI – KCP&L AMI upgrade
  - DA – moved to DMS/D-SCADA
  - D-SCADA – DA moved from T-SCADA
  - OMS - moved to DMS
- Extend DA Field Mon & Control to field devices

- Expand AMI Operations to Rural Meters
- TMS/T-SCADA incorporate PMU
- Consumer Home Automation
- DR & DER Integration
  - Solar Rebates
  - DMS DR & DER Mgt
  - Retail Rate Designs

At this point in time the Draft SmartGrid Road Map was only a technology road map put forward to management for discussion and evaluation purposes. Cost benefit of individual or groups of plan elements had not been performed. Before proceeding with any individual plan element one of the following analysis would have to be positive.

1) Individual element benefit/cost analysis
2) element group benefit/cost analysis, or
3) a determination by management that the element was strategic to the overall SmartGrid vision.

American Recovery and Reinvestment Act of 2009

In February 2009, Congress passed, and the President approved, American Recovery and Reinvestment Act of 2009 (ARRA). ARRA provided, among other recoverey act funding, the appropriations required the DOE and NIST to implement their legslative mandate established by Title 13 of EISA.

- NIST - $20 Million to fund Smart Grid Interoperability Framework.Initiative
- DOE - $3.4 billion to fund SmartGrid Investment grants
- DOE - $600 million to fund Smart Grid Demonstration Grants

As 2009 progressed, it became apparent that the SmartGrid deployments outlined in the draft road map may be too aggressive and possibly imprudent from a technical point of view. The architecture on which the plan was based revolved around the prior EPRI Intelligrid research. It was unclear how much the NIST Interoperability Framework initiative may change our defined architecture and technology selection.

The DOE also issued the funding opportunity announcements for the demonstration and the initial round of investment grants on parallel schedules. The SmartGrid department was not staffed to develop two applications simultaneously. With technology architecture uncertainties and the resource limitations, KCP&L management decided to focus on pursuing a demonstration grant. The KCP&L's SmartGrid Demonstration Project Application – Project Narrative is included as Appendix 4.5.E. The KCP&L project was selected in late 2009 and a contract with the DOE was subsequently awarded in August 2010. KCP&L will use this demonstration grant opportunity to:

- Define, implement & test a number of SmartGrid technologies and a systems architecture based on the evolving NIST Interoperability Framework.
- Define and document the requirements of the various SmartGrid technologies and systems for potential future deployment company wide.
- Measure and document the benefits of the various SmartGrid technologies, systems, and grid operating practices.

KCP&L plans to use the finding of the SmartGrid demonstration project to develop a well founded SmartGrid Vision, Architecture, and Road Map that will provide framework for evaluating the feasibility of and guiding the implementation of advanced distribution grid technologies and become an integral component of future IRP processes.

KCP&L SmartGrid Demonstration Project

For the SmartGrid Demonstration, KCP&L and our project partners will deploy an end-to-end SmartGrid that will include renewable generation, storage resources, leading edge substation and advanced distribution automation and control, interoperable energy management interfaces, and innovative customer programs. The project will include detailed analysis and testing to demonstrate the benefits of optimizing energy and information flows and utility operations across supply and demand resources, T&D operations, and customer end-use programs.

Distribution Grid Management Infrastructure

The project will deploy a next generation end-to-end (or top-to-bottom) distribution grid management infrastructure. The grid management systems integration will be based on distributed-hierarchical control concepts, an emerging technology, and will include:

- DERM - DR/DER Management System (centralized, back office)
- DMS - Distribution Management System (centralized, back office) includes:
    - D-SCADA – Distribution SCADA
    - DNA – Dynamic Network Analysis
    - OMS – Outage Management
- AMI Head End (centralized, back office)
- MDM-Meter Data Management System (centralized, back office)
- DCADA-Distributed Control and Data Acquisition (distributed substation controller)

SmartSubstation

The primary objective of the SmartSubstation project component is to develop and demonstrate a fully automated; next-generation distribution SmartSubstation with a local distributed control system based on IEC 61850 protocols. The new SmartSubstation will enable the following benefits that will be quantified throughout the demonstration period.

- Improved real-time operating data on critical substation equipment
- Reduced O&M costs of relay maintenance, and

- Improved reliability by enabling distribution automation

In achieving these objectives, we expect to demonstrate Advanced Distribution Automation (ADA) capabilities such as the ability to monitor and capture real-time transformer temperature and gas data; the enablement of real-time equipment ratings; full substation automation with intelligent bus throw-over; and all the benefits of intelligent electronic relays such as peer-to-peer communication, fault recording, fault location, circuit breaker monitoring and increased ease

SmartDistribution

The primary objective of the SmartDistribution project component is to develop and demonstrate a fully automated, next generation Distributed Control and Data Acquisition (DCADA) controller that incorporates a Common Information Management (CIM) based model of the local distribution network and performs local grid assessment and control of individual intelligent electronic device (IED) field controls. The DMS and Smart-Substation^{TM} Controllers will provide the operational backbone of the system supporting significant levels of automation on the feeders, complex and automated feeder reconfiguration decisions, and tightly integrated supervision with the Control Centers.

The new SmartDistribution implementation will enable the following benefits that will be quantified throughout the demonstration period:

- Improved service reliability by reducing the frequency and duration of sustained outages.
- Reduced frequency of momentary outages.
- Reduced operational expenses as many functions will occur automatically without human intervention or be performed remotely without a field crew.
- Reduced maintenance expenses by providing rich data to enable predictive and proactive maintenance strategies

In achieving the above objectives, we expect to demonstrate a family of automatic, distributed “First Responder” distribution grid monitoring and control functions:

- Circuit outage and faulted section identification and isolation switching
- Feeder Integrated Volt/VAR Management
- Feeder Overload Management w/Dynamic Voltage Control (DVC & CVR)
- Distributed DER monitoring & management
- Sub and Feeder Overload Management w/ DER
- Feeder Overload Management with Ambient & Duct Temperature
- Feeder Optimized (economic) Configuration
- Digital Fault Recording on Breaker Relays

SmartDR/DER Management

The primary objective of the Smart DR/DERM project component is to develop and demonstrate a next-generation, end-to-end DERM system that provides balancing of renewable and variable energy sources with controllable demand as it becomes integrated in the utility grid, coordination with market systems, and provision of pricing signals. We expect to demonstrate a number of capabilities including:

- The ability to manage and control diverse types of Distributed Energy Resources (e.g. DVC, DG, bulk and mobile storage).
- The ability to manage and control various DR programs including dispatchable / direct load control programs.
- The ability to manage price-based and voluntary programs with market-based and dynamic tariffs similar to those described under SmartEnd-Use.

- The ability to manage various market and transmission operation support products such as mapping DR/DER capabilities to wholesale energy products and managing energy and ancillary services capacity

- The interoperability with the DMS to monitor distribution grid conditions and manage distribution grid congestion.

- The ability to track and manage renewable portfolio standards (RPS) and greenhouse gas (GHG) reduction capabilities of distributed and demand side resources.

In achieving these objectives, KCP&L expects to demonstrate advanced capabilities in demand side resource management, including the ability to leverage those capabilities for operational and environmental efficiencies as well as the ability to aggregate and use such capabilities in support of wholesale market operations.

SmartGeneration

KCP&L's primary objective in its SmartGeneration project component is the implementation of DER technologies and DR programs sufficient in quantity and diversity to support the DERM development and demonstration. To achieve this objective, the demonstration program will include:

- Installation of a variety of roof-top solar system on a mix of residential and commercial buildings. A larger scale, 100kw, installation is planned for a school or public building.

- Installation of a 1MW grid-connected battery to provide grid support.

- Integration of the existing EnergyOptimizer DR thermostat program in the demonstration area

- Integrate the existing MPower load curtailment program customers in the demonstration area

- Implement public accessible plug-in hybrid electric vehicle (PHEV) charging stations to demonstrate and smart charging strategies.

In addition to the primary objective, KCP&L expects to demonstrate the ability to offset fossil-based generation with renewable sources as well as the potential for flexible, alternative business ownership models. In achieving these objectives, KCP&L further expects to analyze the cost effectiveness of distributed roof-top solar and distributed battery storage technologies.

SmartMetering

The primary objective of the SmartMetering project component is to develop and demonstrate state-of-the-art integrated AMI & meter data management (MDM) systems that support two-way communication with 14,000 SmartMeters in the demonstration area and provides the integration with CIS, DMS, OMS, and DERM. The SmartMetering infrastructure will provide the technology basis for recording customer and grid data that will be used to measure many SmartGrid benefits. The new AMI/MDM implementation will enable the following operational benefits that will be quantified throughout the demonstration period:

- Improved accuracy of meter reads, frequency of reads and flexibility of read scheduling by enabling customers to select dates for turn on/turn off requests without associated field visits.
- Improved accuracy of meter inventory and reduction in untracked meters.
- Increased percentage of automated reads and reduced amount of stale reading within the existing automated one-way meter reading system.
- Increased percentage of near real-time outage notifications and power restoration that would be supplied by a two-way metering system.
- Provided real-time, two-way communication for Demand Response (DR) program control initiation and verification of program participation

The SmartMetering technology will also provide advanced meter-to-HAN communications to facilitate in-home display, home energy management systems, and other consumer facing programs.

SmartEnd-Use

The primary objective of the SmartEnd-Use program is two-fold. The program will achieve a sufficient number of consumers enrolled in a variety of consumer facing program to 1) support the DERM development and demonstration, and 2) measure, analyze, and evaluate the impact of consumer education, enhanced energy consumption information, energy cost and pricing programs and other consumer based programs have on end-use consumption. We have identified several secondary objectives for the suite of SmartEnd-Use programs expected to be deployed in the Demonstration Area:

- First, we intend to improve customer satisfaction by increasing awareness and reducing costs through energy efficiency and demand response program execution.
- Second, we expect to improve KCP&L productivity through increased knowledge of customer behavior and usage patterns.
- Third, we expect to improve peak load profiles, reducing the need for capacity expansion, as customers are incented to utilize energy in off peak periods.
- Fourth, we expect to pilot alternative time-of-use (TOU) rate programs designed to provide the incentives to reduce energy usage during peak periods.

In achieving these objectives, we expect to demonstrate how the integration of a broad suite of efficiency and innovative rate programs into a complete SmartGrid solution can enhance the overall benefits of the solution and optimally leverage the additional technical and operational capabilities that are enabled by the investment.

4.6.3 DISTRIBUTION ADVANCED GRID TECHNOLOGIES IMPACT DESCRIPTION

2. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

The implementation of (or lack there of) distribution advanced grid technologies did not influence the selection of the resource acquisition strategy presented in this filing.

The advanced distribution grid technologies being evaluated through KCP&L's SmartGrid Demonstration Project, are foundational, enabling technologies that will provide traditional operational benefits to the utility while enabling new demand side management and pricing programs; integration of utility and customer owned distributed generation; greater grid utilization through increased monitoring and control of grid resources; and enhanced utilization of customer demand response capabilities.

KCP&L anticipates that the results of SmartGrid Demonstration Project and subsequent benefit cost analyses will determine that several of the advanced distribution grid technologies will be determined to be cost effective, or at a minimum we will understand under what conditions they become cost effective.

At that juncture, KCP&L believes the impact of distribution grid technologies on resource acquisition can be analyzed and it may then influence the resource acquisitions presented in subsequent future filing.

4.6.4 TRANSMISSION ADVANCED GRID TECHNOLOGIES IMPACT DESCRIPTION

3. A description of the impact of the implementation of transmission advanced grid technologies on the selection of a resource acquisition strategy.

SECTION 5: UTILITY AFFILIATION

(5) The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation requirements in sections (1) through (4) also apply to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility

On April 4, 2012 Great Plains Energy ("GXP"), the holding company for both KCP&L and GMO, and American Electric Power ("AEP") announced the formation of a company to build and invest in transmission infrastructure. The new company, Transource EnergySM LLC ("Transource"), will pursue competitive transmission projects in the SPP region, the MISO and PJM regions, and potentially other regions in the future. GXP owns 13.5 percent of Transource through its newly-formed subsidiary, GPE Transmission Holding Company, LLC ("GPETHCO"). AEP owns the other 86.5 percent of Transource through its subsidiary, AEP Transmission Holding Company, LLC ("AEPTHC").

At this point, it is GXP's intent to pursue, develop, construct, and own through GPETHCO's interest in Transource – rather than through KCP&L and/or GMO – any future regional and inter-regional transmission projects subject to regional cost allocation. While it is premature to determine the specific impact on the regionally allocated costs resulting from constructing projects within Transource, it is anticipated that the partnership between GXP and AEP will provide for a financially-strong, cost-competitive, and technically-proficient transmission development entity. The scale, execution experience, and engineering expertise that Transource expects to be able to bring to the projects should provide benefits to customers through lower construction costs, better access to capital, and operational efficiencies.

Separate filings with the Commission, apart from this IRP filing, are planned for later this year to further detail the benefits related to development of regional transmission projects through Transource.

SECTION 6: FUTURE TRANSMISSION PROJECTS

(6) The electric utility shall identify and describe any transmission projects under consideration by an RTO for the electric utility's service territory.

SPP identified one project bordering the KCP&L service territory in the 2010 ITP20 planning process. That was the Jeffery – Iatan 345 kV transmission line. Majority of this project would be in Westar's territory. There is also one project under study by SPP as part of the 2011 ITP10 planning process. This is the LaCygne – Morgan 345 kV transmission line that would interconnect KCP&L and AECI. Neither of these projects was selected in the recently completed ITP10 study process. They may be considered again in the next ITP20 process.