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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2012-0174

DIRECT TESTIMONY

OF

PAUL M. NORMAND

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
February 2012

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DIRECT TESTIMONY

OF

PAUL M. NORMAND

Case No. ER-2012-0174

Q. Please state your name, address and position.

A. My name is Paul M. Normand. I am a management consultant and president with the firm of Management Applications Consulting, Inc., 1103 Rocky Drive, Suite 201, Reading, PA 19609. I am testifying on behalf of Kansas City Power & Light Company ("KCP&L" or the "Company").

Q. Please state your qualifications.

A. My qualifications are shown on Schedule PMN-1.

SCOPE OF TESTIMONY

Q. Mr. Normand, what is your responsibility in connection with this filing?

A. I am responsible for developing the accounting class cost of service ("CCOS") study which provides the rate of return results at existing revenue levels for the Missouri jurisdiction customer class cost of service study for KCP&L's electric business.

The cost of service study results presented in my testimony and exhibits were based on the jurisdictional revenue requirement data offered in this case by Mr. John Weisensee.

Q. Please outline the organization of your testimony and schedules.

A. Schedule PMN-1 describes my qualifications and experience. Schedule PMN-2 presents the summary results of the Missouri jurisdictional class cost of service. Schedule PMN-3 presents a summary of the unbundled Missouri class costs presented in Schedule PMN-2 for major cost components at existing and uniform rates of return. Schedule PMN-4 presents a detailed description of the external allocators used in these studies.

ACCOUNTING COST OF SERVICE STUDY

Allocated Cost of Service Study

Q. Would you briefly define an Allocated Cost of Service Study?

A. The cost to serve the customers of any utility company consists generally of allowable investments, operating expenses and a return. For a historical test period, these costs are a matter of record and the overall cost to serve the collective customers of the utility may be readily established. On the other hand, the unique cost to provide services and energy to customers of the various customer classes is much less apparent. Costs can vary significantly between customer classes depending upon the nature of their demands, delivery voltage on the system, and the facilities and services required. The purpose of an Allocated Cost of Service Study is to directly assign costs based on company records or allocate each relevant and identifiable component of cost on an appropriate basis in order to determine the proper cost to serve the Company's customer classes (Schedules PMN-2, PMN-3, and PMN-4) under study. The analyses result in matrices displaying the detailed costs of serving each customer class for the functional cost category. Additional costs can be further unbundled into various cost categories reflecting the services provided by the Company to its customers for energy delivery.

Q. Please describe the procedure that you used in preparing your Allocated Cost of Service Study.

A. Through the application of a computerized microcomputer cost model developed by Management Applications Consulting specifically for KCP&L's electric operations, it was possible to treat each element of Rate Base, Revenues and Operating Expenses in detail and to either directly assign based on Company input or to allocate each cost item to specific jurisdictions and customer classes.

Q. Please summarize your Allocated Cost of Service Study.

A. Schedules PMN-2 through PMN-4 present the Missouri class cost of service result summaries. Schedule PMN-2 presents the summary of revenues, expenses, rate base, and return at the existing, uniform, and proposed revenue levels. Schedule PMN-3 presents the unbundled costs and revenue requirements for the Missouri class cost of service for the major services and cost functions provided. Table 3, included later in my testimony, presents the rate of return ("ROR") results for each customer class and season. Table 4 in my testimony presents the appropriate charges for each customer class and season for customer, demand and energy costs on a uniform rate of return target as established by the Company.

Description of Cost Model

Q. How does the computerized cost model operate?

A. The cost of service model is essentially a very large cost matrix. The vertical dimension of the study consists of all the cost of service elements as provided by the Company. The horizontal portion consists of each retail customer class (Schedules PMN-2 and PMN-3). The development of a cost of service study begins with rate base details for each account of plant and continues with rate base adjustments, revenues, operating expenses, taxes, and the computation of a labor allocator. The cost model includes three additional pieces, a summary of costs to serve, a list of the allocation factors employed in the study and a revenue requirements summary section. Once completed, this detail information is reformatted to calculate and show the unbundled cost to serve the Missouri jurisdiction customer classes and rates as presented in Schedule PMN-3.

Each page, starting with page 1 has an important column immediately preceding the numerical data marked "ALLOCATION BASIS." This column contains an acronym to indicate the allocation factor used to allocate or assign the costs shown in the "MISSOURI RETAIL" column to individual customer classes to the right.

Using these allocation factors, costs shown in the Missouri Retail column are assigned or allocated to each customer class and rate shown on the horizontal for each page of the cost study.

Q. What customer classes did you recognize in your Missouri Retail CCOS study?

A. The Missouri CCOS study recognized and allocated the Company's costs to all major retail customer classes as follows:

Residential
General Service – Small
General Service – Medium
General Service – Large
Large Power Service
Total Lighting

This summarized class cost of service detail (page 1) is consistent with the Company's last cost of service study.

Q. What additional detail did you undertake in preparing your CCOS study?

A. Based on KCP&L's historical major CCOS study, an additional step was undertaken which further separates the various rate groups which are included within the major classes shown. This expanded cost detail is primarily for voltage levels and all electric rates, but also includes all rates in order to identify any seasonal cost differences based on the same methodology for each rate. In preparing this cost detail, each additional sub-page is totaled into the first page for each major customer class as follows:

Page	Customer Class	Sub-Page	Description	Summer	Winter	Total
1	***ALL MAJOR CLASSES***	***1-1***	***Summary Cost of Service by Major Customer Class***			
1	Residential		Residential			
		1-2	Regular			
			Time of Day			
		1-3	All Electric			
			Separately Metered			
1	Small General Service		Small General Service			
		1-4	Regular			
			Other			
		1-5	All Electric			
			Separately Metered			
1	Medium General Service		Medium General Service			
		1-6	Primary			
			Secondary			
		1-7	All Electric			
			Separately Metered			
1	Large General Service		Large General Service			
		1-8	Primary			
			Secondary			
		1-9	All Electric			
			Separately Metered			
1	Large Power Service		Large Power Service			
		1-10	Primary			
			Secondary			
		1-11	Substation			
			Transmission			
1	Other Lighting	On Summary Page Only		No Seasonal Analysis		

Cost of Service Model Allocation Methodology

Q. Would you please tell us how you choose allocation factors for your accounting cost of service study?

A. In the cost allocation process, I attempted to determine the intended use of specific plant investments and then examined the specific use of these assets in the test period. As part of the cost of service process, several allocation factors were developed external to the cost of service study and inputted in to the model.

In addition, internal allocation factors were developed internal to the model to assign the various costs appropriately to functions and customer classes. Schedule PMN-4 provides a detailed description of each external allocation factor used in the study.

Q. Could you please provide a summary overview of the class and seasonal allocators used for major cost categories?

A. The following Table 1 lists the major cost categories and identifies the class and seasonal allocation approach used for each major area of cost:

TABLE 1

KCP&L MO CLASS AND SEASONAL ALLOCATION METHODS

Account/Function	Class Allocation	Seasonal Allocation
Production Plant		
Base	Lowest Monthly (non-zero) Usage for each rate	Summed by Seasons
Intermediate	12 CP Remaining 12 CP less Base	Summed by Seasons
Peak	4 CP Remaining 4 CP less Base less 12 CP Remaining	Summer Only
Transmission Plant	12 CP average	Seasonal average CP ratio
Distribution Plant		
Substations	NCP	Seasonal demand ratio
Primary	NCP	Seasonal demand ratio
Secondary	Average of NCP and MDD-Small Customers (none to larger secondary > 250 kW)	Seasonal demand ratio
Line Transformers	Average of NCP and MDD-Small Customers MDD-Large Customers > 250 kW	Seasonal demand ratio
Services (customer related only)	MDD all secondary (adjusted for number of services)	Months per season
Meters (customer related only)	KCP&L analysis to rate	Months per season
General Plant	Functional Separations and Salaries and Wages	Indirect calculation from summary of all allocated plant-related costs
Energy (fuel)	Class allocation based on gross product of monthly fuel costs and calendar month kWh sales with losses for each customer class	Summed by seasonal customer class/rate
Customer Sales & Services	Various customer count and weighted class allocation factors	Months per season
O&M Expense	Follows plant allocations	
Purchased Power	12 CP average	Demand portion on 12 CP Energy portion on energy with losses
Customer Accounting	Number of meters Direct Assignments	Months per season

Rate Base Allocation

Q. Please describe the allocation of Production Plant in your cost of service study.

A. KCP&L maintains supply resources that are required to provide both capacity and energy for its customers throughout the year (8,760 hours). Each of these generating resources has fixed (plant) investments along with corresponding variable (fuel) costs. KCP&L generates energy through a combination of these resources. It also acquires additional energy capability through its purchased power arrangements with other entities. In order to recognize these varied resources and associated costs in a systematic and equitable manner, a reasonable and representative dispatch order was established in order to achieve an equitable allocation of all of both fixed and variable costs to customer classes, rates and seasons.

This approach resulted in grouping KCP&L's generation facilities into three major categories for allocation to customer classes:

Base – First units available to meet KCP&L load. The load served by these units represents a base level of each customer's annual hourly load.

Intermediate – Units that would generally be used to meet load after the dispatch of base units.

Peak – Units dispatched last in order to meet load in any one hour.

Table 2, below, summarizes each group, generating unit, and percentage responsibility.

TABLE 2 WORK PAPER

GENERATION ALLOCATION DEVELOPMENT - KCPL MO

			54.04%	4 CP		
1	UNIT NAME	RATING	MO PORTION	RATIO	PERCENT	ALLOCATOR
2		MW	MW	0.7465	OF TOTAL	
3	WOLF CREEK	544	295.1	215.7	12.15%	BASE ENERGY
4	IATAN II	465	252.2	184.4	10.38%	BASE ENERGY
5	IATAN I	493	267.4	195.5	11.01%	BASE ENERGY
6	HAWTHORNE 5	564	305.9	223.6	12.59%	BASE ENERGY
7	TOTAL BASE		1,120.7	819.2	46.13%	
8	LA CYGNE 2	343	186.1	136.0	7.66%	12 CP
9	LA CYGNE 1	367	199.1	145.5	8.19%	12 CP
10	MONTROSE 3	176	95.5	69.8	3.93%	12 CP
11	MONTROSE 1	170	92.2	67.4	3.80%	12 CP
12	MONTROSE 2	164	89.0	65.0	3.66%	12 CP
13	SUB TOTAL		661.8	483.8	27.24%	
14	HAWTHORNE 6/9	180	97.6	71.4	4.02%	4 CP
15	HAWTHORNE 6/9	52	28.2	20.6	1.16%	4 CP
16	SUB TOTAL		125.8	92.0	5.18%	
17	WEST GARDNER	310	168.2	122.9	6.92%	4 CP
18	HAWTHORNE 7 & 8	154	83.5	61.1	3.44%	4 CP
19	OSAWATOMIE	75	40.7	29.7	1.67%	4 CP
20	SUB TOTAL		292.4	213.7	12.03%	
21	NORTHEAST	410	222.4	162.6	9.15%	4 CP
22	SPEARVILLE	12	6.5	4.8	0.27%	BASE ENERGY
23	INSTALLED CAPACITY	4,479	2,429.6	1,776.0	100.00%	
24	MO 1 CP		1,857.0			
25	CALCULATED MO 4 CP		1,776.0			
26	CALCULATED MO 12 CP		1,461.0			
27	LOAD TO TOTAL CAPACITY RATIO		0.7310	FOR COST OF SERVICE ALLOCATION		
28	SUMMARY OF KCP&L GENERATING PLANT MO MW TOTALS BY ALLOCATION METHOD					
29	BASE ENERGY		1,127.2	839.9	46.39%	
30	12 CP Remaining		661.8	660.0	27.24%	
	4 CP Remaining		640.6	321.1	26.37%	
	TOTAL ALL GENERATION		2,429.6	1,821.0	100.00%	

Note: All CP load data based on 12 months ended December 2010

Q. How did you develop your base allocation factor?

A. A base allocation factor was developed by using the lowest monthly (non-zero) energy use for the test year and applying this level to each month. This level of average demand formed the basis for allocating the base KCPL-MO MW capability to each customer class which was also used to allocate all base-related costs.

Q. Did you consider this base allocator in developing your remaining allocation factors for production plant and related costs?

A. Yes, I did.

Q. Please describe how you developed your intermediate allocator.

A. The intermediate allocation factor was based on the use of the 12 coincident peak ("12 CP") 1,461 MW less the allocated base amount. This residual unserved load (called "12 CP Remaining") formed the basis for allocating the intermediate steam generating units identified in Table 2.

Q. How were the remaining generating units allocated?

A. The remaining generating units were allocated by using a four coincident peak ("4 CP") 1,776 MW less the base and intermediate MW amounts. To the extent that certain rates could become negative in the calculations, these values were set equal to zero to derive a final 4 CP Remaining.

Q. Why is it important that a production allocation method such as the BIP be reasonable?

A. The use of a production stacking approach such as the BIP to the class allocation for the largest portion (approximately 72%) of a utility's costs is by far the most representative procedure that mirrors both the planning as well as the operation of any utility's production facilities.

Utilities must provide energy for all hours of the year (Figure 1) based on a load duration curve which is simply the combined hourly usage of all its customers. To accomplish this, the overall resource planning effort is quite complex and considers a myriad of costs and engineering factors associated with planning.

The BIP method allows for a more complete recognition of the dual nature of generating resources (fixed and variable) and therefore provides a more structured and robust way to model these joint costs and develop an equitable class allocation of production plants and their associated variable fuel costs.

As Figure 1 shows, the annual load duration curve is segmented by horizontal partitions (dashed lines) to identify various energy threshold requirements that will be provided by KCP&L from its available generation resources. Figure 1 also shows the class allocations that I have recommended as appropriate for the corresponding production facilities. Figure 2 is a separate representation of Figure 1 which represents the Company's monthly coincident peaks with the four (4 CP) and twelve (12 CP) identified as dashed lines. A review of these figures clearly demonstrates that a simple one or even four CP approach is totally inappropriate for either production or transmission cost allocation to customer classes. This is further highlighted when reviewing the kWh usage by customer class relative to per customer and kW. Larger energy use classes will greatly benefit from reduced energy costs from base generation units, and the corresponding fixed capacity costs must be synchronized with these benefits in order to achieve a reasonable and equitable allocation of these costs.

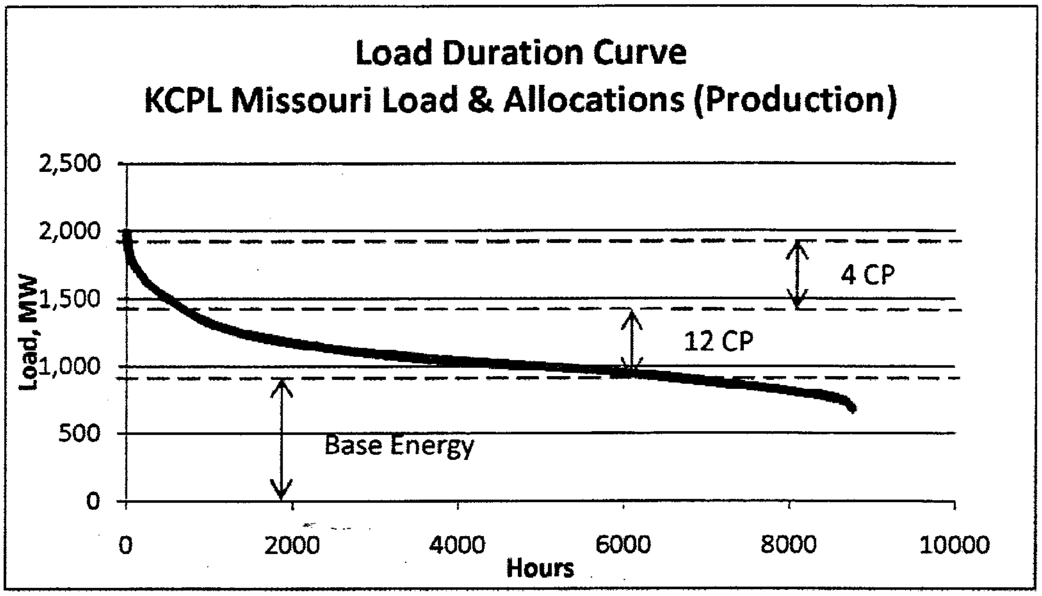

Figure 1

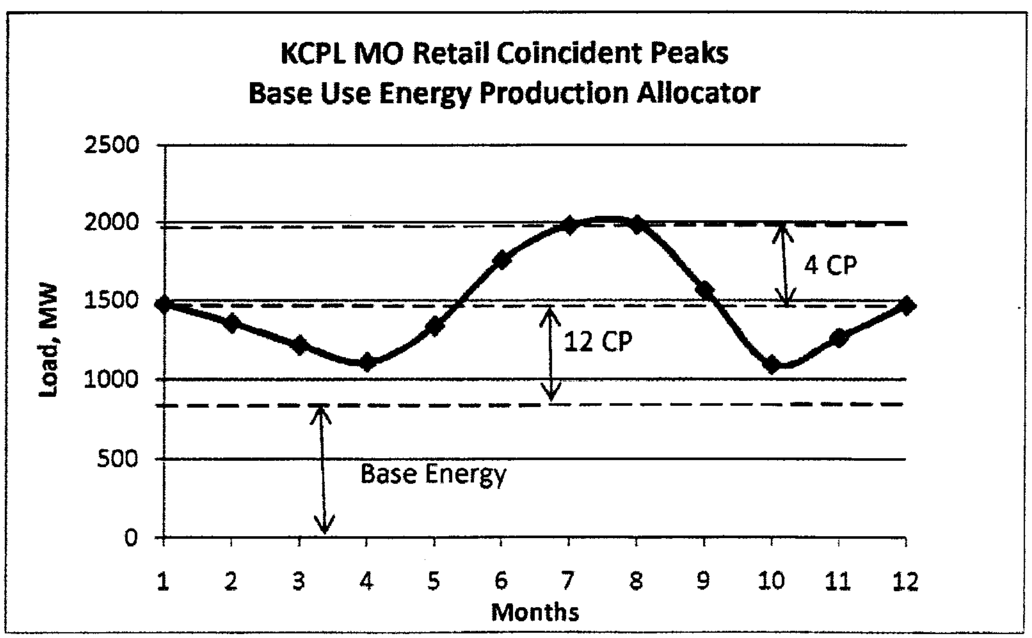

Figure 2

Q. How did you allocate the fuel costs associated with the production plant in your cost study?

A. I obtained the monthly fuel costs from the Company for the twelve months ended 9/30/2011. I then allocated each month's fuel costs to each customer class's corresponding calendar month kWh sales adjusted for losses. These allocated results were summed seasonally, by rate and major customer class to identify a proxy fuel allocator which was then used to allocate the actual fuel costs shown in the cost study.

Q. How did you allocate the demand portion of purchased power costs shown in Account 555?

A. The demand portion of purchased power costs was considered in the resource mix as equivalent in use/dispatch to the non-base units but prior in dispatch of peaking facilities and was therefore allocated on the 12 CP.

Q. What is another important aspect to consider in the allocation of production plant?

A. As I mentioned earlier, both the planning and operation point of view reflect two distinct costs that represent production facilities: fixed and variable. Unless these two costs are synchronized in the allocation process, a potentially severe and material misallocation will occur in customer class cost allocations. This can be clearly evidenced by simply reviewing Schedule PMN-3 of this direct testimony which provides the major unbundled costs that make up the total revenue requirement for the Company based on the cost of service assumptions included in the model. The listing, below, compares these current functional costs along with the Company's prior case:

	ER-2010-0355		ER-2012-0174	
	($M)	%	($M)	%
Demand				
Production	346.9	45.6	419.0	52.1
Transmission	36.8	4.8	48.0	6.0
Sub-Transmission	1.3	0.2	–	–
Distribution	129.9	17.1	135.3	16.8
Total Demand	514.9	67.7	602.3	74.9
Energy	208.7	27.4	157.2	19.5
Customer	37.4	4.9	45.1	5.6
Total Company	760.9	100.0	804.6	100.0
Total Production	555.6	73.0	576.2	71.6

The current total production-related costs equal 52.1% (Demand) plus 19.5% (Energy), or 71.6% of total costs. Allocating 52.1% of all revenue requirements on simply one, two or even four coincident peaks is certainly illogical and will distort the class allocation away from larger energy users who enjoy the majority of lower energy costs and, more importantly, deviate from the basic planning and operation process which gave rise to these production costs.

Larger base units provide a tremendous amount of lower cost energy supply for the base portion of all customer usage which underscores the importance of synchronizing the fixed and variable costs associated with these units.

Q. Please compare the class allocation methods used in your allocated cost of service study.

A. Using the class allocation methods described herein, the following class usage and cost statistics are calculated:

Class	4CP (MW)	%	12 CP (MW)	%	Energy (MWH)	%
Residential	764.7	40.8	581.5	36.4	2,742,028	30.3
Small GS	96.4	5.1	83.3	5.2	438,496	4.9
Medium GS	238.2	12.7	201.1	12.6	1,154,656	12.8
Large GS	434.4	23.2	398.9	25.0	2,362,973	26.1
Large Power	341.2	18.2	310.2	19.4	2,256,681	25.0
Lighting	0.0	0.0	22.0	1.4	90,467	1.0
MO Totals	1,874.9	100.0	1,597.0	100.0	9,045,302	100.0

Q. How did you allocate the margins that KCP&L receives from its sale of energy to various other customers not considered as retail customers?

A. These customers are served from KCP&L's resources which are available throughout the year. In recognizing that the initial KCP&L units are placed in service to meet the Company's firm retail base portion of each customer's annual load curve, the next and most likely generation available is the non-base or remaining steam units. Using this approach and maintaining consistency in assigning these margins to classes in a manner consistent with the allocation of production plant responsibility, I used the 12 CP Remaining allocator (DEM1B). In doing this, I have synchronized the plant cost assignment to classes with the margins recovered from any sales from these resources. Any other approach would unnecessarily skew the results and be inequitable and inconsistent with the plant allocations to customer classes.

Q. Should any energy calculation be factored into the allocation of these margins?

A. Yes. These margins should follow and be consistent with the allocated production plant. More importantly, these sales are made subsequent to KCP&L providing service to its firm sales customers. Therefore, both an energy and 12 CP allocation would reflect an equitable class allocation consistent with the associated production plant allocation.

Q. How did you allocate transmission plant costs?

A. Transmission plant costs are a function of many factors which include interconnection to other utilities, connecting generation to the grid and single contingency analyses relating to plant loads, maintenance outages, etc. In order to balance all of these factors and recognize a relationship to generation, I simply allocated transmission plant and related costs using a 12 CP average demand factor. This allocator was then used to allocate all of transmission plant and related costs. The seasonal cost allocation was determined by using each class's seasonal average demand ratio.

Q. Please describe the allocation of Distribution Plant to customer classes in your cost of service study.

A. The distribution plant allocation factors begin with "DEM" for demand allocation factors used for the allocation of distribution plant. These non-coincident peak ("NCP") demand allocators were derived based on the use of diversified (non-coincident peak) class demands for Primary Plant in Accounts 360 through and including Account 367.

Q. Did your CCOS study recognize any voltage separation in allocating Distribution costs?

A. Yes, Accounts 364, 365, 366 and 367 identified primary and secondary voltage cost separation.

Q. How were the remaining Distribution plant costs allocated?

A. Line Transformers and secondary plant costs were allocated to all secondary customers based on the weighted average of the diversified class demands (NCP) and undiversified individual customer maximum demands. This approach recognizes a level of diversity for smaller uses where several customers are oftentimes served by one transformer.

Larger general service and large power secondary customers were allocated line transformer costs based on their undiversified customer maximum demands since these customers are generally served individually. In addition, for the larger secondary customers whose demand exceeded a level of 250 kW, no secondary conductor allocation was made. These customers are typically very large, and secondary circuits from transformers are more related and used by smaller users.

Q. What are the customer-related allocation factors included in your cost study?

A. Customer-related Distribution plant items were allocated using CUST-prefixed allocators and were recognized for services, meters, lighting and other such customer-related items. These allocation factors were developed from data analyses available from the Company and used to assign the specific customer-related costs to each customer class.

Q. How were Services, Account 369, allocated to customer classes?

A. Services were considered 100% customer-related and represent the first physical connection between the customer premises and the utility's distribution network. In order to fairly assign these plant costs to appropriate secondary customers, their total undiversified maximum customer demands were calculated. This maximum customer load data (adjusted for the number of services) formed the allocation factor used to assign these customer-related costs to appropriate secondary customers.

Q. How were Meters, Account 370, allocated to customer classes?

A. Meter costs are also a part of the rate base which impact allocated costs to customer classes and were considered 100% customer-related. The Company provided an assignment of all its meters and metering devices to customer classes. The result of this analysis was an identification of all metering costs by rate class which was then used to allocate the booked meter costs to all customers.

Q. How was General plant allocated?

A. General plant was allocated on a combination of identified functional costs and an internally generated labor allocation factor (SALWAGES) based on the O&M salaries and wages expenses. The labor allocation factor was developed on a functional basis and then allocated by function using the sum of the corresponding functional O&M expenses. These allocated labor costs were then subtotaled by class to arrive at the final composite allocation factor, SALWAGES.

Q. How was each account of reserves for depreciation allocated?

A. Production plant accumulated reserves were identified and allocated consistent with production plant account details. The transmission and distribution plant accumulated reserves were allocated on the subtotal of the corresponding allocated plant cost to each rate and customer class. The general plant accumulated reserves were allocated in the same manner as the general plant accounts.

Q. What other elements of rate base were included in your study?

A. The adjustments to rate base have been detailed in the study. Additions to net plant included cash working capital, materials and supplies, prepayments, fuel inventory, and various regulatory assets. The cash working capital component of rate base was developed in detail by the Company and allocated on related expenses or plant in the cost of service study. Materials and supplies were provided by function and allocated using the appropriate plant allocation factor. Prepayment items were allocated using total plant, customers, and demand allocation factors. Fuel inventory was allocated on energy (fuel costs). The regulatory assets were allocated on labor, energy, or demand allocation factors.

The deductions from net plant include accumulated deferred income taxes, deferred gain on SO_2 emission allowance, deferred gain (loss) on emissions allowances, customer advances for construction, and customer deposits.

The accumulated deferred taxes were allocated on total plant. The deferred gain on SO_2 emissions allowance and the deferred gain (loss) emission allowances were allocated on an energy allocation factor. Customer advances for construction were allocated on total distribution plant. Customer deposits were developed using the data analysis by customer group available from the Company. These customer group costs were used to assign the specific customer-related costs to each customer class based on the number of customers in each class of the group.

Revenues

Q. How did you establish the revenues to be utilized in the cost of service study?

A. The Company provided the class and rate revenues used in the cost of service study.

The remaining revenues are listed as Miscellaneous Revenues and reflect primarily Forfeited Discounts, Rent from Electric Property and Transmission Service Revenues.

Operating Expense Allocation

Q. How were the Missouri Operation and Maintenance Expenses allocated?

A. The Missouri portion of Operations and Maintenance Expense for production, transmission and distribution plant was allocated to customer classes following plant. Customer Accounts Expenses, Customer Services and Information Expenses, Sales

Expenses, and Administrative and General Expenses were allocated using a variety of methods based on direct assignments, revenues, salaries and wages, plant in service, number of bills and number of customers. Whenever possible, specific information detailing class cost responsibilities or weightings was utilized in order to develop the most reasonable allocation possible. For example, Account 902, Meter Reading Expense, was allocated to customer classes based on the total number of meters. Account 903, Customer Records and Collections Expense, was allocated based on combining the results of a separate analysis of customer billing. Account 904, Uncollectibles, was assigned to customer classes based on an analysis by the Company. These results were also functionalized based on the corresponding claimed revenues within the cost of service study. Accounts 911 through 916 used customer allocation factors based on a combination of number of customers and allocated direct assignments.

A&G expenses were primarily allocated on the labor allocator. The remaining A&G expenses were allocated on plant in service components, with the exception of Account 930.1, General Advertising, which was allocated based on the number of customers and Account 928, Regulatory Commission expenses, which was primarily allocated to classes on revenues at the uniform claimed rate of return.

Q. What are the remaining operating expenses?

A. The remaining operating expenses consist of depreciation and amortization expenses, taxes other than income taxes, deferred income taxes, Interest on Customer Deposits, and a detailed state and federal income tax calculation.

Q. How were they allocated?

A. Depreciation expenses were allocated on the basis of plant in service consistent with the allocation of depreciation reserves. Taxes Other Than Income Taxes that are plant related were allocated on a plant-related allocator and those that are labor related were allocated on the SALWAGES allocator discussed earlier. Gross Receipts tax was allocated based on sales. Sales Revenues and State Capital Stock Tax was allocated on total plant. Deferred Income Taxes were functionalized and detailed with allocations appropriate to their respective categories of costs. Federal and state income taxes were computed for each jurisdiction customer class based on the allocated expenses.

Accounting Class Cost Study Results

Q. Could you summarize the results of your Missouri class cost study at present rates?

A. The ROR results for each retail rate and customer class are shown on Schedules PMN-2, PMN-3, and PMN-4. Table 3, below, summarizes these ROR results from the CCOS study (Schedule PMN-4).

Q. Could you please briefly discuss your cost of service results as presented on Table 3 for each customer class?

A. The COSS results indicate that the Residential class is at a system average rate of return while the comparable Small General Service class is at twice the system average ROR. The Medium and Large General Service classes are essentially at or slightly higher than the system average ROR. The LPS rate of return is the lowest at a relative level of 66% to the system overall.

KCPL MO
TABLE 3
COST OF SERVICE RESULTS – CLASS ROR AND INDEX

Customer Class	Index of Return Annual	------- Rate of Return % ------- Annual	Seasonal Summer	Winter
RESIDENTIAL	0.98	**5.432%**	**6.509%**	**4.498%**
Regular	1.08	**5.958%**	**6.797%**	**5.174%**
Time of Day	0.91	**5.039%**	**6.438%**	**3.739%**
All Electric	0.75	**4.165%**	**5.859%**	**2.922%**
Separately Metered	0.53	**2.963%**	**4.161%**	**2.284%**
SMALL GS	1.98	**10.969%**	**11.498%**	**10.589%**
Primary & Secondary	2.01	**11.148%**	**11.609%**	**10.810%**
Other	1.82	**10.059%**	**9.453%**	**10.455%**
All Electric	1.50	**8.326%**	**9.396%**	**7.733%**
Separately Metered	1.70	**9.433%**	**12.370%**	**7.954%**
MEDIUM GS	1.28	**7.088%**	**7.199%**	**7.008%**
Primary	1.65	**9.119%**	**9.652%**	**8.808%**
Secondary	1.32	**7.303%**	**7.297%**	**7.307%**
All Electric	0.96	**5.291%**	**6.140%**	**4.771%**
Separately Metered	1.31	**7.262%**	**7.445%**	**7.143%**
LARGE GS	1.05	**5.804%**	**6.459%**	**5.382%**
Primary	1.26	**7.001%**	**7.690%**	**6.549%**
Secondary	1.17	**6.488%**	**6.890%**	**6.212%**
All Electric	0.81	**4.494%**	**5.428%**	**3.945%**
Separately Metered	1.32	**7.319%**	**7.495%**	**7.205%**
LARGE POWER SERVICE	0.54	**3.011%**	**3.756%**	**2.568%**
Primary	0.65	**3.602%**	**4.213%**	**3.234%**
Secondary	0.62	**3.440%**	**4.221%**	**2.951%**
Substation	0.34	**1.879%**	**2.706%**	**1.420%**
Transmission	0.17	**0.931%**	**1.976%**	**0.343%**
TOTAL LIGHTING	1.12	**6.188%**		
MISSOURI RETAIL	1.00	**5.539%**		

These results are based on the Company's last rate case with pro forma adjustments and can be used as a very good guide or input in establishing reasonable revenue targets, class increases, and seasonal differences when used in conjunction with Table 4, below.

Q. What does your Schedule PMN-3 identify?

A. Schedule PMN-3 presents the summary of unbundled Missouri revenue requirements from Schedule PMN-2 at the existing rate of return and at a uniform rate of return. Each ROR section (actual and uniform) presents the costs in total dollars with these same costs also shown on a unitized kWh basis for comparison purposes. Line 15 of Schedule PMN-3 summarizes only the customer-related costs which form the basis for deriving appropriate monthly customer charges for use as a guide in rate design. Table 4, below, details these monthly customer charges along with seasonal demand and energy costs for each major customer class at a uniform percent ROR.

Q. Could you please summarize your cost of service results as presented in Table 4 for each customer class?

A. The results presented on Table 4 summarize the monthly customer charges ($) and seasonal energy and demand $/kWh charges that should be the price target if all customers were paying a uniform ROR target as requested by the Company. These unit cost results ($/kWh) are presented in Schedule PMN-3, pages 43 through 56 in lines 5, 13, and 33.

1

KCPL MO
TABLE 4
COST OF SERVICE RESULTS – UNBUNDLED CUSTOMER, DEMAND AND ENERGY

	UNIFORM RATE OF RETURN @ 8.6%						
	Monthly ($) Customer Charge	Annual Energy Costs ($)	Seasonal Energy Costs ($)		Demand Costs ($/kWh)		
Customer Class			Summer	Winter	Annual	Seasonal Summer	Seasonal Winter
RESIDENTIAL	$11.08	0.0188	0.0210	0.0174	0.0849	0.0980	0.0762
Regular	$10.80	0.0190	0.0210	0.0175	0.0862	0.0963	0.0786
Time of Day	$17.66	0.0188	0.0208	0.0174	0.0837	0.0967	0.0744
All Electric	$11.34	0.0184	0.0209	0.0171	0.0808	0.1023	0.0701
Separately Metered	$14.85	0.0179	0.0210	0.0168	0.0823	0.1132	0.0713
SMALL GS	$16.61	0.0184	0.0207	0.0171	0.0750	0.0840	0.0698
Primary & Secondary	$16.87	0.0185	0.0207	0.0171	0.0748	0.0834	0.0696
Other	$8.61	0.0186	0.0211	0.0174	0.0822	0.0970	0.0751
All Electric	$18.70	0.0179	0.0206	0.0167	0.0770	0.0910	0.0710
Separately Metered	$25.56	0.0178	0.0206	0.0166	0.0775	0.0915	0.0719
MEDIUM GS	$56.62	0.0183	0.0205	0.0170	0.0713	0.0789	0.0667
Primary	$163.71	0.0175	0.0199	0.0164	0.0608	0.0705	0.0563
Secondary	$56.36	0.0184	0.0205	0.0171	0.0716	0.0786	0.0672
All Electric	$50.04	0.0180	0.0205	0.0168	0.0710	0.0830	0.0652
Separately Metered	$55.59	0.0180	0.0206	0.0167	0.0674	0.0783	0.0619
LARGE GS	$132.90	0.0181	0.0204	0.0169	0.0644	0.0705	0.0611
Primary	$272.28	0.0179	0.0200	0.0166	0.0630	0.0671	0.0606
Secondary	$123.18	0.0184	0.0205	0.0171	0.0658	0.0698	0.0633
All Electric	$119.17	0.0179	0.0204	0.0167	0.0632	0.0726	0.0588
Separately Metered	$117.44	0.0181	0.0206	0.0168	0.0615	0.0687	0.0576
LARGE POWER SERVICE	$139.70	0.0179	0.0200	0.0167	0.0575	0.0583	0.0571
Primary	$165.62	0.0179	0.0201	0.0166	0.0581	0.0600	0.0571
Secondary	$56.95	0.0184	0.0205	0.0171	0.0614	0.0622	0.0609
Substation	$352.24	0.0177	0.0196	0.0166	0.0536	0.0531	0.0539
Transmission	$352.23	0.0177	0.0196	0.0165	0.0544	0.0518	0.0561
TOTAL LIGHTING		0.0179			0.0616		

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2012-0174

AFFIDAVIT OF PAUL M. NORMAND

COMMONWEALTH OF PENNSYLVANIA)
) **ss**
COUNTY OF BERKS)

Paul M. Normand, being first duly sworn on his oath, states:

1. My name is Paul M. Normand. I am a management consultant and president with the firm of Management Applications Consulting, Inc. in Reading, Pennsylvania. I have been retained by Great Plains Energy, Inc., the parent company of Kansas City Power & Light Company, to serve as an expert witness to provide testimony on behalf of Kansas City Power & Light Company.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of twenty-six (26) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Paul M. Normand

Subscribed and sworn before me this 6 day of February, 2012.

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Linda L. Rudloff, Notary Public
Sinking Spring Boro, Berks County
My Commission Expires April 16, 2012
Member, Pennsylvania Association of Notaries

Notary Public

My commission expires: 04-16-2012

Schedule PMN-1

Qualifications of Paul M. Normand

SCHEDULE PMN-1

QUALIFICATIONS OF PAUL M. NORMAND

Q. Mr. Normand, what is your present position?

A. I am a principal in the consulting firm of Management Applications Consulting, Inc. (MAC), 1103 Rocky Drive, Suite 201, Reading, PA 19609. This company provides consulting services to the utility industry in such field as loss studies, econometric studies, cost analyses, rate design, expert testimony, and regulatory assistance.

Q. What is your educational background?

A. I graduated from Northeastern University in 1975, with a Bachelor of Science Degree and a Master of Science Degree in Electrical Engineering-Power System Analysis. I have attended various conferences and meeting concerning engineering and cost analysis.

Q. What is your professional background?

A. I was employed by the Massachusetts Electric Company in the Distribution Engineering Department while attending Northeastern University. My principal areas of assignment included new service, voltage conversions, and system planning. Upon graduation from Northeastern University, I joined Westinghouse Electric Corporation Nuclear Division in Pittsburgh, Pennsylvania. In that position, I assisted in the procurement and economic analysis of electrical/electronic control equipment for the nuclear reactor system.

In 1976, I joined Gilbert Associates as an Engineer providing consulting services in the rate and regulatory area to utility companies. I was promoted to Senior Engineer in 1977, Manager of the Austin office 1980, and Director of Rate Regulatory Service in 1981.

In June, 1983, I left Gilbert to form a separate consulting firm and I am now a principal and President of Management Applications Consulting, Inc. My principal areas of concentration have been in loss studies, economic analyses, and pricing.

Q. Have you testified in support of any cost studies that you participated in or performed?

A. Yes, I have testified about such studies before the following regulatory agencies: the Maine Public Utility Commission, the Public Utility Commission of Texas, Illinois Commerce Commission, New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, New York Public Service Commission, Pennsylvania Public Utility Commission, the Massachusetts Department of Public Utilities, the Kentucky Public Service Commission, the Arkansas Public Service Commission, the Public Service Commission of Louisiana, the Public Utilities Commission of Ohio, the Public Service Commission of Missouri, the Delaware Public Service Commission, the Maryland Public Service Commission, the Indiana Utility Regulatory Commission, the North Carolina Utilities Commission, the Kansas Corporation Commission, and the Federal Energy Regulatory Commission.

Q. Could you please briefly discuss your technical experience?

A. I have performed numerous accounting and marginal cost of service studies, time differentiated bundled and fully unbundled cost studies for both electric and gas utilities since 1980. I have also used such studies in the design and presentation of detailed rate proposals before regulatory agencies. My additional experience has been in the area of unaccounted for loss evaluations for electric and gas utilities for over twenty-four years. These studies include a detailed review of each system and the calculation of appropriate recovery factors.

Schedule PMN-2

Total Missouri Class Cost of Service Summary Results

Kansas City Power & Light Company
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**									
0020										
0030	OPERATING REVENUE									
0040	RETAIL SALES REVENUE	TSFR 9 90	699,636,961	259,806,177	47,984,116	94,385,415	163,335,353	125,295,179	8,830,722	
0050	OTHER OPERATING REVENUE	TSFR 9 320	49,051,908	20,541,166	2,685,054	6,146,409	11,613,438	7,794,948	270,892	
0060	TOTAL OPERATING REVENUE		748,688,868	280,347,343	50,669,170	100,531,823	174,948,792	133,090,127	9,101,614	
0070										
0080	OPERATING EXPENSES									
0090	FUEL	TSFR 9 4080	124,790,618	37,864,453	6,039,546	15,954,515	32,485,423	31,219,978	1,226,703	
0100	PURCHASED POWER	TSFR 9 4090	24,345,430	7,532,510	1,189,362	3,103,358	6,331,380	5,935,822	252,997	
0110	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 9 4100	296,422,803	120,345,124	17,708,989	34,976,793	64,059,262	55,676,069	3,656,567	
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	TSFR 5 1390	98,902,485	39,074,462	5,321,388	12,775,676	22,228,969	18,155,921	1,346,069	
0130	AMORTIZATION EXPENSES	TSFR 9 4590	11,107,955	3,985,147	586,486	1,436,072	2,656,032	2,307,222	136,997	
0140	TAXES OTHER THAN INCOME TAXES	TSFR 9 4710	48,547,311	18,458,003	2,666,585	6,177,594	11,168,895	9,471,217	605,017	
0150	CURRENT INCOME TAXES	TSFR 11 820	9,814,637	4,343,848	4,244,510	4,176,724	2,701,561	(5,914,511)	262,505	
0160	DEFERRED INCOME TAXES	TSFR 11 920	16,774,160	6,415,463	909,710	2,149,063	3,857,409	3,233,510	209,004	
0170	TOTAL ELECTRIC OPERATING EXPENSES		630,705,397	238,019,009	38,666,575	80,749,795	145,488,931	120,085,228	7,695,859	
0180										
0190	NET ELECTRIC OPERATING INCOME		117,983,472	42,328,334	12,002,595	19,782,028	29,459,861	13,004,899	1,405,755	
0200										
0210	RATE BASE									
0220	TOTAL ELECTRIC PLANT	TSFR 3 190	4,283,301,236	1,621,887,564	231,168,871	548,518,066	991,782,840	837,335,161	52,608,733	
0230	LESS: ACCUM. PROV. FOR DEPREC	TSFR 6 1700	1,816,407,425	709,268,962	101,651,075	226,046,306	410,166,552	343,710,039	25,564,491	
0240	NET PLANT		2,466,893,811	912,618,602	129,517,796	322,471,761	581,616,288	493,625,122	27,044,242	
0250	PLUS:									
0260	CASH WORKING CAPITAL	TSFR 2 40	(47,690,286)	(18,252,266)	(2,912,655)	(6,276,857)	(10,964,912)	(8,691,821)	(591,775)	
0270	MATERIALS & SUPPLIES	TSFR 2 110	51,855,549	22,397,496	2,925,053	6,579,099	11,781,081	7,780,693	392,128	
0280	PREPAYMENTS	TSFR 2 180	5,522,723	1,651,385	275,874	707,002	1,434,097	1,389,399	64,965	
0290	FUEL INVENTORY	TSFR 2 250	66,901,141	20,299,403	3,237,844	8,553,329	17,415,667	16,737,253	657,644	
0300	REGULATORY ASSETS	TSFR 2 350	121,304,313	40,306,225	6,374,051	15,336,788	30,547,520	27,172,725	1,567,005	
0310	LESS:									
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	TSFR 2 410	158,781	88,149	10,508	20,915	24,434	11,469	3,306	
0330	CUSTOMER DEPOSITS	TSFR 2 420	4,192,439	2,179,087	1,607,581	335,161	65,338	5,272	0	
0340	DEFERRED INCOME TAXES	TSFR 2 430	485,201,862	183,723,447	26,186,243	62,134,782	112,346,728	94,851,274	5,959,388	
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	TSFR 2 440	45,275,933	13,725,121	2,194,878	5,779,590	11,827,778	11,295,737	452,829	
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	TSFR 2 450	2,121	643	103	271	554	529	21	
0370	TOTAL RATE BASE		2,129,956,114	779,304,399	109,418,650	279,100,402	507,564,910	431,849,089	22,718,665	
0380										
0390	RATE OF RETURN		5.539%	5.432%	10.969%	7.088%	5.804%	3.011%	6.188%	
0400	RELATIVE RATE OF RETURN		1.00	0.98	1.98	1.28	1.05	0.54	1.12	
0410										
0420										
0430										
0440										
0450										
0460										
0470										
0480										
0490										
0500										

Schedule PMN-3

Summary Results of Unbundled Missouri Class Cost of Service

- Actual Rate of Return
- Uniform Rate of Return

Kansas City Power & Light Company
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	PRESENT RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		5.54%	5.43%	10.97%	7.09%	5.80%	3.01%	6.19%	
2										
3	REVENUES REQUIRED									
4										
5	**DEMAND COMPONENT**	498,998,672	498,998,672	179,760,981	35,145,199	70,950,447	121,505,442	87,061,911	4,574,693	
6	DEMAND PRODUCTION COMPONENT		345,051,372	103,363,580	23,092,836	49,230,453	92,872,147	72,832,576	3,659,781	
7	DEMAND TRANSMISSION COMPONENT		41,141,278	15,125,831	2,776,715	5,567,524	10,292,958	6,796,249	582,000	
8	DEMAND DISTRIBUTION COMPONENT		112,806,023	61,271,570	9,275,647	16,152,470	18,340,338	7,433,086	332,911	
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		69,689,692	32,239,399	4,911,560	9,062,173	16,011,945	7,131,704	332,911	
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		31,488,015	22,660,823	3,335,263	5,491,929	0	0	0	
11	DEMAND DISTRIBUTION TRANSFORMATION		11,628,316	6,371,348	1,028,825	1,598,368	2,328,393	301,382	0	
12										
13	**ENERGY COMPONENT**		154,974,376	47,961,918	7,693,672	19,807,051	40,023,058	37,975,502	1,513,175	
14										
15	**CUSTOMER COMPONENT**	44,927,542	44,927,542	31,809,830	5,094,741	3,528,576	1,634,943	125,893	2,733,559	
16										
17										
18	CUSTOMER LIGHTING COMPONENT		2,733,559	0	0	0	0	0	2,733,559	
19	CUSTOMER SERVICES COMPONENT		5,750,947	4,238,934	606,104	905,910	0	0	0	
20	CUSTOMER METERS COMPONENT		9,533,621	5,674,712	1,987,122	1,371,438	376,689	123,661	0	
21	CUSTOMER METER READING COMPONENT		3,068,129	2,732,732	265,257	57,814	11,437	889	0	
22	CUSTOMER OTHER RECORDS & COLLECTIONS		12,076,651	9,333,163	1,388,573	701,158	653,757	0	0	
23										
24	CUSTOMER OTHER CUST ACCTS, SERV, INFO		11,577,212	9,254,378	1,215,120	512,859	594,013	842	0	
25	CUSTOMER SALES COMPONENT		426,470	376,418	40,122	8,216	1,588	126	0	
26	CUSTOMER MISC OTHER COMPONENT		(239,048)	199,494	(407,557)	(28,818)	(2,541)	374	0	
27										
28	**TOTAL COMPANY**	698,900,591	698,900,591	259,532,730	47,933,612	94,286,074	163,163,442	125,163,306	8,821,428	
29										
30										
31										
32	ANNUAL BOOKED KWH SALES @ METER (WN)		8,581,648,037	2,583,679,109	413,203,689	1,088,291,409	2,235,521,539	2,175,709,650	85,242,641	
33	ANNUAL NUMBER OF CUSTOMERS		3,282,519	2,856,576	307,284	63,900	12,396	1,005	41,358	
34										
35										
36										
37										
38										
39										
40										
41										
42										
43										
44										

Schedule PMN-3

Kansas City Power & Light Company
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	PRESENT RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		5.539%	5.432%	10.969%	7.088%	5.804%	3.011%	6.188%	
2										
3	$ / KWH									
4										
5	**DEMAND COMPONENT**		0.0581	0.0696	0.0851	0.0652	0.0544	0.0400	0.0537	
6	DEMAND PRODUCTION COMPONENT		0.0402	0.0400	0.0559	0.0452	0.0415	0.0335	0.0429	
7	DEMAND TRANSMISSION COMPONENT		0.0048	0.0059	0.0067	0.0051	0.0046	0.0031	0.0068	
8	DEMAND DISTRIBUTION COMPONENT		0.0131	0.0237	0.0224	0.0148	0.0082	0.0034	0.0039	
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		0.0081	0.0125	0.0119	0.0083	0.0072	0.0033	0.0039	
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		0.0037	0.0088	0.0081	0.0050	0.0000	0.0000	0.0000	
11	DEMAND DISTRIBUTION TRANSFORMATION		0.0014	0.0025	0.0025	0.0015	0.0010	0.0001	0.0000	
12										
13	**ENERGY COMPONENT**		0.0181	0.0186	0.0186	0.0182	0.0179	0.0175	0.0178	
14										
15	**CUSTOMER COMPONENT**		0.0052	0.0123	0.0123	0.0032	0.0007	0.0001	0.0321	
16										
17										
18	CUSTOMER LIGHTING COMPONENT		0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0321	
19	CUSTOMER SERVICES COMPONENT		0.0007	0.0016	0.0015	0.0008	0.0000	0.0000	0.0000	
20	CUSTOMER METERS COMPONENT		0.0011	0.0022	0.0048	0.0013	0.0002	0.0001	0.0000	
21	CUSTOMER METER READING COMPONENT		0.0004	0.0011	0.0006	0.0001	0.0000	0.0000	0.0000	
22	CUSTOMER OTHER RECORDS & COLLECTIONS		0.0014	0.0036	0.0034	0.0006	0.0003	0.0000	0.0000	
23										
24	CUSTOMER OTHER CUST ACCTS, SERV, INFO		0.0013	0.0036	0.0029	0.0005	0.0003	0.0000	0.0000	
25	CUSTOMER SALES COMPONENT		0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	
26	CUSTOMER MISC OTHER COMPONENT		(0.0000)	0.0001	(0.0010)	(0.0000)	(0.0000)	0.0000	0.0000	
27										
28	**TOTAL COMPANY**		0.0814	0.1005	0.1160	0.0866	0.0730	0.0575	0.1035	
29										
30										
31	$/MO/CUST									
32										
33	**CUSTOMER COMPONENT**		$13.69	$11.14	$16.58	$55.22	$131.89	$125.27	$66.10	
34										
35										
36	CUSTOMER LIGHTING COMPONENT		$0.83	$0.00	$0.00	$0.00	$0.00	$0.00	$66.10	
37	CUSTOMER SERVICES COMPONENT		$1.75	$1.48	$1.97	$14.18	$0.00	$0.00	$0.00	
38	CUSTOMER METERS COMPONENT		$2.90	$1.99	$6.47	$21.46	$30.39	$123.05	$0.00	
39	CUSTOMER METER READING COMPONENT		$0.93	$0.96	$0.86	$0.90	$0.92	$0.88	$0.00	
40	CUSTOMER OTHER RECORDS & COLLECTIONS		$3.68	$3.27	$4.52	$10.97	$52.74	$0.00	$0.00	
41										
42	CUSTOMER OTHER CUST ACCTS, SERV, INFO		$3.53	$3.24	$3.95	$8.03	$47.92	$0.84	$0.00	
43	CUSTOMER SALES COMPONENT		$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.00	
44	CUSTOMER MISC OTHER COMPONENT		($0.07)	$0.07	($1.33)	($0.45)	($0.20)	$0.37	$0.00	

Kansas City Power & Light Company
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	EQUALIZED RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		8.596%	8.596%	8.596%	8.596%	8.596%	8.596%	8.596%	
2										
3	REVENUES REQUIRED									
4										
5	**DEMAND COMPONENT**	602,305,316	602,305,316	219,289,161	31,004,169	77,559,375	143,988,913	125,210,283	5,253,416	
6	DEMAND PRODUCTION COMPONENT		419,014,863	125,731,490	20,435,874	53,688,915	109,897,189	105,056,618	4,204,779	
7	DEMAND TRANSMISSION COMPONENT		47,969,604	17,732,128	2,505,140	5,989,424	11,864,567	9,222,592	655,752	
8	DEMAND DISTRIBUTION COMPONENT		135,320,849	75,825,543	8,063,155	17,881,036	22,227,156	10,931,074	392,884	
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		84,227,020	39,790,289	4,274,301	10,022,963	19,301,302	10,445,281	392,884	
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		36,721,591	27,754,356	2,916,879	6,050,356	(0)	(0)	(0)	
11	DEMAND DISTRIBUTION TRANSFORMATION		14,372,238	8,280,898	871,976	1,807,717	2,925,854	485,792	(0)	
12										
13	**ENERGY COMPONENT**		157,210,375	48,637,226	7,611,830	19,942,474	40,530,120	38,959,003	1,529,722	
14										
15	**CUSTOMER COMPONENT**	45,073,500	45,073,500	31,637,646	5,103,237	3,618,299	1,647,429	140,397	2,926,492	
16										
17										
18	CUSTOMER LIGHTING COMPONENT		2,926,492	0	0	(0)	(0)	(0)	2,926,492	
19	CUSTOMER SERVICES COMPONENT		6,597,844	5,073,085	545,700	979,059	0	0	(0)	
20	CUSTOMER METERS COMPONENT		9,920,127	6,082,217	1,896,844	1,407,582	394,202	139,283	0	
21	CUSTOMER METER READING COMPONENT		3,075,749	2,740,803	264,701	57,889	11,463	893	0	
22	CUSTOMER OTHER RECORDS & COLLECTIONS		12,118,950	9,376,246	1,383,953	702,613	656,138	0	0	
23										
24	CUSTOMER OTHER CUST ACCTS, SERV, INFO		11,570,706	9,247,728	1,215,742	512,700	593,695	841	0	
25	CUSTOMER SALES COMPONENT		428,462	378,543	39,959	8,237	1,595	127	0	
26	CUSTOMER MISC OTHER COMPONENT		(1,564,829)	(1,260,975)	(243,662)	(49,780)	(9,664)	(748)	0	
27										
28	**TOTAL COMPANY**	804,589,191	804,589,191	299,564,033	43,719,236	101,120,148	186,166,461	164,309,683	9,709,630	
29										
30										
31										
32	ANNUAL BOOKED KWH SALES @ METER (WN)		8,581,648,037	2,583,679,109	413,203,689	1,088,291,409	2,235,521,539	2,175,709,650	85,242,641	
33	ANNUAL NUMBER OF CUSTOMERS		3,282,519	2,856,576	307,284	63,900	12,396	1,005	41,358	
34										
35										
36										
37										
38										
39										
40										
41										
42										
43										
44										

Kansas City Power & Light Company
2012 RATE CASE - Direct Filing
COST OF SERVICE - Missouri Jurisdiction
TY 9/30/11; Update TBD; K&M 8/31/12

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	EQUALIZED RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		8.596%	8.596%	8.596%	8.596%	8.596%	8.596%	8.596%	
2										
3	$ / KWH									
4										
5	**DEMAND COMPONENT**		0.0702	0.0849	0.0750	0.0713	0.0644	0.0575	0.0616	
6	DEMAND PRODUCTION COMPONENT		0.0488	0.0487	0.0495	0.0493	0.0492	0.0483	0.0493	
7	DEMAND TRANSMISSION COMPONENT		0.0056	0.0069	0.0061	0.0055	0.0053	0.0042	0.0077	
8	DEMAND DISTRIBUTION COMPONENT		0.0158	0.0293	0.0195	0.0164	0.0099	0.0050	0.0046	
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		0.0098	0.0154	0.0103	0.0092	0.0086	0.0048	0.0046	
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		0.0043	0.0107	0.0071	0.0056	(0.0000)	(0.0000)	(0.0000)	
11	DEMAND DISTRIBUTION TRANSFORMATION		0.0017	0.0032	0.0021	0.0017	0.0013	0.0002	(0.0000)	
12										
13	**ENERGY COMPONENT**		0.0183	0.0188	0.0184	0.0183	0.0181	0.0179	0.0179	
14										
15	**CUSTOMER COMPONENT**		0.0053	0.0122	0.0124	0.0033	0.0007	0.0001	0.0343	
16										
17										
18	CUSTOMER LIGHTING COMPONENT		0.0003	0.0000	0.0000	(0.0000)	(0.0000)	(0.0000)	0.0343	
19	CUSTOMER SERVICES COMPONENT		0.0008	0.0020	0.0013	0.0009	0.0000	0.0000	(0.0000)	
20	CUSTOMER METERS COMPONENT		0.0012	0.0024	0.0046	0.0013	0.0002	0.0001	0.0000	
21	CUSTOMER METER READING COMPONENT		0.0004	0.0011	0.0006	0.0001	0.0000	0.0000	0.0000	
22	CUSTOMER OTHER RECORDS & COLLECTIONS		0.0014	0.0036	0.0033	0.0006	0.0003	0.0000	0.0000	
23										
24	CUSTOMER OTHER CUST ACCTS, SERV, INFO		0.0013	0.0036	0.0029	0.0005	0.0003	0.0000	0.0000	
25	CUSTOMER SALES COMPONENT		0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	
26	CUSTOMER MISC OTHER COMPONENT		(0.0002)	(0.0005)	(0.0006)	(0.0000)	(0.0000)	(0.0000)	0.0000	
27										
28	**TOTAL COMPANY**		0.0938	0.1159	0.1058	0.0929	0.0833	0.0755	0.1139	
29										
30										
31	$/MO/CUST									
32										
33	**CUSTOMER COMPONENT**		$13.73	$11.08	$16.61	$56.62	$132.90	$139.70	$70.76	
34										
35										
36	CUSTOMER LIGHTING COMPONENT									
37	CUSTOMER SERVICES COMPONENT		$2.01	$1.78	$1.78	$15.32	$0.00	$0.00	($0.00)	
38	CUSTOMER METERS COMPONENT		$3.02	$2.13	$6.17	$22.03	$31.80	$138.59	$0.00	
39	CUSTOMER METER READING COMPONENT		$0.94	$0.96	$0.86	$0.91	$0.92	$0.89	$0.00	
40	CUSTOMER OTHER RECORDS & COLLECTIONS		$3.69	$3.28	$4.50	$11.00	$52.93	$0.00	$0.00	
41										
42	CUSTOMER OTHER CUST ACCTS, SERV, INFO		$3.52	$3.24	$3.96	$8.02	$47.89	$0.84	$0.00	
43	CUSTOMER SALES COMPONENT		$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.00	
44	CUSTOMER MISC OTHER COMPONENT		($0.48)	($0.44)	($0.79)	($0.78)	($0.78)	($0.74)	$0.00	

Schedule PMN-4

Detailed Allocation Factor Description

KANSAS CITY POWER & LIGHT COMPANY
2012 RATE CASE - Direct Filing
MISSOURI JURISDICTION
TY 9/30/11; Update TBD; K&M 8/31/12
DETAILED ALLOCATION FACTOR DESCRIPTION

DESCRIPTION	ALLOCATION FACTOR	REFERENCE
EXTERNALLY DEVELOPED DEMAND RELATED		
PRODUCTION DEMAND (ENE @ GEN) - AVERAGE DEMAND	DEMAVG	INPUT - Sales Data, Source File: BFandWN_TYE (Monthly Files)_CG_CurrRates.xls, (Monthly Sheets)
PRODUCTION DEMAND - 12 CP REMAINING	DEM12CPR	INPUT - Average 12 Coincident Peaks (Remaining), Source File: KCPL Energy and Demand for COSS with CustGrth - Aug 2012 PMN Gen aloc.xls, Peak Sheet
PRODUCTION DEMAND - 12 CP	DEM12CP	INPUT - Average 12 Coincident Peaks, Source File: KCPL Energy and Demand for COSS with CustGrth - Aug 2012 PMN Gen aloc.xls, Peak Sheet
PRODUCTION DEMAND - 4 CP	DEM4CP	INPUT - Average 4 Coincident Peaks, Source File:KCPL Energy and Demand for COSSD with CustGrth - Aug 2012 PMN Gen aloc.xls.xls, Peak Sheet
PROD AVERAGE DEMAND (LOWEST MO RT USAGE) - **BASE**	DEM1A	INPUT - Base Average Demand Lowest Month, Source File: KCPL MO TABLE 2 GENERATION ALLOCATION FACTOR 02-06-12 PMN.xls, Sheet 1
PROD REMAINING STEAM (12CP - BASE) - **INTERMEDIATE**	DEM1B	INPUT - Average 12 Coincident Peaks less Base Average Demand, Source File:KCPL MO TABLE 2 GENERATION ALLOCATION FACTOR 02-06-12 PMN.xls, Sheet 1
PROD DEMAND (4 CP - BASE - INTERMEDIATE) - **PEAKING**	DEM1C	INPUT - Average 4 Coincident Peaks less Base Average Demand less Remaining CP, Source File:KCPL MO TABLE 2 GENERATION ALLOCATION FACTOR 02-06-12 PMN.xls, Sheet 1
TOTAL BASE, INTERMEDIATE, & PEAKING	DEM1	DEM1A = DEM1A + DEM1B + DEM1C
DIST DEMAND (NCP) - SUBSTATION VOLTAGE	DEM6	INPUT - Maximum Non Coincident Peaks, Source File:KCPLSUMMARY.xls, KCPLmo2010 Sheet (Excludes Transmission)
DIST DEMAND (NCP) - PRIMARY VOLTAGE	DEM8	INPUT - Maximum Non Coincident Peaks, Source File:KCPLSUMMARY.xls, KCPLmo2010 Sheet (Excludes Subtation and Transmission)
DIST DEMAND (NCP) - SECONDARY VOLTAGE	DEM7	INPUT - Average Non Coincident Peaks and Maximum Diversified Demands, Source File:KCPLSUMMARY.xls, KCPLmo2010 Sheet (Secondary only excluding Large General Service & Large Power)
DIST DEMAND (NCP) - SECONDARY LINE XFMR	DEM9	INPUT - Average Non Coincident Peaks and Maximum Diversified Demands except Large General Service and Large Power Maximum Diversified Demands, Source File:KCPLSUMMARY.xls, KCPLmo2010 Sheet (Secondary only)
DIST DEMAND (NCP) - PRIMARY LINE XFMR (=DEM8 NA)	DEM10	DEM10 = DEM8 (not used)
EXTERNALLY DEVELOPED ENERGY RELATED		
ENERGY SALES @ GENERATION WITH LOSSES	ENERGY1	INPUT - Sales Data, Source File: BFandWN_TYE (Monthly Files)_CG_CurrRates.xls, (Monthly Sheets)
ENERGY BOOKED KWH SALES @ METER (WN)	ENERGY2	INPUT - Sales Data, Source File: BFandWN_TYE (Monthly Files)_CG_CurrRates.xls, (Monthly Sheets)
MO ENE @ GEN W/LOSSES * MO AVG FUEL COSTS	ENEFUEL	INPUT - Loss Adjusted Energy Sales @ Generation Ratios * Avg Fuel Cost, Source File: KCPL MONTHLY FUEL COSTS FOR COS MO.xls, Sheet 1

KANSAS CITY POWER & LIGHT COMPANY
2012 RATE CASE - Direct Filing
MISSOURI JURISDICTION
TY 9/30/11; Update TBD; K&M 8/31/12
DETAILED ALLOCATION FACTOR DESCRIPTION

Line	DESCRIPTION	ALLOCATION FACTOR	REFERENCE
40	**EXTERNALLY DEVELOPED CUSTOMER RELATED**		
42	WEIGHTED AVERAGE CUSTOMERS - PRI & SEC	CUST1	INPUT - Weather Normalized Average Monthly Number of Primary and Secondary Customers, Source File: BFandWN_TYE 201109_CG_CurrRates.xls, TOTALS Sheet
44	WEIGHTED AVERAGE CUSTOMERS - SEC ONLY	CUST2	INPUT - Weather Normalized Average Monthly Number of Secondary Customers excludes Large General Service & Large Power, Source File: BFandWN_TYE .xls, TOTALS Sheet
46	WEIGHTED CUSTOMERS - TRANSFORMERS (=CUST2)	CUST3	INPUT - Weather Normalized Average Monthly Number of Secondary Customers, Source File: BFandWN_TYE .xls, TOTALS Sheet
48	MAXIMUM DIVERSIFIED DEMANDS - 369 SERVICES	CUST4	INPUT - MDD adjusted for the number of services per customer class, Source File: KCPLSUMMARY.xls, KCPLmo2010 Sheet (excludes LGS, LPG & lighting).
50	PLANT ACCOUNT 370 - METER INVESTMENT	CUST5	INPUT - Account 370-Meter Investment (meter portion) based on number of meter and meter cost, Source File: KCPL-MO Meter Allocation (Acct 370)(C5)(Cust) MAC.xls, Missouri Sheet
52	AVERAGE NUMBER OF METERS - 902 METER READING EXP	CUST6	INPUT - Average Number of Meters, Source File: KCPL-MO Meter Allocation (Acct 370)(C5)(Cust) MAC.xls, Missouri Sheet
54	EXPENSE ACCOUNT 903 - RECORDS & COLLECT (COLLECT)	CUST7	INPUT - Collections Expense by Rate Class, Source File: KCPL-MO_Customer_Exp_Studies_by Acct 903 (C9)(Deliquent).xls, Allocation-Acct 903 Sheet
56	EXPENSE ACCOUNT 903 - "B" READING (NOT USED)	CUST8	Not used
58	EXPENSE ACCOUNT 903 - RECORDS & COLLECT (OTHER)	CUST9	INPUT - Records and Collections Expense (other than collections) by Rate Class, Source File: KCPL-MO_Customer_Exp_Studies_by Acct 903(C9)(Other).xls, Allocation-Acct 903 Sheet
60	EXPENSE ACCOUNT 904 - UNCOLLECTIBLES	CUST10	INPUT - Rate Class Write Offs net of Recoveries, Source File: MO Customer_Exp_Studies_by Acct 904 (C7-C10).xls, Allocation-Acct 904 by Class Sheet
62	EXPENSE ACCOUNT 908 - CUST ASSIST (PUBLIC INFO)	CUST11	Not used
64	EXPENSE ACCOUNT 908 - CUST ASSIST (OTHER)	CUST12	INPUT - Rate Class Customer Assistance Expense, Source File: MO Customer_Exp_Studies_by Acct 908(C11-C12).xls, Allocation-Acct 908 Sheet

KANSAS CITY POWER & LIGHT COMPANY
2012 RATE CASE - Direct Filing
MISSOURI JURISDICTION
TY 9/30/11; Update TBD; K&M 8/31/12
DETAILED ALLOCATION FACTOR DESCRIPTION

	DESCRIPTION	ALLOCATION FACTOR	REFERENCE
66	WEIGHTED AVG CUST - 910 MISC CUSTOMER SERVICE EXP	CUST13	INPUT - Weather Normalized Average Monthly Number of Customers, Source File: BFandWN_TYE 201109_CG_CurrRates.xls, TOTALS Sheet
67			
68	WEIGHTED AVG CUST - 912 DEMO & SELLING (=CUST1)	CUST14	INPUT - Weather Normalized Average Monthly Number of Customers, Source File: BFandWN_TYE 201109_CG_CurrRates.xls, TOTALS Sheet
69			
70	WEIGHTED AVG CUST - 913 ADVERTISING (=CUST1)	CUST15	INPUT - Weather Normalized Average Monthly Number of Customers, Source File: BFandWN_TYE 201109_CG_CurrRates.xls, TOTALS Sheet
71			
72	WEIGHTED AVG CUST - 916 MISC SALES EXP (=CUST1)	CUST16	INPUT - Weather Normalized Average Monthly Number of Customers, Source File: BFandWN_TYE 201109_CG_CurrRates.xls, TOTALS Sheet
73			
74	WEIGHTED CUSTOMERS - OTHER MISC CUST (=CUST1)	CUST17	INPUT - Weather Normalized Average Monthly Number of Customers, Source File: BFandWN_TYE 201109_CG_CurrRates.xls, TOTALS Sheet
75			
76	PLANT ACCOUNT 371 - INSTALLATIONS ON CUST PREMISES	CUST18	INPUT - Direct Assignment to Other Lighting
77			
78	PLANT ACCOUNT 373 - STREET LTG & SIGNAL SYSTEMS	CUST19	INPUT - Direct Assignment to Other Lighting
79			
80	PLANT ACCOUNT 370 - METER INVEST (BILLING RECORDERS)	CUST20	INPUT - Account 370-Meter Investment (billing recorder portion) based on number of meters and billing recorder cost, Source File: KCPL -MO Meter Equipment Breakdown (C20).xls, Sheet 1
81			
82	CUSTOMER DEPOSITS	CUST21	INPUT - Customer Deposits based dollars and allocated on number of customers, Source File: KCPL-MO Deposit Allocator Workpaper (C21).xls, Sheet 1
83			
84			