Exhibit No.:	
Issue:	Class Cost of Service
Witness:	Paul M. Normand
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2009-____
Date Testimony Prepared:	September 5, 2008

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2009-____

DIRECT TESTIMONY

OF

PAUL M. NORMAND

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
September 2008

DIRECT TESTIMONY
OF
PAUL M. NORMAND
Case No. ER-2009-____

LIST OF SCHEDULES

Schedule	Description
PMN-1	Qualifications of Paul M. Normand
PMN-2	Total Missouri Class Cost of Service Summary Results – Existing ROR
PMN-3	Summary Results of Unbundled Missouri Class Cost of Service ➢ Actual Rate of Return ➢ Uniform Rate of Return
PMN-4	Detailed Allocation Factor Description

LIST OF TABLES

Table	Description
1	KCP&L Class and Seasonal Allocation Methods
2	Generation Allocation Development
3	Cost of Service Results – Class ROR and Index
4	Cost of Service Results – Unbundled Customer, Demand and Energy

INTRODUCTION

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", "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 study (CCOS) which provides the rate of return results at existing revenue levels for the Missouri 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 a last rate case cost of service with the January 1, 2008 rate increase.

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 service classifications is much less apparent. Costs can vary significantly between services and 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 and 3,) under study. The analyses result in matrices displaying the detailed costs of serving each customer class for the functional cost category. Finally, additional cost 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 cost of service study.

A. Schedules PMN-2 and PMN-3 present the Missouri class cost of service result summaries. 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 presents the rate of return results for each customer class and season. Table 4 presents the appropriate charges for each customer class and season for customer, demand and energy costs on a uniform rate of return.

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 costs of service elements as provided by the Company. The horizontal portion consists of each retail customer class (Schedules PMN-2 and 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 class cost of service study?

A. The Missouri class cost of service 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
Off-Peak Lighting
Other Lighting

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

Q. What additional detail did you undertake in preparing your class cost of service study?

A. Based on KCP&L's historical major class cost of service study, and additional step was undertaken which further separates the various rates which are included within the major classes shown. This expanded cost detail is primarily for the all electric rates but includes all rates in order to identify seasonal cost differences for each rate. In preparing this additional detail, each additional subpage 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	1-10	Primary			
			Secondary			
		1-11	Substation Service			
			Transmission			
1	Off-Peak Lighting	On Summary Page Only		No Seasonal Analysis		
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 into 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 studies.

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 cost:

TABLE 1

KCP&L 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	Sum of Production Allocation Results	Summed by season from allocated production results
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	Months per season
Meters (customer related only)	KCP&L analysis to rate	Months per season
General Plant O&M Expense	Salaries and wages	Indirect calculation from summary of all plant-related costs
Energy (fuel)	Class allocation based on gross product of monthly fuel costs and monthly kWh sales for each rate	Summed by seasonal customer class/rate
Customer Sales & Services	Various customer-weighted allocation factors	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. Each of these generating resources has fixed (plant) investments along with corresponding variable (fuel) costs. The customers of KCP&L receive energy through a combination of these resources for every hour of the year along with 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 review was undertaken for the years 2006 and 2007 with respect to hours of operation, generated kWh, MW contribution to system peak to arrive at a reasonable and representative proxy for the equitable allocation of all of these costs to customer classes, rates and seasons.

This review 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 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
GENERATION ALLOCATION DEVELOPMENT

			53.75% 4 CP	4 CP		
1	UNIT NAME	RATING	MO PORTION	SCALING	PERCENT	ALLOCATOR
2		MW	MW	0.8315	OF TOTAL	
3	WOLF CREEK	548	294.5	244.9	13.53%	BASE ENERGY
4	IATAN	456	245.1	203.8	11.26%	BASE ENERGY
5	HAWTHORNE 5	563	302.6	251.6	13.90%	BASE ENERGY
6			842.2	700.3		
7	HAWTHORNE 6+9	266	143.0	118.9	6.57%	12 CP REM
8	HAWTHORNE 7	75	40.3	33.5	1.85%	12 CP REM
9	HAWTHORNE 8	76	40.8	34.0	1.88%	12 CP REM
10			224.1	186.4		
11	LA CYGNE 1	368	197.8	164.5	9.08%	12 CP REM
12	LA CYGNE 2	341	183.3	152.4	8.42%	12 CP REM
13			381.1	316.9	17.50%	
14	MONTROSE 1	170	91.4	76.0	4.20%	12 CP REM
15	MONTROSE 2	164	88.1	73.3	4.05%	12 CP REM
16	MONTROSE 3	176	94.6	78.7	4.34%	12 CP REM
17			274.1	227.9	12.59%	
18	NORTHEAST	449	241.3	200.7	11.08%	4 CP REM
19	WEST GARDNER	308	165.5	137.6	7.60%	4 CP REM
20	OSAWATOMIE	76	40.8	34.0	1.88%	4 CP REM
21	SPEARVILLE	15	8.1	6.7	0.37%	BASE ENERGY
22	INSTALLED CAPACITY	4,051	2,177.2	1,810.4		
23	CALCULATED 4 CP		1,810.4			
24	LOAD TO TOTAL CAPACITY RATIO		0.8315			
25	MO CP		1,944			
26	SUMMARY TOTALS BY ALLOCATION METHOD					
27	BASE ENERGY			707.0	39.05%	
28	12 CP Remaining			731.1	40.39%	
29	4 CP Remaining			372.3	20.56%	
30	TOTAL ALL GENERATION			1,810.4	100.00%	

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 MW capability of 707 to each customer class which was 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) 1,488 MW less the allocated base amount of 707 MW. This residual unserved load I called 12 CP Remaining and formed the basis for allocating the intermediate steam generating units identified.

Q. How were the remaining other generating units allocated?

A. The remaining other generating units were allocated by using a four coincident peak (4 CP) less the base and intermediate peak. 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. 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 2006 and 2007. I then averaged each month's fuel costs and allocated this monthly average to each customer class's corresponding monthly 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 purchased power costs shown in Account 555?

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

Q. How did you allocate the margins that KCP&L receives from their 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 a 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. 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.

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

A. No. These margins should follow and be consistent with the same portion of allocated production plant. More importantly, these sales are made subsequent to KCP&L providing service to its firm sales customers and generally from other non-base initial load portions of the Company's curve.

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, 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 summed up the allocated production plant costs into a composite allocator which includes base use, 12 CP remaining and 4 CP remaining. This summed allocator was then used to allocate all of transmission plant and related costs.

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 capacity 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 class cost of service study recognize any voltage separation in allocating Distribution costs?

A. Yes. A separate analysis was undertaken by the Company of Accounts 364, 365, 366 and 367 to identify the appropriate primary and secondary 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 to the utility's distribution network. In order to fairly assign these plant costs to all secondary customers, the total undiversified maximum customer demands for all secondary customers was calculated. This maximum customer load data formed the allocation factor used to assign these customer-related costs to 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 undertook an analysis of all its meters and metering devices. 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 were General and Common plant allocated?

A. General and Common plant were allocated on an internally generated labor allocation factor (**SALWAGES**) based on labor expenses. This labor allocation factor was developed by reviewing each Operations and Maintenance account to determine the labor portion of expense included. The labor portion of these costs was then allocated separately in the same manner as the total accounts were allocated. The 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. Total accumulated reserves were identified consistent with production plant and remaining plant functional details and allocated on the subtotal of the corresponding allocated plant cost to each rate and customer class.

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 working capital and regulatory assets.

The deductions from net plant include accumulated deferred income taxes, deferred gains on emission credit, customer advances and customer deposits.

Each adjustment to rate base was allocated on the most appropriate allocation factor. 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. Deferred taxes were functionalized as reviewed by the Company and allocated on the corresponding plant totals or labor totals.

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 was allocated to customer classes following primary plant. Customer Accounts, 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 907 through 915 used customer allocation factors based on number of customers.

A&G expenses were primarily allocated on the labor allocator. The remaining A&G expenses were partly allocated on revenue and partly on plant in service components, all developed internally to the cost of service study. Account 928, Regulatory Commission expenses, was allocated on revenues at the 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. Franchise taxes were functionalized based on claimed revenues, the delivery tax was allocated on claimed revenues and the Gross Receipts tax was allocated based on sales. 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 and 3. Table 3, below, summarizes these ROR results from the class cost of service study.

TABLE 3
COST OF SERVICE RESULTS – CLASS ROR AND INDEX

	Index of Return	---------- Rate of Return % ----------		
Customer Class	Annual	Annual	Seasonal	
			Summer	Winter
RESIDENTIAL	1.06	7.919%		
Regular	1.11	8.298%	7.865%	8.787%
Time of Day	1.05	7.859%	8.777%	6.947%
All Electric	0.86	6.443%	10.737%	3.590%
Separately Metered	0.84	6.286%	9.710%	4.428%
SMALL	1.78	13.296%		
Primary & Secondary	1.85	13.798%	11.863%	15.576%
Other	1.08	8.065%	5.942%	9.768%
All Electric	1.18	8.813%	10.438%	7.796%
Separately Metered	1.28	9.541%	14.444%	7.437%
MEDIUM	1.17	8.752%		
Primary	1.74	12.980%	11.482%	13.833%
Secondary	1.23	9.174%	8.183%	9.997%
All Electric	0.83	6.179%	7.552%	5.291%
Separately Metered	1.16	8.673%	8.487%	8.803%
LARGE	1.05	7.849%		
Primary	1.28	9.536%	7.569%	10.856%
Secondary	1.26	9.380%	9.323%	9.421%
All Electric	0.75	5.594%	7.076%	4.708%
Separately Metered	1.13	8.446%	8.869%	8.189%
LARGE POWER SERVICE	0.55	4.073%		
Primary	0.62	4.599%	3.041%	5.657%
Secondary	0.64	4.806%	3.285%	5.909%
Substation	0.30	2.236%	3.221%	1.652%
Transmission	0.06	0.425%	1.316%	-0.068%
OFF PEAK LIGHTING	2.85	21.230%		
OTHER LIGHTING	(3.86)	-28.816%		
RETAIL	1.00	7.457%		

Note: Data obtained from Schedule PMN-5.

While these results are based on the last rate case, they do not reflect the Company's current cost of service in this proceeding. However, they 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 unbundled Missouri revenue requirements from the study 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 this Schedule 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 and rate at a uniform 7.39% ROR as follows:

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

Customer Class	Monthly ($) Customer Charge	Annual Energy Costs ($)	Seasonal Energy Costs ($) Summer	Seasonal Energy Costs ($) Winter	Demand Costs ($/kWh) Annual	Demand Costs ($/kWh) Seasonal Summer	Demand Costs ($/kWh) Seasonal Winter
	- - - - UNIFORM ROR - - - -						
RESIDENTIAL	$10.43	0.0262					
Regular	$10.24	0.0263	0.0279	0.0251	0.0451	0.0577	0.0357
Time of Day	$15.03	0.0262	0.0279	0.0250	0.0419	0.0529	0.0343
All Electric	$10.67	0.0258	0.0279	0.0248	0.0391	0.0467	0.0353
Separately Metered	$13.25	0.0255	0.0281	0.0245	0.0376	0.0502	0.0330
SMALL	$14.02	0.0261					
Primary & Secondary	$14.20	0.0261	0.0280	0.0250	0.0400	0.0507	0.0334
Other	$7.86	0.0259	0.0281	0.0248	0.0440	0.0610	0.0361
All Electric	$15.40	0.0259	0.0282	0.0248	0.0472	0.0564	0.0426
Separately Metered	$21.17	0.0257	0.0278	0.0247	0.0483	0.0495	0.0478
MEDIUM	$43.64	0.0262					
Primary	$138.14	0.0251	0.0274	0.0241	0.0291	0.0352	0.0264
Secondary	$43.89	0.0262	0.0280	0.0251	0.0381	0.0448	0.0339
All Electric	$36.74	0.0259	0.0282	0.0248	0.0384	0.0455	0.0349
Separately Metered	$43.65	0.0260	0.0283	0.0248	0.0378	0.0447	0.0342
LARGE	$125.43	0.0260					
Primary	$204.90	0.0255	0.0274	0.0244	0.0296	0.0323	0.0280
Secondary	$111.36	0.0262	0.0281	0.0250	0.0319	0.0349	0.0301
All Electric	$144.84	0.0258	0.0280	0.0248	0.0307	0.0353	0.0285
Separately Metered	$138.40	0.0259	0.0281	0.0247	0.0322	0.0356	0.0305
LARGE POWER SERVICE	$755.22	0.0257					
Primary	$581.71	0.0257	0.0274	0.0247	0.0283	0.0305	0.0270
Secondary	$736.19	0.0264	0.0282	0.0253	0.0315	0.0340	0.0300
Substation	$1,523.14	0.0254	0.0269	0.0245	0.0247	0.0252	0.0244
Transmission	$8,010.74	0.0251	0.0270	0.0241	0.0243	0.0247	0.0241
OFF PEAK LIGHTING	($0.00)	0.0256			0.0251		
OTHER LIGHTING	$143.72	0.0257			0.0256		

Note: Data obtained from Schedule PMN-3.

Q. Could you please summarize these cost of service results?

A. The CCOS study show that rates for the non-electric heating customers during the winter time provide a higher contribution to the average return on investment than the summer rates. The study also shows that the customers who receive service under the all-electric tariff or separately metered tariff in combination with the general service tariff provide a lower return to the Company in the winter than the summer and also provide a lower return than a comparable general service rate. The winter, non-electric heating customer rates are substantially above the Company's average return. Company witness Tim M. Rush discusses this further in his Direct Testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company to Modify Its Tariff to Continue the Implementation of Its Regulatory Plan	)))	Case No. ER-2009-____

AFFIDAVIT OF PAUL M. NORMAND

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

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, 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-one (21) 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 4th day of September 2008.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2011

" NOTARY SEAL "
Nicole A. Wehry, Notary Public
Jackson County, State of Missouri
My Commission Expires 2/4/2011
Commission Number 07391200

QUALIFICATIONS OF PAUL M. NORMAND

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. 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. 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 since 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.

I have testified about cost 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 and the Federal Energy Regulatory Commission.

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 factor

KANSAS CITY POWER & LIGHT COMPANY
CASE NO. ______________________
CLASS COST OF SERVICE FOR MISSOURI CUSTOMERS
2006 TEST YR INCL KNOWN & MEAS TO 9-30-07 (SEPT TRUE-UP)

LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL COL. 601	RESIDENTIAL COL. 602	SMALL GEN. SERVICE COL. 603	MEDIUM GEN. SERVICE COL. 604	LARGE GEN. SERVICE COL. 605	LARGE PWR SERVICE COL. 606	OFF-PEAK LIGHTING COL. 607	OTHER LIGHTING COL. 608
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**									
0020										
0030	OPERATING REVENUE									
0040	RETAIL SALES REVENUE	TSFR 2 190	577,886,532	212,430,348	43,688,127	71,402,934	131,666,374	111,784,481	4,460,136	2,454,132
0050	OTHER OPERATING REVENUE	TSFR 2 610	73,959,466	34,545,134	3,883,979	8,043,462	16,360,749	10,989,073	37,622	99,448
0060	TOTAL OPERATING REVENUE		651,845,998	246,975,481	47,572,106	79,446,397	148,027,122	122,773,554	4,497,758	2,553,580
0070										
0080	OPERATING EXPENSES									
0090	FUEL	TSFR 4 3940	104,927,671	31,187,790	5,720,036	12,362,939	26,925,334	27,728,593	766,910	236,070
0100	PURCHASED POWER	TSFR 4 3950	25,786,590	8,015,779	1,397,725	3,021,020	6,587,608	6,535,495	173,414	55,548
0110	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 4 3960	250,423,517	95,898,633	15,432,783	27,974,253	54,126,457	51,424,698	1,287,433	4,279,259
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	TSFR 5 1420	73,388,512	28,961,889	4,720,080	8,882,844	15,825,056	13,602,803	289,052	1,106,788
0130	AMORTIZATION EXPENSES	TSFR 5 1650	26,906,520	9,353,336	1,575,559	3,022,496	6,334,166	6,384,661	174,516	61,785
0140	INTEREST ON CUSTOMER DEPOSITS	CUST21	438,857	245,904	160,489	26,937	4,614	914	0	0
0150	TAXES OTHER THAN INCOME TAXES	TSFR 6 360	39,632,232	15,156,337	2,517,744	4,780,248	8,840,585	7,832,670	191,471	313,177
0160	FEDERAL AND STATE INCOME TAXES	TSFR 7 1280	31,270,139	15,865,837	5,095,633	5,132,573	6,673,990	(797,446)	506,471	(1,206,920)
0170	GAINS ON DISPOSITION OF PLANT	NETPLANT	0	0	0	0	0	0	0	0
0180	TOTAL ELECTRIC OPERATING EXPENSES		552,774,038	204,685,505	36,620,049	65,203,309	125,317,810	112,712,388	3,389,268	4,845,708
0190										
0200	NET ELECTRIC OPERATING INCOME		99,071,960	42,289,977	10,952,057	14,243,087	22,709,312	10,061,166	1,108,490	(2,292,129)
0210										
0220	RATE BASE									
0230	TOTAL ELECTRIC PLANT	TSFR 10 240	3,088,544,295	1,193,442,819	194,056,075	374,762,406	686,535,014	603,907,875	13,740,415	22,099,690
0240	LESS: ACCUM. PROV. FOR DEPREC	TSFR 10 330	1,485,975,111	558,034,613	92,459,186	177,966,586	336,046,056	301,786,933	7,135,842	12,545,894
0250	NET PLANT		1,602,569,185	635,408,206	101,596,889	196,795,820	350,488,958	302,120,942	6,604,573	9,553,796
0260	PLUS:									
0270	WORKING CAPITAL	TSFR 15 380	47,586,165	13,732,518	2,378,331	5,547,374	12,405,179	13,085,862	342,345	94,555
0280	PRIOR NET PREPAID PENSION ASSET	SALWAGES	9,492,881	3,536,310	580,113	1,064,760	2,084,814	2,008,789	51,196	166,898
0290	PENSION REGULATORY ASSET	SALWAGES	14,616,226	5,444,870	893,203	1,639,416	3,209,997	3,092,941	78,826	256,974
0300	REG ASSET - HOMELAND SECURITY	TOTPLANT	0	0	0	0	0	0	0	0
0310	REG ASSET - DSM PROGRAMS	DEM1B	6,615,449	3,162,180	338,989	708,746	1,461,217	940,814	0	3,503
0320	REG ASSET - REGULATORY EXPENSE	CLAIMEDREV	0	0	0	0	0	0	0	0
0330	JANUARY 2002 ICE STORM	DISTPLANT	0	0	0	0	0	0	0	0
0340	LESS:									
0350	ACCUM. DEFERRED TAXES	TSFR 8 560	310,088,409	113,324,314	19,406,425	38,363,941	70,805,968	64,567,582	1,585,995	2,034,185
0360	DEFERRED GAIN ON EMISSION CR.	ENERGY1	37,225,452	10,982,024	2,028,956	4,384,944	9,625,586	9,843,345	275,007	85,591
0370	DEFERRED GAIN ON SO2 ALLOWANCE	ENERGY1	(736,462)	(217,266)	(40,141)	(86,751)	(190,431)	(194,739)	(5,441)	(1,693)
0380	CUST. ADVANCES FOR CONSTRUCTION	DISTPLANT	194,810	100,733	15,329	25,295	33,219	16,823	0	3,413
0390	CUSTOMER DEPOSITS	CUST21	5,477,012	3,068,924	2,002,926	336,183	57,578	11,402	0	0
0400	TOTAL RATE BASE		1,328,630,683	534,025,356	82,374,030	162,732,504	289,318,246	247,004,936	5,221,379	7,954,232
0410										
0420	RATE OF RETURN		7.457%	7.919%	13.296%	8.752%	7.849%	4.073%	21.230%	-28.816%
0430	RELATIVE RATE OF RETURN		1.00	1.06	1.78	1.17	1.05	0.55	2.85	(3.86)
0440										

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	PRESENT RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		7.46%	7.92%	13.30%	8.75%	7.85%	4.07%	21.23%	-28.82%
2										
3	REVENUES REQUIRED									
4	---									
5	**DEMAND COMPONENT**	310,200,641	310,200,641	115,634,890	26,111,237	41,887,711	71,671,274	52,641,056	2,639,688	(385,216)
6	DEMAND PRODUCTION COMPONENT		173,755,163	50,338,458	13,389,425	23,159,392	45,589,608	39,301,856	2,300,852	(324,428)
7	DEMAND TRANSMISSION COMPONENT		31,479,292	10,626,075	2,316,860	4,040,346	7,961,753	6,256,211	338,835	(60,788)
8	DEMAND DISTRIBUTION COMPONENT		104,966,186	54,670,358	10,404,953	14,687,973	18,119,914	7,082,988	0	(0)
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		61,414,564	26,557,525	5,115,456	8,002,582	15,043,215	6,695,787	0	0
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		28,763,460	20,151,672	3,814,546	4,797,242	0	(0)	0	0
11	DEMAND DISTRIBUTION TRANSFORMATION		14,788,162	7,961,162	1,474,951	1,888,149	3,076,699	387,202	0	0
12										
13	**ENERGY COMPONENT**		225,895,392	67,281,800	12,868,556	26,904,386	58,278,247	58,362,513	1,820,448	379,440
14										
15	**CUSTOMER COMPONENT**	41,790,499	41,790,499	29,513,657	4,708,334	2,610,837	1,716,852	780,912	0	2,459,907
16	CUSTOMER PRIMARY COMPONENT									
17	CUSTOMER SECONDARY COMPONENT									
18	CUSTOMER TRANSFORMATION COMPONENT									
19	CUSTOMER SERVICES COMPONENT		4,136,299	2,392,248	457,665	504,348	690,509	91,529	0	0
20	CUSTOMER METERS COMPONENT		7,892,164	4,463,935	1,662,090	975,083	419,195	371,860	0	0
21	CUSTOMER METER READING COMPONENT		3,573,612	3,154,309	337,757	64,033	15,052	2,461	0	0
22	CUSTOMER OTHER RECORDS & COLLECTIONS		12,491,689	10,278,972	1,346,066	680,226	182,938	3,487	0	0
23	CUSTOMER UNCOLLECTIBLE ACCTS		5,405,085	4,665,138	559,961	179,986	(0)	0	0	0
24	CUSTOMER OTHER CUSTOMER ASSISTANCE		1,230,406	297,816	97,745	134,402	390,765	309,678	0	0
25	CUSTOMER SALES COMPONENT		905,997	791,332	94,132	16,436	3,794	302	0	0
26	CUSTOMER MISC OTHER COMPONENT		6,155,247	3,469,908	152,917	56,322	14,599	1,594	0	2,459,907
27										
28	**TOTAL COMPANY**	577,886,532	577,886,532	212,430,348	43,688,127	71,402,934	131,666,374	111,784,481	4,460,136	2,454,132
29										
30										
31										
32	ANNUAL BOOKED KWH SALES @ METER (WN)		8,703,319,121	2,562,745,581	472,047,983	1,018,723,719	2,239,439,522	2,325,753,345	64,700,757	19,908,214
33	MONTHLY AVERAGE NUMBER OF CUSTOMERS		269,127	233,688	25,798	4,791	1,114	93	71	3,572
34										
35										
36										
37										
38										
39										
40										

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	PRESENT RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		7.46%	7.92%	13.30%	8.75%	7.85%	4.07%	21.23%	-28.82%
2										
3	$ / KWH									
4	---									
5	**DEMAND COMPONENT**		0.0356	0.0451	0.0553	0.0411	0.0320	0.0226	0.0408	(0.0193)
6	DEMAND PRODUCTION COMPONENT		0.0200	0.0196	0.0284	0.0227	0.0204	0.0169	0.0356	(0.0163)
7	DEMAND TRANSMISSION COMPONENT		0.0036	0.0041	0.0049	0.0040	0.0036	0.0027	0.0052	(0.0031)
8	DEMAND DISTRIBUTION COMPONENT		0.0121	0.0213	0.0220	0.0144	0.0081	0.0030	0.0000	(0.0000)
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		0.0071	0.0104	0.0108	0.0079	0.0067	0.0029	0.0000	0.0000
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		0.0033	0.0079	0.0081	0.0047	0.0000	(0.0000)	0.0000	0.0000
11	DEMAND DISTRIBUTION TRANSFORMATION		0.0017	0.0031	0.0031	0.0019	0.0014	0.0002	0.0000	0.0000
12										
13	**ENERGY COMPONENT**		0.0260	0.0263	0.0273	0.0264	0.0260	0.0251	0.0281	0.0191
14										
15	**CUSTOMER COMPONENT**		0.0048	0.0115	0.0100	0.0026	0.0008	0.0003	0.0000	0.1236
16	CUSTOMER PRIMARY COMPONENT									
17	CUSTOMER SECONDARY COMPONENT									
18	CUSTOMER TRANSFORMATION COMPONENT									
19	CUSTOMER SERVICES COMPONENT		0.0005	0.0009	0.0010	0.0005	0.0003	0.0000	0.0000	0.0000
20	CUSTOMER METERS COMPONENT		0.0009	0.0017	0.0035	0.0010	0.0002	0.0002	0.0000	0.0000
21	CUSTOMER METER READING COMPONENT		0.0004	0.0012	0.0007	0.0001	0.0000	0.0000	0.0000	0.0000
22	CUSTOMER OTHER RECORDS & COLLECTIONS		0.0014	0.0040	0.0029	0.0007	0.0001	0.0000	0.0000	0.0000
23	CUSTOMER UNCOLLECTIBLE ACCTS		0.0006	0.0018	0.0012	0.0002	(0.0000)	0.0000	0.0000	0.0000
24	CUSTOMER OTHER CUSTOMER ASSISTANCE		0.0001	0.0001	0.0002	0.0001	0.0002	0.0001	0.0000	0.0000
25	CUSTOMER SALES COMPONENT		0.0001	0.0003	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000
26	CUSTOMER MISC OTHER COMPONENT		0.0007	0.0014	0.0003	0.0001	0.0000	0.0000	0.0000	0.1236
27										
28	**TOTAL COMPANY**		0.0664	0.0829	0.0926	0.0701	0.0588	0.0481	0.0689	0.1233
29										
30										
31	$/MO/CUST									
32	---									
33	**CUSTOMER COMPONENT**		$12.94	$10.52	$15.21	$45.41	$128.45	$697.17	$0.00	$57.39
34	CUSTOMER PRIMARY COMPONENT									
35	CUSTOMER SECONDARY COMPONENT									
36	CUSTOMER TRANSFORMATION COMPONENT									
37	CUSTOMER SERVICES COMPONENT		$1.28	$0.85	$1.48	$8.77	$51.66	$81.71	$0.00	$0.00
38	CUSTOMER METERS COMPONENT		$2.44	$1.59	$5.37	$16.96	$31.36	$331.99	$0.00	$0.00
39	CUSTOMER METER READING COMPONENT		$1.11	$1.12	$1.09	$1.11	$1.13	$2.20	$0.00	$0.00
40	CUSTOMER OTHER RECORDS & COLLECTIONS		$3.87	$3.67	$4.35	$11.83	$13.69	$3.11	$0.00	$0.00
41	CUSTOMER UNCOLLECTIBLE ACCTS		$1.67	$1.66	$1.81	$3.13	($0.00)	$0.00	$0.00	$0.00
42	CUSTOMER OTHER CUSTOMER ASSISTANCE		$0.38	$0.11	$0.32	$2.34	$29.24	$276.47	$0.00	$0.00
43	CUSTOMER SALES COMPONENT		$0.28	$0.28	$0.30	$0.29	$0.28	$0.27	$0.00	$0.00
44	CUSTOMER MISC OTHER COMPONENT		$1.91	$1.24	$0.49	$0.98	$1.09	$1.42	$0.00	$57.39

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	EQUALIZED RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		7.46%	7.46%	7.47%	7.46%	7.46%	7.46%	7.46%	7.46%
2										
3	REVENUES REQUIRED									
4	--									
5	**DEMAND COMPONENT**	306,916,388	306,916,388	112,048,944	19,138,632	38,791,342	69,993,134	64,810,742	1,623,617	509,976
6	DEMAND PRODUCTION COMPONENT		174,240,034	48,736,353	9,889,542	21,429,981	44,457,318	47,853,630	1,428,270	444,940
7	DEMAND TRANSMISSION COMPONENT		31,568,300	10,369,681	1,750,971	3,761,291	7,779,230	7,646,744	195,347	65,036
8	DEMAND DISTRIBUTION COMPONENT		101,108,053	52,942,911	7,498,119	13,600,070	17,756,586	9,310,368	(0)	0
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		60,295,449	25,649,904	3,647,656	7,392,758	14,774,088	8,831,043	0	0
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		26,753,798	19,549,697	2,757,900	4,446,200	(0)	0	0	0
11	DEMAND DISTRIBUTION TRANSFORMATION		14,058,806	7,743,310	1,092,563	1,761,112	2,982,497	479,325	0	0
12										
13	**ENERGY COMPONENT**		226,183,496	67,080,729	12,327,047	26,647,587	58,135,719	59,822,114	1,658,113	512,187
14										
15	**CUSTOMER COMPONENT**	44,786,648	44,786,648	29,254,399	4,341,239	2,508,791	1,676,499	845,934	(0)	6,159,787
16	CUSTOMER PRIMARY COMPONENT									
17	CUSTOMER SECONDARY COMPONENT									
18	CUSTOMER TRANSFORMATION COMPONENT									
19	CUSTOMER SERVICES COMPONENT		3,899,596	2,328,798	327,515	462,497	672,704	108,083	0	0
20	CUSTOMER METERS COMPONENT		7,580,252	4,406,263	1,427,751	930,442	402,803	412,992	0	0
21	CUSTOMER METER READING COMPONENT		3,541,364	3,140,523	320,189	63,200	14,920	2,532	0	0
22	CUSTOMER OTHER RECORDS & COLLECTIONS		12,232,999	10,173,435	1,213,964	662,257	179,684	3,659	0	0
23	CUSTOMER UNCOLLECTIBLE ACCTS		5,350,923	4,641,591	531,700	177,632	0	(0)	0	0
24	CUSTOMER OTHER CUSTOMER ASSISTANCE		1,225,878	296,251	92,618	132,572	387,197	317,239	0	0
25	CUSTOMER SALES COMPONENT		891,545	784,814	86,590	16,087	3,740	314	0	0
26	CUSTOMER MISC OTHER COMPONENT		10,064,091	3,482,724	340,912	64,104	15,450	1,115	0	6,159,787
27										
28	**TOTAL COMPANY**	577,886,532	577,886,532	208,384,072	35,806,917	67,947,720	129,805,352	125,478,790	3,281,730	7,181,950
29										
30										
31										
32	ANNUAL BOOKED KWH SALES @ METER (WN)		8,703,319,121	2,562,745,581	472,047,983	1,018,723,719	2,239,439,522	2,325,753,345	64,700,757	19,908,214
33	MONTHLY AVERAGE NUMBER OF CUSTOMERS		269,127	233,688	25,798	4,791	1,114	93	71	3,572
34										
35										
36										
37										
38										
39										
40										

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	EQUALIZED RATE OF RETURN SUMMARY SCHEDULE									
1	RATE OF RETURN		7.46%	7.46%	7.47%	7.46%	7.46%	7.46%	7.46%	7.46%
2										
3	$ / KWH									
4	--									
5	**DEMAND COMPONENT**		0.0353	0.0437	0.0405	0.0381	0.0313	0.0279	0.0251	0.0256
6	DEMAND PRODUCTION COMPONENT		0.0200	0.0190	0.0210	0.0210	0.0199	0.0206	0.0221	0.0223
7	DEMAND TRANSMISSION COMPONENT		0.0036	0.0040	0.0037	0.0037	0.0035	0.0033	0.0030	0.0033
8	DEMAND DISTRIBUTION COMPONENT		0.0116	0.0207	0.0159	0.0134	0.0079	0.0040	(0.0000)	0.0000
9	DEMAND DISTRIBUTION PRIMARY COMPONENT		0.0069	0.0100	0.0077	0.0073	0.0066	0.0038	0.0000	0.0000
10	DEMAND DISTRIBUTION SECONDARY COMPONENT		0.0031	0.0076	0.0058	0.0044	(0.0000)	0.0000	0.0000	0.0000
11	DEMAND DISTRIBUTION TRANSFORMATION		0.0016	0.0030	0.0023	0.0017	0.0013	0.0002	0.0000	0.0000
12										
13	**ENERGY COMPONENT**		0.0260	0.0262	0.0261	0.0262	0.0260	0.0257	0.0256	0.0257
14										
15	**CUSTOMER COMPONENT**		0.0051	0.0114	0.0092	0.0025	0.0007	0.0004	(0.0000)	0.3094
16	CUSTOMER PRIMARY COMPONENT									
17	CUSTOMER SECONDARY COMPONENT									
18	CUSTOMER TRANSFORMATION COMPONENT									
19	CUSTOMER SERVICES COMPONENT		0.0004	0.0009	0.0007	0.0005	0.0003	0.0000	0.0000	0.0000
20	CUSTOMER METERS COMPONENT		0.0009	0.0017	0.0030	0.0009	0.0002	0.0002	0.0000	0.0000
21	CUSTOMER METER READING COMPONENT		0.0004	0.0012	0.0007	0.0001	0.0000	0.0000	0.0000	0.0000
22	CUSTOMER OTHER RECORDS & COLLECTIONS		0.0014	0.0040	0.0026	0.0007	0.0001	0.0000	0.0000	0.0000
23	CUSTOMER UNCOLLECTIBLE ACCTS		0.0006	0.0018	0.0011	0.0002	0.0000	(0.0000)	0.0000	0.0000
24	CUSTOMER OTHER CUSTOMER ASSISTANCE		0.0001	0.0001	0.0002	0.0001	0.0002	0.0001	0.0000	0.0000
25	CUSTOMER SALES COMPONENT		0.0001	0.0003	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000
26	CUSTOMER MISC OTHER COMPONENT		0.0012	0.0014	0.0007	0.0001	0.0000	0.0000	0.0000	0.3094
27										
28	**TOTAL COMPANY**		0.0664	0.0813	0.0759	0.0667	0.0580	0.0540	0.0507	0.3608
29										
30										
31	$/MO/CUST									
32	--									
33	**CUSTOMER COMPONENT**		$13.87	$10.43	$14.02	$43.64	$125.43	$755.22	($0.00)	$143.72
34	CUSTOMER PRIMARY COMPONENT									
35	CUSTOMER SECONDARY COMPONENT									
36	CUSTOMER TRANSFORMATION COMPONENT									
37	CUSTOMER SERVICES COMPONENT		$1.21	$0.83	$1.06	$8.04	$50.33	$96.49	$0.00	$0.00
38	CUSTOMER METERS COMPONENT		$2.35	$1.57	$4.61	$16.18	$30.14	$368.71	$0.00	$0.00
39	CUSTOMER METER READING COMPONENT		$1.10	$1.12	$1.03	$1.10	$1.12	$2.26	$0.00	$0.00
40	CUSTOMER OTHER RECORDS & COLLECTIONS		$3.79	$3.63	$3.92	$11.52	$13.44	$3.27	$0.00	$0.00
41	CUSTOMER UNCOLLECTIBLE ACCTS		$1.66	$1.66	$1.72	$3.09	$0.00	($0.00)	$0.00	$0.00
42	CUSTOMER OTHER CUSTOMER ASSISTANCE		$0.38	$0.11	$0.30	$2.31	$28.97	$283.22	$0.00	$0.00
43	CUSTOMER SALES COMPONENT		$0.28	$0.28	$0.28	$0.28	$0.28	$0.28	$0.00	$0.00
44	CUSTOMER MISC OTHER COMPONENT		$3.12	$1.24	$1.10	$1.12	$1.16	$1.00	$0.00	$143.72

KANSAS CITY POWER & LIGHT COMPANY
CASE NO. ______________________
CLASS COST OF SERVICE FOR MISSOURI CUSTOMERS
2006 TEST YR INCL KNOWN & MEAS TO 9-30-07 (SEPT TRUE-UP)
DETAILED ALLOCATION FACTOR DESCRIPTION

	DESCRIPTION	ALLOCATION FACTOR	REFERENCE
1	**EXTERNALLY DEVELOPED DEMAND RELATED**		
2			
3	PRODUCTION DEMAND (ENE @ GEN) - AVERAGE DEMAND	DEMAVG	INPUT - Average Demand, Source File: KCPL Allocators - PMN Final 1.xls, Energy Summary Sheet, Columns 13 thru15
4			
5	PRODUCTION DEMAND - 12 CP REMAINING	DEM12CPR	INPUT - Average 12 Coincident Peaks (Remaining), Source File: KCPL Allocators - PMN Final 1.xls, CP Sheet, Columns 24 thru 26
6			
7	PRODUCTION DEMAND - 12 CP	DEM12CP	INPUT - Average 12 Coincident Peaks, Source File:KCPL Allocators - PMN Final 1.xls, CP Sheet, Columns 13 thru15
8			
9	PRODUCTION DEMAND - 4 CP	DEM4CP	INPUT - Average 4 Coincident Peaks, Source File:KCPL Allocators - PMN Final 1.xls, CP Sheet, Column 28
10			
11	PROD AVERAGE DEMAND (LOWEST MO RT USAGE) - BASE	DEM1A	INPUT - Base Average Demand, Source File:KCPL Allocators - PMN Final 1.xls, CP Sheet, Columns 16 thru18
12	PROD REMAINING STEAM (12CP - BASE) - INTERMEDIATE	DEM1B	INPUT - Average 12 Coincident Peaks less Base Average Demand, Source File:KCPL Allocators - PMN Final.xls, CP Sheet, Columns 13 thru15
13	PROD DEMAND (4 CP-BASE & INTERMEDIATE) - PEAKING	DEM1C	INPUT - Average 4 Coincident Peaks less Base Average Demand less Remaining CP, Source File:KCPL Allocators - PMN Final 1.xls, CP Sheet, Column 31
14	TOTAL BASE, INTERMEDIATE, & PEAKING	DEM1	DEM1A = DEM1A + DEM1B + DEM1C
15			
16	PRODUCTION DEMAND (=DEM1A) - NOT USED	DEM2	DEM2 = DEM1A
17	PRODUCTION ALLOCATION TO OTHER LIGHTING	DEM11	INPUT - Direct assignment to Other Lighting
18	PLCC CREDITS	DEM12	INPUT - Direct assignment (not used)
19			
20			
21	TRANSMISSION DEMAND (SUM OF PRODUCTION PLANT)	DEM3	Sum of Production Plant
22			
23	DIST CUSTOMER (NCP) - PRIMARY (=DEM8) - NOT USED	DEM4	DEM4 = DEM8
24	DIST CUSTOMER (NCP) - SECONDARY (=DEM7) - NOT USED	DEM5	DEM5 = DEM7
25	DIST DEMAND (NCP) - SUBSTATION VOLTAGE	DEM6	INPUT - Maximum Non Coincident Peaks, Source File:KCPL Allocators - PMN Final 1.xls, NCP Sheet, Columns 19 and 20 (Excludes Transmission)
26	DIST DEMAND (NCP) - PRIMARY VOLTAGE	DEM8	INPUT - Maximum Non Coincident Peaks, Source File:KCPL Allocators - PMN Final 1.xls, NCP Sheet, Columns 19 and 20 (Excludes Subtation and Transmission)
27	DIST DEMAND (NCP) - SECONDARY VOLTAGE	DEM7	INPUT - Maximum Non Coincident Peaks, Source File:KCPL Allocators - PMN Final 1.xls, NCP Sheet, Columns 25 and 26 (Secondary only)
28	DIST DEMAND (NCP) - SECONDARY LINE XFMR	DEM9	INPUT - Maximum Non Coincident Peak Demands (Same as DEM7 excluding Large General Service)
29	DIST DEMAND (NCP) - PRIMARY LINE XFMR (=DEM8 NA)	DEM10	DEM10 = DEM8 (not used)
30			
31			
32	**EXTERNALLY DEVELOPED ENERGY RELATED**		
33			
34	ENERGY SALES @ GENERATION WITH LOSSES	ENERGY1	INPUT - Loss Adjusted Energy Sales @ Generation, Source File: KCPL Allocators - PMN Final 1.xls, Energy Summary Sheet, Columns 13 thru 15
35	ENERGY BOOKED KWH SALES @ METER (WN)	ENERGY2	INPUT - Loss Adjusted Weather Normalized Energy Sales @ Meter, Source File: KCPL Allocators - PMN Final 1.xls, Sales Sheet, Columns 13 thru 15
36	OFF-SYSTEM SALES PROFITS - NOT USED	ENERGY3	Not Used
37	EDR CREDITS - NOT USED	ENERGY4	Not Used
38	MO ENE @ GEN W/LOSSES * MO AVG FUEL COSTS	ENEFUEL	INPUT - Loss Adjusted Energy Sales @ Generation Ratios * Avg 2006 & 2007 Fuel Cost, Source File: KCPL Allocators - PMN Final 1.xls, Energy Summary Sheet, Columns 13 thru 15
39			
40			

KANSAS CITY POWER & LIGHT COMPANY
CASE NO. ____________________
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DETAILED ALLOCATION FACTOR DESCRIPTION

	DESCRIPTION	ALLOCATION FACTOR	REFERENCE
41			
42	**EXTERNALLY DEVELOPED CUSTOMER RELATED**		
43			
44	WEIGHTED AVERAGE CUSTOMERS - PRI & SEC	CUST1	INPUT - Weather Normalized Average Monthly Number of Primary and Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 3
45	WEIGHTED AVERAGE CUSTOMERS - SEC ONLY	CUST2	INPUT - Weather Normalized Average Monthly Number of Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 4
46	WEIGHTED CUSTOMERS - TRANSFORMERS (=CUST2)	CUST3	INPUT - Weather Normalized Average Monthly Number of Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 5
47	MAXIMUM DIVERSIFIED DEMANDS - 369 SERVICES	CUST4	INPUT - MDD, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 6 (excludes primary, substation, and transmission)
48	PLANT ACCOUNT 370 - METER INVESTMENT	CUST5	INPUT - Account 370-Meter Investment (meter portion) based on number of meter and meter cost, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 7
49	AVERAGE NUMBER OF METERS - 902 METER READING EXP	CUST6	INPUT - Average Monthly Number of Meters, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 8
50	EXPENSE ACCOUNT 903 - RECORDS & COLLECT (COLLECT)	CUST7	INPUT - Collections Expense by Rate Class, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 9
51	EXPENSE ACCOUNT 903 - "B" READING (NOT USED)	CUST8	Not used
52	EXPENSE ACCOUNT 903 - RECORDS & COLLECT (OTHER)	CUST9	INPUT - Records and Collections Expense (other than collections) by Rate Class, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 11
53	EXPENSE ACCOUNT 904 - UNCOLLECTIBLES	CUST10	INPUT - Rate Class Write Offs net of Recoveries, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 12
54	EXPENSE ACCOUNT 908 - CUST ASSIST (PUBLIC INFO)	CUST11	INPUT - Rate Class Customer Assistance Expense, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 13
55	EXPENSE ACCOUNT 908 - CUST ASSIST (OTHER)	CUST12	INPUT - Rate Class Customer Assistance Expense, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 14
56	WEIGHTED AVG CUST - 911 SUPERVISION (NOT USED)	CUST13	Not used
57	WEIGHTED AVG CUST - 912 DEMO & SELLING (=CUST1)	CUST14	INPUT - Weather Normalized Average Monthly Number of Primary and Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 16
58	WEIGHTED AVG CUST - 913 ADVERTISING (=CUST1)	CUST15	INPUT - Weather Normalized Average Monthly Number of Primary and Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 17
59	WEIGHTED AVG CUST - 916 MISC SALES EXP (=CUST1)	CUST16	INPUT - Weather Normalized Average Monthly Number of Primary and Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 18
60	WEIGHTED CUSTOMERS - OTHER MISC CUST (=CUST1)	CUST17	INPUT - Weather Normalized Average Monthly Number of Primary and Secondary Customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 19
61	PLANT ACCOUNT 371 - INSTALLATIONS ON CUST PREMISES	CUST18	INPUT - Direct Assignment to Other Lighting
62	PLANT ACCOUNT 373 - STREET LTG & SIGNAL SYSTEMS	CUST19	INPUT - Direct Assignment to Other Lighting
63	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 Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 22
64	CUSTOMER DEPOSITS	CUST21	INPUT - Customer Deposits based dollars and allocated on number of customers, Source File: KCPL Allocators - PMN Final 1.xls, Customer Summary Sheet, Column 23
65			

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	DESCRIPTION	ALLOCATION FACTOR	REFERENCE
66			
67	**INTERNALLY DEVELOPED ALLOCATION FACTORS**		
68			
69	ACCT 303-MISC. INTANGIBLE PLANT	PLT303	SCHEDULE 11, LINE 2860
70	ACCT 340 -LAND RIGHTSACCT 340 -LAND RIGHTS	PLT340	SCHEDULE 11, LINE 680 + LINE 780
71	ACCT 341-STRUCTURES & IMPROVEMENTS	PLT341	SCHEDULE 11, LINE 690 + LINE 790
72	ACCT 342-FUEL HOLDERS, PRODUCERS AND ACC	PLT342	SCHEDULE 11, LINE 700
73	ACCT 344 -GENERATORS	PLT344	SCHEDULE 11, LINE 710 + LINE 800
74	ACCT 345 -ACCESSORY ELECTRIC EQUIPMENT	PLT345	SCHEDULE 11, LINE 720 + LINE 810
75	ACCT 350-LAND RIGHTS	PLT350LR	SCHEDULE 11, LINE 980
76	ACCT 352- STRUCTURES & IMPROVEMENTS	PLT352	SCHEDULE 11, LINE 1030
77	ACCT 353-STATION EQUIPMENT	PLT353	SCHEDULE 11, LINE 1080
78	ACCT 354-TOWERS & FIXTURES	PLT354	SCHEDULE 11, LINE 1100
79	ACCT 355-POLES & FIXTURES	PLT355	SCHEDULE 11, LINE 1170
80	ACCT 356-OVERHEAD COND. & DEVICES	PLT356	SCHEDULE 11, LINE 1240
81	ACCT 357-UNDERGROUND CONDUIT	PLT357	SCHEDULE 11, LINE 1260
82	ACCT 358-UNDERGROUND COND. & DEVICES	PLT358	SCHEDULE 11, LINE 1280
83	ACCT 360- LAND RIGHTS	PLT360LR	SCHEDULE 11, LINE 1390
84	ACCT 361-STRUCTURES & IMPROVEMENTS	PLT361	SCHEDULE 11, LINE 1420
85	ACCT 362-STATION EQUIPMENT	PLT362	SCHEDULE 11, LINE 1470
86	ACCT 362-COMMUNICATIONS	PLT362COM	SCHEDULE 11, LINE 1460
87	ACCT 364-POLES, TOWERS & FIXTURES	PLT364	SCHEDULE 11, LINE 1560
88	ACCT 365-OH CONDUCT & DEVICES	PLT365	SCHEDULE 11, LINE 1650
89	ACCT 366-UNDERGROUND CONDUIT	PLT366	SCHEDULE 11, LINE 1740
90	ACCT 367-UG CONDUCT & DEVICES	PLT367	SCHEDULE 11, LINE 1880
91	ACCT 368-LINE TRANSFORMERS	PLT368	SCHEDULE 11, LINE 1970
92	ACCT 369-SERVICES	PLT369	SCHEDULE 11, LINE 1990
93	ACCT 370-METERS	PLT370	SCHEDULE 11, LINE 2060
94	ACCT 370R-LOAD RESEARCH EQUIPMENT	PLT370LR	SCHEDULE 11, LINE 2020
95	ACCT 371-INSTALLATION ON CUST. PREMISES	PLT371	SCHEDULE 11, LINE 2080
96	ACCT 373-STREET LIGHTS & SIGNAL SYSTEMS	PLT373	SCHEDULE 11, LINE 2100
97	ACCT 392-TRANSPORTATION EQUIPMENT	PLT392	SCHEDULE 11, LINE 2440
98	TOTAL STEAM PRODUCTION PLANT	STEAMPLANT	SCHEDULE 11, LINE 350
99	TOTAL NUCLEAR PRODUCTION PLANT	NUCLPLANT	SCHEDULE 11, LINE 640
100	TOTAL OTHER PRODUCTION PLANT	OTHPPLANT	SCHEDULE 11, LINE 740 + LINE 830
101	TOTAL OTHER PRODUCTION PLANT - CT	OTHPPLTCT	SCHEDULE 11, LINE 740
102	TOTAL OTHER PRODUCTION PLANT - WIND	OTHPPLTW	SCHEDULE 11, LINE 830
103	TOTAL PRODUCTION PLANT	PRODPLANT	SCHEDULE 11, LINE 850
104	TOTAL PROD. PLANT LESS NUCLEAR (WOLF CREEK)	PRODWOWC	SCHEDULE 11, LINE 850 - LINE 640
105	TOTAL TRANSMISSION PLANT	TRANSPLT	SCHEDULE 11, LINE 1310
106	TOTAL DISTRIBUTION PLANT	DISTPLANT	SCHEDULE 11, LINE 2330
107	TOTAL GENERAL PLANT	GENPLANT	SCHEDULE 11, LINE 2560
108			

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	DESCRIPTION	ALLOCATION FACTOR	REFERENCE
109			
110	**INTERNALLY DEVELOPED ALLOCATION FACTORS**		
111			
112	TOTAL TRANS. & DIST. PLANT	TD	SCHEDULE 11, LINE 1310 + LINE 2330
113	TOTAL PROD., TRANS., DIST.	PTD	SCHEDULE 11, LINE 2350
114	TOTAL PTD PLANT LESS WOLF CREEK	PTDWOWC	SCHEDULE 11, LINE 2350 - LINE 640
115	TOTAL PROD., TRANS., DIST., GEN.	PTDG	SCHEDULE 11, LINE 2350 + LINE 2560
116	TOTAL ELECTRIC PLANT IN SERVICE	TOTPLANT	SCHEDULE 11, LINE 2930
117	TOTAL ELEC. PLANT LESS WOLF CREEK	ELECWOWC	SCHEDULE 11, LINE 2930 - LINE 640
118	GROSS ELECTRIC PLANT IN SERVICE	PLTINSERV	SCHEDULE 11, LINE 2930
119	PROD. ACCUM. DEPR. SUBTOTAL BEFORE RWIP	PRODRES	SCHEDULE 12, LINE 780
120	TRANS. ACCUM. DEPR. SUBTOTAL BEFORE RWIP	TRANSRES	SCHEDULE 12, LINE 1080
121	DIST ACCUM. DEPR. SUBTOTAL BEFORE RWIP	DISTRES	SCHEDULE 12, LINE 1270
122	GEN ACCUM. DEPR. BEFORE RWIP	GENRES	SCHEDULE 12, LINE 1510
123	TOTAL NET ELECTRIC PLANT	NETPLANT	SCHEDULE 11, LINE 2930 - SCHEDULE 12, LINE 1610
124	TOTAL RATE BASE	RATEBASE	SCHEDULE 1, LINE 400
125			
126	ACCT 904-UNCOLLECTIBLE ACCOUNTS	BADDEBT	SCHEDULE 4, LINE 3050
127	TOTAL CUST. ACCT. EXPENSE	CUSACEXP	SCHEDULE 4, LINE 3070
128	TOTAL CUST SERVICES & INFOR EXPENSE	CUSSVEXP	SCHEDULE 4, LINE 3190
129	TOTAL DISTRIBUTION EXPENSES	DISTEXP	SCHEDULE 4, LINE 2940
130	TOTAL DISTRIBUTION MAINTENANCE	DISTMTC	SCHEDULE 4, LINE 2890
131	TOTAL DISTRIBUTION OPERATIONS	DISTOPS	SCHEDULE 4, LINE 2760
132	GROSS RECEIPTS TAX	GRT	SCHEDULE 6, LINE 170
133	TOTAL NUCLEAR PRODUCTION EXPENSES	NUCLEXP	SCHEDULE 4, LINE 1590
134	TOTAL POWER PRODUCTION EXPENSES	PRODEXP	SCHEDULE 4, LINE 2400
135			
136	SUBTOTAL - RETAIL SALES REVENUE	RDREV	SCHEDULE 2, LINE 40 + LINE 60
137	SUBTOTAL - COS RETAIL SALES	REVENUE	SCHEDULE 2, LINE 40 + LINE 60 + LINE 170
138			
139	SUBTOTAL SALARIES & WAGES W/O A&G	SALWAGES	SCHEDULE 18, LINE 130
140	SALES EXPENSE	SALESEXP	SCHEDULE 4, LINE 3300
141	TOTAL TRANSMISSION EXPENSES	TRANSEXP	SCHEDULE 4, LINE 2620
142	CASH WORKING CAPITAL	CWC	SCHEDULE 16, LINE 2100
143	ACCUMULATED DEFERRED TAX	ACCDEFTAX	SCHEDULE 8, LINE 560
144	RETAIL SALES AT CLAIMED RATE OF RETURN	CLAIMEDREV	SCHEDULE 2, LINE 40 + LINE 60 + LINE 170
145	REVENUE INCREASE	REVINCR	SCHEDULE 1, LINE 860
146			
147	WOLF CREEK PRODUCTION PAYROLL	WCPRODPAY	SCHEDULE 4, LINE 3810
148			