Exhibit No.:	
Issue:	Cost of Service | Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Missouri Industrial Energy Consumers and Midwest Energy Consumers' Group
Case No.:	ER-2014-0370
Date Testimony Prepared:	April 16, 2015

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-2014-0370**

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers
and
Midwest Energy Consumers' Group

April 16, 2015

BRUBAKER & ASSOCIATES, INC.

Project 9979

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-2014-0370**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers and Midwest Energy Consumers' Group in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0370.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

M E Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 15th day of April, 2015.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2019
Commission # 15024862

Tammy S Klossner
Notary Public

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Direct Testimony of Maurice Brubaker

BEFORE THE PUBLIC SERVICE COMMISSION
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Direct Testimony of Maurice Brubaker

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **ARE YOU THE SAME MAURICE BRUBAKER WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?**

A Yes. I have previously filed direct testimony on revenue requirement issues presented in this proceeding.

Q **ARE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN YOUR PRIOR TESTIMONY?**

A Yes. This information is included in Appendix A to my revenue requirement direct testimony filed April 2, 2015.

Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC") and Midwest Energy Consumers' Group ("MECG"). These companies purchase substantial amounts of electricity from Kansas City Power & Light Company

("KCPL") and the outcome of this proceeding will have an impact on their cost of electricity.

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A The purpose of my testimony is to present the results of a class cost of service study for KCPL, to explain how the study should be used, to recommend an appropriate allocation of any rate increase, and to make rate design recommendations.

Q **HOW IS YOUR TESTIMONY ORGANIZED?**

A First, I present an overview of cost of service principles and concepts. This includes a description of how electricity is produced and distributed as well as a description of the various functions that are involved; namely, generation, transmission and distribution. This is followed by a discussion of the typical classification of these functionalized costs into demand-related costs, energy-related costs and customer-related costs.

With this as a background, I then explain the various factors which should be considered in determining how to allocate these functionalized and classified costs among customer classes.

Finally, I present the results of the detailed cost of service analysis for KCPL. This cost study indicates how individual customer class revenues compare to the costs incurred in providing service to them. This analysis and interpretation is then followed by recommendations with respect to the alignment of class revenues with class costs. I conclude by addressing rate design issues.

Summary

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level of rates charged to customers.

2. KCPL exhibits significant summer peak demands as compared to demands in other months.

3. There are two generally accepted methods for allocating generation and transmission fixed costs that would apply to KCPL. These are the coincident peak methodology and the average and excess ("A&E") methodology.

4. The A&E methodology appropriately considers both class maximum demands and class load factor, as well as diversity between class peaks and the system peak.

5. In order to better reflect cost-causation, I have changed KCPL's submitted cost of service methodology by substituting the Average and Excess - 4 Non-Coincident Peak ("A&E-4NCP") method for KCPL's seriously flawed Average and Peak ("A&P") method.

6. The results of my class cost of service study, incorporating the change in methodology that I have applied, are summarized on Schedule MEB-COS-4. Schedule MEB-COS-5 shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates.

7. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6.

8. Schedules MEB-COS-7 and MEB-COS-8 show my recommended adjustments to the design of the Large Power Service ("LPS") and Large General Service ("LGS") rates, respectively.

9. If the Commission approves a Fuel Adjustment Charge ("FAC"), the voltage level distinctions (for purposes of recognizing losses) should be secondary, primary, substation and transmission.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A The objective of *cost allocation* is to determine what proportion of the utility's total revenue requirement should be recovered from each customer class. As an aid to this determination, cost of service studies are usually performed to determine the portions of the total costs that are incurred to serve each customer class. The cost of service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design. For many regulators, cost-based rates are an expressed goal. To better interpret cost allocation and cost of service studies, it is important to understand the production and delivery of electricity.

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

A No. Electricity is different from most other goods or services purchased by consumers. For example:

- It cannot be stored; must be delivered as produced;
- It must be delivered to the customer's home or place of business;
- The delivery occurs instantaneously when and in the amount needed by the customer; and
- Both the total quantity used (energy or kWh) by a customer and the rate of use (demand or kW) are important.

These unique characteristics differentiate electric utilities from other service-related industries.

The service provided by electric utilities is multi-dimensional. First, unlike most vital services, electricity must be delivered at the place of consumption – homes, schools, businesses, factories – because this is where the lights, appliances, machines, air conditioning, etc. are located. Thus, every utility must provide a path through which electricity can be delivered regardless of the customer's **demand** and **energy** requirements at any point in time.

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, air conditioning, perhaps heating, and to operate various appliances. At any instant, several appliances may be operating (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and when reflects the second dimension of utility service – the rate of electricity use or **demand**. The demand imposed by customers is an especially important characteristic because the maximum demands determine how much capacity the utility is obligated to provide.

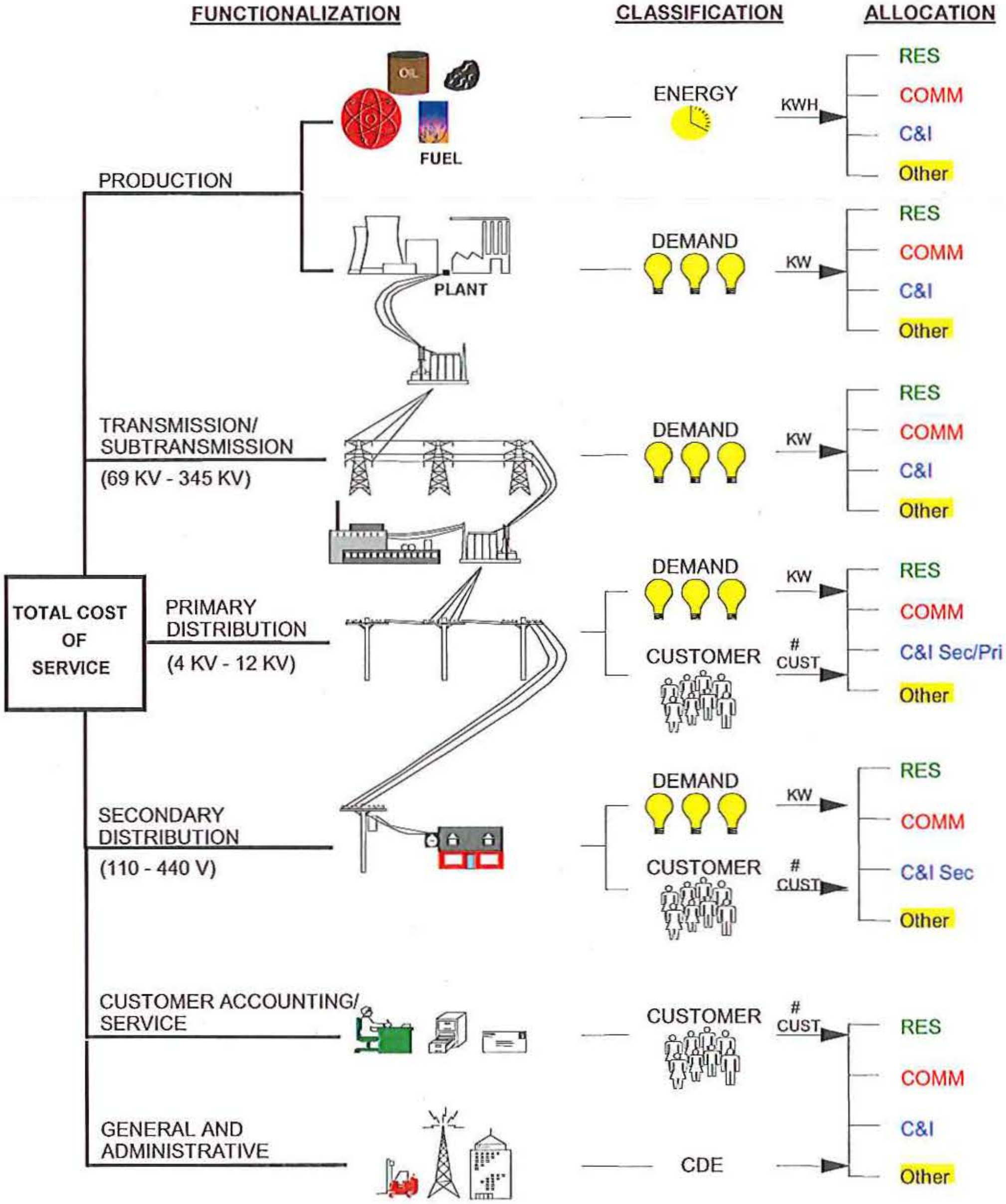
Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can safely be imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 2,000 MW of electricity, the utility must have at least 2,000 MW of generation, plus additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and air conditioning systems cool our homes, schools, offices, and factories.

Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so, consider a more familiar commodity – tomatoes, for example.

The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the service of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

As illustrated in Figure 1, electric utilities are similar, except that in most cases (including Missouri), a single company handles everything from production on down through wholesale (bulk and area transmission) and retail (distribution to homes and stores). The crucial difference is that, unlike producers and distributors of tomatoes, electric utilities have an obligation to provide continuous reliable service. The obligation is assumed in return for the exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kWh) requirements of its customers, the obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

Figure 1
PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

Q PLEASE EXPLAIN HOW A COST OF SERVICE STUDY IS PREPARED.

A To the extent possible, the unique characteristics that differentiate electric utilities from other service-related industries should be recognized in determining the cost of providing service to each of the various customer classes. The basic procedure for conducting a class cost of service study is simple. In an allocated cost of service study, we identify the different types of costs (**functionalization**), determine their primary causative factors (**classification**) and then apportion each item of cost among the various rate classes (**allocation**). Adding up the individual pieces gives the total cost for each customer class.

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

A Identifying the different levels of operation is a process referred to as **functionalization**. The utility's investment and expenses are separated by function (production, transmission, etc.). To a large extent, this is done in accordance with the Uniform System of Accounts.

Referring to Figure 1, at the top level there is generation. The next level is the extra high voltage transmission and subtransmission system (69,000 volts to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution – 4,160 to 12,000 volts. Finally, the voltage is stepped down by pole transformers at the "secondary" level to 110-440 volts used to serve homes, barbershops, light manufacturing and the like. Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltage.

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but when you buy a kWh at home you're not only buying the energy itself but also the service of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like some of the Large Power Service customers – pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment, or pay separately for some services.)

Classification

Q WHAT IS CLASSIFICATION?

A Once the costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as **classification**. Costs are classified as demand-related, energy-related or customer-related.

Looking at the production function, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 2,000 MW – it must install and/or contract for enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance ("O&M") expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kWhs generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned – and therefore the amount of fuel expense – is closely related to the amount of energy (number of kWhs) that customers use. Therefore, fuel expense is an energy-related cost.

Most other O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.

Customer-related costs are the third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

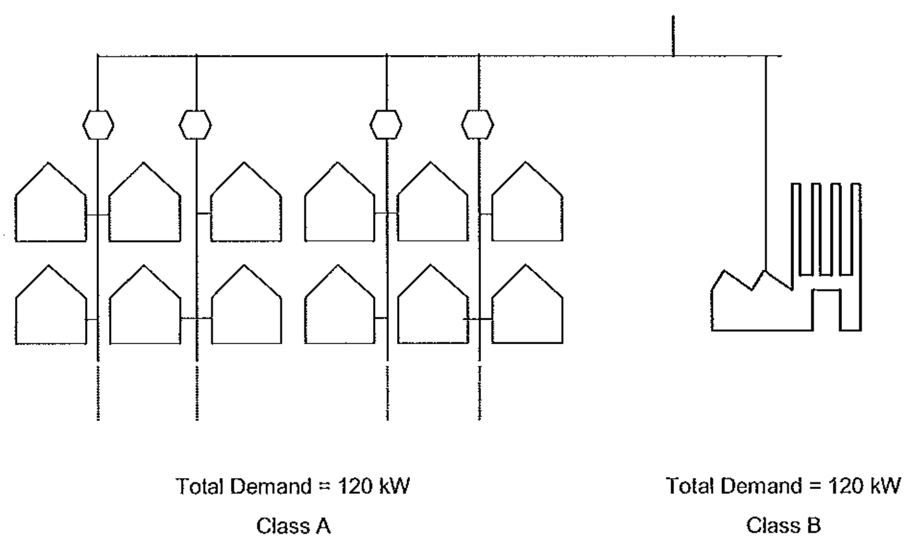
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2

Classification of Distribution Investment



Demand vs. Energy Costs

Q WHAT IS THE DISTINCTION BETWEEN DEMAND-RELATED COSTS AND ENERGY-RELATED COSTS?

A The difference between demand-related and energy-related costs explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3 compares the electrical requirements of two customers, A and B, each using 100-watt light bulbs.

Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy -- 1,000 watthours or 1 kWh. However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kW, than Customer B who demanded only 200 watts per hour or 0.2 kW.

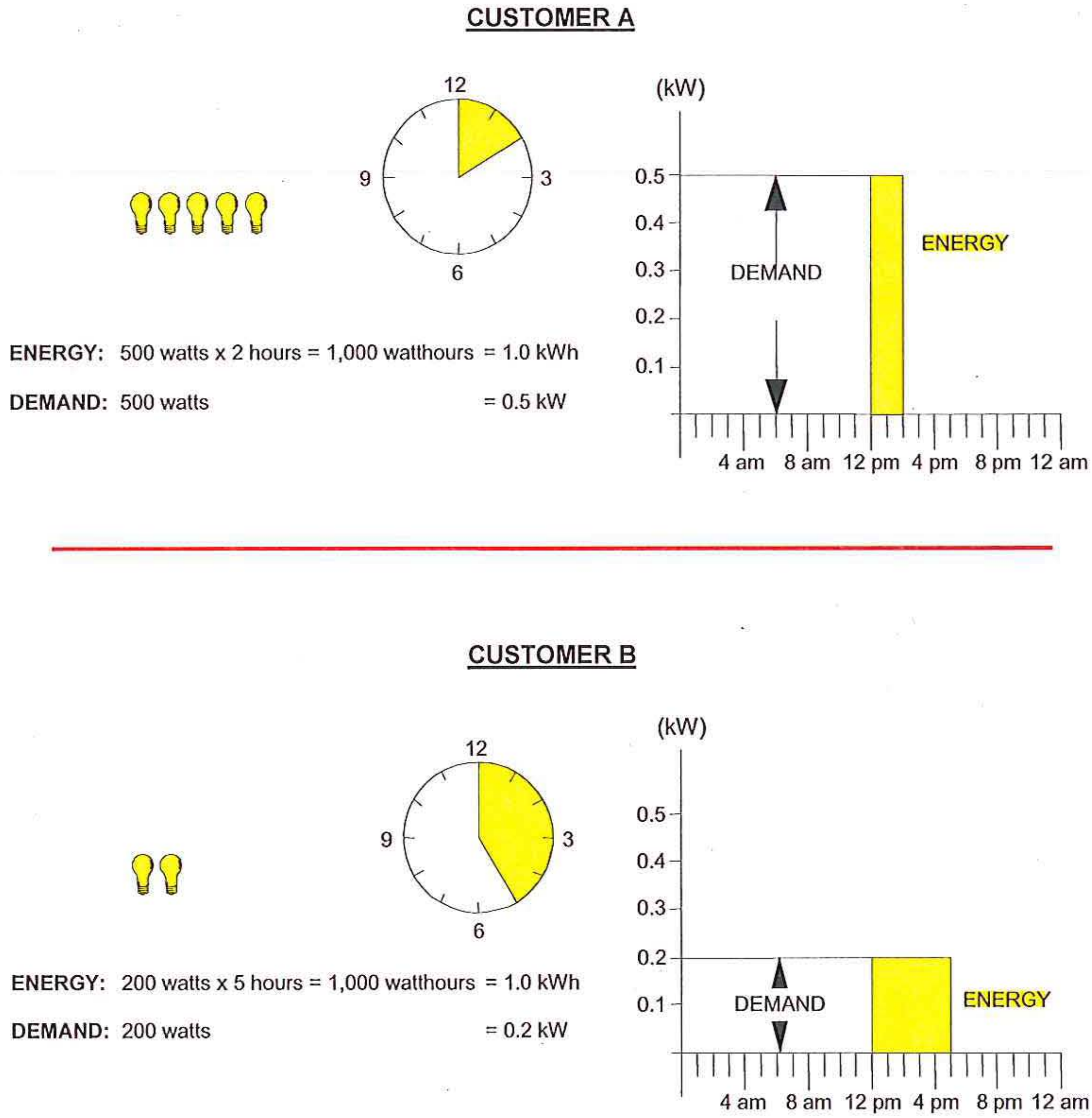
Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each kilowatt of demand imposed on the system is much greater in the case of Customer B.

Figure 3

DEMAND VS. ENERGY



Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kWh basis, than a customer with a low load factor, irrespective of size.

Consider also the analogy of a rental car which costs $40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be $2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the <u>average total</u> cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kWh will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industrial customers generally have higher load factors than residential or commercial customers, they are less costly to serve on a per-kWh basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

Allocation

Q WHAT IS ALLOCATION?

A The final step in the cost of service analysis is the **allocation** of the costs to the customer classes. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. For demand-related costs, we construct an allocation factor by looking at the important class demands.

Utility System Characteristics

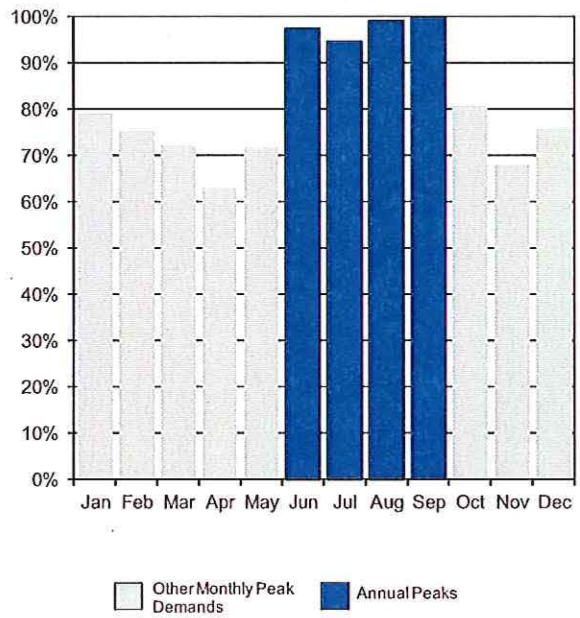
Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for KCPL's Missouri jurisdiction are shown on Schedule MEB-COS-1. For convenience, it is also shown here as Figure 4.

Figure 4

KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak For the Test Year Ended March 31, 2014



This shows the monthly system peak demands for the test year used in the study. The highlighted bar shows the month in which the highest peak occurred.

This analysis shows that summer peaks dominate the KCPL system. (This same information is presented in tabular form on Schedule MEB-COS-2.) This clearly shows that the system peak occurred in September, and was substantially higher than the monthly peaks occurring in most other months. The peaks in June, July and August were only 2.4%, 5.2%, and 0.7%, respectively, lower than the annual peak.

Q **WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?**

A The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that caused the utility to incur capacity costs.

Q **WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?**

A As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class's contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then demands in all months may be important.

Q **WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE KCPL SYSTEM?**

A As noted, the KCPL load pattern has predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission costs. Demands in other months are of much less significance, do not compel the addition of generation capacity to serve them and should not be used in determining the allocation of costs.

Q **WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?**

A The two most predominantly used allocation methods in the industry are the coincident peak method and the A&E demand method.

The coincident method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of KCPL, this would be one or more peaks occurring during the summer.

Q **WHAT IS THE A&E METHOD?**

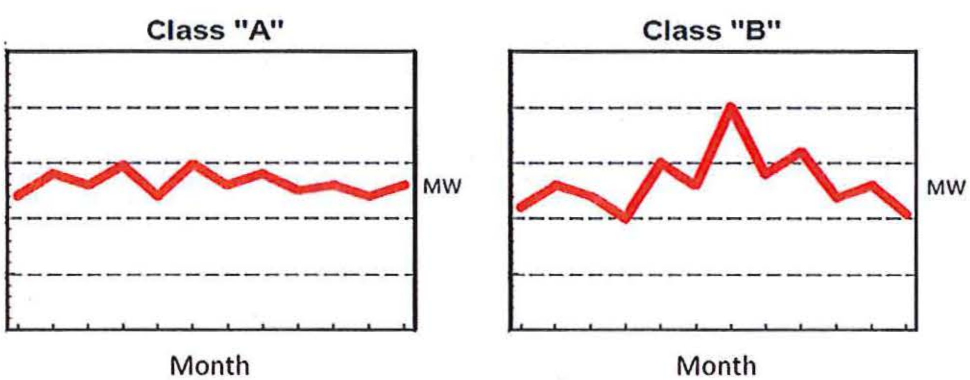
A The A&E method is one of a family of methods which incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.

Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.[1]

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

A As an example, Figure 5 shows two classes that have different monthly usage patterns.

Figure 5
Load Patterns



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[2] than Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected

[1] NARUC Electric Utility Cost Allocation Manual, 1992, page 81.
[2] During any specified time period (e.g., month, year), the maximum demand of a class, regardless of when it occurs, is called the non-coincident peak demand.

maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment, resulting in higher maintenance cost.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).

Q **WHAT DEMAND ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR GENERATION AND TRANSMISSION?**

A First, in order to reflect cost-causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

Either a coincident peak study, using the demands during the summer (peak) months, or a version of an A&E cost of service study that uses class non-coincident peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I will make my recommendations based on the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

Based on test year load characteristics, I believe the most appropriate A&E allocation would be using the two highest system peaks. However, the allocation factors for all classes are very close to the A&E-4NCP allocation factors, and I have chosen to use the 4NCP version that has previously been endorsed by the Commission.

Schedule MEB-COS-3 shows the derivation of the A&E demand allocation factor for generation using the four annual class non-coincident peaks, and page 1 of my MEB-COS-Appendix shows the derivation of the A&E-2NCP allocation factor.

Q REFERRING TO SCHEDULE MEB-COS-3, PLEASE EXPLAIN THE DEVELOPMENT OF THE A&E ALLOCATION FACTOR.

A Line 2 shows the average of the four non-coincident peaks for each class. Line 3 shows the annual amount of energy required by each class. Line 4 is the average demand, in kilowatts, which is determined by dividing the annual energy in line 3 by the number of hours (8,760) in a year. Line 5 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown on line 6, is equal to the non-coincident peak demand shown on line 2 minus the average demand that is shown on line 4. Line 7 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

Finally, line 10 presents the composite A&E allocation factor. It is determined by weighting the average demand responsibility of each class (which is the same as each class's energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

Making the Cost of Service Study – Summary

Q PLEASE SUMMARIZE THE PROCESS AND THE RESULTS OF A COST OF SERVICE ANALYSIS.

A As previously discussed, the cost of service procedure involves three steps:

1. Functionalization – Identify the different functional "levels" of the system;
2. Classification – Determine, for each functional type, the primary cause or causes (customer, demand or energy) of that cost being incurred; and
3. Allocation – Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

A The results are presented in Schedule MEB-COS-4, which reflects results at present rates.

Q REFERRING TO SCHEDULE MEB-COS-4, PLEASE EXPLAIN THE ORGANIZATION AND WHAT IS SHOWN.

A Schedule MEB-COS-4 is a summary of the key elements and the results of the class cost of service study. The top section of the schedule shows the revenues, expenses and operating income based on an A&E-4NCP cost of service study.

The next section shows the major elements of rate base, and the rate of return at present rates for each customer class based on this cost of service study.

Q DID KCPL SUBMIT A CLASS COST OF SERVICE STUDY?

A Yes. KCPL submitted a class cost of service study. This study bases the allocation of generation costs on a seriously flawed average and peak allocation method. KCPL's method is not grounded in appropriate cost-causation principles, and should not be accepted. I will address this proposed methodology in more detail in my rebuttal testimony.

Q HAVE YOU USED ITS STUDY?

A I have used the study framework as a basis for preparing my cost of service study. As explained below, I have developed a cost of service study using a different allocation for generation fixed costs.

Q HAVE YOU PREPARED ANY COST OF SERVICE STUDIES BESIDES THE A&E-4NCP STUDY PRESENTED IN SCHEDULE MEB-COS-4?

A Yes. I have prepared studies based on A&E-2NCP, and also 4CP methodologies. The derivation of the generation capacity allocation factor and the results of each cost of service study are presented in the Appendix to my schedules.

Q HOW DID YOU USE KCPL'S COST OF SERVICE MODEL IN PRODUCING YOUR CLASS COST OF SERVICE STUDY?

A It was the starting point. The results of KCPL's allocation first were replicated by utilizing the data contained in its cost of service model. Many of KCPL's allocation factors and functionalizations and classifications have been utilized. The principal area where I depart from KCPL and use a different approach were incorporated into the allocations. They have previously been explained in this testimony.

Adjustment of Class Revenues

Q WHAT SHOULD BE THE PRIMARY BASIS FOR ESTABLISHING CLASS REVENUE REQUIREMENTS AND DESIGNING RATES?

A Cost should be the primary factor used in both steps.

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the primary basis used to establish the revenues collected from each customer class and to design rate schedules.

Factors such as simplicity, gradualism and ease of administration may also be taken into account, but the basic starting point and guideline throughout the process should be cost of service. To the extent practicable, rate schedules should be structured and designed to reflect the important cost-causative features of the service provided, and to collect the appropriate cost from the customers within each class or rate schedule, based upon the individual load patterns exhibited by those customers.

Electric rates also play a role in economic development, both with respect to job creation and job retention. This is particularly true in the case of industries where electricity is one of the largest components of the cost of production.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT COST BE USED AS THE PRIMARY FACTOR FOR THESE PURPOSES?

A The basic reasons for using cost as the primary factor are equity, conservation, and engineering efficiency (cost-minimization).

Q PLEASE EXPLAIN HOW EQUITY IS ACHIEVED BY BASING RATES ON COST.

A When rates are based on cost, each customer pays what it costs the utility to provide service to that customer; no more and no less. If rates are based on anything other than cost factors, then some customers will pay the costs attributable to providing service to other customers – which is inherently inequitable.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be mislead into using electricity inefficiently in response to the distorted rate design signals they receive.

Q WILL COST-BASED RATES ASSIST IN THE DEVELOPMENT OF COST-EFFECTIVE DEMAND-SIDE MANAGEMENT ("DSM") PROGRAMS?

A Yes. The success of DSM (both energy efficiency and demand response programs) depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is subsidized by other customers; that is, the bill is determined using rates which are below cost, that customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

For example, assume that the relevant cost to produce and deliver energy is 8¢ per kWh. If a customer has an opportunity to install energy efficiency or DSM equipment that would allow the customer to reduce energy use or demand, the customer will be much more likely to make that investment if the price of electricity equals the cost of electricity, i.e., 8¢ per kWh, than if the customer is receiving a subsidized rate of 6¢ per kWh.

Q HOW DO COST-BASED RATES ACHIEVE THE COST-MINIMIZATION OBJECTIVE?

A When the rates are designed so that the energy costs, demand costs and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

If a utility attempts to extract a disproportionate share of revenues from a class that has alternatives available (such as producing products at other locations where costs are lower), then the utility will be faced with the situation where it must discount the rates or lose the load, either in part or in total. To the extent that the load could have been served more economically by the utility, then either the other customers of the utility or the stockholders (or some combination of both) will be worse off than if the rates were properly designed on the basis of cost.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from large customers and high load factor customers. To the extent that these customers may have lower cost alternatives than do the smaller or the low load factor customers, the same problems noted above are created.

REVENUE ALLOCATION

Q PLEASE REFER AGAIN TO SCHEDULE MEB-COS-4 AND SUMMARIZE THE RESULTS OF YOUR CLASS COST OF SERVICE STUDY.

A As indicated on line 0400 of Schedule MEB-COS-4, movement of all classes to cost of service will require an increase to the Residential class and a decrease to all other classes.

Q WHAT ADJUSTMENTS TO REVENUES WOULD BE REQUIRED AT PRESENT RATES TO MOVE ALL CLASSES TO COST OF SERVICE?

A This is shown on Schedule MEB-COS-5. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall increase in revenues. Note that the Residential class would require an increase of about $46 million, or 11.2%, in order to move to cost of service. All other classes would require a corresponding decrease. The decreases range from about 8.3% for the Large General Service class to 1.3% for the Lighting class.

Q HOW DOES KCPL PROPOSE TO ADJUST REVENUES?

A KCPL proposes essentially an equal percentage across-the-board increase.

Q WOULD KCPL'S ALLOCATION MOVE CLASS RATES CLOSER TO COST OF SERVICE?

A No. KCPL's allocation would essentially maintain the status quo in which the Residential class is below cost of service, and other classes are above cost of service.

Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF KCPL'S REVENUE REQUIREMENT?

A Yes. I will focus on adjustments to be made on a revenue neutral basis at present rates. After having made my recommended revenue neutral adjustments at present rates, any overall change in revenues allowed to KCPL can then be applied on an equal percentage across-the-board basis to these adjusted class revenues.

Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.

A My specific proposal is shown on Schedule MEB-COS-6. Column 1 shows class revenues at current rates. Column 2 shows my proposed cost of service adjustment. This adjustment moves classes roughly 25% of the way toward cost of service. This 25% movement was selected because it makes a reasonable step in the right direction without imposing too disruptive of a revenue increase on the Residential class. An overall revenue-neutral increase of about 2.8% on the Residential class is a relatively modest step, but at least it is a step in the right direction.

While some will want to talk about the impact on the Residential class of this increase, it is also important not to lose sight of the fact that by not moving all the way to cost of service, the other customer classes are continuing to bear more of the burden of the revenue responsibility than they should. My recommendation of moving 25% of the way toward cost of service, which limits the Residential class revenue-neutral increase to 2.8% (as compared to the 11.2% increase required to move all the way to cost of service) is relatively moderate, and must be considered in light of the fact that other classes are being asked to continue to provide part of the revenue responsibility that rightly should be shouldered by the Residential class.

ANALYSIS OF LARGE CUSTOMER RATES

Q WHAT IS THE STRUCTURE OF THE TARIFFS APPLICABLE TO KCPL'S LARGEST CUSTOMERS?

A The LGS and LPS tariffs consist of a series of charges differentiated by voltage level. There are separate charges for service at secondary voltage, service at primary voltage, service at substation voltage, and service at transmission voltage. The rates charged at the higher voltage levels are lower than the rates charged at the lower voltage levels in order to recognize differences in cost of service.

At each voltage level, the rate consists of customer charges, facilities charges, charges for reactive power, demand charges and energy charges. Demand charges and energy charges also are seasonally differentiated, with summer charges being applied during the four consecutive months beginning May 16 and ending September 15.

Q WHAT IS THE STRUCTURE OF THE DEMAND CHARGES?

A In addition to being seasonally differentiated, the demand charges at each voltage level consist of multiple block charges.

Q WHAT IS THE STRUCTURE OF THE ENERGY CHARGES?

A The energy charges are structured as three "hours use" blocks. The three blocks consist of the first 180 hours use of the billing demand, the next 180 hours use of the billing demand and the tail block is for consumption in excess of 360 hours use of the billing demand.

These are what are known as hours use, or load factor based charges. The rates decrease as the hours use increases to recognize the spreading of fixed costs over more kilowatthours as the number of hours use, or load factor, increases. This structure also recognizes that energy consumed in the high load factor block likely will be off-peak or at times when energy costs are lower than during on-peak periods.

Q PLEASE EXPLAIN HOW THE HOURS USE FUNCTION WORKS.

A The number of kWh to be billed in each hours use block is determined by the customer's billing demand and the amount of kWh purchased.

A customer operating basically one shift (eight hours a day for five days a week) would have usage in the range of 180 kWh per kW of billing demand.[3] A customer operating two shifts would utilize approximately twice that much energy, and therefore use an additional 180 or so kWh per kW of demand, thereby filling up both the first and second blocks.

Thus, it is reasonable to consider the first block as being primarily the daytime on-peak hours, the second block for early morning, evening and/or weekend hours, and the third block for additional use in weekend and nighttime hours. Given these considerations, it is appropriate that the energy charges for the initial hours use blocks be higher than for the third hours use block in order to collect more fixed costs during the on-peak and shoulder periods.

[3] 8 hours/day x 5 days per week x 4.33 weeks per month = 173 hours

Q CAN YOU ILLUSTRATE WITH AN EXAMPLE OF HOW THE RATE WORKS?

A Yes. Assume that a customer has a 1,000 kW billing demand, and uses 500,000 kWh in a month. This customer would be using 500 kWh per kW,[4] or 500 kWh for each kW of demand. To apply the rate, the 1,000 kW of demand would be multiplied times 180 kWh per kW, which is the size of the first block, and would result in 180,000 kWh being priced out at the first block. The customer would also fully utilize the second block, so 180,000 kWh would go in it as well and be priced at the second block rate. The remaining 140,000 kWh[5] would be billed in the third, or high load factor block.

Q WHAT IS THE LEVEL OF THE ENERGY CHARGES FOR THE HIGH LOAD FACTOR (OVER 360 HOURS USE) BLOCK UNDER CURRENT TARIFFS?

A The charges vary slightly by voltage level and by season, but range from approximately 2.4¢/kWh to 2.6¢/kWh in LPS and from 3.1¢/kWh to 4.3¢/kWh for LGS.

Q DO YOU AGREE WITH THE LEVEL OF THE OFF-PEAK ENERGY CHARGES IN THE CURRENT TARIFFS?

A No, I do not. I believe the high load factor block energy charges collect more fixed costs than is appropriate.

Q PLEASE EXPLAIN.

A I have analyzed KCPL's current rate case filing and its claims for costs. KCPL's calculated average variable costs (Schedule TMR-8) are less than 1.7¢/kWh. The energy charges in the high load factor block of KCPL's current LGS and LPS tariffs

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[4] 500,000 ÷ 1,000 kW = 500 kWh/kW
[5] 500,000 - 180,000 - 180,000 = 140,000 kWh

are substantially higher, as previously noted. Since KCPL proposes an essentially equal percentage increase to collect its requested revenue increase, these relationships would be perpetuated. Since the primary driver for this case is increased fixed costs, this equal percentage on the total rate is particularly inappropriate.

Q WHAT DO YOU CONCLUDE FROM THIS REVIEW?

A Based on the level of the average variable costs and also the avoided energy costs, it is clear that the off-peak energy charges are collecting more costs than appropriate.

Q WHAT SHOULD BE THE LEVEL OF THE OFF-PEAK ENERGY CHARGE?

A Recognizing that most of the fixed costs should be collected from use during the on-peak period and that consumption in the high load factor block occurs mostly during evening and weekend periods when KCPL's energy costs would be lower than they are during the on-peak periods, it is reasonable that the high load factor energy block be at a level approximating the utility's average variable costs.

This structure would collect more costs through demand charges and provide better price signals to customers. It would also be a more equitable rate because it will charge high load factor and low load factor customers more appropriately. This structure also would improve the stability of KCPL's earnings. Because customer demands are generally more stable than their energy purchases, this rate design would make KCPL's revenue collection and earnings less volatile.

Q HOW DO YOU PROPOSE TO ADJUST THE LGS AND LPS RATES IN THIS CASE?

A In the interest of gradualism, my proposal is to maintain the energy charges for the high load factor (over 360 hours use per month, or over a 50% load factor) block at their current levels, increase the middle blocks (hours use from 181 to 360) by three quarters of the average percentage increase, and to collect the balance of the revenue requirement for the tariff by applying a uniform percentage increase to the remaining charges in the tariff. This includes the customer charge, the reactive demand charge, the facilities charges, the demand charges and the initial block energy charges.

Q HAVE YOU PREPARED AN ILLUSTRATION OF THIS RATE DESIGN?

A Yes. This appears on Schedules MEB-COS-7 and MEB-COS-8 attached to my testimony.

Q PLEASE EXPLAIN SCHEDULE MEB-COS-7.

A The first two pages contain a summary of the rate values for the LPS rate. The first column is present rates, the second is KCPL's proposed rates and the third is my proposal at the level of KCPL's proposed increase. The first column of the detail sheets for this schedule (pages 3-8) shows the billing units for each block of each voltage level of the LPS rate. The next two columns show the current rates and resulting revenues by block. The middle two columns show KCPL's proposed rates and the resulting revenues.

The final two columns show the rate based on KCPL's proposed increase to the LPS class, but with my rate design proposal.

Schedule MEB-COS-8 shows the same information for the LGS rate.

Q **HOW WOULD THE RATES BE DESIGNED TO MATCH WHATEVER AMOUNT OF INCREASE THE COMMISSION AWARDS TO KCPL IN THIS CASE?**

A First, the amount of additional revenue to be collected from the LPS and LGS tariffs would be determined. The increase for the middle block energy charges would be equal to the overall percentage increase times 75%. The high load factor energy blocks would not change. The balance of the increased revenue from each tariff would be collected by uniformly increasing all of the remaining charges in the tariff.

Q **IN ADDITION TO ITS PROPOSAL FOR AN EQUAL PERCENTAGE ACROSS-THE-BOARD INCREASE, HAS KCPL PROPOSED ANY NEW RATES OR RATE DESIGN?**

A No, it has not. It seems content to simply apply an equal percentage increase to all of the charges. KCPL should be examining the tariff schedules and attempting to move the rate elements closer to cost of service, to enhance the price signals given to customers.

Q **IS THERE ANYTHING ELSE THAT KCPL SHOULD BE DOING?**

A Yes. KCPL should be working with its larger customers, especially those who have unique load patterns and abilities to curtail load, to determine what rate or contract features would be appropriate to meet the needs of these customers, which may be different from what is contained in the standard tariffs.

Q **DO THESE CUSTOMERS OFFER BENEFITS TO KCPL AND ITS OTHER RATEPAYERS?**

A Yes. In many cases, these customers have unique load characteristics which allow KCPL to reduce its peak demand or to otherwise improve its overall load factor. For instance, some large customers have significant abilities to interrupt load. By making effective use of the interruptible nature of these customers, KCPL should be better able to reduce its annual peak and thereby reduce its overall revenue requirement. Other customers may offer other features. By providing tailored opportunities to these customers, KCPL should be able to increase its overall load factor and reduce its overall operating costs.

ENERGY LOSSES

Q **EARLIER IN YOUR TESTIMONY (PAGE 9) YOU MENTIONED ENERGY LOSSES AND HOW THEY DIFFER ACROSS CUSTOMER CLASSES. HAVE YOU PREPARED A SUMMARY OF ENERGY LOSSES BY RATE AND BY VOLTAGE LEVEL?**

A Yes. They are summarized on Schedule MEB-COS-9. Column 1 shows energy sales at the customer's meter and column 2 shows the amount of energy required to be produced at the generator in order to overcome the losses incurred through the system in order to deliver the energy to the meter shown in column 1. Column 3 shows the loss factor, which is determined by dividing the energy at the generator by the energy at the meter. As shown on this schedule, and as summarized on lines 41 through 45, KCPL delivers energy to customers at four distinct voltage levels. They are the secondary voltage level, the primary voltage level, the substation voltage level and the transmission voltage level. Losses range from a high of 6.1288% at the secondary voltage level down to 1.5651% at the transmission voltage level.

Q **WERE THESE DIFFERENCES IN LOSSES TAKEN INTO ACCOUNT IN PREPARING THE CLASS COST OF SERVICE STUDY?**

A Yes.

Q **KCPL HAS PROPOSED A FUEL ADJUSTMENT CHARGE ("FAC") IN THIS CASE. WHAT VOLTAGE LEVELS HAS IT PROPOSED TO DISTINGUISH IN THIS FAC?**

A Only two. The secondary voltage level, and the primary voltage level.

Q **WHERE ARE SUBSTATION AND TRANSMISSION LEVEL CUSTOMERS ACCOUNTED FOR?**

A They are accounted for in the primary voltage category in KCPL's proposed FAC.

Q **IS THIS APPROPRIATE?**

A No. As can be seen from Schedule MEB-COS-9, lines 41 through 44, charging substation customers the primary voltage level line loss factor would essentially overcharge them by 50% for losses (3.7072% versus the correct 2.4828%); and would overcharge transmission level customers by 140% for losses compared to what they should be charged (3.7072% instead of the correct 1.5651%).

Q **WHAT IS YOUR RECOMMENDATION?**

A Should the Commission determine to allow KCPL to have an FAC, either in this case or in a future case, KCPL should be required to track and charge customers according to the four separate voltage levels at which delivery takes place, and not the two levels it has proposed in this case.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

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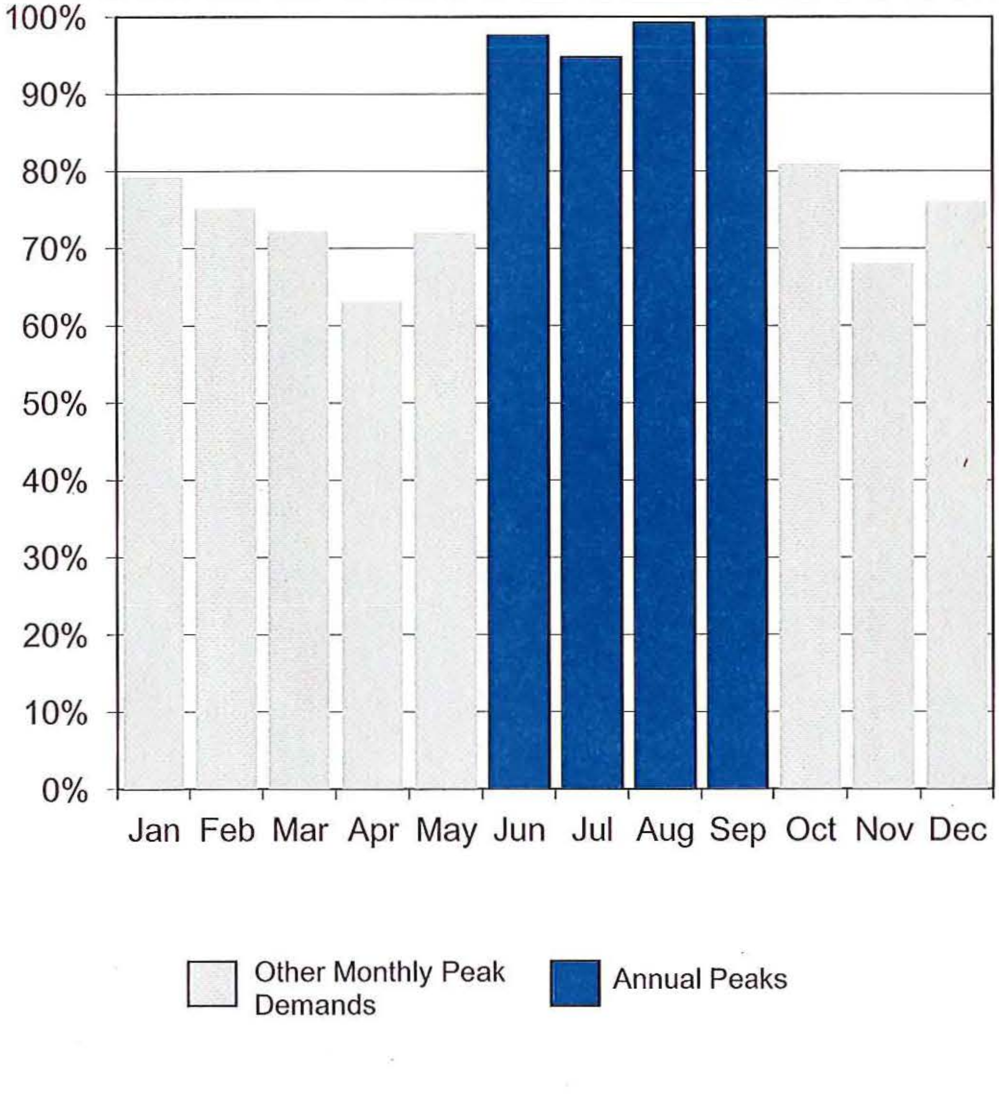
KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's (Missouri) Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended March 31, 2014



Schedule MEB-COS-1

KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) For the Test Year Ended March 31, 2014

Line	Description	Total Company MW (1)	Percent (2)
1	January	1,475	79.1
2	February	1,403	75.2
3	March	1,347	72.2
4	April	1,177	63.1
5	May	1,341	71.9
6	June	1,821	97.6
7	July	1,768	94.8
8	August	1,852	99.3
9	September	1,865	100.0
10	October	1,507	80.8
11	November	1,268	68.0
12	December	1,417	76.0

Source: KCPL Allocators MO Rev 10-9-14 Avg-Pk 4 CP
- not included in 12-1-14 wkps.xls

KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended March 31, 2014

Line	Description	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Other Lighting (7)
1	Missouri System Peak	1,865,474						
2	Avg of 4 Highest Monthly NCP Values	1,995,865	829,217	107,989	259,550	433,597	344,357	21,155
3	Energy Sales with Losses - MWh	9,137,285	2,762,813	437,815	1,180,913	2,374,639	2,289,849	91,256
4	Average Demand - kW	1,043,069	315,390	49,979	134,807	271,077	261,398	10,417
5	Average Demand - Percent	1.000000	0.302367	0.047915	0.129241	0.259884	0.250605	0.009987
6	Class Excess Demand - kW	952,795	513,827	58,010	124,742	162,519	82,959	10,737
7	Class Excess Demand - Percent	1.000000	0.539284	0.060884	0.130922	0.170571	0.087069	0.011269
	Allocator:							
8	Annual Load Factor * Average Demand	0.559144	0.169067	0.026792	0.072264	0.145313	0.140124	0.005584
9	(1-LF) * Excess Demand	0.440856	0.237746	0.026841	0.057718	0.075197	0.038385	0.004968
10	Average and Excess Demand Allocator	1.000000	0.406813	0.053633	0.129982	0.220510	0.178509	0.010552

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	55.91%
1 - Load Factor	44.09%

Source: KCPL Allocators MO_BAI A&E 4NCP.xls

Schedule MEB-COS-3

KANSAS CITY POWER & LIGHT COMPANY
2015 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 3/31/14; Update 10/31/14; K&M 4/30/15

LINE NO.	DESCRIPTION	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	767,355,793	285,159,916	48,836,426	103,290,211	180,113,158	140,231,588	9,724,494
0050	OTHER OPERATING REVENUE	413,609,396	125,837,740	19,884,843	53,458,451	107,158,663	103,120,092	4,149,607
0060	TOTAL OPERATING REVENUE	1,180,965,189	410,997,657	68,721,269	156,748,662	287,271,821	243,351,680	13,874,101
0070								
0080	OPERATING EXPENSES							
0090	FUEL	222,511,027	67,728,466	10,682,297	28,775,951	57,587,231	55,508,702	2,228,380
0100	PURCHASED POWER	304,735,754	92,266,295	14,608,136	39,377,911	79,157,649	76,274,910	3,050,853
0110	OTHER OPERATION & MAINTENANCE EXPENSES	303,491,601	139,689,302	18,682,799	36,027,870	57,267,707	47,518,146	4,305,777
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	116,953,542	52,208,247	6,970,884	15,425,179	23,247,599	17,613,915	1,487,717
0130	AMORTIZATION EXPENSES	15,665,901	6,865,297	916,243	2,054,517	3,195,373	2,433,169	201,304
0140	TAXES OTHER THAN INCOME TAXES	58,619,563	26,071,981	3,481,329	7,562,820	11,747,578	8,992,931	762,924
0150	CURRENT INCOME TAXES	14,819,681	(9,089,993)	2,552,016	4,638,729	11,166,150	5,349,505	203,275
0160	DEFERRED INCOME TAXES	15,669,609	6,977,397	928,259	2,036,240	3,142,916	2,383,050	201,748
0170	TOTAL ELECTRIC OPERATING EXPENSES	1,052,466,678	382,716,990	58,821,963	135,899,216	246,512,204	216,074,328	12,441,978
0180								
0190	NET ELECTRIC OPERATING INCOME	128,498,510	28,280,667	9,899,306	20,849,446	40,759,617	27,277,352	1,432,123
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,043,175,544	2,237,230,843	297,417,210	654,870,945	1,015,991,409	773,405,343	64,259,795
0230	LESS: ACCUM. PROV. FOR DEPREC	2,040,172,942	907,460,159	121,870,051	260,887,951	407,122,970	310,854,552	31,977,259
0240	NET PLANT	3,003,002,603	1,329,770,684	175,547,159	393,982,994	608,868,439	462,550,791	32,282,536
0250	PLUS:							
0260	CASH WORKING CAPITAL	(58,530,428)	(24,593,292)	(3,597,758)	(7,713,909)	(12,436,892)	(9,449,627)	(738,950)
0270	MATERIALS & SUPPLIES	57,386,822	24,327,688	3,229,513	7,495,633	12,137,420	9,519,192	677,376
0280	PREPAYMENTS	6,397,922	2,767,998	361,890	811,368	1,330,598	1,055,766	70,301
0290	FUEL INVENTORY	80,107,604	24,200,924	3,835,784	10,358,639	20,800,550	20,110,413	801,295
0300	REGULATORY ASSETS	111,292,579	46,523,925	7,623,896	13,604,587	23,309,701	18,914,583	1,315,888
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	167,781	91,553	12,598	22,671	24,733	12,753	3,474
0330	CUSTOMER DEPOSITS	3,567,416	1,780,441	1,424,044	301,429	56,982	4,521	0
0340	DEFERRED INCOME TAXES	599,672,820	266,024,158	35,365,221	77,869,252	120,809,285	91,963,914	7,640,990
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	39,136,133	11,833,473	1,875,216	5,058,000	10,170,874	9,807,708	390,863
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	23,191	7,012	1,111	2,997	6,027	5,812	232
0370	TOTAL RATE BASE	2,557,089,761	1,123,261,290	148,322,294	335,284,963	522,941,916	400,906,411	26,372,888
0380								
0390	RATE OF RETURN	5.025%	2.518%	6.674%	6.218%	7.794%	6.804%	5.430%
0400	RELATIVE RATE OF RETURN	1.00	0.50	1.33	1.24	1.55	1.35	1.08

Notes:
Production Plant and Expense, and Transmission Allocated using A&E-4NCP.

KANSAS CITY POWER & LIGHT COMPANY

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using Modified ECOS at Present Rates
($ in Thousands)

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 410,998	$ 1,123,261	$ 28,281	2.518%	50	$ 56,446	$ 28,165	$ 46,220	11.2%
2	Small General Service	68,721	148,322	9,899	6.674%	133	7,453	(2,446)	(4,014)	-5.8%
3	Medium General Service	156,749	335,285	20,849	6.218%	124	16,849	(4,001)	(6,565)	-4.2%
4	Large General Service	287,272	522,942	40,760	7.794%	155	26,279	(14,481)	(23,764)	-8.3%
5	Large Power Service	243,352	400,906	27,277	6.804%	135	20,146	(7,131)	(11,702)	-4.8%
6	Total Lighting	13,874	26,373	1,432	5.430%	108	1,325	(107)	(175)	-1.3%
7	Total	$ 1,180,965	$ 2,557,090	$ 128,499	5.025%	100	$ 128,499	$ 0	$ 0	0.0%

Source: Schedule MEB-COS-4

KANSAS CITY POWER & LIGHT COMPANY

Recommended Cost of Service Adjustments
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues	Move 25% Toward Cost Of Service[1]	Adjusted Current Revenue	Revenue-neutral Percent increase in Current Revenue
		(1)	(2)	(3)	(4)
1	Residential	$ 411.0	$ 11.6	$ 422.6	2.8 %
2	Small General Service	68.7	(1.0)	67.7	(1.5)%
3	Medium General Service	156.7	(1.6)	155.1	(1.0)%
4	Large General Service	287.3	(5.9)	281.3	(2.1)%
5	Large Power Service	243.4	(2.9)	240.4	(1.2)%
6	Total Lighting	13.9	(0.0)	13.8	(0.3)%
7	Total	$ 1,181.0	$ -	$ 1,181.0	0.0 %

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-5, times 25%.

KCP&L-MO LARGE POWER SERVICE
SUMMARY OF PROPOSED SCENARIOS
ER-2014-0370 Direct Filing
*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	**Current Rates**	**Company Proposed Rates**	**Rate Design Rates ***
A: CUSTOMER CHARGE			
	961.50	1,110.63	1,157.29
	-	-	-
	-	-	-
B: FACILITIES CHARGE			
SECONDARY:	3.220	3.719	3.876
PRIMARY:	2.669	3.083	3.212
SUBSTATION VOLTAGE	0.806	0.931	0.970
TRANSM VOLTAGE	-	-	-
C: DEMAND CHARGE			
SECONDARY-SUMMER:			
First 2443 kw	12.493	14.431	15.037
Next 2443 kw	9.993	11.543	12.028
Next 2443 kw	8.371	9.669	10.076
All kw over 7329 kw	6.111	7.059	7.355
SECONDARY-WINTER			
First 2443 kw	8.492	9.809	10.221
Next 2443 kw	6.626	7.654	7.975
Next 2443 kw	5.846	6.753	7.036
All kw over 7329 kw	4.500	5.198	5.416
PRIMARY-SUMMER			
First 2500 kw	12.206	14.099	14.691
Next 2500 kw	9.765	11.280	11.753
Next 2500 kw	8.179	9.448	9.844
All kw over 7500 kw	5.972	6.898	7.188
PRIMARY-WINTER			
First 2500 kw	8.296	9.583	9.985
Next 2500 kw	6.476	7.480	7.795
Next 2500 kw	5.712	6.598	6.875
All kw over 7500 kw	4.399	5.081	5.295
SUBSTATION-SUMMER			
First 2530 kw	12.060	13.931	14.516
Next 2530 kw	9.648	11.144	11.613
Next 2530 kw	8.082	9.336	9.728
All kw over 7590 kw	5.901	6.816	7.103
SUBSTATION-WINTER			
First 2530 kw	8.199	9.471	9.869
Next 2530 kw	6.399	7.392	7.702
Next 2530 kw	5.646	6.522	6.796
All kw over 7590 kw	4.346	5.020	5.231
TRANSMISSION-SUMMER			
First 2553 kw	11.956	13.810	14.391
Next 2553 kw	9.562	11.045	11.509
Next 2553 kw	8.008	9.250	9.639
All kw over 7659 kw	5.848	6.755	7.039
TRANSMISSION-WINTER			
First 2553 kw	8.125	9.385	9.779
Next 2553 kw	6.342	7.326	7.633
Next 2553 kw	5.595	6.463	6.734
All kw over 7659 kw	4.307	4.975	5.184

KCP&L-MO LARGE POWER SERVICE
SUMMARY OF PROPOSED SCENARIOS
ER-2014-0370 Direct Filing

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	Current Rates	Company Proposed Rates	Rate Design Rates *
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.07822	0.09035	0.09415
181-360 hrs use per month	0.04911	0.05673	0.05482
361+ hrs use per month	0.02566	0.02964	0.02566
SECONDARY-WINTER:			
0-180 hrs use per month	0.06631	0.07659	0.07981
181-360 hrs use per month	0.04468	0.05161	0.04988
361+ hrs use per month	0.02541	0.02935	0.02541
PRIMARY-SUMMER:			
0-180 hrs use per month	0.07643	0.08828	0.09199
181-360 hrs use per month	0.04800	0.05544	0.05358
361+ hrs use per month	0.02507	0.02896	0.02507
PRIMARY-WINTER:			
0-180 hrs use per month	0.06480	0.07485	0.07799
181-360 hrs use per month	0.04365	0.05042	0.04873
361+ hrs use per month	0.02484	0.02869	0.02484
SUBSTATION-SUMMER			
0-180 hrs use per month	0.07554	0.08726	0.09092
181-360 hrs use per month	0.04744	0.05480	0.05296
361+ hrs use per month	0.02477	0.02861	0.02477
SUBSTATION-WINTER			
0-180 hrs use per month	0.06405	0.07398	0.07709
181-360 hrs use per month	0.04314	0.04983	0.04816
361+ hrs use per month	0.02454	0.02835	0.02454
TRANSMISSION-SUMMER			
0-180 hrs use per month	0.07487	0.08648	0.09012
181-360 hrs use per month	0.04701	0.05430	0.05248
361+ hrs use per month	0.02456	0.02837	0.02456
TRANSMISSION-WINTER			
0-180 hrs use per month	0.06346	0.07330	0.07638
181-360 hrs use per month	0.04275	0.04938	0.04772
361+ hrs use per month	0.02431	0.02808	0.02431
E: REACTIVE DEMAND ADJUSTMENT	0.808	0.935	0.973
		-	-
LGS Secondary	100.00%	15.51%	15.83%
LGS Primary	100.00%	15.51%	15.74%
LGS Substation Voltage	100.00%	15.51%	14.71%
LGS Transmission Voltage	100.00%	15.51%	15.50%
LGS Overall Change (*)	0.00%	15.51%	15.51%
Winter Price Below Summer (SUM-WIN)/SUM	12.8%	12.8%	13.2%
Overall Change		15.51%	15.51%
Revenue	$142,458,316	$164,551,370	$164,550,723
Change in Revenue			$22,092,407
Proposed change per Revenue Summary			$22,093,056
			($648)

MO LARGE POWER
SECONDARY VOLTAGE - LPGSS

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	112.3	$961.50	$108,003	1,110.63	$124,755	$1,157.29	$129,996
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	112		$108,003		$124,755		$129,996
B: FACILITIES CHARGE	270,925.0	$3.220	$872,378	$3.719	$1,007,570	$3.876	$1,050,105
C: DEMAND CHARGE							
First 2443 kw	216,105.0	$12.493	$2,699,800	$14.431	$3,118,611	$15.037	$3,249,571
Next 2443 kw	60,492.5	$9.993	$604,501	$11.543	$698,264	$12.028	$727,603
Next 2443 kw	20,603.7	$8.371	$172,473	$9.669	$199,217	$10.076	$207,603
Over 7329 kw	2,093.4	$6.111	$12,793	$7.059	$14,777	$7.355	$15,397
	299,294		$3,489,567		$4,030,869		$4,200,173
D: ENERGY CHARGE							
0-180 hrs use per month	53,750,800.9	$0.07822	$4,204,388	$0.09035	$4,856,385	$0.09415	$5,060,638
181-360 hrs use per month	53,123,832.1	$0.04911	$2,608,911	$0.05673	$3,013,715	$0.05482	$2,912,248
361+ hrs use per month	65,994,995.5	$0.02566	$1,693,432	$0.02964	$1,956,092	$0.02566	$1,693,432
	172,869,629		$8,506,731		$9,826,192		$9,666,318
E: REACTIVE DEMAND ADJUSTMENT	2,478.4	$0.8080	$2,003	$0.9347	$2,317	$0.9730	$2,411
MANUAL BILLS	-		$0		$0		$0
REVENUE			$12,978,681		$14,991,702		$15,049,004
c/kwh			$0.0751		$0.0867		$0.0871
OVERALL CHANGE (%)	*2664*				15.51%		15.95%
used to reference avg customer	*1,538,973*						

WINTER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	269.7	$961.50	$259,290	1,110.63	$299,506	$1,157.29	$312,089
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	270		$259,290		$299,506		$312,089
B: FACILITIES CHARGE	654,443.0	$3.220	$2,107,307	$3.719	$2,433,874	$3.876	$2,536,621
C: DEMAND CHARGE							
First 2443 kw	403,533.0	$8.492	$3,426,802	$9.809	$3,958,255	$10.221	$4,124,511
Next 2443 kw	91,833.5	$6.626	$608,489	$7.654	$702,894	$7.975	$732,372
Next 2443 kw	20,259.3	$5.846	$118,436	$6.753	$136,811	$7.036	$142,545
Over 7329 kw	93.6	$4.500	$421	$5.198	$487	$5.416	$507
	515,720		$4,154,149		$4,798,447		$4,999,935
D: ENERGY CHARGE							
0-180 hrs use per month	91,449,979.1	$0.06631	$6,064,048	$0.07659	$7,004,154	$0.07981	$7,298,623
181-360 hrs use per month	90,314,589.5	$0.04468	$4,035,256	$0.05161	$4,661,136	$0.04988	$4,504,892
361+ hrs use per month	103,223,817.2	$0.02541	$2,622,917	$0.02935	$3,029,619	$0.02541	$2,622,917
	284,988,386		$12,722,221		$14,694,909		$14,426,432
E: REACTIVE DEMAND ADJUSTMENT	5,219.6	$0.8080	$4,217	$0.9347	$4,879	$0.9730	$5,079
F: MANUAL BILL USAGE/REVENUE	3,133,800		$202,007		$233,339		$233,339
REVENUE			$19,449,191		$22,464,954		$22,513,495
c/kwh			$0.0675		$0.0780		$0.0781
OVERALL CHANGE (%)	*1912*				15.51%		15.76%
used to reference avg customer	*1,068,417*						

ANNUAL	460,991,814		$32,427,872		$37,456,656		$37,562,499
c/kwh			$0.0703		$0.0813		$0.0815
OVERALL CHANGE (%)					15.51%		15.83%
Winter Price Below Summer (SUM-WIN)/SUM			10.1%		10.1%		10.2%

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MO LARGE POWER
PRIMARY VOLTAGE - LPGSP

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	104.7	$961.50	$100,705	1,110.63	$116,325	1,157.29	$121,212
	-	$0.00	$0	-	$0	-	$0
	-	$0.00	$0	-	$0	-	$0
	105		$100,705		$116,325		$121,212
B: FACILITIES CHARGE	517,154.0	$2.669	$1,380,284	$3.083	$1,594,386	$3.212	$1,661,099
C: DEMAND CHARGE							
First 2500 kw	266,726.0	$12.206	$3,255,658	$14.099	$3,760,570	$14.691	$3,918,472
Next 2500 kw	134,291.2	$9.765	$1,311,353	$11.280	$1,514,804	$11.753	$1,578,324
Next 2500 kw	66,761.8	$8.179	$546,045	$9.448	$630,765	$9.844	$657,203
Over 7500 kw	92,512.7	$5.972	$552,486	$6.898	$638,153	$7.188	$664,981
	560,292		$5,665,541		$6,544,292		$6,818,980
D: ENERGY CHARGE							
0-180 hrs use per month	100,638,671.3	$0.07643	$7,691,814	$0.08828	$8,884,382	$0.09199	$9,257,751
181-360 hrs use per month	99,100,446.1	$0.04800	$4,756,821	$0.05544	$5,494,129	$0.05358	$5,309,802
361+ hrs use per month	108,621,955.3	$0.02507	$2,723,152	$0.02896	$3,145,692	$0.02507	$2,723,152
	308,361,073		$15,171,787		$17,524,202		$17,290,706
E: REACTIVE DEMAND ADJUSTMENT	35,318	$0.808	$28,537	$0.935	$33,012	$0.973	$34,365
E: MANUAL BILL USAGE/REVENUE	3,978,179		$373,142		$431,018		$431,018
REVENUE			$22,719,998		$26,243,236		$26,357,379
c/kwh			$0.0727		$0.0840		$0.0844
OVERALL CHANGE (%)	*5349*				15.51%		16.01%
used to reference avg customer	*2,982,112*						

WINTER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	256.3	$961.50	$246,396	1,110.63	$284,613	$1,157.29	$296,570
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	256		$246,396		$284,613		$296,570
B: FACILITIES CHARGE	1,262,470.0	$2.669	$3,369,532	$3.083	$3,892,195	$3.212	$4,055,054
C: DEMAND CHARGE							
First 2500 kw	504,984.0	$8.296	$4,189,347	$9.583	$4,839,262	$9.985	$5,042,265
Next 2500 kw	207,041.8	$6.476	$1,340,803	$7.480	$1,548,673	$7.795	$1,613,891
Next 2500 kw	108,097.2	$5.712	$617,451	$6.598	$713,226	$6.875	$743,168
Over 7500 kw	121,202.3	$4.399	$533,169	$5.081	$615,829	$5.295	$641,766
	941,325		$6,680,770		$7,716,989		$8,041,091
D: ENERGY CHARGE							
0-180 hrs use per month	168,932,388.7	$0.06480	$10,946,819	$0.07485	$12,644,589	$0.07799	$13,175,037
181-360 hrs use per month	167,352,863.0	$0.04365	$7,304,952	$0.05042	$8,437,931	$0.04873	$8,155,105
361+ hrs use per month	189,365,701.6	$0.02484	$4,703,844	$0.02869	$5,432,902	$0.02484	$4,703,844
	525,650,953		$22,955,615		$26,515,423		$26,033,986
E: REACTIVE DEMAND ADJUSTMENT	72,830	$0.808	$58,847	$0.935	$68,074	$0.973	$70,863
MANUAL BILLS	10,769,579		$798,952		$922,873		$922,873
REVENUE			$34,110,113		$39,400,166		$39,420,436
c/kwh			$0.0636		$0.0735		$0.0735
OVERALL CHANGE (%)	*3673*				15.51%		15.57%
used to reference avg customer	*2,093,247*						

ANNUAL	848,759,784		$56,830,110		$65,643,402		$65,777,816
c/kwh			$0.0670		$0.0773		$0.0775
OVERALL CHANGE (%)					15.51%		15.74%
Winter Price Below Summer (SUM-WIN)/SUM			12.6%		12.6%		12.9%

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MO LARGE POWER
SUBSTATION VOLTAGE - LPGSSS

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	10.4	$961.50	$10,039	1,110.63	$11,596	$1,157.29	$12,083
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	10		$10,039		$11,596		$12,083
B: FACILITIES CHARGE	193,230.4	$0.806	$155,744	$0.931	$179,898	$0.970	$187,434
C: DEMAND CHARGE							
First 2530 kw	30,580.5	$12.060	$368,801	$13.931	$426,017	$14.516	$443,906
Next 2530 kw	29,058.6	$9.648	$280,357	$11.144	$323,829	$11.613	$337,458
Next 2530 kw	20,403.2	$8.082	$164,899	$9.336	$190,485	$9.728	$198,483
Over 7590 kw	135,165.7	$5.901	$797,613	$6.816	$921,289	$7.103	$960,082
	215,208		$1,611,670		$1,861,620		$1,939,928
D: ENERGY CHARGE							
0-180 hrs use per month	38,737,438.5	$0.07554	$2,926,226	$0.08726	$3,380,229	$0.09092	$3,522,008
181-360 hrs use per month	38,737,438.5	$0.04744	$1,837,704	$0.05480	$2,122,812	$0.05296	$2,051,535
361+ hrs use per month	49,922,763.1	$0.02477	$1,236,587	$0.02861	$1,428,290	$0.02477	$1,236,587
	127,397,640		$6,000,517		$6,931,331		$6,810,129
E: REACTIVE DEMAND ADJUSTMENT	9,336	$0.808	$7,544	$0.935	$8,727	$0.973	$9,084
REVENUE			$7,785,513		$8,993,171		$8,958,659
c/kwh			$0.0611		$0.0706		$0.0703
OVERALL CHANGE (%)	*20612*				15.51%		15.07%
used to reference avg customer	*12,201,855*						

WINTER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	25.6	$961.50	$24,575	1,110.63	$28,387	$1,157.29	$29,579
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	26		$24,575		$28,387		$29,579
B: FACILITIES CHARGE	479,585.6	$0.806	$386,546	$0.931	$446,494	$0.970	$465,198
C: DEMAND CHARGE							
First 2530 kw	60,499.5	$8.199	$496,036	$9.471	$572,991	$9.869	$597,070
Next 2530 kw	54,272.4	$6.399	$347,289	$7.392	$401,182	$7.702	$418,006
Next 2530 kw	40,316.8	$5.646	$227,629	$6.522	$262,946	$6.796	$273,993
Over 7590 kw	231,990.3	$4.346	$1,008,230	$5.020	$1,164,591	$5.231	$1,213,541
	387,079		$2,079,183		$2,401,710		$2,502,610
D: ENERGY CHARGE							
0-180 hrs use per month	64,530,386.1	$0.06405	$4,133,171	$0.07398	$4,773,958	$0.07709	$4,974,647
181-360 hrs use per month	63,978,481.5	$0.04314	$2,760,032	$0.04983	$3,188,048	$0.04816	$3,081,204
361+ hrs use per month	88,346,168.7	$0.02454	$2,168,015	$0.02835	$2,504,614	$0.02454	$2,168,015
	216,855,036		$9,061,218		$10,466,620		$10,223,866
E: REACTIVE DEMAND ADJUSTMENT	18,003	$0.808	$14,546	$0.935	$16,827	$0.973	$17,517
REVENUE			$11,566,068		$13,360,037		$13,238,770
c/kwh			$0.0533		$0.0616		$0.0610
OVERALL CHANGE (%)	*15144*				15.51%		14.46%
used to reference avg customer	*8,484,436*						

ANNUAL	344,252,676	$19,351,581	$22,353,208	$22,197,429
c/kwh		$0.0562	$0.0649	$0.0645
OVERALL CHANGE (%)			15.51%	14.71%
Winter Price Below Summer (SUM-WIN)/SUM		12.7%	12.7%	13.2%

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MO LARGE POWER
TRANSMISSION VOLTAGE - LPGSTR

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	10.1	$961.50	$9,719	1,110.63	$11,226	$1,157.29	$11,698
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	10		$9,719		$11,226		$11,698
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	30,847.6	$11.956	$368,814	$13.810	$426,005	$14.391	$443,927
Next 2553 kw	11,584.6	$9.562	$110,772	$11.045	$127,952	$11.509	$133,327
Next 2553 kw	10,294.4	$8.008	$82,437	$9.250	$95,223	$9.639	$99,227
Over 7659 kw	33,112.8	$5.848	$193,644	$6.755	$223,677	$7.039	$233,081
	85,839		$755,666		$872,857		$909,563
D: ENERGY CHARGE							
0-180 hrs use per month	15,451,077.6	$0.07487	$1,156,822	$0.08648	$1,336,209	$0.09012	$1,392,451
181-360 hrs use per month	15,317,864.5	$0.04701	$720,093	$0.05430	$831,760	$0.05248	$803,882
361+ hrs use per month	14,355,410.5	$0.02456	$352,569	$0.02837	$407,263	$0.02456	$352,569
	45,124,353		$2,229,484		$2,575,232		$2,548,902
E: REACTIVE DEMAND ADJUSTMENT	4,805	$0.808	$3,883	$0.935	$4,492	$0.973	$4,676
REVENUE			$2,998,752		$3,463,807		$3,474,838
c/kwh			$0.0665		$0.0768		$0.0770
OVERALL CHANGE (%)	*8492*				15.51%		15.88%
used to reference avg customer	*4,464,271*						

WINTER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	25.9	$961.50	$24,895	1,110.63	$28,757	$1,157.29	$29,965
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	26		$24,895		$28,757		$29,965
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	61,060.4	$8.125	$496,116	$9.385	$573,052	$9.779	$597,110
Next 2553 kw	23,622.4	$6.342	$149,813	$7.326	$173,058	$7.633	$180,310
Next 2553 kw	20,341.6	$5.595	$113,812	$6.463	$131,468	$6.734	$136,981
Over 7659 kw	59,010.2	$4.307	$254,157	$4.975	$293,576	$5.184	$305,909
	164,035		$1,013,898		$1,171,154		$1,220,309
D: ENERGY CHARGE							
0-180 hrs use per month	29,526,242.4	$0.06346	$1,873,735	$0.07330	$2,164,274	$0.07638	$2,255,214
181-360 hrs use per month	29,501,738.5	$0.04275	$1,261,199	$0.04938	$1,456,796	$0.04772	$1,407,823
361+ hrs use per month	27,665,337.0	$0.02431	$672,544	$0.02808	$776,843	$0.02431	$672,544
	86,693,318		$3,807,479		$4,397,912		$4,335,582
E: REACTIVE DEMAND ADJUSTMENT	6,237	$0.808	$5,039	$0.935	$5,829	$0.973	$6,068
REVENUE			$4,851,311		$5,603,652		$5,591,924
c/kwh			$0.0560		$0.0646		$0.0645
OVERALL CHANGE (%)	*6335*				15.51%		15.27%
used to reference avg customer	*3,348,252*						

	BILLING UNITS	PRESENT RATES	COMPANY PROPOSED RATES	RATES W/RATE DESIGN *
ANNUAL	131,817,671	$7,850,063	$9,067,458	$9,066,762
c/kwh		$0.0596	$0.0688	$0.0688
OVERALL CHANGE (%)			15.51%	15.50%
Winter Price Below Summer (SUM-WIN)/SUM		15.8%	15.8%	16.2%

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MO LARGE POWER
TRANSMISSION VOLTAGE - OFF PEAK - LPSTRO

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
	5.5	961.50	$5,334	1,110.63	$6,161	1,157.29	$6,420
	-	-	$0	-	$0	-	$0
	-	-	$0	-	$0	-	$0
	6		$5,334		$6,161		$6,420
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	17,994.5	$11.956	$215,143	$13.810	$248,504	$14.391	$258,959
Next 2553 kw	11,983.4	$9.562	$114,585	$11.045	$132,356	$11.509	$137,917
Next 2553 kw	7,700.2	$8.008	$61,663	$9.250	$71,227	$9.639	$74,222
Over 7659 kw	34,507.9	$5.848	$201,802	$6.755	$233,101	$7.039	$242,901
	72,186		$593,193		$685,188		$713,999
D: ENERGY CHARGE							
0-180 hrs use per month	12,993,474.2	$0.07487	$972,821	$0.08648	$1,123,676	$0.09012	$1,170,972
181-360 hrs use per month	12,993,474.2	$0.04701	$610,823	$0.05430	$705,546	$0.05248	$681,898
361+ hrs use per month	20,996,877.3	$0.02456	$515,683	$0.02837	$595,681	$0.02456	$515,683
	46,983,826		$2,099,328		$2,424,903		$2,368,553
E: REACTIVE DEMAND ADJUSTMENT	1,689	$0.808	$1,365	$0.935	$1,579	$0.973	$1,644
REVENUE			$2,699,220		$3,117,831		$3,090,615
c/kwh			$0.0574		$0.0664		$0.0658
OVERALL CHANGE (%)	*13012*				15.51%		14.50%
used to reference avg customer	*8,469,447*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
	17.5	961.50	$16,781	1,110.63	$19,383	1,157.29	$20,198
	-	-	$0	-	$0	-	$0
	-	-	$0	-	$0	-	$0
	17		$16,781		$19,383		$20,198
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	40,724.5	$8.125	$330,886	$9.385	$382,199	$9.779	$398,245
Next 2553 kw	27,053.6	$6.342	$171,574	$7.326	$198,195	$7.633	$206,500
Next 2553 kw	20,382.8	$5.595	$114,042	$6.463	$131,734	$6.734	$137,258
Over 7659 kw	62,519.1	$4.307	$269,270	$4.975	$311,033	$5.184	$324,099
	150,680		$885,772		$1,023,161		$1,066,102
D: ENERGY CHARGE							
0-180 hrs use per month	27,122,405.8	$0.06346	$1,721,188	$0.07330	$1,988,072	$0.07638	$2,071,609
181-360 hrs use per month	27,122,405.8	$0.04275	$1,159,483	$0.04938	$1,339,304	$0.04772	$1,294,281
361+ hrs use per month	46,319,221.4	$0.02431	$1,126,020	$0.02808	$1,300,644	$0.02431	$1,126,020
	100,564,033		$4,006,691		$4,628,020		$4,491,911
E: REACTIVE DEMAND ADJUSTMENT	2,597	$0.808	$2,098	$0.935	$2,427	$0.973	$2,527
REVENUE			$4,911,342		$5,672,992		$5,580,737
c/kwh			$0.0488		$0.0564		$0.0555
OVERALL CHANGE (%)	*8634*				15.51%		13.63%
used to reference avg customer	*5,762,139*						
ADJUSTMENT			$0		$0		$0
ANNUAL	147,547,859		$7,610,561		$8,790,823		$8,671,352
c/kwh			$0.0516		$0.0596		$0.0588
OVERALL CHANGE (%)					15.51%		13.94%
Winter Price Below Summer (SUM-WIN)/SUM			15.0%		15.0%		15.6%

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MO LARGE POWER
PRIMARY VOLTAGE, OFF PEAK - LPGSPO

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
	32.9	$961.50	$31,628	$1,110.63	$36,534	$1,157.29	$38,068
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	33		$31,628		$36,534		$38,068
B: FACILITIES CHARGE	184,768.3	$2.669	$493,146	$3.083	$569,641	$3.212	$593,476
C: DEMAND CHARGE							
First 2500 kw	83,025.4	$12.206	$1,013,408	$14.099	$1,170,576	$14.691	$1,219,727
Next 2500 kw	47,301.2	$9.765	$461,896	$11.280	$533,557	$11.753	$555,931
Next 2500 kw	27,094.7	$8.179	$221,607	$9.448	$255,991	$9.844	$266,720
Over 7500 kw	25,643.6	$5.972	$153,144	$6.898	$176,890	$7.188	$184,326
	183,065		$1,850,056		$2,137,013		$2,226,704
D: ENERGY CHARGE							
0-180 hrs use per month	32,583,022.2	$0.07643	$2,490,320	$0.08828	$2,876,429	$0.09199	$2,997,312
181-360 hrs use per month	31,848,183.5	$0.04800	$1,528,713	$0.05544	$1,765,663	$0.05358	$1,706,426
361+ hrs use per month	35,621,082.4	$0.02507	$893,021	$0.02896	$1,031,587	$0.02507	$893,021
	100,052,288		$4,912,054		$5,673,679		$5,596,758
E: REACTIVE DEMAND ADJUSTMENT	18,467	$0.808	$14,922	$0.935	$17,261	$0.973	$17,969
F: MANUAL BILL USAGE/REVENUE	3,331,242		$275,851		$318,637		$318,637
REVENUE			$7,577,656		$8,752,764		$8,791,612
c/kwh			0.0733		0.0847		0.0850
OVERALL CHANGE (%)	*5565*				15.51%		16.02%
used to reference avg customer	*3,142,887*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
	74.1	$961.50	$71,252	$1,110.63	$82,304	$1,157.29	$85,762
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	74		$71,252		$82,304		$85,762
B: FACILITIES CHARGE	421,362.7	$2.669	$1,124,617	$3.083	$1,299,061	$3.212	$1,353,417
C: DEMAND CHARGE							
First 2500 kw	135,518.6	$8.296	$1,124,262	$9.583	$1,298,674	$9.985	$1,353,153
Next 2500 kw	65,208.8	$6.476	$422,292	$7.480	$487,762	$7.795	$508,303
Next 2500 kw	34,137.3	$5.712	$194,992	$6.598	$225,238	$6.875	$234,694
Over 7500 kw	50,764.4	$4.399	$223,313	$5.081	$257,934	$5.295	$268,797
	285,629		$1,964,859		$2,269,608		$2,364,947
D: ENERGY CHARGE							
0-180 hrs use per month	50,915,537.2	$0.06480	$3,299,327	$0.07485	$3,811,028	$0.07799	$3,970,903
181-360 hrs use per month	50,438,882.7	$0.04365	$2,201,657	$0.05042	$2,543,128	$0.04873	$2,457,887
361+ hrs use per month	60,572,834.9	$0.02484	$1,504,629	$0.02869	$1,737,835	$0.02484	$1,504,629
	161,927,255		$7,005,613		$8,091,991		$7,933,419
E: REACTIVE DEMAND ADJUSTMENT	42,179	$0.808	$34,080	$0.935	$39,425	$0.973	$41,040
F: MANUAL BILL USAGE/REVENUE	. 8,383,635		$610,049		$704,670		$704,670
REVENUE			$10,810,471		$12,487,059		$12,483,255
c/kwh			$0.0635		$0.0733		$0.0733
OVERALL CHANGE (%)	*3854*				15.51%		15.47%
used to reference avg customer	*2,298,220*						

ANNUAL	273,694,420	$18,388,128	$21,239,823	$21,274,866
c/kwh		$0.0672	$0.0776	$0.0777
OVERALL CHANGE (%)			15.51%	15.70%
Winter Price Below Summer (SUM-WIN)/SUM		13.4%	13.4%	13.8%

SUMMER TOTAL (ALL RATES)	800,788,808	$56,110,826	$64,812,855	$64,972,452
WINTER TOTAL (ALL RATES)	1,376,678,981	$84,087,488	$97,127,977	$96,967,735
Manual Bills	29,596,435	$2,260,002	$2,610,537	$2,610,537
GRAND TOTAL (ANNUAL - ALL RATES)	**2,207,064,224**	**$142,458,316**	**$164,551,370**	**$164,550,723**
c/kwh Summer		**$0.0701**	**$0.0809**	**$0.0811**
c/kwh Winter		**$0.0611**	**$0.0706**	**$0.0704**
c/kwh Annual		**$0.0645**	**$0.0746**	**$0.0746**
Winter Price Below Summer (SUM-WIN)/SUM		**12.8%**	**12.8%**	**13.2%**
OVERALL CHANGE (%)			**15.508%**	**15.508%**

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KCP&L-MO LARGE GENERAL SERVICE
SUMMARY OF PROPOSED SCENARIOS
ER-2014-0370 Direct Filing
*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	Current Rates	Company Proposed Rates	Rate Design Rates *
A: CUSTOMER CHARGE			
0-24 KW	101.15	117.26	120.29
25-199 KW	101.15	117.26	120.29
200-999 KW	101.15	117.26	120.29
1001+ KW	863.59	1,001.15	1,027.03
Separately Metered Space Heat	2.32	2.69	2.76
B: FACILITIES CHARGE			
SECONDARY:	2.894	3.355	3.442
PRIMARY:	2.399	2.781	2.853
C: DEMAND CHARGE			
SECONDARY-SUMMER:	5.778	6.698	6.872
SECONDARY-WINTER	3.109	3.604	3.697
PRIMARY-SUMMER	5.647	6.547	6.716
PRIMARY-WINTER	3.039	3.523	3.614
SECONDARY-WINTER - ELEC ONLY	2.879	3.338	3.424
PRIMARY-WINTER - ELEC ONLY	2.811	3.259	3.343
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.08486	0.09838	0.10092
181-360 hrs use per month	0.06075	0.07043	0.06801
361+ hrs use per month	0.04260	0.04939	0.04260
SECONDARY-WINTER:			
0-180 hrs use per month	0.07798	0.09040	0.09274
181-360 hrs use per month	0.04670	0.05414	0.05228
361+ hrs use per month	0.03580	0.04150	0.03580
PRIMARY-SUMMER:			
0-180 hrs use per month	0.08296	0.09617	0.09866
181-360 hrs use per month	0.05930	0.06875	0.06638
361+ hrs use per month	0.04160	0.04823	0.04160
PRIMARY-WINTER:			
0-180 hrs use per month	0.07620	0.08834	0.09062
181-360 hrs use per month	0.04558	0.05284	0.05103
361+ hrs use per month	0.03510	0.04069	0.03510
SECONDARY-WINTER - ALL ELECTRIC			
0-180 hrs use per month	0.07141	0.08278	0.08492
181-360 hrs use per month	0.04023	0.04664	0.04504
361+ hrs use per month	0.03140	0.03640	0.03140
PRIMARY-WINTER - ALL ELECTRIC		-	
0-180 hrs use per month	0.06991	0.08105	0.08314
181-360 hrs use per month	0.03934	0.04561	0.04404
361+ hrs use per month	0.03080	0.03571	0.03080
E: SEPARATELY METERED S/H-WINTER			
SECONDARY	0.05246	0.03640	0.06239
PRIMARY	0.00000	-	-
F: REACTIVE DEMAND ADJUSTMENT	0.726	0.843	0.863
LGS Secondary	100.00%	15.93%	15.82%
LGS Primary	100.00%	15.93%	15.75%
LGS Overall Change (*)	0.00%	15.93%	15.81%
LGA Secondary	100.00%	15.93%	15.53%
LGA Primary	100.00%	15.93%	15.34%
LGA Winter Energy Overall Change		15.93%	14.85%
LGA Overall Change (*)	0.00%	15.93%	15.49%
Winter Price Below Summer (SUM-WIN)/SUM	28.0%	16.4%	15.8%
Overall Change		15.73%	15.73%

Revenue	$180,421,101	$208,797,372	$208,796,772
Change in Revenue			$28,375,671
Proposed change per Revenue Summary			$28,376,275
			($604)

MO LARGE GENERAL
SECONDARY VOLTAGE - LGSS

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	2,255.5	$101.15	$228,145	$117.26	$264,481	$120.29	$271,315
1001+ KW	102.0	$863.59	$88,050	$1,001.15	$102,076	$1,027.03	$104,715
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	2,357		$316,195		$366,557		$376,030
B: FACILITIES CHARGE	1,060,170.9	$2.894	$3,068,135	$3.355	$3,556,873	$3.442	$3,649,108
C: DEMAND CHARGE	1,082,957.6	$5.778	$6,257,329	$6.698	$7,253,650	$6.872	$7,442,085
D: ENERGY CHARGE							
0-180 hrs use per month	185,940,957.7	$0.08486	$15,778,950	$0.09838	$18,293,057	$0.10092	$18,765,161
181-360 hrs use per month	152,515,075.4	$0.06075	$9,265,291	$0.07043	$10,741,637	$0.06801	$10,372,550
361+ hrs use per month	79,598,160.9	$0.04260	$3,390,882	$0.04939	$3,931,353	$0.04260	$3,390,882
	418,054,194		$28,435,122		$32,966,047		$32,528,593
E: SEPARATELY METERED SPACE HEAT	-	$0.05246	$0	$0.03640	$0	$0.06239	$0
F: REACTIVE DEMAND ADJUSTMENT	1,890.8	$0.726	$1,373	$0.843	$1,595	$0.863	$1,632
MANUAL BILLS	8,599,450		$861,345		$998,550		$998,550
REVENUE			$38,939,499		$45,143,272		$44,995,998
c/kwh			$0.0913		$0.1058		$0.1055
FLUCTUATION (%)					15.93%		15.55%
used to reference avg customer	*180,980*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	120.29	$0
200-999 KW	5,443.5	$101.15	$550,608	$117.26	$638,302	120.29	$654,796
1001+ KW	242.2	$863.59	$209,137	$1,001.15	$242,450	1,027.03	$248,718
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	2.76	$0
	5,686		$759,745		$880,753		$903,514
B: FACILITIES CHARGE	2,573,224.0	$2.894	$7,446,910	$3.355	$8,633,166	$3.442	$8,857,037
C: DEMAND CHARGE	1,951,349.2	$3.109	$6,066,745	$3.604	$7,032,663	$3.697	$7,214,138
D: ENERGY CHARGE							
0-180 hrs use per month	323,263,444.2	$0.07798	$25,208,083	$0.09040	$29,223,015	$0.09274	$29,979,452
181-360 hrs use per month	255,144,981.6	$0.04670	$11,915,271	$0.05414	$13,813,549	$0.05228	$13,338,980
361+ hrs use per month	116,636,957.8	$0.03580	$4,175,603	$0.04150	$4,840,434	$0.03580	$4,175,603
	695,045,384		$41,298,957		$47,876,998		$47,494,035
E: SEPARATELY METERED SPACE HEAT	-	$0.05246	$0	$0.03640	$0	$0.06239	$0
F: REACTIVE DEMAND ADJUSTMENT	4,244.1	$0.726	$3,081	$0.843	$3,579	$0.863	$3,663
MANUAL BILLS	23,350,249.9		$2,049,246		$2,375,674		$2,375,674
REVENUE			$57,624,685		$66,802,833		$66,848,060
c/kwh			$0.0802		$0.0930		$0.0931
FLUCTUATION (%)					15.93%		16.01%
used to reference avg customer	*126,352*						
ANNUAL ENERGY/REVENUE	1,145,049,278		$96,564,183		$111,946,105		$111,844,057
c/kwh			$0.0843		$0.0978		$0.0977
FLUCTUATION (%)					15.93%		15.82%
Winter Price Below Summer (SUM-WIN)/SUM			12.1%		12.1%		11.8%

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MO LARGE GENERAL
PRIMARY VOLTAGE - LGSP

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	194.2	$101.15	$19,640	$117.26	$22,768	$120.29	$23,357
1001+ KW	65.2	$863.59	$56,285	$1,001.15	$65,250	$1,027.03	$66,937
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	259		$75,925		$88,019		$90,294
B: FACILITIES CHARGE	215,594.6	$2.399	$517,211	$2.781	$599,569	$2.853	$615,091
C: DEMAND CHARGE	220,881.5	$5.647	$1,247,318	$6.547	$1,446,111	$6.716	$1,483,440
D: ENERGY CHARGE							
0-180 hrs use per month	38,579,132.5	$0.08296	$3,200,525	$0.09617	$3,710,194	$0.09866	$3,806,217
181-360 hrs use per month	31,653,080.7	$0.05930	$1,877,028	$0.06875	$2,176,149	$0.06638	$2,101,131
361+ hrs use per month	15,330,719.3	$0.04160	$637,758	$0.04823	$739,401	$0.04160	$637,758
	85,562,932		$5,715,310		$6,625,744		$6,545,107
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	18,135	$0.726	$13,166	$0.843	$15,294	$0.863	$15,650
MANUAL BILLS	2,096,422.2		$272,307		$315,683		$315,683
REVENUE			$7,841,237		$9,090,419		$9,065,265
c/kwh			$0.0895		$0.1037		$0.1034
FLUCTUATION (%)					15.93%		15.61%
used to reference avg customer	*338,004*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	490.1	$101.15	$49,575	$117.26	$57,470	$120.29	$58,955
1001+ KW	178.3	$863.59	$153,965	$1,001.15	$178,490	$1,027.03	$183,104
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	668		$203,540		$235,960		$242,059
B: FACILITIES CHARGE	569,171.9	$2.399	$1,365,443	$2.781	$1,582,867	$2.853	$1,623,847
C: DEMAND CHARGE	404,048.3	$3.039	$1,227,903	$3.523	$1,423,462	$3.614	$1,460,231
D: ENERGY CHARGE							
0-180 hrs use per month	70,214,441.7	$0.07620	$5,350,340	$0.08834	$6,202,744	$0.09062	$6,362,833
181-360 hrs use per month	57,751,799.9	$0.04558	$2,632,327	$0.05284	$3,051,605	$0.05103	$2,947,074
361+ hrs use per month	26,921,516.0	$0.03510	$944,945	$0.04069	$1,095,436	$0.03510	$944,945
	154,887,758		$8,927,613		$10,349,785		$10,254,852
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	41,754	$0.726	$30,313	$0.843	$35,213	$0.863	$36,033
MANUAL BILLS	2,140,656.8		$387,957		$449,755		$449,755
REVENUE			$12,142,768		$14,077,042		$14,066,778
c/kwh			$0.0773		$0.0896		$0.0896
FLUCTUATION (%)					15.93%		15.84%
used to reference avg customer	*234,934*						
ANNUAL ENERGY/REVENUE	244,687,769		$19,984,005		$23,167,461		$23,132,043
c/kwh			$0.0817		$0.0947		$0.0945
FLUCTUATION (%)					15.93%		15.75%
Winter Price Below Summer (SUM-WIN)/SUM			13.6%		13.6%		13.4%
SUMMER TOTAL (LGSS/LGSP)	514,312,999		$46,780,736		$54,233,691		$54,061,263
WINTER TOTAL (LGSS/LGSP)	875,424,048		$69,767,453		$80,879,875		$80,914,837
GRAND TOTAL (ANNUAL-LGSS/LGSP)	**1,389,737,047**		**$116,548,189**		**$135,113,566**		**$134,976,100**
c/kwh			**$0.0839**		**$0.0972**		**$0.0971**
OVERAL CHANGE (%)					**15.93%**		**15.81%**

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MO LARGE GENERAL
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSSA

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	519.0	$101.15	$52,495	$117.26	$60,856	$120.29	$62,428
1001+ KW	141.4	$863.59	$122,116	$1,001.15	$141,568	$1,027.03	$145,227
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	660		$174,611		$202,423		$207,655
B: FACILITIES CHARGE	477,275.8	$2.894	$1,381,236	$3.355	$1,601,260	$3.442	$1,642,783
C: DEMAND CHARGE	436,829.9	$5.778	$2,524,003	$6.698	$2,925,887	$6.872	$3,001,895
D: ENERGY CHARGE							
0-180 hrs use per month	76,809,758.3	$0.08486	$6,518,076	$0.09838	$7,556,621	$0.10092	$7,751,641
181-360 hrs use per month	70,540,530.7	$0.06075	$4,285,337	$0.07043	$4,968,170	$0.06801	$4,797,461
361+ hrs use per month	42,238,222.9	$0.04260	$1,799,348	$0.04939	$2,086,146	$0.04260	$1,799,348
	189,588,512		$12,602,762		$14,610,936		$14,348,451
E: SEPARATELY METERED SPACE HEAT	-	$0.05246	$0	$0.03640	$0	$0.06239	$0
F: REACTIVE DEMAND ADJUSTMENT	3,048	$0.726	$2,213	$0.843	$2,571	$0.863	$2,631
MANUAL BILLS	10,424,776.5		$811,768		$941,076		$941,076
REVENUE			$17,496,593		$20,284,154		$20,144,491
c/kwh			$0.0875		$0.1014		$0.1007
FLUCTUATION (%)					15.93%		15.13%
used to reference avg customer	*302,873*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	1,352.6	$101.15	$136,816	$117.26	$158,607	$120.29	$162,705
1001+ KW	388.8	$863.59	$335,773	$1,001.15	$389,257	$1,027.03	$399,320
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	1,741		$472,589		$547,864		$562,025
B: FACILITIES CHARGE	1,285,518.6	$2.894	$3,720,291	$3.355	$4,312,915	$3.442	$4,424,755
C: DEMAND CHARGE	1,001,446.4	$2.879	$2,883,164	$3.338	$3,342,828	$3.424	$3,428,953
D: ENERGY CHARGE							
0-180 hrs use per month	176,405,679.9	$0.07141	$12,597,130	$0.08278	$14,602,862	$0.08492	$14,980,370
181-360 hrs use per month	154,681,102.8	$0.04023	$6,222,821	$0.04664	$7,214,327	$0.04504	$6,966,837
361+ hrs use per month	78,860,547.3	$0.03140	$2,476,221	$0.03640	$2,870,524	$0.03140	$2,476,221
	409,947,330		$21,296,172		$24,687,713		$24,423,428
E: SEPARATELY METERED SPACE HEAT	-	$0.05246	$0	$0.03640	$0	$0.06239	$0
F: REACTIVE DEMAND ADJUSTMENT	3,594	$0.726	$2,609	$0.843	$3,031	$0.863	$3,101
MANUAL BILLS	34,003,869.5		$2,103,124		$2,438,134		$2,438,134
REVENUE			$30,477,949		$35,332,485		$35,280,396
c/kwh			$0.0687		$0.0796		$0.0795
FLUCTUATION (%)					15.93%		15.76%
used to reference avg customer	*254,936*						
ANNUAL ENERGY/REVENUE	643,964,488		$47,974,542		$55,616,638		$55,424,888
c/kwh			$0.0745		$0.0864		$0.0861
FLUCTUATION (%)					15.93%		15.53%
Winter Price Below Summer (SUM-WIN)/SUM			21.5%		21.5%		21.1%

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MO LARGE GENERAL
PRIMARY VOLTAGE, ALL ELECTRIC (ONE METER) - LGSPA

*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	9.8	$101.15	$992	$117.26	$1,150	$120.29	$1,179
1001+ KW	36.0	$863.59	$31,049	$1,001.15	$35,995	$1,027.03	$36,925
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	46		$32,041		$37,144		$38,105
B: FACILITIES CHARGE	130,922.0	$2.399	$314,082	$2.781	$364,094	$2.853	$373,521
C: DEMAND CHARGE	116,842.2	$5.647	$659,808	$6.547	$764,966	$6.716	$784,712
D: ENERGY CHARGE							
0-180 hrs use per month	21,029,231.8	$0.08296	$1,744,585	$0.09617	$2,022,402	$0.09866	$2,074,744
181-360 hrs use per month	17,955,019.7	$0.05930	$1,064,733	$0.06875	$1,234,408	$0.06638	$1,191,854
361+ hrs use per month	12,213,990.9	$0.04160	$508,102	$0.04823	$589,081	$0.04160	$508,102
	51,198,242		$3,317,420		$3,845,891		$3,774,700
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	6,810	$0.726	$4,944	$0.843	$5,743	$0.863	$5,877
REVENUE			$4,328,294		$5,017,838		$4,976,914
c/kwh			$0.0845		$0.0980		$0.0972
FLUCTUATION (%)					15.93%		14.99%
used to reference avg customer	*1,118,873*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	COMPANY PROPOSED RATES Rate	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Rate	RATES W/RATE DESIGN * Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	26.4	$101.15	$2,672	$117.26	$3,097	$120.29	$3,177
1001+ KW	96.8	$863.59	$83,636	$1,001.15	$96,958	$1,027.03	$99,464
Separately Metered Space Heat	-	$2.32	$0	$2.69	$0	$2.76	$0
	123		$86,307		$100,055		$102,641
B: FACILITIES CHARGE	366,052.1	$2.399	$878,159	$2.781	$1,017,991	$2.853	$1,044,347
C: DEMAND CHARGE	268,430.9	$2.811	$754,559	$3.259	$874,816	$3.343	$897,365
D: ENERGY CHARGE							
0-180 hrs use per month	48,281,458.1	$0.06991	$3,375,357	$0.08105	$3,913,212	$0.08314	$4,014,120
181-360 hrs use per month	41,243,905.7	$0.03934	$1,622,535	$0.04561	$1,881,135	$0.04404	$1,816,382
361+ hrs use per month	23,694,554.7	$0.03080	$729,792	$0.03571	$846,133	$0.03080	$729,792
	113,219,919		$5,727,684		$6,640,479		$6,560,294
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	8,288	$0.726	$6,017	$0.843	$6,990	$0.863	$7,153
ADJUSTMENT			$0		$0		$0
REVENUE			$7,452,727		$8,640,332		$8,611,800
c/kwh			$0.0658		$0.0763		$0.0761
FLUCTUATION (%)					15.94%		15.55%
used to reference avg customer	*918,551*						

	BILLING UNITS	PRESENT RATES Revenue	COMPANY PROPOSED RATES Revenue	RATES W/RATE DESIGN * Revenue
ANNUAL ENERGY/REVENUE	164,418,161	$11,781,022	$13,658,170	$13,588,714
c/kwh		$0.0717	$0.0831	$0.0826
FLUCTUATION (%)			15.93%	15.34%
Winter Price Below Summer (SUM-WIN)/SUM		22.1%	22.1%	21.8%
SUMMER TOTAL (LGSSA/LGSPA)	251,211,531	$21,824,888	$25,301,992	$25,121,406
WINTER TOTAL (LGSSA/LGSPA)	557,171,118	$37,930,676	$43,972,816	$43,892,196
GRAND TOTAL (ANNUAL-LGSSA/LGSPA)	808,382,649	59,755,564	69,274,808	69,013,602
c/kwh		$0.0739	$0.0857	$0.0854
OVERALL WINTER ENERGY CHANGE			15.93%	14.65%
OVERAL CHANGE (%)			15.93%	15.49%

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MO LARGE GENERAL
SECONDARY VOLTAGE, SPACE HEAT (TWO METER) - LGSSH

* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

SUMMER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	112.3	$101.15	$11,361	$117.26	$13,171	$120.29	$13,511
1001+ KW	12.1	$863.59	$10,440	$1,001.15	$12,103	$1,027.03	$12,415
Separately Metered Space Heat	124.4	$2.32	$289	$2.69	$335	$2.76	$343
	249		$22,090		$25,608		$26,270
B: FACILITIES CHARGE	56,753.6	$2.894	$164,245	$3.355	$190,408	$3.442	$195,346
C: DEMAND CHARGE	46,146.0	$5.778	$266,631	$6.698	$309,086	$6.872	$317,115
D: ENERGY CHARGE							
0-180 hrs use per month	7,136,110.3	$0.08486	$605,570	$0.09838	$702,058	$0.10092	$720,176
181-360 hrs use per month	6,127,525.1	$0.06075	$372,247	$0.07043	$431,562	$0.06801	$416,733
361+ hrs use per month	2,910,295.9	$0.04260	$123,979	$0.04939	$143,740	$0.04260	$123,979
	16,173,931		$1,101,796		$1,277,359		$1,260,888
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.726	$0	$0.843	$0	$0.863	$0
MANUAL BILLS	243,022.3		$27,405		$31,770		$31,770
REVENUE			$1,582,167		$1,834,231		$1,831,389
c/kwh			$0.0964		$0.1117		$0.1116
FLUCTUATION (%)					15.93%		15.75%
used to reference avg customer	*65,978*						

WINTER

	BILLING UNITS	PRESENT RATES		COMPANY PROPOSED RATES		RATES W/RATE DESIGN *	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
25-199 KW	-	$101.15	$0	$117.26	$0	$120.29	$0
200-999 KW	222.8	$101.15	$22,533	$117.26	$26,122	$120.29	$26,797
1001+ KW	24.1	$863.59	$20,845	$1,001.15	$24,165	$1,027.03	$24,790
Separately Metered Space Heat	246.9	$2.32	$573	$2.69	$664	$2.76	$681
	494		$43,951		$50,952		$52,269
B: FACILITIES CHARGE	115,338.7	$2.894	$333,790	$3.355	$386,961	$3.442	$396,996
C: DEMAND CHARGE	100,383.7	$3.109	$312,093	$3.604	$361,783	$3.697	$371,118
D: ENERGY CHARGE							
0-180 hrs use per month	7,634,008.2	$0.07798	$595,300	$0.09040	$690,114	$0.09274	$707,978
181-360 hrs use per month	6,151,501.5	$0.04670	$287,275	$0.05414	$333,042	$0.05228	$321,600
361+ hrs use per month	2,435,101.7	$0.03580	$87,177	$0.04150	$101,057	$0.03580	$87,177
	16,220,611		$969,752		$1,124,213		$1,116,755
E: SEPARATELY METERED SPACE HEAT	14,916,720.8	$0.05246	$782,531	$0.03640	$542,969	$0.06239	$930,654
F: REACTIVE DEMAND ADJUSTMENT	-	$0.726	$0	$0.843	$0	$0.863	$0
MANUAL BILLS	1,167,057.7		$93,065		$107,889		$107,889
REVENUE			$2,535,182		$2,574,767		$2,975,681
c/kwh			$0.0785		$0.0797		$0.0921
FLUCTUATION (%)					1.56%		17.38%
used to reference avg customer	*65,694*						
	60,414						
ANNUAL ENERGY/REVENUE	48,721,343		$4,117,349		$4,408,998		$4,807,070
c/kwh			$0.0845		$0.0905		$0.0987
FLUCTUATION (%)					7.08%		16.75%
Winter Price Below Summer (SUM-WIN)/SUM			18.6%		28.7%		17.4%

SUMMER TOTAL (ALL RATES)	760,577,812	$68,214,966	$79,082,835	$78,726,979
WINTER TOTAL (ALL RATES)	1,404,237,722	$105,599,919	$122,056,007	$122,411,263
MANUAL BILLS-CREDITS-ADJUSTMENTS	82,025,505	$6,606,216	$7,658,530	$7,658,530
GRAND TOTAL (ANNUAL - ALL RATES)	**2,246,841,039**	**$180,421,101**	**$208,797,372**	**$208,796,772**
c/kwh Summer		**$0.0897**	**$0.1040**	**$0.1035**
c/kwh Winter		**$0.0752**	**$0.0869**	**$0.0872**
c/kwh Annual		**$0.0803**	**$0.0929**	**$0.0929**
Winter Price Below Summer (SUM-WIN)/SUM		**16.2%**	**16.4%**	**15.8%**
OVERALL CHANGE (%)			**15.728%**	**15.73%**

C:\Users\tsk\AppData\Local\Temp\[277168_1.xlsx]RATE SUMMARIES

KANSAS CITY POWER & LIGHT COMPANY
2015 Rate Case - Direct Filing
Missouri Jurisdiction
Energy Losses by Rate and Voltage Level
TY 3/31/14; Update 10/31/14; K&M 4/30/15

Line	Missouri Rate Group	Energy @ Meter (kWh)	Energy @ Generator (kWh)	Loss Factor
		(1)	(2)	(3)
1	LGSP	244,687,769	253,758,834	1.037072
2	LGSPA	164,418,161	170,513,471	1.037072
3	LGSPH	0	0	
4	LGSS	1,145,049,278	1,215,227,058	1.061288
5	LGSSA	643,964,488	683,431,783	1.061288
6	LGSSH	48,721,343	51,707,377	1.061288
7	TOTAL	2,246,841,039	2,374,638,523	
8	LPGSP	848,759,784	880,225,007	1.037072
9	LPGSPO	273,694,420	283,840,819	1.037072
10	LPGSS	460,991,814	489,245,081	1.061288
11	LPGSPO	0	0	
12	LPGSSS	344,252,676	352,799,782	1.024828
13	LPGSTR	131,817,671	133,880,749	1.015651
14	LPSTRO	147,547,859	149,857,130	1.015651
15	TOTAL	2,207,064,224	2,289,848,568	
16	MGSP	9,396,192	9,744,528	1.037072
17	MGSPA	396,843	411,555	1.037072
18	MGSPH	0	0	
19	MGSS	970,815,626	1,030,314,974	1.061288
20	MGSSA	110,317,475	117,078,613	1.061288
21	MGSSH	22,014,495	23,363,719	1.061288
22	TOTAL	1,112,940,632	1,180,913,389	
23	SGSP	1,252,067	1,298,483	1.037072
24	SGSPA	0	0	
25	SGSPH	0	0	
26	SGSPU	0	0	
27	SGSS	382,747,826	406,205,675	1.061288
28	SGSSA	15,366,343	16,308,115	1.061288
29	SGSSH	5,816,232	6,172,697	1.061288
30	SGSSU	7,377,858	7,830,032	1.061288
31	TOTAL	412,560,325	437,815,002	
32	RESA	1,870,294,513	1,984,921,123	1.061288
33	RESB	570,415,845	605,375,491	1.061288
34	RESC	162,008,520	171,937,698	1.061288
35	RTOD	545,195	578,609	1.061288
36	TOTAL	2,603,264,072	2,762,812,921	
37	Off Peak Ltg	646,391	686,007	1.061288
38	Other	85,340,160	90,570,488	1.061288
39	TOTAL NON-BF	85,986,551	91,256,495	
40	MO TOTALS	***8,668,656,844***	***9,137,284,899***	
	By Voltage Level:			
41	Secondary	6,502,433,402	6,900,954,540	1.061288
42	Primary	1,542,605,236	1,599,792,698	1.037072
43	Substation	344,252,676	352,799,782	1.024828
44	Transmission	279,365,529	283,737,879	1.015651
45	Total	***8,668,656,844***	***9,137,284,899***	

Source: KCPL Allocators MO Rev 10-9-14 Avg-Pk 4 CP - not included in 12-1-14 wkps.xls, Sales tab

KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 2 Non-Coincident Peaks
For the Test Year Ended March 31, 2014

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak	1,865,474						
2	Avg of 2 Highest Monthly NCP Values	2,062,266	878,647	109,779	269,011	445,725	337,519	21,586
3	Energy Sales with Losses - MWh	9,137,285	2,762,813	437,815	1,180,913	2,374,639	2,289,849	91,256
4	Average Demand - kW	1,043,069	315,390	49,979	134,807	271,077	261,398	10,417
5	Average Demand - Percent	1.000000	0.302367	0.047915	0.129241	0.259884	0.250605	0.009987
6	Class Excess Demand - kW	1,019,197	563,257	59,800	134,203	174,648	76,121	11,169
7	Class Excess Demand - Percent	1.000000	0.552648	0.058673	0.131675	0.171358	0.074687	0.010958
	Allocator:							
8	Annual Load Factor * Average Demand	0.559144	0.169067	0.026792	0.072264	0.145313	0.140124	0.005584
9	(1-LF) * Excess Demand	0.440856	0.243638	0.025867	0.058050	0.075544	0.032926	0.004831
10	Average and Excess Demand Allocator	1.000000	0.412705	0.052658	0.130314	0.220857	0.173050	0.010415

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	55.91%
1 - Load Factor	44.09%

Source: KCPL Allocators MO_BAI A&E 2NCP.xls

KANSAS CITY POWER & LIGHT COMPANY
2015 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 3/31/14; Update 10/31/14; K&M 4/30/15

LINE NO.	DESCRIPTION	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	767,355,793	285,159,916	48,836,426	103,290,211	180,113,158	140,231,588	9,724,494
0050	OTHER OPERATING REVENUE	413,609,396	125,856,489	19,881,740	53,459,512	107,159,767	103,102,717	4,149,170
0060	TOTAL OPERATING REVENUE	1,180,965,189	411,016,406	68,718,167	156,749,723	287,272,925	243,334,305	13,873,664
0070								
0080	OPERATING EXPENSES							
0090	FUEL	222,511,027	67,756,974	10,677,580	28,777,564	57,588,910	55,482,283	2,227,716
0100	PURCHASED POWER	304,735,754	92,266,295	14,608,136	39,377,911	79,157,649	76,274,910	3,050,853
0110	OTHER OPERATION & MAINTENANCE EXPENSES	303,491,601	140,753,773	18,506,651	36,088,107	57,330,382	46,531,706	4,280,982
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	116,953,542	52,713,586	6,887,261	15,453,775	23,277,353	17,145,619	1,475,947
0130	AMORTIZATION EXPENSES	15,665,901	6,936,700	904,427	2,058,557	3,199,577	2,366,999	199,641
0140	TAXES OTHER THAN INCOME TAXES	58,619,563	26,330,339	3,438,576	7,577,440	11,762,790	8,753,512	756,906
0150	CURRENT INCOME TAXES	14,819,681	(9,994,524)	2,701,697	4,587,542	11,112,892	6,187,730	224,343
0160	DEFERRED INCOME TAXES	15,669,609	7,045,970	916,911	2,040,121	3,146,954	2,319,503	200,151
0170	TOTAL ELECTRIC OPERATING EXPENSES	1,052,466,678	383,809,113	58,641,239	135,961,018	246,576,507	215,062,262	12,416,539
0180								
0190	NET ELECTRIC OPERATING INCOME	128,498,510	27,207,292	10,076,928	20,788,704	40,696,418	28,272,044	1,457,125
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,043,175,544	2,259,671,150	293,703,793	656,140,823	1,017,312,668	752,610,009	63,737,101
0230	LESS: ACCUM. PROV. FOR DEPREC	2,040,172,942	916,587,381	120,359,680	261,404,453	407,660,370	302,396,395	31,764,661
0240	NET PLANT	3,003,002,603	1,343,083,769	173,344,113	394,736,370	609,652,298	450,213,614	31,972,439
0250	PLUS:							
0260	CASH WORKING CAPITAL	(58,530,428)	(24,757,768)	(3,570,540)	(7,723,217)	(12,446,576)	(9,297,208)	(735,119)
0270	MATERIALS & SUPPLIES	57,386,822	24,624,083	3,180,466	7,512,406	12,154,872	9,244,524	670,472
0280	PREPAYMENTS	6,397,922	2,801,525	356,342	813,265	1,332,572	1,024,697	69,520
0290	FUEL INVENTORY	80,107,604	24,200,924	3,835,784	10,358,639	20,800,550	20,110,413	801,295
0300	REGULATORY ASSETS	111,292,579	46,842,653	7,571,153	13,622,623	23,328,467	18,619,219	1,308,464
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	167,781	91,553	12,598	22,671	24,733	12,753	3,474
0330	CUSTOMER DEPOSITS	3,567,416	1,780,441	1,424,044	301,429	56,982	4,521	0
0340	DEFERRED INCOME TAXES	599,672,820	268,692,485	34,923,667	78,020,250	120,966,393	89,491,187	7,578,837
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCI	39,136,133	11,833,473	1,875,216	5,058,000	10,170,874	9,807,708	390,863
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	23,191	7,012	1,111	2,997	6,027	5,812	232
0370	TOTAL RATE BASE	2,557,089,761	1,134,390,222	146,480,681	335,914,739	523,597,174	390,593,278	26,113,666
0380								
0390	RATE OF RETURN	5.025%	2.398%	6.879%	6.189%	7.772%	7.238%	5.580%
0400	RELATIVE RATE OF RETURN	1.00	0.48	1.37	1.23	1.55	1.44	1.11

Notes:
Production Plant and Expense, and Transmission Allocated using A&E-2NCP.

KANSAS CITY POWER & LIGHT COMPANY

Development of
4 CP Demand Allocator
For the Test Year Ended March 31, 2014

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	4 CP Demand - kW	1,805,371	749,919	100,773	232,203	391,759	330,717	-
2	4 CP Demand - Percent	1.000000	0.415382	0.055818	0.128618	0.216996	0.183185	-

Source: KCPL Allocators MO_BAI 4CP.xls

KANSAS CITY POWER & LIGHT COMPANY
2015 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 3/31/14; Update 10/31/14; K&M 4/30/15

LINE NO.	DESCRIPTION	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	767,355,793	285,159,916	48,836,426	103,290,211	180,113,158	140,231,588	9,724,494
0050	OTHER OPERATING REVENUE	413,609,396	125,865,014	19,891,799	53,454,109	107,147,479	103,134,974	4,116,021
0060	TOTAL OPERATING REVENUE	1,180,965,189	411,024,931	68,728,225	156,744,320	287,260,637	243,366,561	13,840,515
0070								
0080	OPERATING EXPENSES							
0090	FUEL	222,511,027	67,769,937	10,692,874	28,769,349	57,570,226	55,531,330	2,177,312
0100	PURCHASED POWER	304,735,754	92,266,295	14,608,136	39,377,911	79,157,649	76,274,910	3,050,853
0110	OTHER OPERATION & MAINTENANCE EXPENSES	303,491,601	141,237,779	19,077,730	35,781,352	56,632,736	48,363,063	2,398,941
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	116,953,542	52,943,360	7,158,371	15,308,148	22,946,157	18,015,025	582,479
0130	AMORTIZATION EXPENSES	15,665,901	6,969,167	942,734	2,037,980	3,152,780	2,489,845	73,395
0140	TAXES OTHER THAN INCOME TAXES	58,619,563	26,447,812	3,577,183	7,502,988	11,593,464	9,198,001	300,115
0150	CURRENT INCOME TAXES	14,819,681	(10,405,807)	2,216,425	4,848,206	11,705,714	4,631,540	1,823,602
0160	DEFERRED INCOME TAXES	15,669,609	7,077,150	953,700	2,020,359	3,102,011	2,437,479	78,909
0170	TOTAL ELECTRIC OPERATING EXPENSES	1,052,466,678	384,305,693	59,227,154	135,646,294	245,860,738	216,941,194	10,485,606
0180								
0190	NET ELECTRIC OPERATING INCOME	128,498,510	26,719,237	9,501,071	21,098,025	41,399,899	26,425,368	3,354,909
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,043,175,544	2,269,874,580	305,742,823	649,674,057	1,002,605,465	791,217,186	24,061,433
0230	LESS: ACCUM. PROV. FOR DEPREC	2,040,172,942	920,737,457	125,256,356	258,774,203	401,678,459	318,099,223	15,627,243
0240	NET PLANT	3,003,002,603	1,349,137,123	180,486,467	390,899,853	600,927,005	473,117,963	8,434,191
0250	PLUS:							
0260	CASH WORKING CAPITAL	(58,530,428)	(24,832,553)	(3,658,780)	(7,675,819)	(12,338,780)	(9,580,178)	(444,317)
0270	MATERIALS & SUPPLIES	57,386,822	24,758,852	3,339,479	7,426,992	11,960,617	9,754,453	146,429
0280	PREPAYMENTS	6,397,922	2,816,769	374,328	803,604	1,310,599	1,082,378	10,243
0290	FUEL INVENTORY	80,107,604	24,200,924	3,835,784	10,358,639	20,800,550	20,110,413	801,295
0300	REGULATORY ASSETS	111,292,579	46,987,576	7,742,148	13,530,773	23,119,575	19,167,572	744,935
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	167,781	91,553	12,598	22,671	24,733	12,753	3,474
0330	CUSTOMER DEPOSITS	3,567,416	1,780,441	1,424,044	301,429	56,982	4,521	0
0340	DEFERRED INCOME TAXES	599,672,820	269,905,753	36,355,201	77,251,301	119,217,592	94,081,881	2,861,092
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCI	39,136,133	11,833,473	1,875,216	5,058,000	10,170,874	9,807,708	390,863
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	23,191	7,012	1,111	2,997	6,027	5,812	232
0370	TOTAL RATE BASE	2,557,089,761	1,139,450,460	152,451,257	332,707,644	516,303,358	409,739,926	6,437,116
0380								
0390	RATE OF RETURN	5.025%	2.345%	6.232%	6.341%	8.019%	6.449%	52.118%
0400	RELATIVE RATE OF RETURN	1.00	0.47	1.24	1.26	1.60	1.28	10.37

Notes:
Production Plant and Expense, and Transmission Allocated using 4CP.