Exhibit No.:	
Issue:	Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Industrials
Case No.:	ER-2010-0355
Date Testimony Prepared:	November 24, 2010

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Continue the Implementation of Its Regulatory Plan	)	**Case No. ER-2010-0355**

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Ford Motor Company
Midwest Energy Users Association
Missouri Industrial Energy Consumers
Praxair, Inc.

REDACTED VERSION

November 24, 2010

BAI
Brubaker & Associates, Inc.
Chesterfield, MO 63017

Project 9215

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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 Ford Motor Company, Midwest Energy Users Association, Missouri Industrial Energy Consumers and Praxair, Inc. in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony which was prepared in written form for introduction into evidence in the Missouri Public Service Commission's Case No. ER-2010-0355.

3. I hereby swear and affirm that the testimony is true and correct and that it shows the matters and things that it purports to show.

M E Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 23rd day of November, 2010.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2011
Commission # 07024862

Tammy S Klossner

Notary Public

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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 WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and President of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Ford Motor Company, Midwest Energy Users Association, Missouri Industrial Energy Consumers and Praxair, Inc. (collectively "Industrials"). 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 in two respects:

   (1) KCPL has used an obscure and inappropriate method to allocate generation fixed costs, which I will address in my rebuttal testimony. I have, instead, applied main-stream methods that this Commission has previously endorsed.

   (2) KCPL allocates the margin on off-system sales on a demand basis. I have changed the allocation to reflect the more appropriate energy-based allocation which the Commission has previously approved for this purpose.

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.

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 <u>and</u> 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.

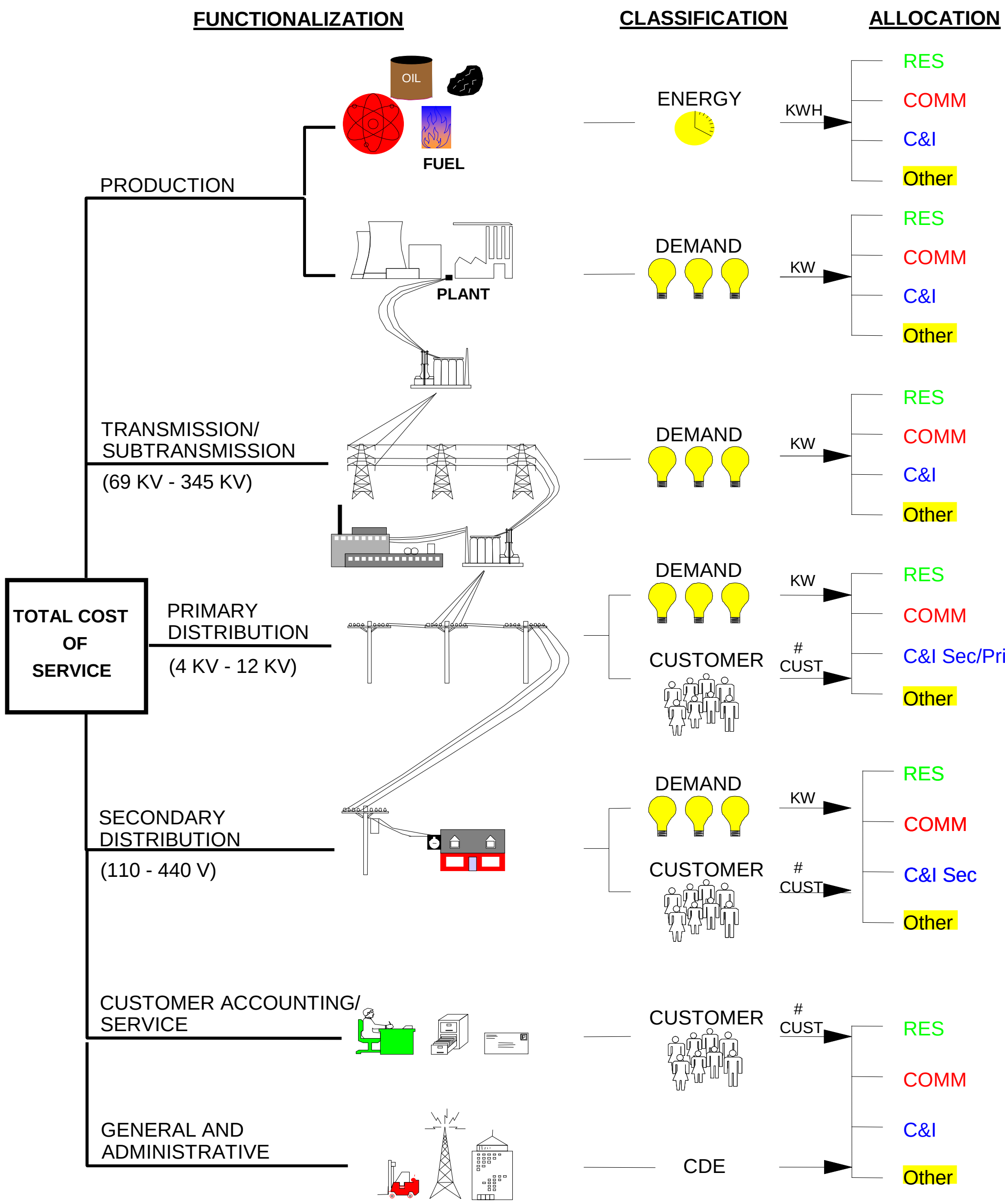
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so, consider 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 <u>service</u> 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 Large Transmission and Large Primary 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.

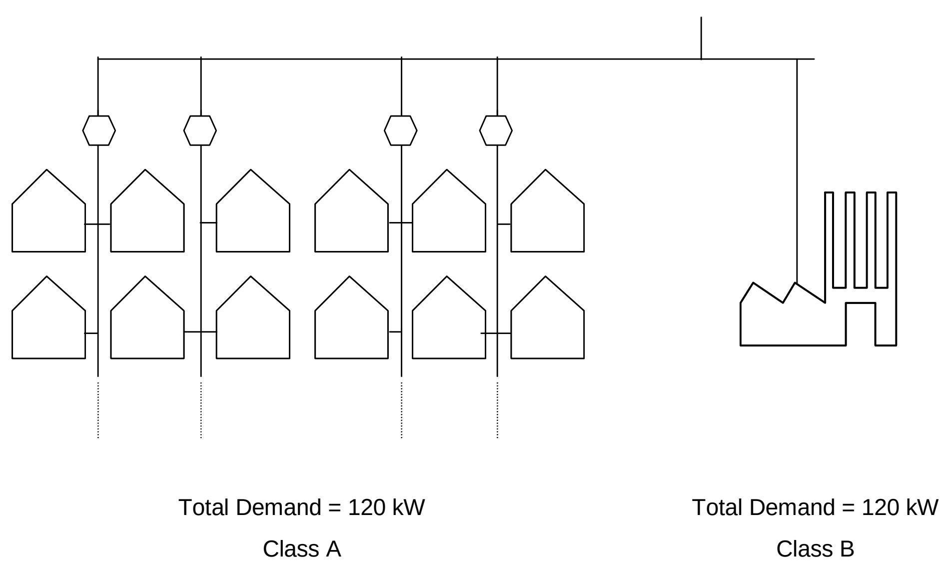
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

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.

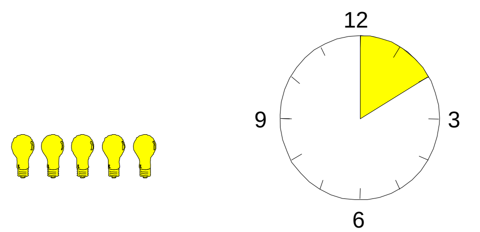
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

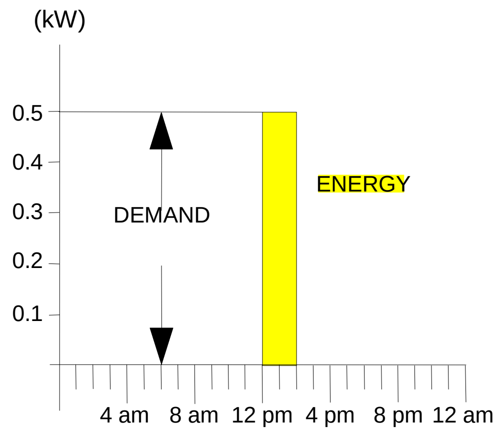
A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each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

Figure 3

DEMAND VS. ENERGY

CUSTOMER A

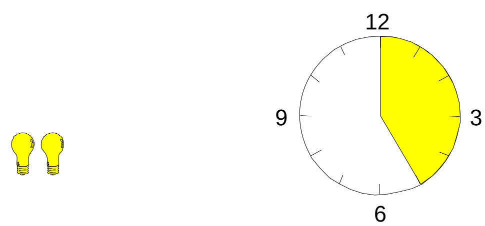


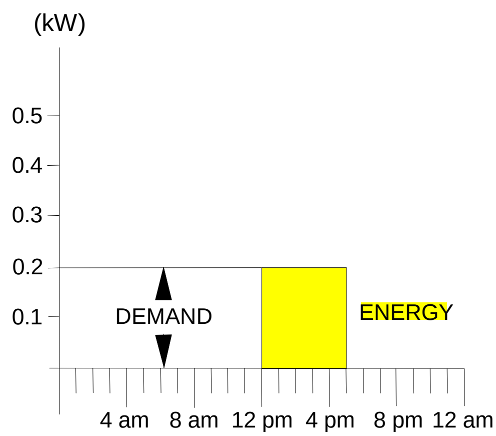


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

DEMAND: 500 watts = 0.5 kW

CUSTOMER B





ENERGY: 200 watts x 5 hours = 1,000 watthours = 1.0 kWh

DEMAND: 200 watts = 0.2 kW

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.

<u>Allocation</u>

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

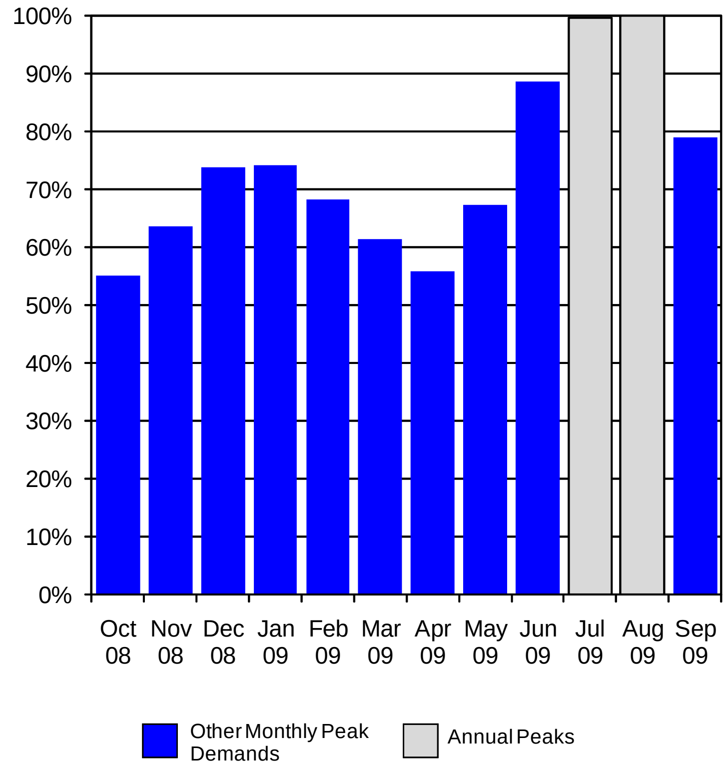
Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

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 September 2009



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 August, and was substantially higher than the monthly peaks occurring in most other months. The July peak was close, at 99.8% of the annual peak. The peaks in June and September were 11% and 21%, 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]

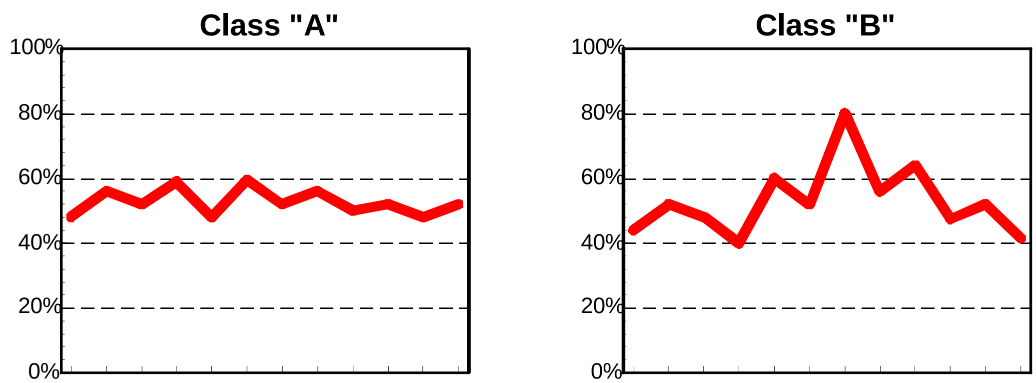
[1] NARUC Electric Utility Cost Allocation Manual, 1992, page 81.

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 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

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[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.

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 July and August system peaks. However, the allocation factors for all classes under that approach are very close to the A&E-4NCP allocation factors.

Schedule MEB-COS-3 shows the derivation of the A&E demand allocation factor for generation using the four annual class non-coincident peaks.

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 an obscure and inappropriate 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, and also a different allocation of the margin on off-system sales.

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 OTHER THAN THE USE OF A DIFFERENT ALLOCATION FOR GENERATION FIXED COSTS, HOW DOES YOUR STUDY DIFFER FROM THE ONE PRESENTED BY KCPL?

A There also is a difference in the allocation of the margin on off-system sales.

Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF OFF-SYSTEM SALES?

A KCPL has allocated the margin from off-system sales on the basis of the allocation of steam fixed generation plant.

The more traditional approach is to allocate the revenues from off-system sales to customer classes on the basis of class kWh requirements. This would make the allocation of the revenues consistent with the allocation of the underlying costs. (This method was recently adopted in a KCPL rate case, Case No. ER-2006-0314, and re-affirmed in Ameren Missouri's most recently concluded rate case, Case No. ER-2010-0036.)

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 areas 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 0420 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 $29 million, or 11%, in order to move to cost of service. All other classes would require a corresponding decrease. The decreases range from about 19% for the Small General Service class to 4% for the Medium General Service 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 2.7% 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 2.7% (as compared to the 10.6% 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.

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

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.

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. 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.

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

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 claimed average variable costs (before being offset by the margin earned from off-system sales) are approximately 2.0¢/kWh. Factoring in the off-system sales margin as an offset, net variable costs would be reduced to a value significantly lower. (This additional offset is equal to the Missouri retail jurisdictional share of the off-system sales margin divided by Missouri retail sales of approximately 8,800,000 MWh.) The energy charges in the high load factor block of KCPL's current LGS and LPS tariffs 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.

Q HAVE YOU EXAMINED KCPL'S LEVEL OF AVOIDED COSTS?

A Yes, I have.

Q WHAT ARE AVOIDED COSTS?

A These are the costs that would be avoided by the purchase of energy from an alternative source, such as a customer-owned generation facility, and are essentially the same as the incremental costs of energy.

Q DO YOU BELIEVE THAT THE AVOIDED ENERGY COSTS ARE RELEVANT TO THE DESIGN OF EMBEDDED COST TARIFFS?

A No, I do not. However, in a previous rate case, KCPL referred to its avoided costs as one of the objections to my proposed LPS rate design in that case.

Q WHAT IS THE LEVEL OF KCPL'S AVOIDED ENERGY COSTS?

A For 2011, KCPL provided an estimate for off-peak energy charges during both summer and during the winter of approximately ***************. The estimates for 2012 were approximately ****************** in the summer and **************** during the winter; for 2013, approximately ****************** in the summer and ************** in the winter; and in 2014 approximately ************ during the summer and ************** during the winter.

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 column of the detail sheets for this schedule 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 percentage up 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.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A

<u>Qualifications of Maurice Brubaker</u>

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 PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission ("FERC"), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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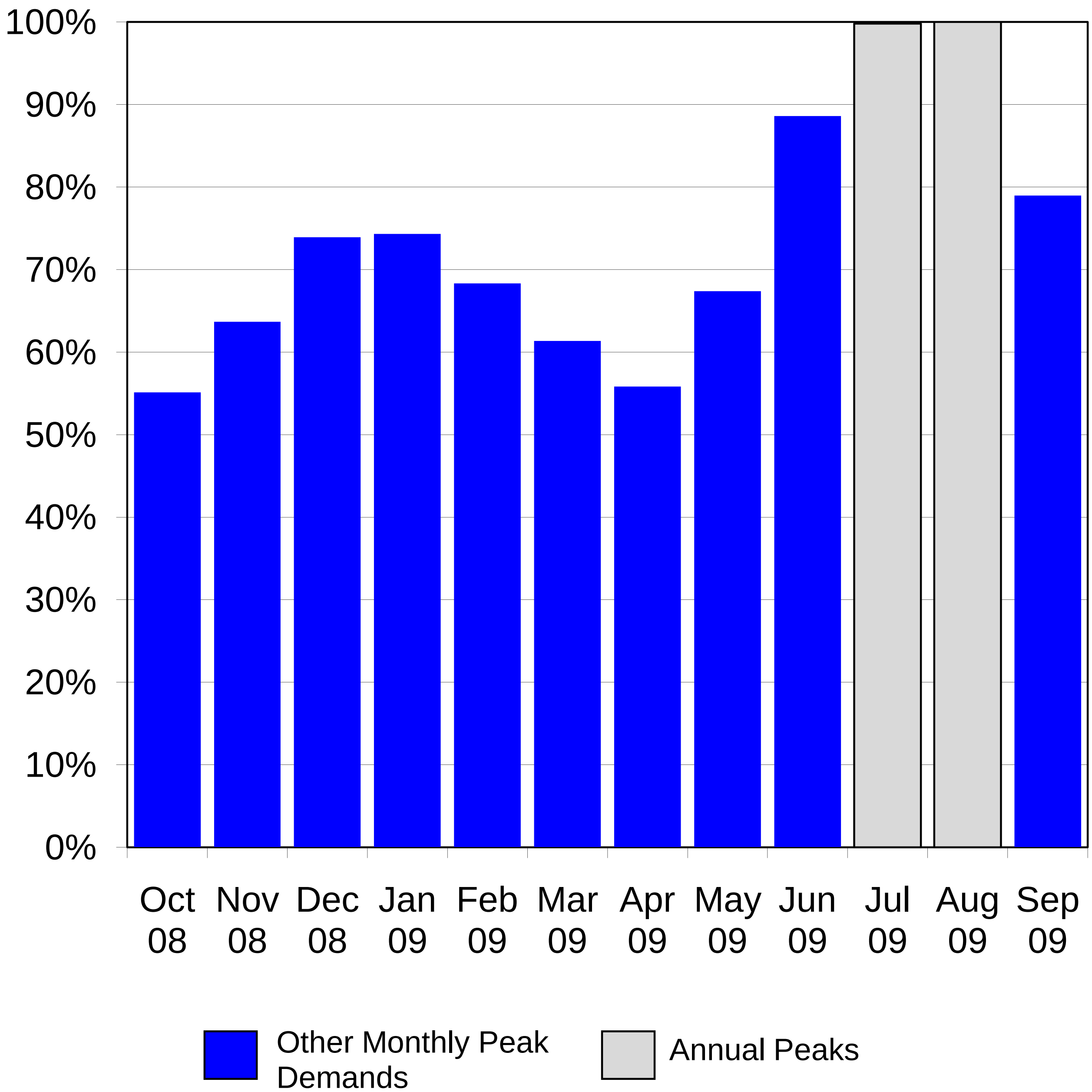
KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCP&L's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak For the Test Year Ended September 2009



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 September 2009

Line	Description	Missouri Retail MW (1)	Percent (2)
1	January	1,474	74.3
2	February	1,355	68.3
3	March	1,217	61.4
4	April	1,107	55.8
5	May	1,336	67.4
6	June	1,757	88.6
7	July	1,979	99.8
8	August	1,983	100.0
9	September	1,566	79.0
10	October	1,093	55.1
11	November	1,263	63.7
12	December	1,466	73.9

Source: Schedule GMM2010-2

KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended December 2009

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Total Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak - kW	1,982,705						
2	Avg of 4 Highest Monthly NCP Values - kW	1,976,201	795,323	104,389	257,548	422,281	375,450	21,210
3	Energy Sales with Losses - MWh	9,227,940	2,787,139	447,074	1,174,444	2,429,101	2,297,861	92,321
4	Average Demand - kW	1,053,418	318,167	51,036	134,069	277,295	262,313	10,539
5	Average Demand - Percent	1.000000	0.302033	0.048448	0.127270	0.263233	0.249011	0.010005
6	Class Excess Demand - kW	922,783	477,156	53,354	123,479	144,986	113,137	10,671
7	Class Excess Demand - Percent	1.000000	0.517084	0.057818	0.133812	0.157119	0.122604	0.011564
	Allocator:							
8	Annual Load Factor * Average Demand	0.531303	0.160471	0.025741	0.067619	0.139857	0.132301	0.005315
9	(1-LF) * Excess Demand	0.468697	0.242355	0.027099	0.062717	0.073641	0.057464	0.005420
10	Average and Excess Demand Allocator	1.000000	0.402826	0.052840	0.130336	0.213498	0.189764	0.010735

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

System Annual Load Factor	53.13%
1 - Load Factor	46.87%

Source: KCPL MO Allocators 05-21-10.xls

KANSAS CITY POWER & LIGHT COMPANY
MISSOURI CUSTOMERS
CLASS COST OF SERVICE
DEC2009 TEST YEAR INCL KNOWN & MEAS TO 12/31/2010

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	668,323,387	247,439,033	46,531,284	89,839,660	154,950,292	121,279,587	8,283,530
0050	OTHER OPERATING REVENUE	69,914,288	22,833,590	3,448,633	8,922,651	17,668,141	16,348,231	693,043
0060	TOTAL OPERATING REVENUE	738,237,675	270,272,623	49,979,917	98,762,311	172,618,433	137,627,818	8,976,573
0070								
0080	OPERATING EXPENSES							
0090	FUEL	167,502,786	50,550,549	8,114,053	21,341,211	43,949,885	41,875,025	1,672,062
0100	PURCHASED POWER	17,930,093	5,610,776	860,240	2,268,559	4,666,459	4,358,952	165,106
0110	OTHER OPERATION & MAINTENANCE EXPENSES	247,431,627	107,721,845	14,769,775	30,733,752	48,485,523	41,968,133	3,752,598
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	92,323,818	40,300,227	5,150,792	12,335,676	18,312,026	15,046,934	1,178,162
0130	AMORTIZATION EXPENSES	10,089,113	5,423,265	660,947	987,082	1,572,231	1,365,579	80,008
0140	INTEREST ON CUSTOMER DEPOSITS	227,566	9,561	173,419	36,224	7,194	676	491
0150	TAXES OTHER THAN INCOME TAXES	43,366,539	18,567,008	2,446,211	5,660,394	8,804,802	7,347,314	540,811
0160	FEDERAL AND STATE INCOME TAXES	23,596,471	502,713	4,855,240	4,846,254	10,019,897	3,116,491	255,876
0170	TOTAL ELECTRIC OPERATING EXPENSES	602,468,012	228,685,944	37,030,678	78,209,153	135,818,017	115,079,105	7,645,115
0180								
0190	NET ELECTRIC OPERATING INCOME	135,769,663	41,586,679	12,949,239	20,553,157	36,800,416	22,548,713	1,331,458
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	4,016,606,546	1,746,625,318	226,742,963	529,031,798	805,884,696	659,653,943	48,667,828
0230	LESS: ACCUM. PROV. FOR DEPREC	1,517,382,643	659,628,044	87,105,909	196,575,003	302,979,842	247,913,597	23,180,248
0240	NET PLANT	2,499,223,903	1,086,997,274	139,637,054	332,456,795	502,904,854	411,740,346	25,487,580
0250	PLUS:							
0260	WORKING CAPITAL	88,558,503	29,191,437	4,290,351	11,239,843	22,004,068	20,901,840	930,965
0270	PRIOR NET PREPAID PENSION ASSET	0	0	0	0	0	0	0
0280	PENSION REGULATORY ASSET	8,257,718	3,300,738	477,052	1,020,041	1,754,931	1,578,088	126,867
0290	REG ASSET - DSM PROGRAMS	29,779,838	11,996,105	1,573,557	3,881,394	6,357,928	5,651,156	319,698
0300	REG ASSET - ERPP PROGRAMS	289,914	126,070	16,366	38,185	58,168	47,613	3,513
0310	REG ASSET - IATAN 1 & COMMMON PLANT	13,290,035	5,353,577	702,241	1,732,174	2,837,392	2,521,977	142,674
0320	LESS:							
0330	ACCUM. DEFERRED TAXES	330,262,211	144,488,278	18,550,860	44,026,913	65,833,197	53,386,684	3,976,279
0340	DEFERRED GAIN ON SO2 EMISSION CR.	49,523,837	14,957,813	2,399,326	6,302,921	13,036,321	12,331,994	495,462
0350	DEFERRED GAIN ON SO2 ALLOWANCE	(963,168)	(290,908)	(46,663)	(122,583)	(253,538)	(239,840)	(9,636)
0360	CUST. ADVANCES FOR CONSTRUCTION	184,485	95,855	12,383	26,209	30,040	16,734	3,264
0370	CUSTOMER DEPOSITS	5,354,483	224,965	4,080,455	852,323	169,276	15,900	11,563
0380	REGULATORY PLAN ADDITIONAL AMORT	132,221,058	54,981,776	7,336,613	17,033,125	27,507,303	23,762,063	1,600,178
0390	TOTAL RATE BASE	2,122,817,005	922,507,421	114,363,648	282,249,523	429,594,740	353,167,485	20,934,186
0400								
0410	RATE OF RETURN	6.396%	4.508%	11.323%	7.282%	8.566%	6.385%	6.360%
0420	RELATIVE RATE OF RETURN	1.00	0.70	1.77	1.14	1.34	1.00	0.99

Notes:
Production Plant and Expense Allocated using A&E-4NCP.
Margin on Sales Revenue Allocated on Energy.

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 @ Average Current ROR* (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 270,273	$ 922,507	$ 41,587	4.508%	70	$ 59,001	$ 17,414	$ 28,745	10.6%
2	Small General Service	49,980	114,364	12,949	11.323%	177	7,314	(5,635)	(9,301)	-18.6%
3	Medium General Service	98,762	282,250	20,553	7.282%	114	18,052	(2,501)	(4,129)	-4.2%
4	Large General Service	172,618	429,595	36,800	8.566%	134	27,476	(9,325)	(15,392)	-8.9%
5	Large Power Service	137,628	353,167	22,549	6.385%	100	22,588	39	64	0.0%
6	Total Lighting	8,977	20,934	1,331	6.360%	99	1,339	7	12	0.1%
7	Total	$ 738,238	$ 2,122,817	$ 135,770	6.396%	100	$ 135,770	$ (0)	$ (0)	0.0%

Source: Schedule MEB-COS-4
* Column 2 x Column 4, Line 7 (6.396%)

KANSAS CITY POWER & LIGHT COMPANY

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

Line	Rate Class	Current Revenues (1)	Move 25% Toward Cost Of Service (2)	Adjusted Current Revenue (3)	Percent of Adjusted Current Revenue (4)
1	Residential	$ 270.3	$ 7.2	$ 277.5	37.58%
2	Small General Service	50.0	(2.3)	47.7	6.46%
3	Medium General Service	98.8	(1.0)	97.7	13.24%
4	Large General Service	172.6	(3.8)	168.8	22.86%
5	Large Power Service	137.6	0.0	137.6	18.64%
6	Total Lighting	9.0	0.0	9.0	1.22%
7	Subtotal	$ 738.2	$ -	$ 738.2	100.00%

MO LARGE POWER SERVICE
SUMMARY OF PROPOSAL SCENARIO
*** 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 With Increase***
			10.2564%
JURISDICTIONAL INCREASE (%)		**13.6752%**	**18.2810%**
A: CUSTOMER CHARGE			
	755.69	859.03	893.84
	-	-	-
	-	-	-
B: FACILITIES CHARGE			
SECONDARY:	2.530	2.875	2.993
PRIMARY:	2.098	2.384	2.482
SUBSTATION VOLTAGE	0.633	0.719	0.749
TRANSM VOLTAGE	-	-	-
C: DEMAND CHARGE			
SECONDARY-SUMMER:			
First 2450 kw	9.819	11.162	11.614
Next 2450 kw	7.854	8.928	9.290
Next 2450 kw	6.579	7.479	7.782
All kw over 7350 kw	4.803	5.460	5.681
SECONDARY-WINTER			
First 2450 kw	6.674	7.586	7.894
Next 2450 kw	5.208	5.920	6.160
Next 2450 kw	4.595	5.223	5.435
All kw over 7350 kw	3.537	4.021	4.184
PRIMARY-SUMMER			
First 2500 kw	9.593	10.905	11.347
Next 2500 kw	7.675	8.725	9.078
Next 2500 kw	6.428	7.307	7.603
All kw over 7500 kw	4.693	5.335	5.551
PRIMARY-WINTER			
First 2500 kw	6.521	7.413	7.713
Next 2500 kw	5.090	5.786	6.021
Next 2500 kw	4.490	5.104	5.311
All kw over 7500 kw	3.456	3.929	4.088
SUBSTATION-SUMMER			
First 2520 kw	9.479	10.775	11.212
Next 2520 kw	7.583	8.620	8.969
Next 2520 kw	6.352	7.221	7.513
All kw over 7560 kw	4.638	5.272	5.486
SUBSTATION-WINTER			
First 2520 kw	6.444	7.325	7.622
Next 2520 kw	5.029	5.717	5.948
Next 2520 kw	4.437	5.044	5.248
All kw over 7560 kw	3.415	3.882	4.039
TRANSMISSION-SUMMER			
First 2541 kw	9.397	10.682	11.115
Next 2541 kw	7.516	8.544	8.890
Next 2541 kw	6.294	7.155	7.445
All kw over 7623 kw	4.596	5.225	5.436
TRANSMISSION-WINTER			
First 2541 kw	6.386	7.259	7.553
Next 2541 kw	4.984	5.666	5.895
Next 2541 kw	4.397	4.998	5.201
All kw over 7623 kw	3.385	3.848	4.004

MO LARGE POWER SERVICE
SUMMARY OF PROPOSAL SCENARIO
*** 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 With Increase***
			10.2564%
JURISDICTIONAL INCREASE (%)		**13.6752%**	**18.2810%**
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.06148	0.06989	0.07272
181-360 hrs use per month	0.04276	0.04861	0.04715
361+ hrs use per month	0.02566	0.02917	0.02566
SECONDARY-WINTER:			
0-180 hrs use per month	0.05212	0.05925	0.06165
181-360 hrs use per month	0.03890	0.04422	0.04289
361+ hrs use per month	0.02541	0.02888	0.02541
PRIMARY-SUMMER:			
0-180 hrs use per month	0.06008	0.06830	0.07106
181-360 hrs use per month	0.04179	0.04750	0.04608
361+ hrs use per month	0.02507	0.02850	0.02507
PRIMARY-WINTER:			
0-180 hrs use per month	0.05094	0.05791	0.06025
181-360 hrs use per month	0.03800	0.04320	0.04190
361+ hrs use per month	0.02484	0.02824	0.02484
SUBSTATION-SUMMER			
0-180 hrs use per month	0.05937	0.06749	0.07022
181-360 hrs use per month	0.04130	0.04695	0.04554
361+ hrs use per month	0.02477	0.02816	0.02477
SUBSTATION-WINTER			
0-180 hrs use per month	0.05034	0.05722	0.05954
181-360 hrs use per month	0.03756	0.04270	0.04141
361+ hrs use per month	0.02454	0.02790	0.02454
TRANSMISSION-SUMMER			
0-180 hrs use per month	0.05884	0.06689	0.06960
181-360 hrs use per month	0.04093	0.04653	0.04513
361+ hrs use per month	0.02456	0.02792	0.02456
TRANSMISSION-WINTER			
0-180 hrs use per month	0.04988	0.05670	0.05900
181-360 hrs use per month	0.03722	0.04231	0.04104
361+ hrs use per month	0.02431	0.02763	0.02431
E: REACTIVE DEMAND ADJUSTMENT	0.635	0.722	0.751
LPS Secondary	100.00%	13.67%	13.86%
LPS Primary	100.00%	13.68%	13.86%
LPS Substation Voltage	100.00%	13.68%	13.07%
LPS Transmission Voltage	100.00%	13.68%	13.66%
LPS Overall Change (*)	0.00%	13.68%	13.68%
Winter Price Below Summer (SUM-WIN)/SUM	11.6%	11.6%	11.9%
Overall Change		13.675%	13.68%
Revenue	$123,589,592		$140,490,799
Change in Revenue			$16,901,207
Design Revenue per Revenue Summary			$16,901,094
			$114

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

	KCP&L	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
	BILLING UNITS	Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	130.6	$755.69	$98,708	859.03	$112,207	$893.84	$116,753
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	131		$98,708		$112,207		$116,753
B: FACILITIES CHARGE	273,572.2	$2.530	$692,138	$2.875	$786,520	$2.993	$818,802
C: DEMAND CHARGE							
First 2450 kw	225,308.9	$9.819	$2,212,308	$11.162	$2,514,898	$11.614	$2,616,738
Next 2450 kw	51,829.7	$7.854	$407,070	$8.928	$462,735	$9.290	$481,497
Next 2450 kw	16,184.1	$6.579	$106,475	$7.479	$121,041	$7.782	$125,944
Over 7350 kw	1,035.2	$4.803	$4,972	$5.460	$5,652	$5.681	$5,881
	294,358		$2,730,826		$3,104,326		$3,230,061
D: ENERGY CHARGE							
0-180 hrs use per month	53,102,577.9	$0.06148	$3,264,746	$0.06989	$3,711,339	$0.07272	$3,861,619
181-360 hrs use per month	52,786,814.9	$0.04276	$2,257,164	$0.04861	$2,565,967	$0.04715	$2,488,898
361+ hrs use per month	56,837,548.8	$0.02566	$1,458,452	$0.02917	$1,657,951	$0.02566	$1,458,452
	162,726,942		$6,980,362		$7,935,258		$7,808,969
E: MANUAL BILL USAGE/REVENUE	-		-		$0		$0
REVENUE			$10,502,034		$11,938,310		$11,974,585
c/kwh			$0.0645		$0.0734		$0.0736
OVERALL CHANGE (%)	*2254*				13.68%		14.02%
used to reference avg customer	*1,245,804*						

WINTER

	KCP&L	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
	BILLING UNITS	Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	303.0	$755.69	$228,980	859.03	$260,293	$893.84	$270,841
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	303		$228,980		$260,293		$270,841
B: FACILITIES CHARGE	646,185.5	$2.530	$1,634,849	$2.875	$1,857,783	$2.993	$1,934,033
C: DEMAND CHARGE							
First 2450 kw	403,261.8	$6.674	$2,691,369	$7.586	$3,059,144	$7.894	$3,183,349
Next 2450 kw	74,883.9	$5.208	$389,995	$5.920	$443,313	$6.160	$461,285
Next 2450 kw	11,002.4	$4.595	$50,556	$5.223	$57,466	$5.435	$59,798
Over 7350 kw	-	$3.537	$0	$4.021	$0	$4.184	$0
	489,148		$3,131,921		$3,559,923		$3,704,432
D: ENERGY CHARGE							
0-180 hrs use per month	87,202,264.9	$0.05212	$4,544,982	$0.05925	$5,166,734	$0.06165	$5,376,020
181-360 hrs use per month	86,006,273.9	$0.03890	$3,345,644	$0.04422	$3,803,197	$0.04289	$3,688,809
361+ hrs use per month	90,633,909.8	$0.02541	$2,303,008	$0.02888	$2,617,507	$0.02541	$2,303,008
	263,842,449		$10,193,634		$11,587,439		$11,367,836
E: MANUAL BILL USAGE/REVENUE	-		-		$0		$0
REVENUE			$15,189,384		$17,265,438		$17,277,142
c/kwh			$0.0576		$0.0654		$0.0655
OVERALL CHANGE (%)	*1614*				13.67%		13.74%
used to reference avg customer	*870,744*						

ANNUAL	426,569,390	$25,691,418	$29,203,748	$29,251,727
c/kwh		$0.0602	$0.0685	$0.0686
OVERALL CHANGE (%)			13.67%	13.86%
Winter Price Below Summer (SUM-WIN)/SUM		10.8%	10.8%	11.0%

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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

	KCP&L BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	141.7	$755.69	$107,076	859.03	$121,719	893.84	$126,651
	-	$0.00	$0	-	$0	-	$0
	-	$0.00	$0	-	$0	-	$0
	142		$107,076		$121,719		$126,651
B: FACILITIES CHARGE	592,314.9	$2.098	$1,242,677	$2.384	$1,412,079	$2.482	$1,470,126
C: DEMAND CHARGE							
First 2500 kw	327,653.0	$9.593	$3,143,175	$10.905	$3,573,056	$11.347	$3,717,878
Next 2500 kw	137,855.7	$7.675	$1,058,043	$8.725	$1,202,791	$9.078	$1,251,454
Next 2500 kw	67,351.0	$6.428	$432,932	$7.307	$492,134	$7.603	$512,070
Over 7500 kw	83,815.4	$4.693	$393,346	$5.335	$447,155	$5.551	$465,259
	616,675		$5,027,496		$5,715,136		$5,946,661
D: ENERGY CHARGE							
0-180 hrs use per month	110,567,209.5	$0.06008	$6,642,878	$0.06830	$7,551,740	$0.07106	$7,856,906
181-360 hrs use per month	109,748,945.7	$0.04179	$4,586,408	$0.04750	$5,213,075	$0.04608	$5,057,231
361+ hrs use per month	106,194,925.7	$0.02507	$2,662,307	$0.02850	$3,026,555	$0.02507	$2,662,307
	326,511,081		$13,891,593		$15,791,371		$15,576,444
E: REACTIVE DEMAND ADJUSTMENT	54,869	$0.635	$34,842	$0.722	$39,615	$0.751	$41,207
E: MANUAL BILL USAGE/REVENUE	5,727,235		$347,370		$394,874		$395,516
REVENUE			$20,651,054		$23,474,793		$23,556,605
c/kwh			$0.0622		$0.0707		$0.0709
OVERALL CHANGE (%)	*4352*				13.67%		14.07%
used to reference avg customer	*2,344,768*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	342.1	$755.69	$258,558	859.03	$293,916	$893.84	$305,826
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	342		$258,558		$293,916		$305,826
B: FACILITIES CHARGE	1,459,271.2	$2.098	$3,061,551	$2.384	$3,478,902	$2.482	$3,621,911
C: DEMAND CHARGE							
First 2500 kw	600,641.4	$6.521	$3,916,782	$7.413	$4,452,555	$7.713	$4,632,747
Next 2500 kw	230,312.9	$5.090	$1,172,293	$5.786	$1,332,590	$6.021	$1,386,714
Next 2500 kw	127,334.9	$4.490	$571,734	$5.104	$649,917	$5.311	$676,276
Over 7500 kw	132,831.7	$3.456	$459,067	$3.929	$521,896	$4.088	$543,016
	1,091,121		$6,119,875		$6,956,958		$7,238,753
D: ENERGY CHARGE							
0-180 hrs use per month	193,559,521.9	$0.05094	$9,859,922	$0.05791	$11,209,032	$0.06025	$11,661,961
181-360 hrs use per month	190,876,191.4	$0.03800	$7,253,295	$0.04320	$8,245,851	$0.04190	$7,997,712
361+ hrs use per month	185,586,548.7	$0.02484	$4,609,970	$0.02824	$5,240,964	$0.02484	$4,609,970
	570,022,262		$21,723,187		$24,695,848		$24,269,643
E: REACTIVE DEMAND ADJUSTMENT	95,709	$0.635	$60,775	$0.722	$69,102	$0.751	$71,877
E: MANUAL BILL USAGE/REVENUE	10,778,636		$572,817		$651,150		$652,209
REVENUE			$31,796,764		$36,145,877		$36,160,220
c/kwh			$0.0547		$0.0622		$0.0623
OVERALL CHANGE (%)	*3189*				13.68%		13.72%
used to reference avg customer	*1,666,006*						

ANNUAL	913,039,214		$52,447,818		$59,620,670		$59,716,825
c/kwh			$0.0574		$0.0653		$0.0654
OVERALL CHANGE (%)					13.68%		13.86%
Winter Price Below Summer (SUM-WIN)/SUM			11.9%		11.9%		12.2%

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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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	14.0	$755.69	$10,566	859.03	$12,011	$893.84	$12,498
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	14		$10,566		$12,011		$12,498
B: FACILITIES CHARGE	238,325.1	$0.633	$150,860	$0.719	$171,356	$0.749	$178,505
C: DEMAND CHARGE							
First 2520 kw	42,824.1	$9.479	$405,930	$10.775	$461,430	$11.212	$480,144
Next 2520 kw	39,371.2	$7.583	$298,551	$8.620	$339,379	$8.969	$353,120
Next 2520 kw	22,764.5	$6.352	$144,600	$7.221	$164,382	$7.513	$171,029
Over 7560 kw	190,202.6	$4.638	$882,160	$5.272	$1,002,748	$5.486	$1,043,451
	295,162		$1,731,241		$1,967,939		$2,047,745
D: ENERGY CHARGE							
0-180 hrs use per month	48,224,510.2	$0.05937	$2,863,089	$0.06749	$3,254,672	$0.07022	$3,386,325
181-360 hrs use per month	48,224,510.2	$0.04130	$1,991,672	$0.04695	$2,264,141	$0.04554	$2,196,144
361+ hrs use per month	51,363,298.7	$0.02477	$1,272,269	$0.02816	$1,446,390	$0.02477	$1,272,269
	147,812,319		$6,127,030		$6,965,203		$6,854,738
E: REACTIVE DEMAND ADJUSTMENT	4,446	$0.635	$2,823	$0.722	$3,210	$0.751	$3,339
REVENUE			$8,022,521		$9,119,720		$9,096,826
c/kwh			$0.0543		$0.0617		$0.0615
OVERALL CHANGE (%)	*21109*				13.68%		13.39%
used to reference avg customer	*10,571,269*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	32.7	$755.69	$24,685	859.03	$28,061	$893.84	$29,198
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	33		$24,685		$28,061		$29,198
B: FACILITIES CHARGE	595,400.8	$0.633	$376,889	$0.719	$428,093	$0.749	$445,955
C: DEMAND CHARGE							
First 2520 kw	73,757.3	$6.444	$475,292	$7.325	$540,272	$7.622	$562,178
Next 2520 kw	61,918.2	$5.029	$311,387	$5.717	$353,987	$5.948	$368,290
Next 2520 kw	42,103.4	$4.437	$186,813	$5.044	$212,369	$5.248	$220,959
Over 7560 kw	310,604.0	$3.415	$1,060,713	$3.882	$1,205,765	$4.039	$1,254,530
	488,383		$2,034,204		$2,312,393		$2,405,956
D: ENERGY CHARGE							
0-180 hrs use per month	87,981,379.1	$0.05034	$4,428,983	$0.05722	$5,034,295	$0.05954	$5,238,411
181-360 hrs use per month	87,981,379.1	$0.03756	$3,304,581	$0.04270	$3,756,805	$0.04141	$3,643,309
361+ hrs use per month	90,475,278.1	$0.02454	$2,220,263	$0.02790	$2,524,260	$0.02454	$2,220,263
	266,438,036		$9,953,827		$11,315,360		$11,101,984
E: REACTIVE DEMAND ADJUSTMENT	10,976	$0.635	$6,970	$0.722	$7,924	$0.751	$8,243
REVENUE			$12,396,574		$14,091,831		$13,991,336
c/kwh			$0.0465		$0.0529		$0.0525
OVERALL CHANGE (%)	*14951*				13.68%		12.86%
used to reference avg customer	*8,156,406*						

ANNUAL	414,250,355	$20,419,095	$23,211,552	$23,088,161
c/kwh		$0.0493	$0.0560	$0.0557
OVERALL CHANGE (%)			13.68%	13.07%
Winter Price Below Summer (SUM-WIN)/SUM		14.3%	14.3%	14.7%

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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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	7.3	$755.69	$5,523	859.03	$6,278	$893.84	$6,532
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	7		$5,523		$6,278		$6,532
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2541 kw	19,948.9	$9.397	$187,460	$10.682	$213,094	$11.115	$221,732
Next 2541 kw	9,911.6	$7.516	$74,496	$8.544	$84,685	$8.890	$88,114
Next 2541 kw	9,861.6	$6.294	$62,069	$7.155	$70,560	$7.445	$73,420
Over 7623 kw	26,174.1	$4.596	$120,296	$5.225	$136,760	$5.436	$142,282
	65,896		$444,321		$505,098		$525,548
D: ENERGY CHARGE							
0-180 hrs use per month	11,806,325.6	$0.05884	$694,684	$0.06689	$789,725	$0.06960	$821,720
181-360 hrs use per month	10,689,382.6	$0.04093	$437,516	$0.04653	$497,377	$0.04513	$482,412
361+ hrs use per month	9,558,355.5	$0.02456	$234,753	$0.02792	$266,869	$0.02456	$234,753
	32,054,064		$1,366,954		$1,553,971		$1,538,885
E: REACTIVE DEMAND ADJUSTMENT	6,695	$0.635	$4,251	$0.722	$4,834	$0.751	$5,028
REVENUE			$1,821,048		$2,070,181		$2,075,994
c/kwh			$0.0568		$0.0646		$0.0648
OVERALL CHANGE (%)	*9017*				13.68%		14.00%
used to reference avg customer	*4,386,201*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	13.7	$755.69	$10,384	859.03	$11,804	$893.84	$12,283
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	14		$10,384		$11,804		$12,283
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2541 kw	30,588.0	$6.386	$195,335	$7.259	$222,038	$7.553	$231,031
Next 2541 kw	20,052.3	$4.984	$99,941	$5.666	$113,616	$5.895	$118,208
Next 2541 kw	19,898.7	$4.397	$87,495	$4.998	$99,454	$5.201	$103,493
Over 7623 kw	43,181.0	$3.385	$146,168	$3.848	$166,161	$4.004	$172,897
	113,720		$528,938		$601,269		$625,629
D: ENERGY CHARGE							
0-180 hrs use per month	20,090,632.1	$0.04988	$1,002,121	$0.05670	$1,139,139	$0.05900	$1,185,347
181-360 hrs use per month	19,463,474.5	$0.03722	$724,431	$0.04231	$823,500	$0.04104	$798,781
361+ hrs use per month	15,993,605.0	$0.02431	$388,805	$0.02763	$441,903	$0.02431	$388,805
	55,547,712		$2,115,356		$2,404,542		$2,372,933
E: REACTIVE DEMAND ADJUSTMENT	10,973	$0.635	$6,968	$0.722	$7,922	$0.751	$8,241
REVENUE			$2,661,646		$3,025,538		$3,019,086
c/kwh			$0.0479		$0.0545		$0.0544
OVERALL CHANGE (%)	*8276*				13.67%		13.43%
used to reference avg customer	*4,042,333*						

ANNUAL	87,601,775	$4,482,694	$5,095,719	$5,095,079
c/kwh		$0.0512	$0.0582	$0.0582
OVERALL CHANGE (%)			13.68%	13.66%
Winter Price Below Summer (SUM-WIN)/SUM		15.7%	15.7%	16.1%

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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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	43.9	$755.69	$33,207	$859.03	$37,748	$893.84	$39,278
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	44		$33,207		$37,748		$39,278
B: FACILITIES CHARGE	232,036.9	$2.098	$486,813	$2.384	$553,176	$2.482	$575,916
C: DEMAND CHARGE							
First 2500 kw	95,364.8	$9.593	$914,834	$10.905	$1,039,953	$11.347	$1,082,104
Next 2500 kw	57,617.3	$7.675	$442,213	$8.725	$502,711	$9.078	$523,050
Next 2500 kw	33,885.4	$6.428	$217,815	$7.307	$247,600	$7.603	$257,631
Over 7500 kw	55,360.3	$4.693	$259,806	$5.335	$295,347	$5.551	$307,305
	242,228		$1,834,668		$2,085,612		$2,170,090
D: ENERGY CHARGE							
0-180 hrs use per month	43,474,154.6	$0.06008	$2,611,927	$0.06830	$2,969,285	$0.07106	$3,089,273
181-360 hrs use per month	43,256,407.8	$0.04179	$1,807,685	$0.04750	$2,054,679	$0.04608	$1,993,255
361+ hrs use per month	51,913,925.8	$0.02507	$1,301,482	$0.02850	$1,479,547	$0.02507	$1,301,482
	138,644,488		$5,721,095		$6,503,511		$6,384,011
E: REACTIVE DEMAND ADJUSTMENT	19,782	$0.635	$12,562	$0.722	$14,283	$0.751	$14,857
F: MANUAL BILL USAGE/REVENUE	3,773,138		$240,614		$273,519		$273,964
REVENUE			$8,328,959		$9,467,848		$9,458,114
c/kwh			0.0585		0.0665		0.0664
OVERALL CHANGE (%)	*5512*				13.67%		13.56%
used to reference avg customer	*3,155,134*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
	102.4	$755.69	$77,349	$859.03	$87,927	$893.84	$91,490
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	102		$77,349		$87,927		$91,490
B: FACILITIES CHARGE	514,695.3	$2.098	$1,079,831	$2.384	$1,227,034	$2.482	$1,277,474
C: DEMAND CHARGE							
First 2500 kw	184,814.2	$6.521	$1,205,173	$7.413	$1,370,027	$7.713	$1,425,472
Next 2500 kw	96,845.3	$5.090	$492,943	$5.786	$560,347	$6.021	$583,106
Next 2500 kw	47,617.5	$4.490	$213,803	$5.104	$243,040	$5.311	$252,897
Over 7500 kw	89,380.4	$3.456	$308,899	$3.929	$351,176	$4.088	$365,387
	418,657		$2,220,817		$2,524,590		$2,626,861
D: ENERGY CHARGE							
0-180 hrs use per month	74,617,528.3	$0.05094	$3,801,017	$0.05791	$4,321,101	$0.06025	$4,495,706
181-360 hrs use per month	73,423,994.2	$0.03800	$2,790,112	$0.04320	$3,171,917	$0.04190	$3,076,465
361+ hrs use per month	72,505,450.8	$0.02484	$1,801,035	$0.02824	$2,047,554	$0.02484	$1,801,035
	220,546,973		$8,392,164		$9,540,572		$9,373,207
E: REACTIVE DEMAND ADJUSTMENT	31,941	$0.635	$20,282	$0.722	$23,061	$0.751	$23,987
F: MANUAL BILL USAGE/REVENUE	8,034,388		$429,164		$487,853		$487,873
REVENUE			$12,219,608		$13,891,036		$13,880,893
c/kwh			$0.0535		$0.0608		$0.0607
OVERALL CHANGE (%)	*4090*				13.68%		13.60%
used to reference avg customer	*2,154,704*						

	Billing Units	Present Revenue	Proposed Revenue	Rates W/Rate Design Revenue
ANNUAL	370,998,988	$20,548,567	$23,358,884	$23,339,007
c/kwh		$0.0554	$0.0630	$0.0629
OVERALL CHANGE (%)			13.68%	13.58%
Winter Price Below Summer (SUM-WIN)/SUM		8.6%	8.6%	8.6%

SUMMER TOTAL (ALL RATES)	807,748,893	$49,325,616	$56,070,854	$56,162,123
WINTER TOTAL (ALL RATES)	1,376,397,432	$74,263,976	$84,419,719	$84,328,676
GRAND TOTAL (ANNUAL - ALL RATES)	**2,184,146,325**	**$123,589,592**	**$140,490,573**	**$140,490,799**
c/kwh Summer		**$0.0611**	**$0.0694**	**$0.0695**
c/kwh Winter		**$0.0540**	**$0.0613**	**$0.0613**
c/kwh Annual		**$0.0566**	**$0.0643**	**$0.0643**
Winter Price Below Summer (SUM-WIN)/SUM		**11.6%**	**11.6%**	**11.9%**
OVERALL CHANGE (%)			**13.675%**	**13.675%**

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MO LARGE GENERAL SERVICE
SUMMARY OF PROPOSAL SCENARIO
*** 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 With Increase***
			10.2564%
JURISDICTIONAL INCREASE (%)		**13.6752%**	**17.1253%**
A: CUSTOMER CHARGE			
0-24 KW	85.22	96.87	99.81
25-199 KW	85.22	96.87	99.81
200-999 KW	85.22	96.87	99.81
1001+ KW	727.61	827.11	852.22
Separately Metered Space Heat	1.96	2.23	2.30
B: FACILITIES CHARGE			
SECONDARY:	2.438	2.771	2.856
PRIMARY:	2.020	2.296	2.366
C: DEMAND CHARGE			
SECONDARY-SUMMER:	4.868	5.535	5.702
SECONDARY-WINTER	2.620	2.978	3.069
PRIMARY-SUMMER	4.757	5.408	5.572
PRIMARY-WINTER	2.561	2.911	3.000
SECONDARY-WINTER - ELEC ONLY	2.426	2.758	2.841
PRIMARY-WINTER - ELEC ONLY	2.370	2.694	2.776
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.0715	0.0813	0.08374
181-360 hrs use per month	0.0545	0.0620	0.06009
361+ hrs use per month	0.0426	0.0484	0.04260
SECONDARY-WINTER:			
0-180 hrs use per month	0.0657	0.0747	0.07695
181-360 hrs use per month	0.0419	0.0476	0.04620
361+ hrs use per month	0.0358	0.0407	0.03580
PRIMARY-SUMMER:			
0-180 hrs use per month	0.0699	0.0795	0.08187
181-360 hrs use per month	0.0532	0.0605	0.05866
361+ hrs use per month	0.0416	0.0473	0.04160
PRIMARY-WINTER:			
0-180 hrs use per month	0.0642	0.0730	0.07519
181-360 hrs use per month	0.0409	0.0465	0.04509
361+ hrs use per month	0.0351	0.0399	0.03510
SECONDARY-WINTER - ALL ELECTRIC			
0-180 hrs use per month	0.0573	0.0651	0.06711
181-360 hrs use per month	0.0361	0.0410	0.03980
361+ hrs use per month	0.0314	0.0357	0.03140
PRIMARY-WINTER - ALL ELECTRIC			
0-180 hrs use per month	0.0561	0.0638	0.06571
181-360 hrs use per month	0.0353	0.0401	0.03892
361+ hrs use per month	0.0308	0.0350	0.03080
E: SEPARATELY METERED S/H-WINTER			
SECONDARY	0.0442	0.0502	0.05177
PRIMARY	0.0000	-	-
F: REACTIVE DEMAND ADJUSTMENT	0.611	0.695	0.716
LGS Secondary	100.00%	13.67%	13.79%
LGS Primary	100.00%	13.67%	14.19%
LGS Overall Change (*)	0.00%	13.67%	13.85%
LGA Secondary	100.00%	13.68%	13.42%
LGA Primary	100.00%	13.68%	12.85%
LGA Winter Energy Overall Change		12.03%	10.97%
LGA Overall Change (*)	0.00%	13.68%	13.31%
Winter Price Below Summer (SUM-WIN)/SUM	28.0%	18.7%	18.4%
Overall Change		13.675%	13.67%
Revenue	$156,151,460		$177,504,935
Change in Revenue			$21,353,475
Design Revenue per Revenue Summary			$21,353,986
			($511)

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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	2,359.7	$85.22	$201,092	$96.87	$228,582	$99.81	$235,519
1001+ KW	60.8	$727.61	$44,268	$827.11	$50,322	$852.22	$51,850
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	2,421		$245,360		$278,904		$287,369
B: FACILITIES CHARGE	953,832.1	$2.438	$2,325,443	$2.771	$2,643,069	$2.856	$2,724,144
C: DEMAND CHARGE	976,106.1	$4.868	$4,751,684	$5.535	$5,402,747	$5.702	$5,565,757
D: ENERGY CHARGE							
0-180 hrs use per month	178,826,743.5	$0.0715	$12,786,112	$0.08128	$14,535,038	$0.08374	$14,974,952
181-360 hrs use per month	135,738,355.4	$0.0545	$7,397,740	$0.06195	$8,408,991	$0.06009	$8,156,518
361+ hrs use per month	76,950,015.8	$0.0426	$3,278,071	$0.04843	$3,726,689	$0.04260	$3,278,071
	391,515,115		$23,461,923		$26,670,718		$26,409,540
E: SEPARATELY METERED SPACE HEAT	-	$0.0442	$0	$0.05024	$0	$0.05177	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	864,417		$60,803		$69,118		$69,115
REVENUE			$30,845,213		$35,064,556		$35,055,925
c/kwh			$0.0788		$0.0896		$0.0895
FLUCTUATION (%)					13.68%		13.65%
used to reference avg customer	*162,106*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	99.81	$0
200-999 KW	5,883.8	$85.22	$501,419	$96.87	$569,966	99.81	$587,264
1001+ KW	155.4	$727.61	$113,071	$827.11	$128,533	852.22	$132,435
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	2.30	$0
	6,039		$614,490		$698,499		$719,700
B: FACILITIES CHARGE	2,512,276.9	$2.438	$6,124,931	$2.771	$6,961,519	$2.856	$7,175,063
C: DEMAND CHARGE	1,886,301.7	$2.620	$4,942,111	$2.978	$5,617,407	$3.069	$5,789,060
D: ENERGY CHARGE							
0-180 hrs use per month	315,880,164.9	$0.0657	$20,753,327	$0.07468	$23,589,931	$0.07695	$24,306,979
181-360 hrs use per month	251,652,595.3	$0.0419	$10,544,244	$0.04763	$11,986,213	$0.04620	$11,626,350
361+ hrs use per month	135,268,692.9	$0.0358	$4,842,619	$0.04070	$5,505,436	$0.03580	$4,842,619
	702,801,453		$36,140,190		$41,081,580		$40,775,948
E: SEPARATELY METERED SPACE HEAT	-	$0.0442	$0	$0.05024	$0	$0.05177	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	1,297,730.0		$81,123		$92,216		$92,212
REVENUE			$47,902,844		$54,451,221		$54,551,983
c/kwh			$0.0682		$0.0775		$0.0776
FLUCTUATION (%)					13.67%		13.88%
used to reference avg customer	*116,588*						
ANNUAL ENERGY/REVENUE	1,096,478,715		$78,748,058		$89,515,777		$89,607,908
c/kwh			$0.0718		$0.0816		$0.0817
FLUCTUATION (%)					13.67%		13.79%
Winter Price Below Summer (SUM-WIN)/SUM			13.5%		13.5%		13.3%

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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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	189.0	$85.22	$16,108	$96.87	$18,310	$99.81	$18,865
1001+ KW	45.3	$727.61	$32,990	$827.11	$37,501	$852.22	$38,640
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	234		$49,098		$55,811		$57,505
B: FACILITIES CHARGE	181,870.5	$2.020	$367,378	$2.296	$417,575	$2.366	$430,306
C: DEMAND CHARGE	172,157.4	$4.757	$818,953	$5.408	$931,027	$5.572	$959,261
D: ENERGY CHARGE							
0-180 hrs use per month	31,497,075.3	$0.0699	$2,201,646	$0.07946	$2,502,758	$0.08187	$2,578,666
181-360 hrs use per month	23,146,115.7	$0.0532	$1,231,373	$0.06048	$1,399,877	$0.05866	$1,357,751
361+ hrs use per month	10,531,657.2	$0.0416	$438,117	$0.04729	$498,042	$0.04160	$438,117
	65,174,848		$3,871,136		$4,400,677		$4,374,534
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	3,351,471.0		$311,006		$353,537		$353,521
REVENUE			$5,417,571		$6,158,626		$6,175,126
c/kwh			$0.0831		$0.0945		$0.0947
FLUCTUATION (%)					13.68%		13.98%
used to reference avg customer	*278,107*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	480.0	$85.22	$40,908	$96.87	$46,500	$99.81	$47,912
1001+ KW	115.3	$727.61	$83,913	$827.11	$95,388	$852.22	$98,284
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	595		$124,821		$141,889		$146,196
B: FACILITIES CHARGE	464,552.4	$2.020	$938,396	$2.296	$1,066,612	$2.366	$1,099,131
C: DEMAND CHARGE	336,740.9	$2.561	$862,393	$2.911	$980,253	$3.000	$1,010,223
D: ENERGY CHARGE							
0-180 hrs use per month	59,091,063.2	$0.0642	$3,793,646	$0.07298	$4,312,466	$0.07519	$4,443,057
181-360 hrs use per month	43,567,011.5	$0.0409	$1,781,891	$0.04649	$2,025,430	$0.04509	$1,964,437
361+ hrs use per month	16,986,718.2	$0.0351	$596,234	$0.03990	$677,770	$0.03510	$596,234
	119,644,793		$6,171,771		$7,015,666		$7,003,727
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	1,118,847.0		$202,312		$229,978		$229,968
REVENUE			$8,299,693		$9,434,398		$9,489,245
c/kwh			$0.0694		$0.0789		$0.0793
FLUCTUATION (%)					13.67%		14.33%
used to reference avg customer	*200,963*						

	Energy	Present Revenue	Proposed Revenue	Rate Design Revenue
ANNUAL ENERGY/REVENUE	189,289,959	$13,717,264	$15,593,025	$15,664,371
c/kwh		$0.0725	$0.0824	$0.0828
FLUCTUATION (%)			13.67%	14.19%
Winter Price Below Summer (SUM-WIN)/SUM		16.5%	16.6%	16.3%
SUMMER TOTAL (LGSS/LGSP)	456,689,963	$36,262,784	$41,223,182	$41,231,051
WINTER TOTAL (LGSS/LGSP)	822,446,246	$56,202,538	$63,885,619	$64,041,227
GRAND TOTAL (ANNUAL-LGSS/LGSP)	**1,285,768,674**	**$92,465,322**	**$105,108,802**	**$105,272,279**
c/kwh		**$0.0719**	**$0.0817**	**$0.0819**
OVERAL CHANGE (%)			**13.67%**	**13.85%**

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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

	KCP&L	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
	BILLING UNITS	Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	544.4	$85.22	$46,391	$96.87	$52,733	$99.81	$54,334
1001+ KW	175.2	$727.61	$127,487	$827.11	$144,921	$852.22	$149,320
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	720		$173,878		$197,654		$203,654
B: FACILITIES CHARGE	560,601.4	$2.438	$1,366,746	$2.771	$1,553,426	$2.856	$1,601,078
C: DEMAND CHARGE	496,242.9	$4.868	$2,415,711	$5.535	$2,746,705	$5.702	$2,829,577
D: ENERGY CHARGE							
0-180 hrs use per month	94,015,261.4	$0.0715	$6,722,091	$0.08128	$7,641,560	$0.08374	$7,872,838
181-360 hrs use per month	79,328,600.5	$0.0545	$4,323,409	$0.06195	$4,914,407	$0.06009	$4,766,856
361+ hrs use per month	52,311,740.3	$0.0426	$2,228,480	$0.04843	$2,533,458	$0.04260	$2,228,480
	225,655,602		$13,273,980		$15,089,425		$14,868,174
E: SEPARATELY METERED SPACE HEAT	-	$0.0442	$0	$0.05024	$0	$0.05177	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	4,232,281.0		$285,471		$324,509		$324,523
REVENUE			$17,515,786		$19,911,719		$19,827,006
c/kwh			$0.0776		$0.0882		$0.0879
FLUCTUATION (%)					13.68%		13.20%
used to reference avg customer	*313,591*						

WINTER

	KCP&L	PRESENT RATES		PROPOSED RATES		RATES W/RATE DESIGN	
	BILLING UNITS	Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	1,466.7	$85.22	$124,992	$96.87	$142,079	$99.81	$146,391
1001+ KW	471.5	$727.61	$343,097	$827.11	$390,016	$852.22	$401,856
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	1,938		$468,089		$532,094		$548,247
B: FACILITIES CHARGE	1,559,804.2	$2.438	$3,802,803	$2.771	$4,322,217	$2.856	$4,454,801
C: DEMAND CHARGE	1,175,990.1	$2.426	$2,852,952	$2.758	$3,243,381	$2.841	$3,340,988
D: ENERGY CHARGE							
0-180 hrs use per month	212,193,529.2	$0.0573	$12,158,689	$0.06514	$13,822,286	$0.06711	$14,240,308
181-360 hrs use per month	184,297,707.6	$0.0361	$6,653,147	$0.04104	$7,563,578	$0.03980	$7,335,049
361+ hrs use per month	110,222,908.8	$0.0314	$3,460,999	$0.03569	$3,933,856	$0.03140	$3,460,999
	506,714,146		$22,272,836		$25,319,720		$25,036,356
E: SEPARATELY METERED SPACE HEAT	-	$0.0442	$0	$0.05024	$0	$0.05177	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	9,347,861.0		$441,991		$502,434		$502,455
REVENUE			$29,838,670		$33,919,846		$33,882,846
c/kwh			$0.0589		$0.0669		$0.0669
FLUCTUATION (%)					13.68%		13.55%
used to reference avg customer	*261,431*						
ANNUAL ENERGY/REVENUE	745,949,890		$47,354,456		$53,831,565		$53,709,852
c/kwh			$0.0635		$0.0722		$0.0720
FLUCTUATION (%)					13.68%		13.42%
Winter Price Below Summer (SUM-WIN)/SUM			24.1%		24.1%		23.9%

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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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	9.6	$85.22	$820	$96.87	$932	$99.81	$960
1001+ KW	35.0	$727.61	$25,458	$827.11	$28,939	$852.22	$29,818
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	45		$26,278		$29,871		$30,778
B: FACILITIES CHARGE	141,939.6	$2.020	$286,718	$2.296	$325,893	$2.366	$335,829
C: DEMAND CHARGE	111,201.1	$4.757	$528,984	$5.408	$601,376	$5.572	$619,613
D: ENERGY CHARGE							
0-180 hrs use per month	20,501,318.8	$0.0699	$1,433,042	$0.07946	$1,629,035	$0.08187	$1,678,443
181-360 hrs use per month	19,331,074.7	$0.0532	$1,028,413	$0.06048	$1,169,143	$0.05866	$1,133,961
361+ hrs use per month	17,026,473.3	$0.0416	$708,301	$0.04729	$805,182	$0.04160	$708,301
	56,858,867		$3,169,757		$3,603,360		$3,520,705
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
REVENUE			$4,011,736		$4,560,500		$4,506,925
c/kwh			$0.0706		$0.0802		$0.0793
FLUCTUATION (%)					13.68%		12.34%
used to reference avg customer	*1,274,559*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	26.8	$85.22	$2,280	$96.87	$2,592	$99.81	$2,670
1001+ KW	97.4	$727.61	$70,857	$827.11	$80,547	$852.22	$82,992
Separately Metered Space Heat	-	$1.96	$0	$2.23	$0	$2.30	$0
	124		$73,137		$83,138		$85,662
B: FACILITIES CHARGE	413,418.6	$2.020	$835,106	$2.296	$949,209	$2.366	$978,148
C: DEMAND CHARGE	298,499.1	$2.370	$707,443	$2.694	$804,157	$2.776	$828,634
D: ENERGY CHARGE							
0-180 hrs use per month	55,883,056.6	$0.0561	$3,135,039	$0.06377	$3,563,663	$0.06571	$3,672,076
181-360 hrs use per month	47,704,309.0	$0.0353	$1,683,962	$0.04013	$1,914,374	$0.03892	$1,856,652
361+ hrs use per month	35,328,289.4	$0.0308	$1,088,111	$0.03501	$1,236,843	$0.03080	$1,088,111
	138,915,655		$5,907,113		$6,714,880		$6,616,839
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
REVENUE			$7,522,798		$8,551,384		$8,509,283
c/kwh			$0.0542		$0.0616		$0.0613
FLUCTUATION (%)					13.67%		-0.49%
used to reference avg customer	*1,119,039*						
ANNUAL ENERGY/REVENUE	195,774,522		$11,534,535		$13,111,884		$13,016,208
c/kwh			$0.0589		$0.0670		$0.0665
FLUCTUATION (%)					13.68%		12.85%
Winter Price Below Summer (SUM-WIN)/SUM			23.2%		23.3%		22.7%
SUMMER TOTAL (LGSSA/LGSPA)	282,514,469		$21,527,522		$24,472,219		$24,333,930
WINTER TOTAL (LGSSA/LGSPA)	645,629,801		$37,361,468		$42,471,230		$42,392,129
GRAND TOTAL (ANNUAL-LGSSA/LGSPA)	**941,724,412**		**58,888,990**		**66,943,449**		**66,726,059**
c/kwh			**$0.0625**		**$0.0711**		**$0.0709**
OVERALL WINTER ENERGY CHANGE					**12.03%**		**10.97%**
OVERAL CHANGE (%)					**13.68%**		**13.31%**

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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

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	120.1	$85.22	$10,232	$96.87	$11,630	$99.81	$11,983
1001+ KW	14.0	$727.61	$10,214	$827.11	$11,611	$852.22	$11,963
Separately Metered Space Heat	70.9	$1.96	$139	$2.23	$158	$2.30	$163
	205		$20,584		$23,399		$24,109
B: FACILITIES CHARGE	63,279.9	$2.438	$154,276	$2.771	$175,349	$2.856	$180,727
C: DEMAND CHARGE	54,574.6	$4.868	$265,669	$5.535	$302,071	$5.702	$311,185
D: ENERGY CHARGE							
0-180 hrs use per month	8,146,119.3	$0.0715	$582,448	$0.08128	$662,117	$0.08374	$682,156
181-360 hrs use per month	7,400,936.4	$0.0545	$403,351	$0.06195	$458,488	$0.06009	$444,722
361+ hrs use per month	2,857,573.5	$0.0426	$121,733	$0.04843	$138,392	$0.04260	$121,733
	18,404,629		$1,107,531		$1,258,997		$1,248,611
E: SEPARATELY METERED SPACE HEAT	-	$0.0000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	352,720.0		$27,331		$31,069		$31,067
REVENUE			$1,575,392		$1,790,884		$1,795,700
c/kwh			$0.0856		$0.0973		$0.0976
FLUCTUATION (%)					13.68%		13.98%
used to reference avg customer	*89,777*						

WINTER

	KCP&L BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATES W/RATE DESIGN Rate	RATES W/RATE DESIGN Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
25-199 KW	-	$85.22	$0	$96.87	$0	$99.81	$0
200-999 KW	303.5	$85.22	$25,860	$96.87	$29,395	$99.81	$30,288
1001+ KW	34.5	$727.61	$25,087	$827.11	$28,518	$852.22	$29,384
Separately Metered Space Heat	362.4	$1.96	$710	$2.23	$808	$2.30	$834
	700		$51,658		$58,722		$60,505
B: FACILITIES CHARGE	143,968.9	$2.438	$350,996	$2.771	$398,938	$2.856	$411,175
C: DEMAND CHARGE	129,798.7	$2.620	$340,072	$2.978	$386,540	$3.069	$398,352
D: ENERGY CHARGE							
0-180 hrs use per month	12,363,164.8	$0.0657	$812,260	$0.07468	$923,281	$0.07695	$951,346
181-360 hrs use per month	11,117,575.9	$0.0419	$465,826	$0.04763	$529,530	$0.04620	$513,632
361+ hrs use per month	4,812,431.2	$0.0358	$172,285	$0.04070	$195,866	$0.03580	$172,285
	28,293,172		$1,450,371		$1,648,677		$1,637,263
E: SEPARATELY METERED SPACE HEAT	22,467,515.0	$0.0442	$993,064	$0.05024	$1,128,768	$0.05177	$1,163,143
F: REACTIVE DEMAND ADJUSTMENT	-	$0.611	$0	$0.695	$0	$0.716	$0
MANUAL BILLS	598,560.0		$35,594		$40,461		$40,460
REVENUE			$3,221,756		$3,662,106		$3,710,897
c/kwh			$0.0635		$0.0721		$0.0731
FLUCTUATION (%)					13.67%		15.18%
used to reference avg customer	*83,724*						
	61,995						
ANNUAL ENERGY/REVENUE	70,116,596		$4,797,148		$5,452,990		$5,506,597
c/kwh			$0.0684		$0.0778		$0.0785
FLUCTUATION (%)					13.67%		14.79%
Winter Price Below Summer (SUM-WIN)/SUM			25.9%		25.9%		25.1%

SUMMER TOTAL (ALL RATES)	757,609,061	$59,365,699	$67,486,286	$67,360,681
WINTER TOTAL (ALL RATES)	1,518,836,733	$96,785,762	$110,018,955	$110,144,254
GRAND TOTAL (ANNUAL - ALL RATES)	**2,276,445,795**	**$156,151,460**	**$177,505,241**	**$177,504,935**
c/kwh Summer		**$0.0784**	**$0.0891**	**$0.0889**
c/kwh Winter		**$0.0637**	**$0.0724**	**$0.0725**
c/kwh Annual		**$0.0686**	**$0.0780**	**$0.0780**
Winter Price Below Summer (SUM-WIN)/SUM		**18.7%**	**18.7%**	**18.4%**
OVERALL CHANGE (%)			**13.675%**	**13.67%**

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KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 2 Non-Coincident Peaks
For the Test Year Ended December 2009

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Total Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak - kW	1,982,705						
2	Avg of 2 Highest Monthly NCP Values - kW	2,125,558	899,021	107,014	272,176	434,995	391,198	21,155
3	Energy Sales with Losses - MWh	9,227,940	2,787,139	447,074	1,174,444	2,429,101	2,297,861	92,321
4	Average Demand - kW	1,053,418	318,167	51,036	134,069	277,295	262,313	10,539
5	Average Demand - Percent	1.000000	0.302033	0.048448	0.127270	0.263233	0.249011	0.010005
6	Class Excess Demand - kW	1,072,141	580,854	55,978	138,107	157,700	128,885	10,616
7	Class Excess Demand - Percent	1.000000	0.541771	0.052212	0.128814	0.147089	0.120213	0.009901
	Allocator:							
8	Annual Load Factor * Average Demand	0.531303	0.160471	0.025741	0.067619	0.139857	0.132301	0.005315
9	(1-LF) * Excess Demand	0.468697	0.253926	0.024471	0.060375	0.068940	0.056343	0.004641
10	Average and Excess Demand Allocator	1.000000	0.414397	0.050212	0.127994	0.208797	0.188644	0.009956

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

System Annual Load Factor	53.13%
1 - Load Factor	46.87%

Source: KCPL MO Allocators 05-21-10.xls

KANSAS CITY POWER & LIGHT COMPANY
MISSOURI CUSTOMERS
CLASS COST OF SERVICE
DEC2009 TEST YEAR INCL KNOWN & MEAS TO 12/31/2010

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	668,323,387	247,439,033	46,531,284	89,839,660	154,950,292	121,279,587	8,283,530
0050	OTHER OPERATING REVENUE	69,914,288	22,915,284	3,430,080	8,906,113	17,634,951	16,340,319	687,541
0060	TOTAL OPERATING REVENUE	738,237,675	270,354,318	49,961,364	98,745,773	172,585,243	137,619,907	8,971,071
0070								
0080	OPERATING EXPENSES							
0090	FUEL	167,502,786	50,554,300	8,113,201	21,340,452	43,948,362	41,874,662	1,671,810
0100	PURCHASED POWER	17,930,093	5,610,776	860,240	2,268,559	4,666,459	4,358,952	165,106
0110	OTHER OPERATION & MAINTENANCE EXPENSES	247,431,627	109,108,508	14,454,861	30,453,046	47,922,157	41,833,844	3,659,210
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	92,323,818	41,011,813	4,989,189	12,191,628	18,022,927	14,978,021	1,130,239
0130	AMORTIZATION EXPENSES	10,089,113	5,473,572	649,522	976,899	1,551,793	1,360,708	76,620
0140	INTEREST ON CUSTOMER DEPOSITS	227,566	9,561	173,419	36,224	7,194	676	491
0150	TAXES OTHER THAN INCOME TAXES	43,366,539	18,881,536	2,374,781	5,596,723	8,677,017	7,316,854	519,628
0160	FEDERAL AND STATE INCOME TAXES	23,596,471	(684,924)	5,124,955	5,086,671	10,502,403	3,231,506	335,860
0170	TOTAL ELECTRIC OPERATING EXPENSES	602,468,012	229,965,141	36,740,169	77,950,202	135,298,312	114,955,223	7,558,965
0180								
0190	NET ELECTRIC OPERATING INCOME	135,769,663	40,389,176	13,221,194	20,795,571	37,286,931	22,664,684	1,412,106
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	4,016,606,546	1,777,462,605	219,739,749	522,789,316	793,356,303	656,667,548	46,591,026
0230	LESS: ACCUM. PROV. FOR DEPREC	1,517,382,643	671,686,778	84,367,344	194,133,919	298,080,691	246,745,785	22,368,127
0240	NET PLANT	2,499,223,903	1,105,775,828	135,372,404	328,655,397	495,275,612	409,921,763	24,222,899
0250	PLUS:							
0260	WORKING CAPITAL	88,558,503	29,401,915	4,242,551	11,197,235	21,918,556	20,881,457	916,790
0270	PRIOR NET PREPAID PENSION ASSET	0	0	0	0	0	0	0
0280	PENSION REGULATORY ASSET	8,257,718	3,323,574	471,866	1,015,418	1,745,653	1,575,876	125,329
0290	REG ASSET - DSM PROGRAMS	29,779,838	12,340,676	1,495,305	3,811,641	6,217,938	5,617,787	296,492
0300	REG ASSET - ERPP PROGRAMS	289,914	128,295	15,861	37,734	57,264	47,398	3,363
0310	REG ASSET - IATAN 1 & COMMMON PLANT	13,290,035	5,507,351	667,319	1,701,045	2,774,918	2,507,085	132,317
0320	LESS:							
0330	ACCUM. DEFERRED TAXES	330,262,211	147,392,945	17,891,204	43,438,913	64,653,106	53,105,386	3,780,658
0340	DEFERRED GAIN ON SO2 EMISSION CR.	49,523,837	14,957,813	2,399,326	6,302,921	13,036,321	12,331,994	495,462
0350	DEFERRED GAIN ON SO2 ALLOWANCE	(963,168)	(290,908)	(46,663)	(122,583)	(253,538)	(239,840)	(9,636)
0360	CUST. ADVANCES FOR CONSTRUCTION	184,485	95,858	12,382	26,209	30,039	16,734	3,264
0370	CUSTOMER DEPOSITS	5,354,483	224,965	4,080,455	852,323	169,276	15,900	11,563
0380	REGULATORY PLAN ADDITIONAL AMORT	132,221,058	55,736,045	7,165,317	16,880,436	27,200,863	23,689,017	1,549,380
0390	TOTAL RATE BASE	2,122,817,005	938,360,921	110,763,284	279,040,253	423,153,873	351,632,175	19,866,499
0400								
0410	RATE OF RETURN	6.396%	4.304%	11.936%	7.453%	8.812%	6.446%	7.108%
0420	RELATIVE RATE OF RETURN	1.00	0.67	1.87	1.17	1.38	1.01	1.11

Notes:
Production Plant and Expense Allocated using A&E-2NCP.
Margin on Sales Revenue Allocated on Energy.

KANSAS CITY POWER & LIGHT COMPANY

Development of
4 CP Demand Allocator
For the Test Year Ended December 2009

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Total Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	4 CP Demand - kW	1,821,022	765,214	80,805	225,689	398,103	351,197	14
2	4 CP Demand - Percent	1.000000	0.420211	0.044373	0.123935	0.218615	0.192857	0.000008

Source: KCPL MO Allocators 05-21-10.xls

KANSAS CITY POWER & LIGHT COMPANY
MISSOURI CUSTOMERS
CLASS COST OF SERVICE
DEC2009 TEST YEAR INCL KNOWN & MEAS TO 12/31/2010

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	668,323,387	247,439,033	46,531,284	89,839,660	154,950,292	121,279,587	8,283,530
0050	OTHER OPERATING REVENUE	69,914,288	22,956,335	3,388,855	8,877,456	17,704,274	16,370,066	617,301
0060	TOTAL OPERATING REVENUE	738,237,675	270,395,368	49,920,139	98,717,116	172,654,566	137,649,654	8,900,831
0070								
0080	OPERATING EXPENSES							
0090	FUEL	167,502,786	50,556,184	8,111,308	21,339,136	43,951,544	41,876,028	1,668,585
0100	PURCHASED POWER	17,930,093	5,610,776	860,240	2,268,559	4,666,459	4,358,952	165,106
0110	OTHER OPERATION & MAINTENANCE EXPENSES	247,431,627	109,805,296	13,755,128	29,966,629	49,098,828	42,338,771	2,466,976
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	92,323,818	41,369,380	4,630,111	11,942,016	18,626,752	15,237,132	518,427
0130	AMORTIZATION EXPENSES	10,089,113	5,498,850	624,137	959,252	1,594,481	1,379,026	33,367
0140	INTEREST ON CUSTOMER DEPOSITS	227,566	9,561	173,419	36,224	7,194	676	491
0150	TAXES OTHER THAN INCOME TAXES	43,366,539	19,039,585	2,216,064	5,486,392	8,943,914	7,431,384	249,201
0160	FEDERAL AND STATE INCOME TAXES	23,596,471	(1,281,703)	5,724,257	5,503,273	9,494,618	2,799,051	1,356,975
0170	TOTAL ELECTRIC OPERATING EXPENSES	602,468,012	230,607,928	36,094,665	77,501,482	136,383,792	115,421,018	6,459,128
0180								
0190	NET ELECTRIC OPERATING INCOME	135,769,663	39,787,440	13,825,474	21,215,634	36,270,774	22,228,636	2,441,704
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	4,016,606,546	1,792,958,102	204,178,747	511,972,138	819,523,672	667,896,352	20,077,536
0230	LESS: ACCUM. PROV. FOR DEPREC	1,517,382,643	677,746,197	78,282,310	189,903,927	308,313,281	251,136,741	12,000,188
0240	NET PLANT	2,499,223,903	1,115,211,905	125,896,437	322,068,211	511,210,391	416,759,611	8,077,347
0250	PLUS:							
0260	WORKING CAPITAL	88,558,503	29,507,678	4,136,340	11,123,403	22,097,160	20,958,098	735,824
0270	PRIOR NET PREPAID PENSION ASSET	0	0	0	0	0	0	0
0280	PENSION REGULATORY ASSET	8,257,718	3,335,049	460,343	1,007,407	1,765,031	1,584,192	105,695
0290	REG ASSET - DSM PROGRAMS	29,779,838	12,513,820	1,321,429	3,690,772	6,510,328	5,743,255	235
0300	REG ASSET - ERPP PROGRAMS	289,914	129,414	14,737	36,954	59,152	48,208	1,449
0310	REG ASSET - IATAN 1 & COMMMON PLANT	13,290,035	5,584,621	589,722	1,647,104	2,905,405	2,563,079	105
0320	LESS:							
0330	ACCUM. DEFERRED TAXES	330,262,211	148,852,517	16,425,461	42,420,007	67,117,897	54,163,064	1,283,265
0340	DEFERRED GAIN ON SO2 EMISSION CR.	49,523,837	14,957,813	2,399,326	6,302,921	13,036,321	12,331,994	495,462
0350	DEFERRED GAIN ON SO2 ALLOWANCE	(963,168)	(290,908)	(46,663)	(122,583)	(253,538)	(239,840)	(9,636)
0360	CUST. ADVANCES FOR CONSTRUCTION	184,485	95,859	12,381	26,207	30,042	16,735	3,262
0370	CUSTOMER DEPOSITS	5,354,483	224,965	4,080,455	852,323	169,276	15,900	11,563
0380	REGULATORY PLAN ADDITIONAL AMORT	132,221,058	56,115,059	6,784,701	16,615,852	27,840,908	23,963,669	900,870
0390	TOTAL RATE BASE	2,122,817,005	946,327,181	102,763,348	273,479,124	436,606,560	357,404,921	6,235,870
0400								
0410	RATE OF RETURN	6.396%	4.204%	13.454%	7.758%	8.307%	6.219%	39.156%
0420	RELATIVE RATE OF RETURN	1.00	0.66	2.10	1.21	1.30	0.97	6.12

Notes:
Production Plant and Expense Allocated using 4CP.
Margin on Sales Revenue Allocated on Energy.