MIEC Ex 853

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Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Missouri Industrial Energy Consumers
Case No.:	ER-2016-0285
Date Testimony Prepared:	December 14, 2016

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	**Case No. ER-2016-0285**

FILED²

MAR 2 2017

Missouri Public Service Commission

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers

December 14, 2016

BRUBAKER & ASSOCIATES, INC.

Project 10277

MIEC Exhibit No. 853
Date 2-23-17 Reporter mm
File No. ER-2016-0285

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	)	Case No. ER-2016-0285

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

Affidavit of Maurice Brubaker

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

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

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2016-0285.

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

M Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 13th day of December, 2016.

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

Tammy S. Klossner
Notary Public

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Table of Contents to the
<u>Direct Testimony of Maurice Brubaker</u>

Summary **2**

COST OF SERVICE PROCEDURES **3**
Overview 3
Electricity Fundamentals 4

A CLOSER LOOK AT THE COST OF SERVICE STUDY **8**
Functionalization 8
Classification 9
Demand vs. Energy Costs 12
Allocation 14
Utility System Characteristics 15
Making the Cost of Service Study – Summary 21
Adjustment of Class Revenues 23

REVENUE ALLOCATION **26**

ANALYSIS OF LARGE CUSTOMER RATES **28**

ENERGY LOSSES **35**

Appendix A: Qualifications of Maurice Brubaker

Schedule MEB-COS-1 to Schedule MEB-COS-9

Schedule MEB-COS-Appendix

BEFORE THE PUBLIC SERVICE COMMISSION
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Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A That information is contained in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"), a non-profit company that represents the interests of industrial customers in Missouri utility matters. 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 that should be considered in determining how to allocate these functionalized and classified costs among customer classes.

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

Summary

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

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

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

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

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

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

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

7. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6. Page 1 of Schedule MEB-COS-6 shows a 25% movement toward cost of service, and page 2 shows a 50% movement.

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

9. KCPL's proposal to include in the Fuel Adjustment Charge ("FAC") voltage level distinctions (for purposes of recognizing losses) of secondary, primary and transmission is reasonable.

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.

<u>Electricity Fundamentals</u>

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.

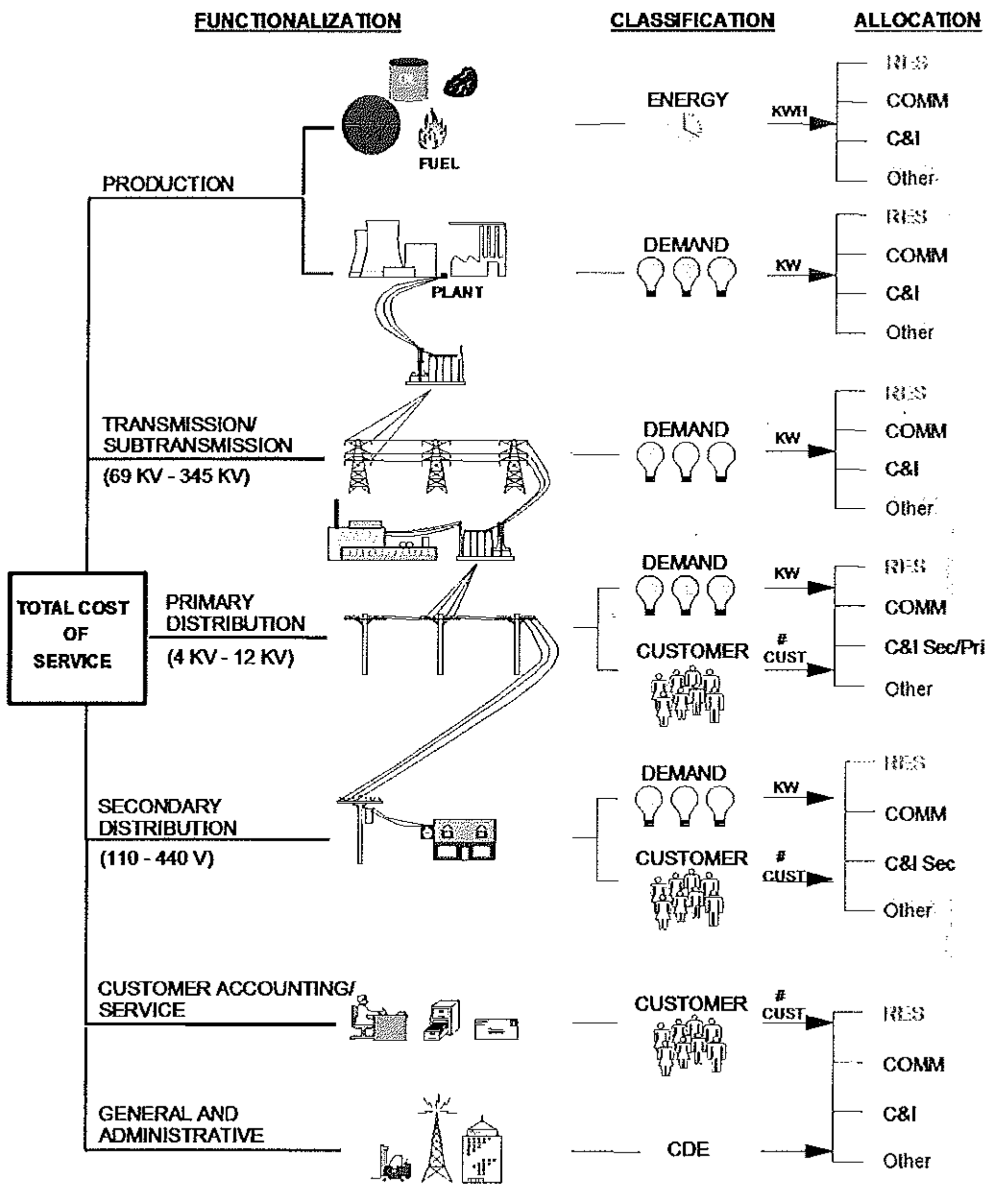
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so, consider 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 service of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

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

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

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

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

Functionalization

Q **PLEASE EXPLAIN FUNCTIONALIZATION.**

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

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

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

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.

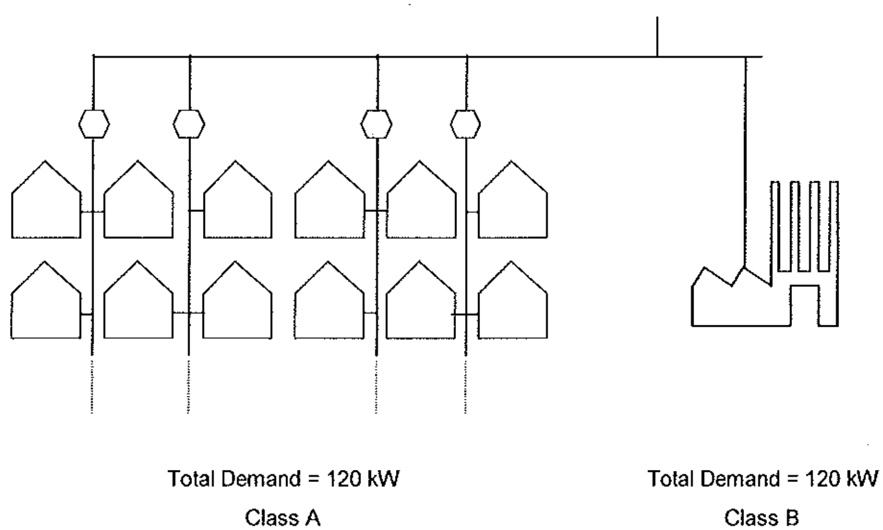
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

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.

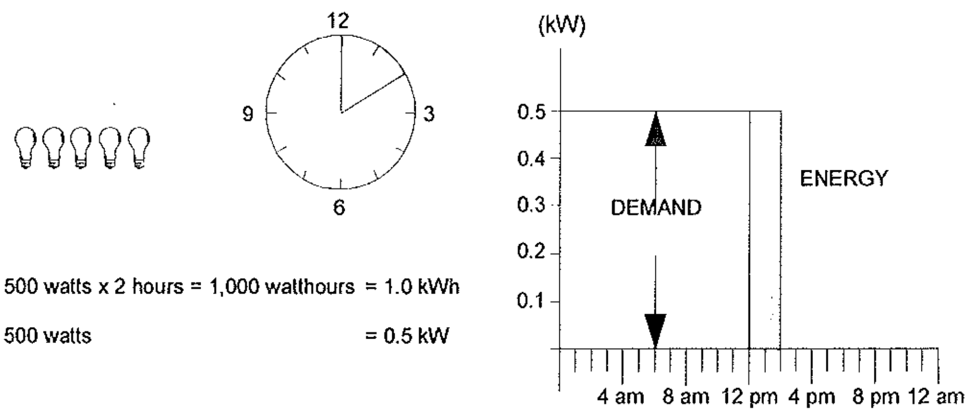
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

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

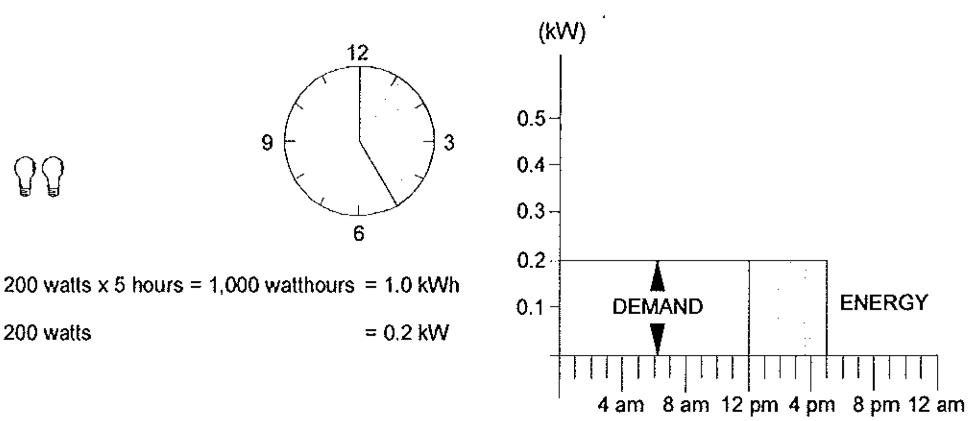
CUSTOMER A



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 average total cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kWh will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industrial customers generally have higher load factors than residential or commercial customers, they are less costly to serve on a per-kWh basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

Allocation

Q WHAT IS ALLOCATION?

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

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

Utility System Characteristics

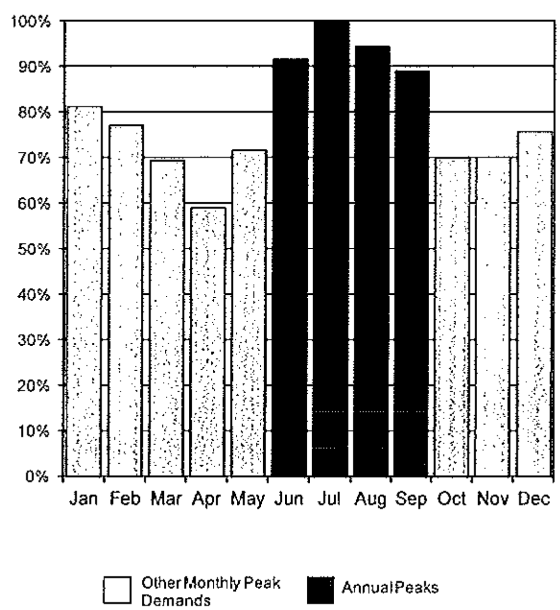
Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method that 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
Case No. ER-2016-0285

Analysis of KCP&L's (Missouri) Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended December 31, 2015



This shows the monthly system peak demands for the test year used in the study. The highlighted bars show the months 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 July, and was substantially higher than the monthly peaks occurring in most other months. The peaks in June, August and September were only 8.4%, 5.5%, and 10.9%, respectively, lower than the annual peak, while peaks in other months were substantially lower.

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 that 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.

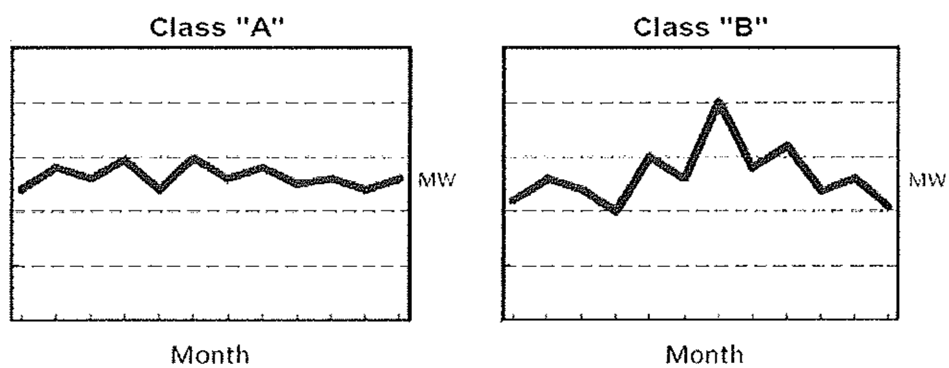
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their contribution to the "peaking"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

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

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

Figure 5

Load Patterns



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

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

[2] During any specified time period (e.g., month, year), the maximum demand of a class, regardless of when it occurs, is called the non-coincident peak demand.

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

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

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

A First, in order to reflect cost-causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver that 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 recommend the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

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

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

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

A Line 2 shows the average of the four months' non-coincident peaks (the highest demands, regardless of when they occur) 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. Line 8 is the result of multiplying the annual load factor (56.31%) times each class's average demand percent from line 5. Line 9 is the result of multiplying the quantity one minus the system load factor (43.69%) times each class's excess demand percent from line 7.

Finally, line 10 presents the composite A&E allocation factor, which is the sum of lines 8 and 9. As noted, it is determined by weighting the average demand responsibility of each class (which is the same as each class's energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

Making the Cost of Service Study – Summary

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

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

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

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

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

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

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

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

Q DID KCPL SUBMIT A CLASS COST OF SERVICE STUDY?

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

Q HAVE YOU USED KCPL'S STUDY?

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

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

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

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

A It was the starting point. Many of KCPL's allocation factors and functionalizations and classifications have been utilized. The principal area where I depart from KCPL and use a different approach were incorporated into the allocations. They have previously been explained in this testimony.

Adjustment of Class Revenues

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REVENUE ALLOCATION

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

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

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

A This is shown on Schedule MEB-COS-5. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall increase in revenues. Note that the Residential class would require an increase of about $58 million, or 14.8%, in order to move to cost of service. All other classes would require a corresponding decrease. The decreases range from about 6.2% for the Medium General Service class to 12.4% for the Lighting class.

Q HOW DOES KCPL PROPOSE TO ADJUST REVENUES?

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

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

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

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

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

Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.

A My proposal is shown on Schedule MEB-COS-6, pages 1 and 2. Column 1 shows class revenues at current rates. Column 2 shows the proposed cost of service adjustment. This adjustment on page 1 moves classes roughly 25% of the way toward cost of service, and the adjustment on page 2 moves 50% of the way toward cost of service. A movement in this range would not be unreasonable. The smaller the overall increase granted to KCPL, the larger the movement toward cost of service can be.

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 subsidize the residential class by bearing more of the burden of the revenue responsibility than they should. My recommendation of moving 25% to 50% of the way toward cost of service, which limits the Residential class revenue-neutral increase to between 3.7% and 7.4% (as compared to the 14.8% 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 a one-day 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 likely would utilize approximately twice that much energy, and therefore use an additional 180 or so kWh per kW of demand, thereby filling up both the first and second blocks.

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

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

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

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

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

A The charges vary slightly by voltage level and by season, but range from approximately 2.4¢/kWh to 2.6¢/kWh in LPS and from 3.5¢/kWh to 4.3¢/kWh for LGS.

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

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

Q PLEASE EXPLAIN.

A I have analyzed KCPL's current rate case filing and its claims for costs. KCPL's calculated average variable costs (Schedule MEM-2, page 2) are 2.0-2.1¢/kWh. The energy charges in the high load factor block of KCPL's current LGS and LPS tariffs

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

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

Q WHAT DO YOU CONCLUDE FROM THIS REVIEW?

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

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

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

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

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

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

Q HAVE YOU PREPARED AN ILLUSTRATION OF THIS RATE DESIGN?

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

Q PLEASE EXPLAIN SCHEDULE MEB-COS-7.

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

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

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

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

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

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

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

Q IS THERE ANYTHING ELSE THAT KCPL SHOULD BE DOING?

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

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

A Yes. In many cases, these customers have unique load characteristics that allow KCPL to reduce its peak demand or to otherwise improve its overall load factor. For instance, some large customers have significant abilities to curtail load. By making effective use of the curtailable 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 **HAS KCPL RECENTLY MADE ANY CHANGES IN ITS LOAD CURTAILMENT PROGRAM?**

A Yes. In its recent MEEIA filing (Case No. EO-2015-0240), KCPL froze the Mpower rate schedule, which specified curtailment credits, and replaced it with a contractual provision under which KCPL retains the discretion to determine the amount of curtailable kW for which it will contract, as well as the curtailment credit that it will offer.

It is my understanding that as a result of this change KCPL has materially reduced both the amount of curtailable load for which it will contract, and the amount of compensation which it offers to customers willing to agree to curtail.

Q **IS THIS CHANGE IN THE CURTAILMENT PROVISIONS OF CONCERN?**

A Yes. It obviously is of concern to those customers who have subscribed to the program, some of whom may have made capital investments in order to be able to participate in the curtailment program.

It also is of concern to firm customers who benefit from having customers who are willing to curtail load in times of system stress, or during high price episodes. Given the retirement of Montrose that currently is underway (and perhaps other retirements as well), the value of interruptibility will increase over time, and not decrease.

Q WHAT IS YOUR RECOMMENDATION?

A In light of its dwindling reserve margins, which increases the probability of the need for curtailment, I recommend that KCPL closely monitor system generation reserves and the level of subscribed curtailable capacity; and consider increasing the amount of curtailable kW of demand for which it contracts, and also increasing the compensation to customers for their willingness to curtail.

ENERGY LOSSES

Q EARLIER IN YOUR TESTIMONY (PAGE 9) YOU MENTIONED ENERGY LOSSES AND HOW THEY DIFFER ACROSS CUSTOMER CLASSES. HAS KCPL RECOGNIZED THESE DIFFERENCES BY VOLTAGE LEVEL IN ITS FAC?

A Yes. KCPL has proposed three separate factors, applicable at the secondary, primary and transmission/substation service.

Q DO YOU AGREE WITH THESE DISTINCTIONS?

A Yes, I do.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

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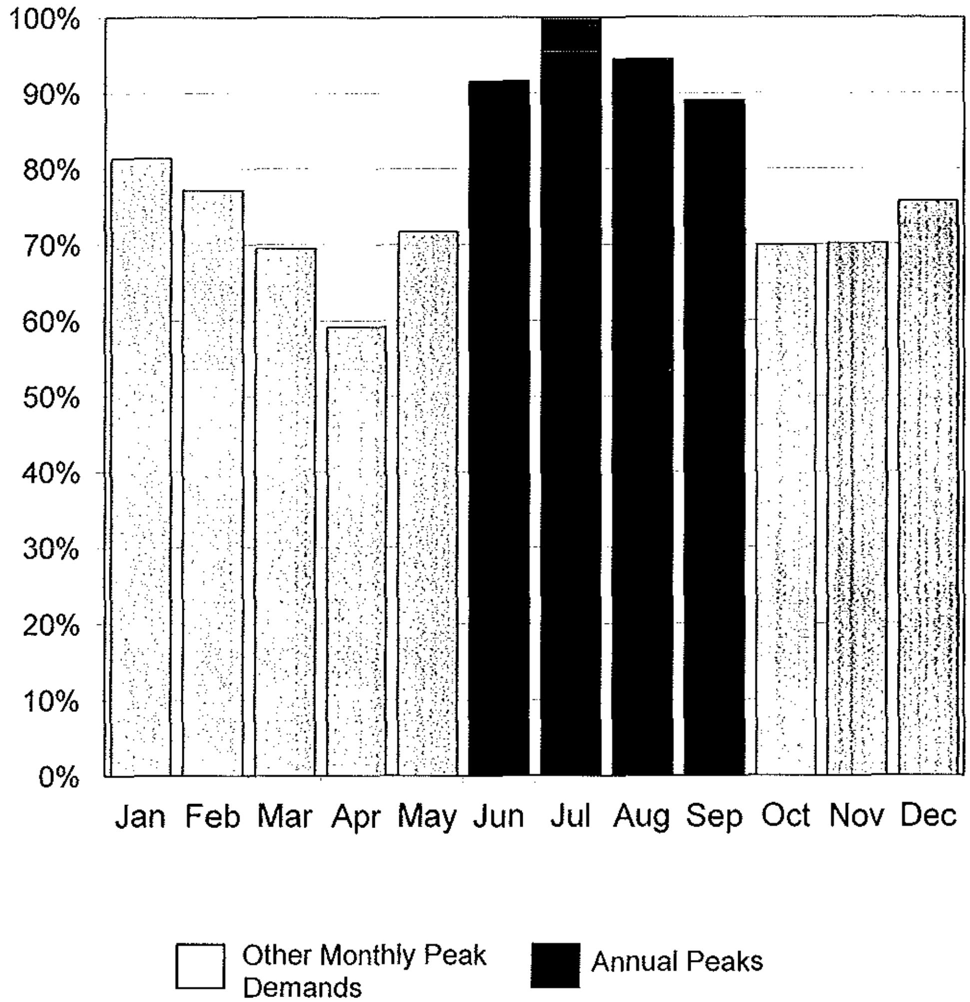
KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Analysis of KCP&L's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses)
For the Test Year Ended December 31, 2015



Schedule MEB-COS-1

KANSAS CITY POWER & LIGHT COMPANY

Case No. ER-2016-0285

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 December 31, 2015

Line	Description	Total Company MW (1)	Percent (2)
1	January	1,454	81.3%
2	February	1,380	77.2%
3	March	1,243	69.5%
4	April	1,057	59.1%
5	May	1,282	71.7%
6	June	1,637	91.6%
7	July	1,788	100.0%
8	August	1,690	94.5%
9	September	1,592	89.1%
10	October	1,250	69.9%
11	November	1,254	70.2%
12	December	1,354	75.7%

Source: KCPL Allocators MO Rev 6-17-16 Avg & Pk 4 CP.xls

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended December 31, 2015

Line	Description	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Other Lighting (7)
1	Missouri System Peak - kW	1,787,693						
2	Avg of 4 Highest Monthly NCP Values - kW	1,836,875	774,431	102,767	256,657	384,679	308,014	10,326
3	Energy Sales with Losses - MWh	8,817,844	2,693,894	442,396	1,249,107	2,230,885	2,111,107	90,455
4	Average Demand - kW	1,006,603	307,522	50,502	142,592	254,667	240,994	10,326
5	Average Demand - Percent	1.000000	0.305505	0.050171	0.141657	0.252997	0.239413	0.010258
6	Class Excess Demand - kW	830,272	466,909	52,266	114,065	130,011	67,020	-
7	Class Excess Demand - Percent	1.000000	0.562357	0.062950	0.137383	0.156589	0.080721	-
	Allocator:							
8	Annual Load Factor * Average Demand - Percent	0.563074	0.172022	0.028250	0.079763	0.142456	0.134807	0.005776
9	(1-LF) * Excess Demand - Percent	0.436926	0.245709	0.027504	0.060026	0.068418	0.035269	-
10	Average and Excess Demand Allocator	1.000000	0.417730	0.055754	0.139789	0.210874	0.170076	0.005776

Notes:
Line 4 equals Line 3 ÷ 8,760
Line 6 equals Line 2- Line 4

System Annual Load Factor	56.31%
1 - Load Factor	43.69%

Source: KCPL Allocators MO Rev 6-17-16_BAI A&E 4 NCP.xls

KANSAS CITY POWER & LIGHT COMPANY
2016 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 12/31/15; Update TBD; K&M 12/31/16

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	837,233,404	315,251,522	55,236,249	121,694,450	188,383,024	146,155,580	10,512,579
0050	OTHER OPERATING REVENUE	250,855,503	77,623,902	12,655,911	35,510,011	63,048,415	59,428,273	2,588,990
0060	TOTAL OPERATING REVENUE	1,088,088,907	392,875,424	67,892,161	157,204,461	251,431,440	205,583,853	13,101,569
0070								
0080	OPERATING EXPENSES							
0090	FUEL	158,701,965	49,146,445	7,982,852	22,469,323	39,860,495	37,645,048	1,597,801
0100	PURCHASED POWER	222,730,875	68,045,349	11,174,536	31,551,320	56,350,176	53,324,669	2,284,824
0110	OTHER OPERATION & MAINTENANCE EXPENSES	306,891,041	149,538,843	19,360,009	37,487,807	53,532,119	43,396,706	3,575,558
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	127,861,126	59,055,104	7,798,428	17,988,685	23,992,149	17,764,991	1,261,769
0130	AMORTIZATION EXPENSES	20,874,322	9,417,170	1,246,799	2,922,972	4,039,756	3,024,536	223,090
0140	TAXES OTHER THAN INCOME TAXES	65,449,969	30,039,681	3,969,181	8,984,347	12,404,067	9,329,991	722,703
0150	CURRENT INCOME TAXES	29,136,031	(7,768,323)	3,841,380	7,995,384	15,052,616	9,170,931	844,042
0160	DEFERRED INCOME TAXES	13,528,201	6,218,708	818,969	1,872,839	2,563,216	1,904,961	149,508
0170	TOTAL ELECTRIC OPERATING EXPENSES	945,173,529	363,692,977	56,192,154	131,272,677	207,794,594	175,561,833	10,659,294
0180								
0190	NET ELECTRIC OPERATING INCOME	142,915,379	29,182,447	11,700,007	25,931,784	43,636,846	30,022,019	2,442,275
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,274,249,638	2,414,464,756	318,069,403	729,859,906	1,004,584,143	750,583,587	56,687,843
0230	LESS: ACCUM. PROV. FOR DEPREC	2,072,173,694	949,215,462	125,355,808	283,633,589	393,750,270	296,550,448	23,668,116
0240	NET PLANT	3,202,075,945	1,465,249,294	192,713,595	446,226,316	610,833,872	454,033,140	33,019,728
0250	PLUS:							
0260	CASH WORKING CAPITAL	(62,071,389)	(26,695,865)	(3,912,039)	(8,766,906)	(12,552,665)	(9,421,051)	(722,863)
0270	MATERIALS & SUPPLIES	59,031,048	26,099,889	3,462,658	8,262,169	11,699,945	8,953,596	552,792
0280	PREPAYMENTS	7,124,681	3,156,760	414,331	967,290	1,416,874	1,119,531	49,895
0290	FUEL INVENTORY	66,320,675	20,308,703	3,324,416	9,393,610	16,742,995	15,874,130	676,821
0300	REGULATORY ASSETS	74,763,183	29,655,054	4,151,524	10,519,960	16,584,561	13,221,720	630,364
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	1,667,781	921,050	119,681	234,735	235,189	114,509	42,618
0330	CUSTOMER DEPOSITS	4,020,118	2,138,954	1,507,973	315,716	53,293	4,181	0
0340	DEFERRED INCOME TAXES	729,963,824	334,165,435	44,021,268	101,013,673	139,035,907	103,881,861	7,845,680
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	35,319,134	10,790,165	1,771,981	5,003,192	8,935,624	8,455,860	362,312
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	0	0	0	0	0	0	0
0370	TOTAL RATE BASE	2,576,273,286	1,169,758,231	152,733,581	360,035,125	496,465,568	371,324,655	25,956,126
0380								
0390	RATE OF RETURN	5.547%	2.495%	7.660%	7.203%	8.790%	8.085%	9.409%
0400	RELATIVE RATE OF RETURN	1.00	0.45	1.38	1.30	1.58	1.46	1.70

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

Schedule MEB-COS-4

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

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	Current Rate Base	Net Operating Income	Earned ROR	Indexed ROR	Income @ Current ROR	Difference in Income	Revenue Increase	Percentage Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Residential	$ 392,875	$ 1,169,758	$ 29,182	2.495%	45	$ 64,891	$ 35,708	$ 57,959	14.8%
2	Small General Service	67,892	152,734	11,700	7.660%	138	8,473	(3,227)	(5,238)	-7.7%
3	Medium General Service	157,204	360,035	25,932	7.203%	130	19,972	(5,959)	(9,673)	-6.2%
4	Large General Service	251,431	496,466	43,637	8.790%	158	27,541	(16,096)	(26,126)	-10.4%
5	Large Power Service	205,584	371,325	30,022	8.085%	146	20,599	(9,423)	(15,295)	-7.4%
6	Total Lighting	13,102	25,956	2,442	9.409%	170	1,440	(1,002)	(1,627)	-12.4%
7	Total	$ 1,088,089	$ 2,576,273	$ 142,915	5.547%	100	$ 142,915	$ 0	$ -	0.0%

Source: Schedule MEB-COS-4

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Cost of Service Adjustments for
25% Movement Toward Cost of Service
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues	Move 25% Toward Cost Of Service[1]	Adjusted Current Revenue	Revenue-neutral Percent Increase in Current Revenue
		(1)	(2)	(3)	(4)
1	Residential	$ 392.9	$ 14.5	$ 407.4	3.7 %
2	Small General Service	67.9	(1.3)	66.6	(1.9)%
3	Medium General Service	157.2	(2.4)	154.8	(1.5)%
4	Large General Service	251.4	(6.5)	244.9	(2.6)%
5	Large Power Service	205.6	(3.8)	201.8	(1.9)%
6	Total Lighting	13.1	(0.4)	12.7	(3.1)%
7	Total	$ 1,088.1	$ -	$ 1,088.1	(0.0)%

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

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Cost of Service Adjustments for
50% Movement Toward Cost of Service
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 50% Toward Cost Of Service[1] (2)	Adjusted Current Revenue (3)	Revenue-neutral Percent Increase in Current Revenue (4)
1	Residential	$ 392.9	$ 29.0	$ 421.9	7.4 %
2	Small General Service	67.9	(2.6)	65.3	(3.9)%
3	Medium General Service	157.2	(4.8)	152.4	(3.1)%
4	Large General Service	251.4	(13.1)	238.4	(5.2)%
5	Large Power Service	205.6	(7.6)	197.9	(3.7)%
6	Total Lighting	13.1	(0.8)	12.3	(6.2)%
7	Total	$ 1,088.1	$ -	$ 1,088.1	(0.0)%

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-5, times 50%.

KCP&L-MO LARGE POWER SERVICE
SUMMARY OF PROPOSED SCENARIOS
ER-2016-0285 Direct Filing
*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	Current Rates	Company Proposed Rates	Rate Design Rates *
A: CUSTOMER CHARGE			
	1,106.30	1,226.93	1,264.12
B: FACILITIES CHARGE			
SECONDARY:	3.705	4.109	4.234
PRIMARY:	3.071	3.406	3.509
SUBSTATION VOLTAGE	0.927	1.028	1.059
TRANSM VOLTAGE	-	-	-
C: DEMAND CHARGE			
SECONDARY-SUMMER:			
First 2443 kw	14.374	15.942	16.425
Next 2443 kw	11.498	12.752	13.138
Next 2443 kw	9.632	10.682	11.006
All kw over 7329 kw	7.031	7.798	8.034
SECONDARY-WINTER			
First 2443 kw	9.771	10.837	11.165
Next 2443 kw	7.624	8.455	8.712
Next 2443 kw	6.726	7.459	7.685
All kw over 7329 kw	5.178	5.743	5.917
PRIMARY-SUMMER			
First 2500 kw	14.044	15.576	16.047
Next 2500 kw	11.236	12.461	12.839
Next 2500 kw	9.411	10.437	10.754
All kw over 7500 kw	6.871	7.620	7.851
PRIMARY-WINTER			
First 2500 kw	9.545	10.587	10.907
Next 2500 kw	7.451	8.263	8.514
Next 2500 kw	6.572	7.289	7.510
All kw over 7500 kw	5.061	5.613	5.783
SUBSTATION-SUMMER			
First 2530 kw	13.876	15.389	15.855
Next 2530 kw	11.101	12.311	12.685
Next 2530 kw	9.299	10.313	10.626
All kw over 7590 kw	6.790	7.530	7.759
SUBSTATION-WINTER			
First 2530 kw	9.434	10.463	10.780
Next 2530 kw	7.363	8.166	8.413
Next 2530 kw	6.496	7.204	7.423
All kw over 7590 kw	5.001	5.546	5.714
TRANSMISSION-SUMMER			
First 2553 kw	13.757	15.257	15.719
Next 2553 kw	11.002	12.202	12.571
Next 2553 kw	9.214	10.219	10.528
All kw over 7659 kw	6.729	7.463	7.689
TRANSMISSION-WINTER			
First 2553 kw	9.349	10.368	10.683
Next 2553 kw	7.297	8.093	8.338
Next 2553 kw	6.438	7.140	7.356
All kw over 7659 kw	4.956	5.496	5.663

KCP&L-MO LARGE POWER SERVICE
SUMMARY OF PROPOSED SCENARIOS
ER-2016-0285 Direct Filing
*** Equal Percent Increase to All Rate Components except**
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	Current Rates	Company Proposed Rates	Rate Design Rates *
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.09000	0.10008	0.10284
181-360 hrs use per month	0.05348	0.05958	0.05785
361+ hrs use per month	0.02566	0.02865	0.02566
SECONDARY-WINTER:			
0-180 hrs use per month	0.07630	0.08489	0.08718
181-360 hrs use per month	0.04866	0.05424	0.05264
361+ hrs use per month	0.02541	0.02837	0.02541
PRIMARY-SUMMER:			
0-180 hrs use per month	0.08794	0.09780	0.10049
181-360 hrs use per month	0.05228	0.05825	0.05656
361+ hrs use per month	0.02507	0.02798	0.02507
PRIMARY-WINTER:			
0-180 hrs use per month	0.07456	0.08296	0.08520
181-360 hrs use per month	0.04754	0.05299	0.05143
361+ hrs use per month	0.02484	0.02773	0.02484
SUBSTATION-SUMMER			
0-180 hrs use per month	0.08692	0.09667	0.09932
181-360 hrs use per month	0.05167	0.05757	0.05590
361+ hrs use per month	0.02477	0.02760	0.02477
SUBSTATION-WINTER			
0-180 hrs use per month	0.07370	0.08201	0.08421
181-360 hrs use per month	0.04698	0.05237	0.05082
361+ hrs use per month	0.02454	0.02735	0.02454
TRANSMISSION-SUMMER			
0-180 hrs use per month	0.08615	0.09581	0.09844
181-360 hrs use per month	0.05120	0.05705	0.05539
361+ hrs use per month	0.02456	0.02737	0.02456
TRANSMISSION-WINTER			
0-180 hrs use per month	0.07302	0.08125	0.08344
181-360 hrs use per month	0.04656	0.05191	0.05037
361+ hrs use per month	0.02431	0.02709	0.02431
E: REACTIVE DEMAND ADJUSTMENT	0.930	1.031	1.063
LPS Secondary	100.00%		11.47%
LPS Primary	100.00%		11.36%
LPS Substation Voltage	100.00%		10.47%
LPS Transmission Voltage	100.00%		10.98%
LPS Overall Change (*)	0.00%		11.22%
Winter Price Below Summer (SUM-WIN)/SUM	14.2%		14.6%
Ovarall Change			11.22%
Revenue	$148,044,229	$164,650,793	$164,650,895
Change in Revenue			$16,606,666
Proposed change per Revenue Summary			$16,606,615
			$51

MO LARGE POWER
SECONDARY VOLTAGE - LPGSS (1PGSE, 1PGSH)

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

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	106.1	$1,106.30	$117,382	1,226.93	$130,181	$1,264.12	$134,127
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	106		$117,382		$130,181		$134,127
B: FACILITIES CHARGE	286,475.1	$3.705	$1,061,390	$4.109	$1,177,126	$4 234	$1,212,936
C: DEMAND CHARGE							
First 2443 kw	179,461.3	$14.374	$2,579,577	$15.942	$2,860,973	$16.425	$2,947,652
Next 2443 kw	62,014.0	$11.498	$713,037	$12.752	$790,802	$13.138	$814,740
Next 2443 kw	24,438.4	$9.632	$235,391	$10.682	$261,051	$11.006	$268,969
Over 7329 kw	3,233.2	$7.031	$22,733	$7.798	$25,213	$8.034	$25,976
	269,147		$3,550,738		$3,938,039		$4,057,337
D: ENERGY CHARGE							
0-180 hrs use per month	48,276,971.3	$0.09000	$4,344,927	$0.10008	$4,831,367	$0.10284	$4,964,804
181-360 hrs use per month	47,836,602.5	$0.05348	$2,558,302	$0.05958	$2,849,914	$0.05785	$2,767,347
361+ hrs use per month	51,111,224.5	$0.02566	$1,311,514	$0.02865	$1,464,143	$0.02566	$1,311,514
	147,224,798		$8,214,743		$9,145,423		$9,043,665
E: REACTIVE DEMAND ADJUSTMENT	1,309.1	$0.9300	$1,217	$1.0310	$1,350	$1.0630	$1,392
MANUAL BILLS	-		$0		$0		$0
REVENUE			$12,945,470		$14,392,119		$14,449,457
c/kwh			$0.0879		$0.0978		$0.0981
OVERALL CHANGE (%)	*2537*				11.17%		11.62%
used to reference avg customer	*1,387,562*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	205.3	$1,106.30	$227,164	1,226.93	$251,934	$1,264.12	$259,571
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	205		$227,164		$251,934		$259,571
B: FACILITIES CHARGE	553,579.5	$3.705	$2,051,012	$4.109	$2,274,658	$4.234	$2,343,856
C: DEMAND CHARGE							
First 2443 kw	338,083.6	$9.771	$3,303,415	$10.837	$3,663,812	$11.165	$3,774,703
Next 2443 kw	98,673.9	$7.624	$752,290	$8.455	$834,288	$8.712	$859,647
Next 2443 kw	23,465.6	$6.726	$157,830	$7.459	$175,030	$7.685	$180,333
Over 7329 kw	251.8	$5.178	$1,304	$5.743	$1,446	$5.917	$1,490
	460,475		$4,214,838		$4,674,576		$4,816,173
D: ENERGY CHARGE							
0-180 hrs use per month	81,753,745.2	$0.07630	$6,237,811	$0.08489	$6,939,749	$0.08718	$7,127,292
181-360 hrs use per month	80,178,689.4	$0.04866	$3,901,495	$0.05424	$4,348,572	$0.05264	$4,220,606
361+ hrs use per month	84,181,158.7	$0.02541	$2,139,043	$0.02837	$2,387,900	$0.02541	$2,139,043
	246,113,593		$12,278,349		$13,676,221		$13,486,941
E: REACTIVE DEMAND ADJUSTMENT	2,012.8	$0.9300	$1,872	$1.0310	$2,075	$1.0630	$2,140
F: MANUAL BILL USAGE/REVENUE	-				$0		$0
REVENUE			$18,773,236		$20,879,465		$20,906,680
c/kwh			$0.0763		$0.0848		$0.0850
OVERALL CHANGE (%)	*2243*				11.22%		11.37%
used to reference avg customer	*1,198,584*						

ANNUAL	393,338,392		$31,718,706		$35,271,584		$35,358,137
c/kwh			$0.0806		$0.0897		$0.0899
OVERALL CHANGE (%)					11.20%		11.47%
Winter Price Below Summer (SUM-WIN)/SUM			13.3%		13.2%		13.4%

MO LARGE POWER
PRIMARY VOLTAGE - LPGSP (1PGSF, 1PGSG, 1POSF, 1POSG)

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

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
	145.8	$1,106.30	$161,306	1,226.93	$178,895	1,264.12	$184,318
	-	$0.00	$0	-	$0	-	$0
	-	$0.00	$0	-	$0	-	$0
	146		$161,306		$178,895		$184,318
B: FACILITIES CHARGE	707,936.6	$3.071	$2,174,073	$3.406	$2,411,232	$3.509	$2,484,149
C: DEMAND CHARGE							
First 2500 kw	308,706.4	$14.044	$4,335,473	$15.576	$4,808,411	$16.047	$4,953,812
Next 2500 kw	157,091.7	$11.236	$1,765,082	$12.461	$1,957,519	$12.839	$2,016,900
Next 2500 kw	79,587.2	$9.411	$748,995	$10.437	$830,652	$10.754	$855,881
Over 7500 kw	110,644.6	$6.871	$760,239	$7.620	$843,112	$7.851	$868,671
	656,030		$7,609,789		$8,439,693		$8,695,263
D: ENERGY CHARGE							
0-180 hrs use per month	123,973,053.3	$0.08794	$10,902,190	$0.09780	$12,124,070	$0.10049	$12,458,052
181-360 hrs use per month	121,737,563.3	$0.05228	$6,364,440	$0.05825	$7,090,727	$0.05656	$6,885,477
361+ hrs use per month	118,586,085.1	$0.02507	$2,972,953	$0.02798	$3,317,907	$0.02507	$2,972,953
	364,296,702		$20,239,583		$22,532,704		$22,316,482
E: REACTIVE DEMAND ADJUSTMENT	54,248	$0.930	$50,451	$1.031	$55,930	$1.063	$57,666
E: MANUAL BILL USAGE/REVENUE	9,805,300		$870,501		$965,422		$965,422
REVENUE			$31,105,703		$34,583,876		$34,703,300
c/kwh			$0.0831		$0.0924		$0.0928
OVERALL CHANGE (%)	*4499*				11.18%		11.57%
used to reference avg customer	*2,565,734*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
	285.4	$1,106.30	$315,683	1,226.93	$350,105	$1,264.12	$360,717
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	285		$315,683		$350,105		$360,717
B: FACILITIES CHARGE	1,379,560.5	$3.071	$4,236,630	$3.406	$4,698,783	$3.509	$4,840,878
C: DEMAND CHARGE							
First 2500 kw	584,377.4	$9.545	$5,577,883	$10.587	$6,186,570	$10.907	$6,373,805
Next 2500 kw	259,407.6	$7.451	$1,932,846	$8.263	$2,143,485	$8.514	$2,208,596
Next 2500 kw	127,584.9	$6.572	$838,488	$7.289	$929,967	$7.510	$958,163
Over 7500 kw	164,311.2	$5.061	$831,579	$5.613	$922,279	$5.783	$950,212
	1,135,681		$9,180,796		$10,182,301		$10,490,776
D: ENERGY CHARGE							
0-180 hrs use per month	213,890,986.7	$0.07456	$15,947,712	$0.08296	$17,743,542	$0.08520	$18,223,512
181-360 hrs use per month	209,947,361.8	$0.04754	$9,980,898	$0.05299	$11,124,273	$0.05143	$10,797,593
361+ hrs use per month	214,202,605.7	$0.02484	$5,320,793	$0.02773	$5,939,601	$0.02484	$5,320,793
	638,040,954		$31,249,402		$34,807,416		$34,341,898
E: REACTIVE DEMAND ADJUSTMENT	96,047	$0.930	$89,324	$1.031	$99,025	$1.063	$102,098
MANUAL BILLS	17,268,517		$1,532,667		$1,699,793		$1,699,793
REVENUE			$46,604,503		$51,837,422		$51,836,159
c/kwh			$0.0711		$0.0791		$0.0791
OVERALL CHANGE (%)	*3980*				11.23%		11.23%
used to reference avg customer	*2,235,992*						

ANNUAL	1,029,411,473		$77,710,206		$86,421,298		$86,539,459
c/kwh			$0.0755		$0.0840		$0.0841
OVERALL CHANGE (%)					11.21%		11.36%
Winter Price Below Summer (SUM-WIN)/SUM			14.5%		14.4%		14.7%

MO LARGE POWER
SUBSTATION VOLTAGE - LPGSSS (1PGSV, 1POSV)

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

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	12.0	$1,106.30	$13,283	1,226.93	$14,731	$1,264.12	$15,177
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	12		$13,283		$14,731		$15,177
B: FACILITIES CHARGE	207,928.6	$0.927	$192,750	$1.028	$213,751	$1.059	$220,196
C: DEMAND CHARGE							
First 2530 kw	30,376.1	$13.876	$421,499	$15.389	$467,458	$15.855	$481,614
Next 2530 kw	30,317.9	$11.101	$336,559	$12.311	$373,243	$12.685	$384,582
Next 2530 kw	13,511.5	$9.299	$125,644	$10.313	$139,344	$10.626	$143,574
Over 7590 kw	111,735.4	$6.790	$758,683	$7.530	$841,368	$7.759	$866,955
	185,941		$1,642,385		$1,821,414		$1,876,725
D: ENERGY CHARGE							
0-180 hrs use per month	33,469,373.8	$0.08692	$2,909,158	$0.09667	$3,235,351	$0.09932	$3,324,178
181-360 hrs use per month	33,469,373.8	$0.05167	$1,729,363	$0.05757	$1,926,698	$0.05590	$1,870,938
361+ hrs use per month	50,507,302.0	$0.02477	$1,251,066	$0.02760	$1,394,153	$0.02477	$1,251,066
	117,446,050		$5,889,586		$6,556,202		$6,446,182
E: REACTIVE DEMAND ADJUSTMENT	12,428	$0.930	$11,558	$1.031	$12,813	$1.063	$13,211
REVENUE			$7,749,562		$8,618,911		$8,571,492
c/kwh			$0.0660		$0.0734		$0.0730
OVERALL CHANGE (%)	*15487*				11.22%		10.61%
used to reference avg customer	*9,781,974*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	23.7	$1,106.30	$26,246	1,226.93	$29,108	$1,264.12	$29,990
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	24		$26,246		$29,108		$29,990
B: FACILITIES CHARGE	409,341.6	$0.927	$379,460	$1.028	$420,803	$1.059	$433,493
C: DEMAND CHARGE							
First 2530 kw	60,022.1	$9.434	$566,249	$10.463	$628,012	$10.780	$647,039
Next 2530 kw	56,384.7	$7.363	$415,161	$8.166	$460,438	$8.413	$474,365
Next 2530 kw	25,685.4	$6.496	$166,852	$7.204	$185,037	$7.423	$190,662
Over 7590 kw	207,183.9	$5.001	$1,036,127	$5.546	$1,149,042	$5.714	$1,183,849
	349,276		$2,184,388		$2,422,528		$2,495,914
D: ENERGY CHARGE							
0-180 hrs use per month	62,869,696.1	$0.07370	$4,633,497	$0.08201	$5,155,693	$0.08421	$5,294,257
181-360 hrs use per month	62,869,696.1	$0.04698	$2,953,618	$0.05237	$3,292,235	$0.05082	$3,195,038
361+ hrs use per month	84,337,104.3	$0.02454	$2,069,633	$0.02735	$2,306,873	$0.02454	$2,069,633
	210,076,497		$9,656,747		$10,754,801		$10,558,928
E: REACTIVE DEMAND ADJUSTMENT	16,996	$0.930	$15,806	$1.031	$17,522	$1.063	$18,066
REVENUE			$12,262,647		$13,644,763		$13,536,391
c/kwh			$0.0584		$0.0650		$0.0644
OVERALL CHANGE (%)	*14722*				11.27%		10.39%
used to reference avg customer	*8,854,959*						
ANNUAL	327,522,546		$20,012,209		$22,263,674		$22,107,883
c/kwh			$0.0611		$0.0680		$0.0675
OVERALL CHANGE (%)					11.25%		10.47%
Winter Price Below Summer (SUM-WIN)/SUM			11.5%		11.5%		11.7%

MO LARGE POWER
TRANSMISSION VOLTAGE - LPGSTR (1PGSZ, 1POSW, 1POSZ)

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

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
	20.0	$1,106.30	$22,096	1,226.93	$24,505	$1,264.12	$25,248
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	20		$22,096		$24,505		$25,248
B: FACILITIES CHARGE	207,749	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	50,989.8	$13.757	$701,467	$15.257	$777,952	$15.719	$801,509
Next 2553 kw	34,293.7	$11.002	$377,300	$12.202	$418,452	$12.571	$431,106
Next 2553 kw	29,647.1	$9.214	$273,168	$10.219	$302,963	$10.528	$312,124
Over 7659 kw	79,699.7	$6.729	$536,299	$7.463	$594,799	$7.689	$612,811
	194,630		$1,888,234		$2,094,166		$2,157,551
D: ENERGY CHARGE							
0-180 hrs use per month	35,033,461.3	$0.08615	$3,018,133	$0.09581	$3,356,416	$0.09844	$3,448,694
181-360 hrs use per month	34,144,185.4	$0.05120	$1,748,182	$0.05705	$1,947,789	$0.05539	$1,891,246
361+ hrs use per month	36,070,245.0	$0.02456	$885,885	$0.02737	$987,351	$0.02456	$885,885
	105,247,892		$5,652,200		$6,291,557		$6,225,826
E: REACTIVE DEMAND ADJUSTMENT	4,368	$0.930	$4,062	$1.031	$4,503	$1.063	$4,643
REVENUE			$7,566,592		$8,414,731		$8,413,267
c/kwh			$0.0719		$0.0800		$0.0799
OVERALL CHANGE (%)	*9745*				11.21%		11.19%
used to reference avg customer	*5,269,636*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
	41.1	$1,106.30	$45,492	1,226.93	$50,453	$1,264.12	$51,982
	-	$0.00	$0	-	$0	$0.00	$0
	-	$0.00	$0	-	$0	$0.00	$0
	41		$45,492		$50,453		$51,982
B: FACILITIES CHARGE	409,795	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	103,452.7	$9.349	$967,179	$10.368	$1,072,597	$10.683	$1,105,185
Next 2553 kw	65,176.1	$7.297	$475,590	$8.093	$527,470	$8.338	$543,438
Next 2553 kw	51,833.5	$6.438	$333,704	$7.140	$370,091	$7.356	$381,287
Over 7659 kw	119,041.5	$4.956	$589,970	$5.496	$654,252	$5.663	$674,132
	339,504		$2,366,443		$2,624,411		$2,704,042
D: ENERGY CHARGE							
0-180 hrs use per month	61,110,675.8	$0.07302	$4,462,302	$0.08125	$4,964,998	$0.08344	$5,099,075
181-360 hrs use per month	56,237,416.4	$0.04656	$2,618,414	$0.05191	$2,919,060	$0.05037	$2,832,679
361+ hrs use per month	63,361,711.2	$0.02431	$1,540,323	$0.02709	$1,716,659	$0.02431	$1,540,323
	180,709,803		$8,621,039		$9,600,717		$9,472,077
E: REACTIVE DEMAND ADJUSTMENT	3,808	$0.930	$3,541	$1.031	$3,926	$1.063	$4,048
REVENUE			$11,036,515		$12,279,507		$12,232,149
c/kwh			$0.0611		$0.0680		$0.0677
OVERALL CHANGE (%)	*8256*				11.26%		10.83%
used to reference avg customer	*4,394,555*						
ANNUAL	285,957,695		$18,603,108		$20,694,238		$20,645,416
c/kwh			$0.0651		$0.0724		$0.0722
OVERALL CHANGE (%)					11.24%		10.98%
Winter Price Below Summer (SUM-WIN)/SUM			15.1%		15.0%		15.3%

MO LARGE POWER
TRANSMISSION VOLTAGE - OFF PEAK - LPSTRO

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

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
	-	1,106.30	$0	1,226.93	$0	1,264.12	$0
	-	-	$0	-	$0	-	$0
	-	-	$0	-	$0	-	$0
	-		$0		$0		$0
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	-	$13.757	$0	$15.257	$0	$15.719	$0
Next 2553 kw	-	$11.002	$0	$12.202	$0	$12.571	$0
Next 2553 kw	-	$9.214	$0	$10.219	$0	$10.528	$0
Over 7659 kw	-	$6.729	$0	$7.463	$0	$7.689	$0
	-		$0		$0		$0
D: ENERGY CHARGE							
0-180 hrs use per month	-	$0.08615	$0	$0.09581	$0	$0.09844	$0
181-360 hrs use per month	-	$0.05120	$0	$0.05705	$0	$0.05539	$0
361+ hrs use per month	-	$0.02456	$0	$0.02737	$0	$0.02456	$0
	-		$0		$0		$0
E: REACTIVE DEMAND ADJUSTMENT	-	$0.930	$0	$1.031	$0	$1.063	$0
REVENUE			$0		$0		$0
c/kwh			#DIV/0!		#DIV/0!		#DIV/0!
OVERALL CHANGE (%)	*#DIV/0!*				#DIV/0!		#DIV/0!
used to reference avg customer	*#DIV/0!*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
	-	1,106.30	$0	1,226.93	$0	1,264.12	$0
	-	-	$0	-	$0	-	$0
	-	-	$0	-	$0	-	$0
	-		$0		$0		$0
B: FACILITIES CHARGE	-	$0.000	$0	$0.000	$0	$0.000	$0
C: DEMAND CHARGE							
First 2553 kw	-	$9.349	$0	$10.368	$0	$10.683	$0
Next 2553 kw	-	$7.297	$0	$8.093	$0	$8.338	$0
Next 2553 kw	-	$6.438	$0	$7.140	$0	$7.356	$0
Over 7659 kw	-	$4.956	$0	$5.496	$0	$5.663	$0
	-		$0		$0		$0
D: ENERGY CHARGE							
0-180 hrs use per month	-	$0.07302	$0	$0.08125	$0	$0.08344	$0
181-360 hrs use per month	-	$0.04656	$0	$0.05191	$0	$0.05037	$0
361+ hrs use per month	-	$0.02431	$0	$0.02709	$0	$0.02431	$0
	-		$0		$0		$0
E: REACTIVE DEMAND ADJUSTMENT	-	$0.930	$0	$1.031	$0	$1.063	$0
REVENUE			$0		$0		$0
c/kwh			#DIV/0!		#DIV/0!		#DIV/0!
OVERALL CHANGE (%)	*#DIV/0!*				#DIV/0!		#DIV/0!
used to reference avg customer	*#DIV/0!*						
ADJUSTMENT			$0		$0		$0
ANNUAL	-		$0		$0		$0
c/kwh			#DIV/0!		#DIV/0!		#DIV/0!
OVERALL CHANGE (%)					#DIV/0!		#DIV/0!
Winter Price Below Summer (SUM-WIN)/SUM			#DIV/0!		#DIV/0!		#DIV/0!

MO LARGE POWER
PRIMARY VOLTAGE, OFF PEAK - LPGSPO

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

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	-	$1,106.30	$0	$1,226.93	$0	$1,264.12	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-		$0		$0		$0
B: FACILITIES CHARGE	-	$3.071	$0	$3.406	$0	$3.509	$0
C: DEMAND CHARGE							
First 2500 kw	-	$14.044	$0	$15.576	$0	$16.047	$0
Next 2500 kw	-	$11.236	$0	$12.461	$0	$12.839	$0
Next 2500 kw	-	$9.411	$0	$10.437	$0	$10.754	$0
Over 7500 kw	-	$6.871	$0	$7.620	$0	$7.851	$0
	-		$0		$0		$0
D: ENERGY CHARGE							
0-180 hrs use per month	-	$0.08794	$0	$0.09780	$0	$0.10049	$0
181-360 hrs use per month	-	$0.05228	$0	$0.05825	$0	$0.05656	$0
361+ hrs use per month	-	$0.02507	$0	$0.02798	$0	$0.02507	$0
	-		$0		$0		$0
E: REACTIVE DEMAND ADJUSTMENT	-	$0.930	$0	$1.031	$0	$1.063	$0
F: MANUAL BILL USAGE/REVENUE	-				$0		$0
REVENUE			$0		$0		$0
c/kwh			#DIV/0!		#DIV/0!		#DIV/0!
OVERALL CHANGE (%)	*#DIV/0!*				#DIV/0!		#DIV/0!
used to reference avg customer	*#DIV/0!*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
	-	$1,106.30	$0	$1,226.93	$0	$1,264.12	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-	$0.00	$0	$0.00	$0	$0.00	$0
	-		$0		$0		$0
B: FACILITIES CHARGE	-	$3.071	$0	$3.406	$0	$3.509	$0
C: DEMAND CHARGE							
First 2500 kw	-	$9.545	$0	$10.587	$0	$10.907	$0
Next 2500 kw	-	$7.451	$0	$8.263	$0	$8.514	$0
Next 2500 kw	-	$6.572	$0	$7.289	$0	$7.510	$0
Over 7500 kw	-	$5.061	$0	$5.613	$0	$5.783	$0
	-		$0		$0		$0
D: ENERGY CHARGE							
0-180 hrs use per month	-	$0.07456	$0	$0.08296	$0	$0.08520	$0
181-360 hrs use per month	-	$0.04754	$0	$0.05299	$0	$0.05143	$0
361+ hrs use per month	-	$0.02484	$0	$0.02773	$0	$0.02484	$0
	-		$0		$0		$0
E: REACTIVE DEMAND ADJUSTMENT	-	$0.930	$0	$1.031	$0	$1.063	$0
F: MANUAL BILL USAGE/REVENUE	-				$0		$0
REVENUE			$0		$0		$0
c/kwh			#DIV/0!		#DIV/0!		#DIV/0!
OVERALL CHANGE (%)	*#DIV/0!*				#DIV/0!		#DIV/0!
used to reference avg customer	*#DIV/0!*						

ANNUAL	-	$0	$0	$0
c/kwh		#DIV/0!	#DIV/0!	#DIV/0!
OVERALL CHANGE (%)			#DIV/0!	#DIV/0!
Winter Price Below Summer (SUM-WIN)/SUM		#DIV/0!	#DIV/0!	#DIV/0!

SUMMER TOTAL (ALL RATES)	734,215,441	$58,496,827	$65,044,215	$65,172,093
WINTER TOTAL (ALL RATES)	1,274,940,847	$87,144,234	$96,941,363	$96,813,587
Manual Bills	27,073,817	$2,403,168	$2,665,215	$2,665,215
GRAND TOTAL (ANNUAL - ALL RATES)	**2,036,230,106**	**$148,044,229**	**$164,650,793**	**$164,650,895**
c/kwh Summer		**$0.0797**	**$0.0886**	**$0.0888**
c/kwh Winter		**$0.0684**	**$0.0760**	**$0.0759**
c/kwh Annual		**$0.0727**	**$0.0809**	**$0.0809**
Winter Price Below Summer (SUM-WIN)/SUM		**14.2%**	**14.2%**	**14.6%**
OVERALL CHANGE (%)			**11.217%**	**11.217%**

KCP&L-MO LARGE GENERAL SERVICE
SUMMARY OF PROPOSED SCENARIOS
ER-2016-0285 Direct Filing
* Equal Percent Increase to All Rate Components except
Energy 181-360 Hours Use -- use 75% of Average Increase
Energy over 360 Hours Use -- use Current Rates
Rates Designed to Achieve KCP&L's Proposed Increase.

INPUT FOR MODEL			
Cust Chg	Current Rates	Company Proposed Rates	Rate Design Rates *
A: CUSTOMER CHARGE			
0-24 KW	114.38	126.85	129.73
25-199 KW	114.38	126.85	129.73
200-999 KW	114.38	126.85	129.73
1001+ KW	976.54	1,083.02	1,107.60
Separately Metered Space Heat	2.62	2.91	2.97
B: FACILITIES CHARGE			
SECONDARY:	3.272	3.629	3.711
PRIMARY:	2.713	3.009	3.077
C: DEMAND CHARGE			
SECONDARY-SUMMER:	6.534	7.246	7.411
SECONDARY-WINTER	3.516	3.899	3.988
PRIMARY-SUMMER	6.386	7.082	7.243
PRIMARY-WINTER	3.436	3.811	3.897
SECONDARY-WINTER - ELEC ONLY	3.256	3.611	3.693
PRIMARY-WINTER - ELEC ONLY	3.179	3.526	3.606
D: ENERGY CHARGE			
SECONDARY-SUMMER:			
0-180 hrs use per month	0.09596	0.10669	0.10884
181-360 hrs use per month	0.06615	0.07363	0.07156
361+ hrs use per month	0.04260	0.04736	0.04260
SECONDARY-WINTER:			
0-180 hrs use per month	0.08818	0.09807	0.10001
181-360 hrs use per month	0.05085	0.05666	0.05501
361+ hrs use per month	0.03580	0.03981	0.03580
PRIMARY-SUMMER:			
0-180 hrs use per month	0.09381	0.10431	0.10640
181-360 hrs use per month	0.06457	0.07188	0.06985
361+ hrs use per month	0.04160	0.04614	0.04160
PRIMARY-WINTER:			
0-180 hrs use per month	0.08617	0.09584	0.09773
181-360 hrs use per month	0.04963	0.05531	0.05369
361+ hrs use per month	0.03510	0.03904	0.03510
SECONDARY-WINTER - ALL ELECTRIC			
0-180 hrs use per month	0.08479	0.09431	0.09617
181-360 hrs use per month	0.04549	0.05072	0.04921
361+ hrs use per month	0.03551	0.03949	0.03551
PRIMARY-WINTER - ALL ELECTRIC			
0-180 hrs use per month	0.08301	0.09233	0.09415
181-360 hrs use per month	0.04449	0.04961	0.04813
361+ hrs use per month	0.03483	0.03874	0.03483
E: SEPARATELY METERED S/H-WINTER			
SECONDARY	0.05932	0.06579	0.07296
PRIMARY			
F: REACTIVE DEMAND ADJUSTMENT	0.821	0.91052	1.00981
LGS Secondary	100.00%	11.16%	11.22%
LGS Primary	100.00%	11.17%	11.11%
LGS Overall Change (!)	0.00%	11.16%	11.20%
LGA Secondary	100.00%	11.16%	11.06%
LGA Primary	100.00%	11.18%	11.07%
LGA Winter Energy Overall Change		10.15%	9.43%
LGA Overall Change (!)	0.00%	11.16%	11.05%
Winter Price Below Summer (SUM-WIN)/SUM	28.0%	17.5%	17.4%
Overall Change		11.168%	11.21%
Revenue	$189,041,225	$210,135,380	$210,229,067
Change in Revenue			$21,187,842
Proposed change per Revenue Summary			$21,094,197
			$93,645

MO LARGE GENERAL
SECONDARY VOLTAGE - (LGSS: LGSE & LGSH)

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

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	2,449	$114.38	$280,086	$126.85	$310,622	$129.73	$317,674
1001+ KW	128	$976.54	$125,186	$1,083.02	$138,836	$1,107.60	$141,987
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	2,577		$405,272		$449,458		$459,661
B: FACILITIES CHARGE	1,193,226.5	$3.272	$3,904,237	$3.629	$4,330,356	$3.711	$4,428,064
C: DEMAND CHARGE	1,049,260.1	$6.534	$6,855,866	$7.246	$7,602,939	$7.411	$7,776,067
D: ENERGY CHARGE							
0-180 hrs use per month	180,856,968.9	$0.09596	$17,355,035	$0.10669	$19,294,908	$0.10884	$19,684,472
181-360 hrs use per month	145,624,099.7	$0.06615	$9,633,034	$0.07363	$10,721,721	$0.07156	$10,420,861
361+ hrs use per month	78,431,698.9	$0.04260	$3,341,190	$0.04736	$3,714,786	$0.04260	$3,341,190
	404,912,767		$30,329,259		$33,731,415		$33,446,523
E: SEPARATELY METERED SPACE HEAT	-	$0.05932	$0	$0.06579	$0	$0.07296	$0
F: REACTIVE DEMAND ADJUSTMENT	4,315.1	$0.821	$3,543	$0.911	$3,929	$1.010	$4,357
MANUAL BILLS	2,975,507		$269,262		$298,623		$298,623
REVENUE			$41,767,440		$46,416,721		$46,413,296
c/kwh			$0.1032		$0.1146		$0.1146
FLUCTUATION (%)					11.13%		11.12%
used to reference avg customer	*158,285*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	129.73	$0
200-999 KW	4,782	$114.38	$546,918	$126.85	$606,545	129.73	$620,316
1001+ KW	237	$976.54	$231,733	$1,083.02	$257,000	1,107.60	$262,833
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	2.97	$0
	5,019		$778,651		$863,545		$883,149
B: FACILITIES CHARGE	2,306,404.6	$3.272	$7,546,556	$3.629	$8,370,207	$3.711	$8,559,067
C: DEMAND CHARGE	1,880,583.6	$3.516	$6,612,132	$3.899	$7,332,396	$3.988	$7,499,767
D: ENERGY CHARGE							
0-180 hrs use per month	314,182,740.5	$0.08818	$27,704,634	$0.09807	$30,810,647	$0.10001	$31,421,416
181-360 hrs use per month	244,021,383.2	$0.05085	$12,408,487	$0.05666	$13,825,277	$0.05501	$13,423,616
361+ hrs use per month	129,461,151.1	$0.03580	$4,634,709	$0.03981	$5,154,278	$0.03580	$4,634,709
	687,665,275		$44,747,831		$49,790,203		$49,479,741
E: SEPARATELY METERED SPACE HEAT	-	$0.05932	$0	$0.06579	$0	$0.07296	$0
F: REACTIVE DEMAND ADJUSTMENT	12,061.2	$0.821	$9,902	$0.911	$10,982	$1.010	$12,180
MANUAL BILLS	5,066,892.5		$458,518		$508,516		$508,516
REVENUE			$60,153,590		$66,875,849		$66,942,421
c/kwh			$0.0875		$0.0973		$0.0973
FLUCTUATION (%)					11.18%		11.29%
used to reference avg customer	*138,025*						

	BILLING UNITS	PRESENT RATES Revenue	PROPOSED RATES Revenue	RATE DESIGN RATES* Revenue
ANNUAL ENERGY/REVENUE	1,100,620,441	$101,921,030	$113,292,570	$113,355,717
c/kwh		$0.0926	$0.1029	$0.1030
FLUCTUATION (%)			11.16%	11.22%
Winter Price Below Summer (SUM-WIN)/SUM		15.2%	15.2%	15.1%

MO LARGE GENERAL
PRIMARY VOLTAGE - LGSP (LGSF and LGSG)

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

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	214	$114.38	$24,457	$126.85	$27,123	$129.73	$27,739
1001+ KW	87	$976.54	$84,649	$1,083.02	$93,878	$1,107.60	$96,009
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	301		$109,105		$121,001		$123,748
B: FACILITIES CHARGE	268,547.9	$2.713	$728,570	$3.009	$808,061	$3.077	$826,322
C: DEMAND CHARGE	233,176.7	$6.386	$1,489,066	$7.082	$1,651,357	$7.243	$1,688,899
D: ENERGY CHARGE							
0-180 hrs use per month	42,016,341.2	$0.09381	$3,941,553	$0.10431	$4,382,557	$0.10640	$4,470,539
181-360 hrs use per month	37,669,992.8	$0.06457	$2,432,351	$0.07188	$2,707,569	$0.06985	$2,631,249
361+ hrs use per month	17,209,704.7	$0.04160	$715,924	$0.04614	$794,056	$0.04160	$715,924
	96,896,039		$7,089,828		$7,884,181		$7,817,711
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	17,238	$0.821	$14,152	$0.911	$15,695	$1.010	$17,407
MANUAL BILLS	1,907,993.8		$214,199		$237,556		$237,556
REVENUE			$9,644,921		$10,717,852		$10,711,642
c/kwh			$0.0995		$0.1106		$0.1105
FLUCTUATION (%)					11.12%		11.06%
used to reference avg customer	*322,447*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	415	$114.38	$47,444	$126.85	$52,616	$129.73	$53,811
1001+ KW	163	$976.54	$159,252	$1,083.02	$176,616	$1,107.60	$180,625
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	578		$206,696		$229,232		$234,436
B: FACILITIES CHARGE	527,905.0	$2.713	$1,432,206	$3.009	$1,588,466	$3.077	$1,624,364
C: DEMAND CHARGE	416,314.6	$3.436	$1,430,457	$3.811	$1,586,575	$3.897	$1,622,378
D: ENERGY CHARGE							
0-180 hrs use per month	74,969,119.2	$0.08617	$6,460,089	$0.09584	$7,184,741	$0.09773	$7,326,732
181-360 hrs use per month	64,941,277.8	$0.04963	$3,223,036	$0.05531	$3,591,643	$0.05369	$3,486,697
361+ hrs use per month	31,323,124.0	$0.03510	$1,099,442	$0.03904	$1,222,959	$0.03510	$1,099,442
	171,233,521		$10,782,566		$11,999,343		$11,912,871
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	22,651	$0.821	$18,596	$0.911	$20,624	$1.010	$22,873
MANUAL BILLS	3,331,706.3		$374,030		$414,816		$414,816
REVENUE			$14,244,552		$15,839,056		$15,831,737
c/kwh			$0.0832		$0.0925		$0.0925
FLUCTUATION (%)					11.19%		11.14%
used to reference avg customer	*296,319*						

ANNUAL ENERGY/REVENUE	273,369,260		$23,889,473		$26,556,908		$26,543,379
c/kwh			$0.0874		$0.0971		$0.0971
FLUCTUATION (%)					11.17%		11.11%
Winter Price Below Summer (SUM-WIN)/SUM			16.4%		16.4%		16.4%

SUMMER TOTAL (LGSS/LGSP)	501,808,806	$51,412,361	$57,134,572	$57,124,939
WINTER TOTAL (LGSS/LGSP)	858,898,796	$74,398,142	$82,714,905	$82,774,158
GRAND TOTAL (ANNUAL-LGSS/LGSP)	**1,373,989,701**	**$125,810,503**	**$139,849,477**	**$139,899,097**
c/kwh		**$0.0916**	**$0.1018**	**$0.1018**
OVERAL CHANGE (%)			**11.16%**	**11.20%**

MO LARGE GENERAL
SECONDARY VOLTAGE, ALL ELECTRIC (ONE METER) - (LGS SA: LGAE & LGAH)

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

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	538	$114.38	$61,484	$126.85	$68,187	$129.73	$69,735
1001+ KW	162	$976.54	$158,477	$1,083.02	$175,757	$1,107.60	$179,746
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	700		$219,961		$243,944		$249,481
B: FACILITIES CHARGE	530,866.8	$3.272	$1,736,996	$3.629	$1,926,577	$3.711	$1,970,047
C: DEMAND CHARGE	383,988.2	$6.534	$2,508,979	$7.246	$2,782,378	$7.411	$2,845,736
D: ENERGY CHARGE							
0-180 hrs use per month	67,666,714.2	$0.09596	$6,493,298	$0.10669	$7,219,092	$0.10884	$7,364,845
181-360 hrs use per month	61,518,828.9	$0.06615	$4,069,471	$0.07363	$4,529,386	$0.07156	$4,402,287
361+ hrs use per month	34,638,442.1	$0.04260	$1,475,598	$0.04736	$1,640,592	$0.04260	$1,475,598
	163,823,985		$12,038,366		$13,389,069		$13,242,730
E: SEPARATELY METERED SPACE HEAT	-	$0.05932	$0	$0.06579	$0	$0.07296	$0
F: REACTIVE DEMAND ADJUSTMENT	3,036	$0.821	$2,492	$0.911	$2,764	$1.010	$3,066
MANUAL BILLS	13,249,144.3		$945,247		$1,048,319		$1,048,319
REVENUE			$17,452,042		$19,393,052		$19,359,379
c/kwh			$0.1065		$0.1184		$0.1182
FLUCTUATION (%)					11.12%		10.93%
used to reference avg customer	*234,092*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	1,074	$114.38	$122,836	$126.85	$136,227	$129.73	$139,320
1001+ KW	322	$976.54	$314,352	$1,083.02	$348,628	$1,107.60	$356,540
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	1,396		$437,187		$484,855		$495,861
B: FACILITIES CHARGE	1,050,206.9	$3.272	$3,436,277	$3.629	$3,811,321	$3.711	$3,897,318
C: DEMAND CHARGE	840,116.7	$3.256	$2,735,420	$3.611	$3,033,661	$3.693	$3,102,551
D: ENERGY CHARGE							
0-180 hrs use per month	148,163,108.7	$0.08479	$12,562,750	$0.09431	$13,972,671	$0.09617	$14,248,846
181-360 hrs use per month	128,795,850.4	$0.04549	$5,858,923	$0.05072	$6,532,011	$0.04921	$6,338,044
361+ hrs use per month	67,676,342.1	$0.03551	$2,403,187	$0.03949	$2,672,295	$0.03551	$2,403,187
	344,635,301		$20,824,860		$23,176,978		$22,990,077
E: SEPARATELY METERED SPACE HEAT	-	$0.05932	$0	$0.06579	$0	$0.07296	$0
F: REACTIVE DEMAND ADJUSTMENT	2,048	$0.821	$1,681	$0.911	$1,865	$1.010	$2,068
MANUAL BILLS	27,064,298.6		$1,931,623		$2,142,252		$2,142,252
REVENUE			$29,367,049		$32,650,933		$32,630,126
c/kwh			$0.0852		$0.0947		$0.0947
FLUCTUATION (%)					11.18%		11.11%
used to reference avg customer	*246,904*						
ANNUAL ENERGY/REVENUE	548,772,729		$46,819,091		$52,043,985		$51,989,506
c/kwh			$0.0853		$0.0948		$0.0947
FLUCTUATION (%)					11.16%		11.04%
Winter Price Below Summer (SUM-WIN)/SUM			20.0%		20.0%		19.9%

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

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

SUMMER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	18	$114.38	$2,068	$126.85	$2,294	$129.73	$2,346
1001+ KW	36	$976.54	$35,510	$1,083.02	$39,382	$1,107.60	$40,276
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	54		$37,579		$41,676		$42,622
B: FACILITIES CHARGE	166,883.8	$2.713	$452,756	$3.009	$502,153	$3.077	$513,501
C: DEMAND CHARGE	113,893.4	$6.386	$727,323	$7.082	$806,593	$7.243	$824,930
D: ENERGY CHARGE							
0-180 hrs use per month	20,477,205.6	$0.09381	$1,920,967	$0.10431	$2,135,896	$0.10640	$2,178,775
181-360 hrs use per month	17,665,622.8	$0.06457	$1,140,669	$0.07188	$1,269,734	$0.06985	$1,233,944
361+ hrs use per month	10,100,614.6	$0.04160	$420,186	$0.04614	$466,042	$0.04160	$420,186
	48,243,443		$3,481,821		$3,871,672		$3,832,904
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	5,655	$0.821	$4,643	$0.911	$5,149	$1.010	$5,711
REVENUE			$4,704,122		$5,227,244		$5,219,668
c/kwh			$0.0975		$0.1084		$0.1082
FLUCTUATION (%)					11.12%		10.96%
used to reference avg customer	*886,075*						

WINTER

	BILLING UNITS	PRESENT RATES		PROPOSED RATES		RATE DESIGN RATES*	
		Rate	Revenue	Rate	Revenue	Rate	Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	34	$114.38	$3,854	$126.85	$4,274	$129.73	$4,371
1001+ KW	73	$976.54	$71,142	$1,083.02	$78,899	$1,107.60	$80,690
Separately Metered Space Heat	-	$2.62	$0	$2.91	$0	$2.97	$0
	107		$74,996		$83,173		$85,061
B: FACILITIES CHARGE	325,730.1	$2.713	$883,706	$3.009	$980,122	$3.077	$1,002,272
C: DEMAND CHARGE	246,227.3	$3.179	$782,757	$3.526	$868,198	$3.606	$887,896
D: ENERGY CHARGE							
0-180 hrs use per month	44,223,233.3	$0.08301	$3,670,971	$0.09233	$4,082,955	$0.09415	$4,163,617
181-360 hrs use per month	36,232,568.3	$0.04449	$1,611,987	$0.04961	$1,797,353	$0.04813	$1,743,874
361+ hrs use per month	19,789,434.9	$0.03483	$689,266	$0.03874	$766,572	$0.03483	$689,266
	100,245,237		$5,972,224		$6,646,879		$6,596,757
E: SEPARATELY METERED SPACE HEAT	-	$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	6,174	$0.821	$5,068	$0.911	$5,621	$1.010	$6,234
ADJUSTMENT			$0		$0		$0
REVENUE			$7,718,750		$8,583,993		$8,578,219
c/kwh			$0.0770		$0.0856		$0.0856
FLUCTUATION (%)					11.21%		-0.07%
used to reference avg customer	*940,891*						
ANNUAL ENERGY/REVENUE	148,488,680		$12,422,872		$13,811,236		$13,797,887
c/kwh			$0.0837		$0.0930		$0.0929
FLUCTUATION (%)					11.18%		11.07%
Winter Price Below Summer (SUM-WIN)/SUM			21.0%		21.0%		20.9%

SUMMER TOTAL (LGSSA/LGSPA)	212,067,428	$22,156,164	$24,620,295	$24,579,047
WINTER TOTAL (LGSSA/LGSPA)	444,880,538	$37,085,799	$41,234,926	$41,208,345
GRAND TOTAL (ANNUAL-LGSSA/LGSPA)	**697,261,409**	**59,241,963**	**65,855,221**	**65,787,392**
c/kwh		**$0.0850**	**$0.0944**	**$0.0944**
OVERALL WINTER ENERGY CHANGE			**10.15%**	**9.43%**
OVERAL CHANGE (%)			**11.16%**	**11.05%**

MO LARGE GENERAL

SECONDARY VOLTAGE, SPACE HEAT (TWO METER) - (LGSSH: LGHE, LGHH, and LSHE)

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

SUMMER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	109	$114.38	$12,508	$126.85	$13,872	$129.73	$14,187
1001+ KW	12	$976.54	$11,449	$1,083.02	$12,697	$1,107.60	$12,985
Separately Metered Space Heat	121.1	$2.62	$317	$2.91	$352	$2.97	$360
	242		$24,274		$26,921		$27,531
B: FACILITIES CHARGE	57,138.9	$3.272	$186,959	$3.629	$207,364	$3.711	$212,043
C: DEMAND CHARGE	43,629.2	$6.534	$285,073	$7.246	$316,137	$7.411	$323,336
D: ENERGY CHARGE							
0-180 hrs use per month	7,490,829.5	$0.09596	$718,820	$0.10669	$799,167	$0.10884	$815,302
181-360 hrs use per month	5,035,752.4	$0.06615	$333,115	$0.07363	$370,762	$0.07156	$360,358
361+ hrs use per month	1,292,549.0	$0.04260	$55,063	$0.04736	$61,219	$0.04260	$55,063
	13,819,131		$1,106,998		$1,231,148		$1,230,723
E: SEPARATELY METERED SPACE HEAT		$0.00000	$0	$0.00000	$0	$0.00000	$0
F: REACTIVE DEMAND ADJUSTMENT	-	$0.821	$0	$0.911	$0	$1.010	$0
MANUAL BILLS					$0		$0
REVENUE			$1,603,303		$1,781,570		$1,793,633
c/kwh			$0.1160		$0.1289		$0.1298
FLUCTUATION (%)					11.12%		11.87%
used to reference avg customer	*57,067*						

WINTER

	BILLING UNITS	PRESENT RATES Rate	PRESENT RATES Revenue	PROPOSED RATES Rate	PROPOSED RATES Revenue	RATE DESIGN RATES* Rate	RATE DESIGN RATES* Revenue
A: CUSTOMER CHARGE							
0-24 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
25-199 KW	-	$114.38	$0	$126.85	$0	$129.73	$0
200-999 KW	205	$114.38	$23,435	$126.85	$25,990	$129.73	$26,580
1001+ KW	23	$976.54	$22,240	$1,083.02	$24,665	$1,107.60	$25,225
Separately Metered Space Heat	227.7	$2.62	$596	$2.91	$662	$2.97	$676
	455		$46,271		$51,317		$52,480
B: FACILITIES CHARGE	109,675.9	$3.272	$358,860	$3.629	$398,027	$3.711	$407,007
C: DEMAND CHARGE	86,227.9	$3.516	$303,177	$3.899	$336,203	$3.988	$343,877
D: ENERGY CHARGE							
0-180 hrs use per month	6,843,150.7	$0.08818	$603,429	$0.09807	$671,080	$0.10001	$684,384
181-360 hrs use per month	5,431,195.1	$0.05085	$276,176	$0.05666	$307,710	$0.05501	$298,770
361+ hrs use per month	2,247,654.2	$0.03580	$80,466	$0.03981	$89,487	$0.03580	$80,466
	14,522,000		$960,071		$1,068,277		$1,063,620
E: SEPARATELY METERED SPACE HEAT	12,088,289.5	$0.05932	$717,077	$0.06579	$795,289	$0.07296	$881,962
F: REACTIVE DEMAND ADJUSTMENT	-	$0.821	$0	$0.911	$0	$1.010	$0
MANUAL BILLS	-				$0		$0
REVENUE			$2,385,457		$2,649,111		$2,748,946
c/kwh			$0.0896		$0.0996		$0.1033
FLUCTUATION (%)					11.05%		15.24%
used to reference avg customer	*63,789*						
	53,098						
ANNUAL ENERGY/REVENUE	40,429,420		$3,988,760		$4,430,682		$4,542,578
c/kwh			$0.0987		$0.1096		$0.1124
FLUCTUATION (%)					11.08%		13.88%
Winter Price Below Summer (SUM-WIN)/SUM			22.7%		22.8%		20.4%

SUMMER TOTAL (ALL RATES)	727,695,365	$73,743,119	$81,951,939	$81,913,120
WINTER TOTAL (ALL RATES)	1,330,389,623	$111,105,226	$123,533,359	$123,665,865
MANUAL BILLS-CREDITS-ADJUSTMENTS	53,595,542	$4,192,881	$4,650,082	$4,650,082
GRAND TOTAL (ANNUAL - ALL RATES)	**2,111,680,530**	**$189,041,225**	**$210,135,380**	**$210,229,067**
c/kwh Summer		**$0.1013**	**$0.1126**	**$0.1126**
c/kwh Winter		**$0.0835**	**$0.0929**	**$0.0930**
c/kwh Annual		**$0.0895**	**$0.0995**	**$0.0996**
Winter Price Below Summer (SUM-WIN)/SUM		**17.6%**	**17.5%**	**17.4%**
OVERALL CHANGE (%)			**11.158%**	**11.21%**

KANSAS CITY POWER & LIGHT COMPANY
2016 Rate Case - Direct
Missouri Jurisdiction
Energy Losses by Rate and Voltage Level
TY 12/31/15; Update TBD; K&M 12/31/16

Line	Missouri Rate Group	Energy @ Meter (kWh) (1)	Energy @ Generator (kWh) (2)	Loss Factor (3)
1	LGSP	273,369,260	283,503,605	1.037072
2	LGSPA	148,488,680	153,993,452	1.037072
3	LGSPH	0	0	
4	LGSS	1,100,620,441	1,168,075,267	1.061288
5	LGSSA	548,772,729	582,405,912	1.061288
6	LGSSH	40,429,420	42,907,259	1.061288
7	TOTAL	2,111,680,530	2,230,885,495	
8	LPGSP	781,157,794	810,116,875	1.037072
9	LPGSPO	248,253,679	257,456,940	1.037072
10	LPGSS	393,338,392	417,445,315	1.061288
11	LPGSPO	0	0	
12	LPGSSS	327,522,546	335,654,276	1.024828
13	LPGSTR	131,293,816	133,348,695	1.015651
14	LPSTRO	154,663,879	157,084,524	1.015651
15	TOTAL	2,036,230,106	2,111,106,625	
16	MGSP	10,673,258	11,068,937	1.037072
17	MGSPA	266,952	276,848	1.037072
18	MGSPH	0	0	
19	MGSS	1,038,365,531	1,102,004,878	1.061288
20	MGSSA	107,418,943	114,002,436	1.061288
21	MGSSH	20,497,349	21,753,590	1.061288
22	TOTAL	1,177,222,033	1,249,106,688	
23	SGSP	1,289,201	1,336,994	1.037072
24	SGSPA	0	0	
25	SGSPH	0	0	
26	SGSPU	0	0	
27	SGSS	390,198,046	414,112,504	1.061288
28	SGSSA	13,316,158	14,132,279	1.061288
29	SGSSH	4,632,067	4,915,957	1.061288
30	SGSSU	7,442,454	7,898,587	1.061288
31	TOTAL	416,877,926	442,396,321	
32	RESA	1,829,258,691	1,941,370,298	1.061288
33	RESB	563,718,711	598,267,904	1.061288
34	RESC	144,846,151	153,723,482	1.061288
35	RTOD	501,235	531,955	1.061288
36	TOTAL	2,538,324,789	2,693,893,638	
37	Off Peak Ltg	646,391	686,007	1.061288
38	Other	84,585,393	89,769,463	1.061288
39	TOTAL NON-BF	85,231,784	90,455,470	
40	MO TOTALS	*8,365,567,167*	*8,817,844,237*	
	By Voltage Level:			
41	Secondary	6,288,588,103	6,674,003,091	1.061288
42	Primary	1,463,498,823	1,517,753,651	1.037072
43	Substation	327,522,546	335,654,276	1.024828
44	Transmission	285,957,695	290,433,219	1.015651
45	Total	*8,365,567,167*	*8,817,844,237*	

Source: KCPL Allocators MO Rev 6-17-16 Avg & Pk 4 CP.xls, Sales tab

Schedule MEB-COS-9

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Development of
Average and Excess Demand Allocator
Based on 2 Non-Coincident Peaks
For the Test Year Ended December 31, 2015

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak - kW	1,787,693						
2	Avg of 2 Highest Monthly NCP Values - kW	1,919,595	839,479	105,522	262,112	392,073	310,082	10,326
3	Energy Sales with Losses - MWh	8,817,844	2,693,894	442,396	1,249,107	2,230,885	2,111,107	90,455
4	Average Demand - kW	1,006,603	307,522	50,502	142,592	254,667	240,994	10,326
5	Average Demand - Percent	1.000000	0.305505	0.050171	0.141657	0.252997	0.239413	0.010258
6	Class Excess Demand - kW	912,992	531,957	55,021	119,520	137,406	69,088	-
7	Class Excess Demand - Percent	1.000000	0.582653	0.060264	0.130910	0.150501	0.075672	-
	Allocator:							
8	Annual Load Factor * Average Demand - Percent	0.563074	0.172022	0.028250	0.079763	0.142456	0.134807	0.005776
9	(1-LF) * Excess Demand - Percent	0.436926	0.254576	0.026331	0.057198	0.065758	0.033063	-
10	Average and Excess Demand Allocator	1.000000	0.426598	0.054581	0.136961	0.208214	0.167870	0.005776

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

System Annual Load Factor 56.31%
1 - Load Factor 43.69%

Source: KCPL Allocators MO Rev 6-17-16_BAI A&E 2 NCP.xls

KANSAS CITY POWER & LIGHT COMPANY
2016 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 12/31/15; Update TBD; K&M 12/31/16

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	837,233,404	315,251,522	55,236,249	121,694,450	188,383,024	146,155,580	10,512,579
0050	OTHER OPERATING REVENUE	250,855,503	77,654,765	12,651,827	35,500,169	63,039,157	59,420,596	2,588,990
0060	TOTAL OPERATING REVENUE	1,088,088,907	392,906,286	67,888,077	157,194,618	251,422,182	205,576,175	13,101,569
0070								
0080	OPERATING EXPENSES							
0090	FUEL	158,701,965	49,190,084	7,977,077	22,455,406	39,847,404	37,634,192	1,597,801
0100	PURCHASED POWER	222,730,875	68,045,349	11,174,536	31,551,320	56,350,176	53,324,669	2,284,824
0110	OTHER OPERATION & MAINTENANCE EXPENSES	306,891,041	151,082,335	19,155,746	36,995,553	53,069,106	43,012,742	3,575,558
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	127,861,126	59,847,526	7,693,561	17,735,964	23,754,440	17,567,866	1,261,769
0130	AMORTIZATION EXPENSES	20,874,322	9,556,311	1,228,385	2,878,596	3,998,017	2,989,922	223,090
0140	TAXES OTHER THAN INCOME TAXES	65,449,969	30,458,488	3,913,757	8,850,781	12,278,434	9,225,807	722,703
0150	CURRENT INCOME TAXES	29,136,031	(9,134,979)	4,022,240	8,431,241	15,462,582	9,510,904	844,042
0160	DEFERRED INCOME TAXES	13,528,201	6,304,118	807,666	1,845,600	2,537,595	1,883,714	149,508
0170	TOTAL ELECTRIC OPERATING EXPENSES	945,173,529	365,349,232	55,972,969	130,744,460	207,297,754	175,149,818	10,659,294
0180								
0190	NET ELECTRIC OPERATING INCOME	142,915,379	27,557,054	11,915,108	26,450,158	44,124,427	30,426,357	2,442,275
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,274,249,638	2,448,454,650	313,571,252	719,019,780	994,387,947	742,128,166	56,687,843
0230	LESS: ACCUM. PROV. FOR DEPREC	2,072,173,694	962,875,815	123,548,026	279,277,002	389,652,475	293,152,260	23,668,116
0240	NET PLANT	3,202,075,945	1,485,578,835	190,023,226	439,742,778	604,735,472	448,975,906	33,019,728
0250	PLUS:							
0260	CASH WORKING CAPITAL	(62,071,389)	(26,948,512)	(3,878,605)	(8,686,331)	(12,476,876)	(9,358,202)	(722,863)
0270	MATERIALS & SUPPLIES	59,031,048	26,528,384	3,405,951	8,125,513	11,571,406	8,847,002	552,792
0280	PREPAYMENTS	7,124,681	3,213,171	406,866	949,299	1,399,952	1,105,498	49,895
0290	FUEL INVENTORY	66,320,675	20,308,703	3,324,416	9,393,610	16,742,995	15,874,130	676,821
0300	REGULATORY ASSETS	74,763,183	30,003,202	4,105,451	10,408,928	16,480,124	13,135,114	630,364
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	1,667,781	921,050	119,681	234,735	235,189	114,509	42,618
0330	CUSTOMER DEPOSITS	4,020,118	2,138,954	1,507,973	315,716	53,293	4,181	0
0340	DEFERRED INCOME TAXES	729,963,824	338,869,686	43,398,718	99,513,384	137,624,739	102,711,618	7,845,680
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	35,319,134	10,790,165	1,771,981	5,003,192	8,935,624	8,455,860	362,312
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	0	0	0	0	0	0	0
0370	TOTAL RATE BASE	2,576,273,286	1,185,963,928	150,588,953	354,866,772	491,604,227	367,293,280	25,956,126
0380								
0390	RATE OF RETURN	5.547%	2.324%	7.912%	7.454%	8.976%	8.284%	9.409%
0400	RELATIVE RATE OF RETURN	1.00	0.42	1.43	1.34	1.62	1.49	1.70

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

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Development of
4 CP Demand Allocator
For the Test Year Ended December 31, 2015

Line	Description	Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	4 CP Demand - kW	1,676,808	680,919	95,533	239,403	357,736	303,200	17
2	4 CP Demand - Percent	1.000000	0.406081	0.056973	0.142773	0.213343	0.180820	0.000010

Source: KCPL Allocators MO Rev 6-17-16 Avg & Pk 4 CP.xls

KANSAS CITY POWER & LIGHT COMPANY
2016 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 12/31/15; Update TBD; K&M 12/31/16

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	837,233,404	315,251,522	55,236,249	121,694,450	188,383,024	146,155,580	10,512,579
0050	OTHER OPERATING REVENUE	250,855,503	77,583,358	12,660,155	35,520,396	63,057,011	59,465,663	2,568,922
0060	TOTAL OPERATING REVENUE	1,088,088,907	392,834,880	67,896,404	157,214,845	251,440,035	205,621,242	13,081,501
0070								
0080	OPERATING EXPENSES							
0090	FUEL	158,701,965	49,089,115	7,988,852	22,484,007	39,872,648	37,697,918	1,569,424
0100	PURCHASED POWER	222,730,875	68,045,349	11,174,536	31,551,320	56,350,176	53,324,669	2,284,824
0110	OTHER OPERATION & MAINTENANCE EXPENSES	306,891,041	147,511,134	19,572,220	38,007,154	53,961,990	45,266,654	2,571,890
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	127,861,126	58,014,087	7,907,376	18,255,315	24,212,843	18,725,014	746,491
0130	AMORTIZATION EXPENSES	20,874,322	9,234,377	1,265,929	2,969,789	4,078,508	3,193,107	132,612
0140	TAXES OTHER THAN INCOME TAXES	65,449,969	29,489,489	4,026,762	9,125,265	12,520,706	9,837,377	450,371
0150	CURRENT INCOME TAXES	29,136,031	(5,972,925)	3,653,482	7,535,538	14,671,995	7,515,221	1,732,721
0160	DEFERRED INCOME TAXES	13,528,201	6,106,503	830,712	1,901,577	2,587,004	2,008,436	93,969
0170	TOTAL ELECTRIC OPERATING EXPENSES	945,173,529	361,517,128	56,419,869	131,829,966	208,255,870	177,568,395	9,582,302
0180								
0190	NET ELECTRIC OPERATING INCOME	142,915,379	31,317,752	11,476,535	25,384,880	43,184,165	28,052,847	3,499,199
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,274,249,638	2,369,811,693	322,742,599	741,296,663	1,014,050,511	791,762,511	34,585,661
0230	LESS: ACCUM. PROV. FOR DEPREC	2,072,173,694	931,269,641	127,233,940	288,229,959	397,554,752	313,100,032	14,785,369
0240	NET PLANT	3,202,075,945	1,438,542,052	195,508,659	453,066,703	616,495,759	478,662,480	19,800,291
0250	PLUS:							
0260	CASH WORKING CAPITAL	(62,071,389)	(26,363,959)	(3,946,775)	(8,851,915)	(12,623,028)	(9,727,134)	(558,578)
0270	MATERIALS & SUPPLIES	59,031,048	25,536,968	3,521,570	8,406,347	11,819,283	9,472,720	274,160
0280	PREPAYMENTS	7,124,681	3,082,653	422,087	986,271	1,432,585	1,187,873	13,214
0290	FUEL INVENTORY	66,320,675	20,308,703	3,324,416	9,393,610	16,742,995	15,874,130	676,821
0300	REGULATORY ASSETS	74,763,183	29,197,686	4,199,390	10,637,103	16,681,522	13,643,504	403,978
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	1,667,781	921,050	119,681	234,735	235,189	114,509	42,618
0330	CUSTOMER DEPOSITS	4,020,118	2,138,954	1,507,973	315,716	53,293	4,181	0
0340	DEFERRED INCOME TAXES	729,963,824	327,985,386	44,668,045	102,596,537	140,346,066	109,581,084	4,786,706
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	35,319,134	10,790,165	1,771,981	5,003,192	8,935,624	8,455,860	362,312
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	0	0	0	0	0	0	0
0370	TOTAL RATE BASE	2,576,273,286	1,148,468,548	154,961,667	365,487,941	500,978,942	390,957,938	15,418,250
0380								
0390	RATE OF RETURN	5.547%	2.727%	7.406%	6.945%	8.620%	7.175%	22.695%
0400	RELATIVE RATE OF RETURN	1.00	0.49	1.34	1.25	1.55	1.29	4.09

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