Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Issue:	Cost of Service, Revenue Allocation and Rate Design
Sponsoring Parties:	Ford Motor Company, Praxair, Inc. and Missouri Industrial Energy Consumers
Case No.:	ER-2006-0314

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan	**)**	**Case No. ER-2006-0314**

Direct Testimony and Schedules of

Maurice Brubaker
on Cost of Service, Revenue
Allocation and Rate Design

On Behalf of

Ford Motor Company
Praxair, Inc. and
Missouri Industrial Energy Consumers

August 22, 2006

BAI
BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

Project 8544

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan	**Case No. ER-2006-0314**

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 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Ford Motor Company, Praxair, Inc. and Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony on rate design issues which was prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2006-0314.

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

M S Brubaker
Maurice Brubaker

Subscribed and sworn to before this 21st day of August 2006.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2008

Carol Schulz
Notary Public

My Commission Expires February 26, 2008.

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<u>Direct Testimony of Maurice Brubaker</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A.

Q ON WHOSE BEHALF ARE YOU PRESENTING THIS DIRECT TESTIMONY ON REVENUE REQUIREMENT ISSUES?

A This testimony is presented on behalf of Ford Motor Company, Praxair, Inc. and the Missouri Industrial Energy Consumers (MIEC).

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of electric system class cost of service studies for Kansas City Power & Light Company (KCPL), to explain how they should be used, and to recommend an adjustment to class revenues that will move rates closer to costs, giving due consideration to impacts on customers.

Q HOW IS YOUR TESTIMONY ORGANIZED?

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

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

Finally, I present the results of the detailed cost of service analysis for KCPL. This cost study indicates the degree to which individual customer class revenues should be increased or decreased to put them in line with the cost incurred in providing the service to the respective classes. This analysis and interpretation is then followed by recommendations with respect to the alignment of class revenues with class costs based on the results of this class cost of service study.

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 most important guideline for establishing the level of rates charged to customers.

2. KCPL exhibits significant summer peak demands.

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. For KCPL's generation and transmission system, I recommend using an A&E demand methodology. Specifically, it is a three non-coincident peak A&E method which uses class peak demands from the three summer peak months and class annual energy consumption.

5. 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. KCPL's Average and Peak method is not explained or supported, and is wholly inappropriate because it gives far too much weighting to energy consumption.

6. KCPL's study has several other deficiencies including a failure to account for losses from the customer's meter to the generation and transmission system, use of an inappropriate allocation factor for the primary distribution system and use of an inappropriate allocation factor for a few of the administrative and general expense accounts.

7. Even KCPL's flawed cost of service study shows that all non-residential customer classes, including the Large Power Class, are providing revenues well in excess of cost of service.

8. A more reasonable cost of service study, which I present and summarize on Schedule 4, shows even greater differences between revenues and costs and an even greater need for adjusting interclass revenues.

9. Other reasonable cost of service studies, shown on my Schedules 5, 6 and 7, show a similar result.

10. KCPL's proposal not to recognize differences in class cost of service and not to attempt to correct these disparities is unreasonable.

11. KCPL's across-the-board allocation does not maintain the status quo, but would cause inter-class subsidies to increase.

12. It has been over ten years since KCPL did a class cost of service study. Waiting an additional four or five years (until Iatan 2 is in service) as KCPL proposes before attempting to correct interclass disparities is unreasonable.

13. We should start to address interclass disparities in this case. While it will take a period of time to correct these disparities, it would be wrong not to begin the process now. Postponing the movements towards cost of service will only make it more difficult and create larger impacts later.

14. Interclass revenue allocations should be designed so as to move classes closer to cost, while mitigating impacts on those customer classes who are below cost of service and who would receive large increases if moved all the way to cost.

15. My Schedule 9 shows an allocation approach which gives consideration to existing interclass disparities and which recognizes impacts on customer classes by capping the increase to the residential class at a level that considers both the interclass disparity and the level of overall increase that KCPL may receive.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

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

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

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

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

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

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

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, space conditioning, 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 4,000 megawatts (MW) of electricity, the utility must have at least 4,000 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 heating and air conditioning systems heat and cool our homes, schools, offices, and factories.

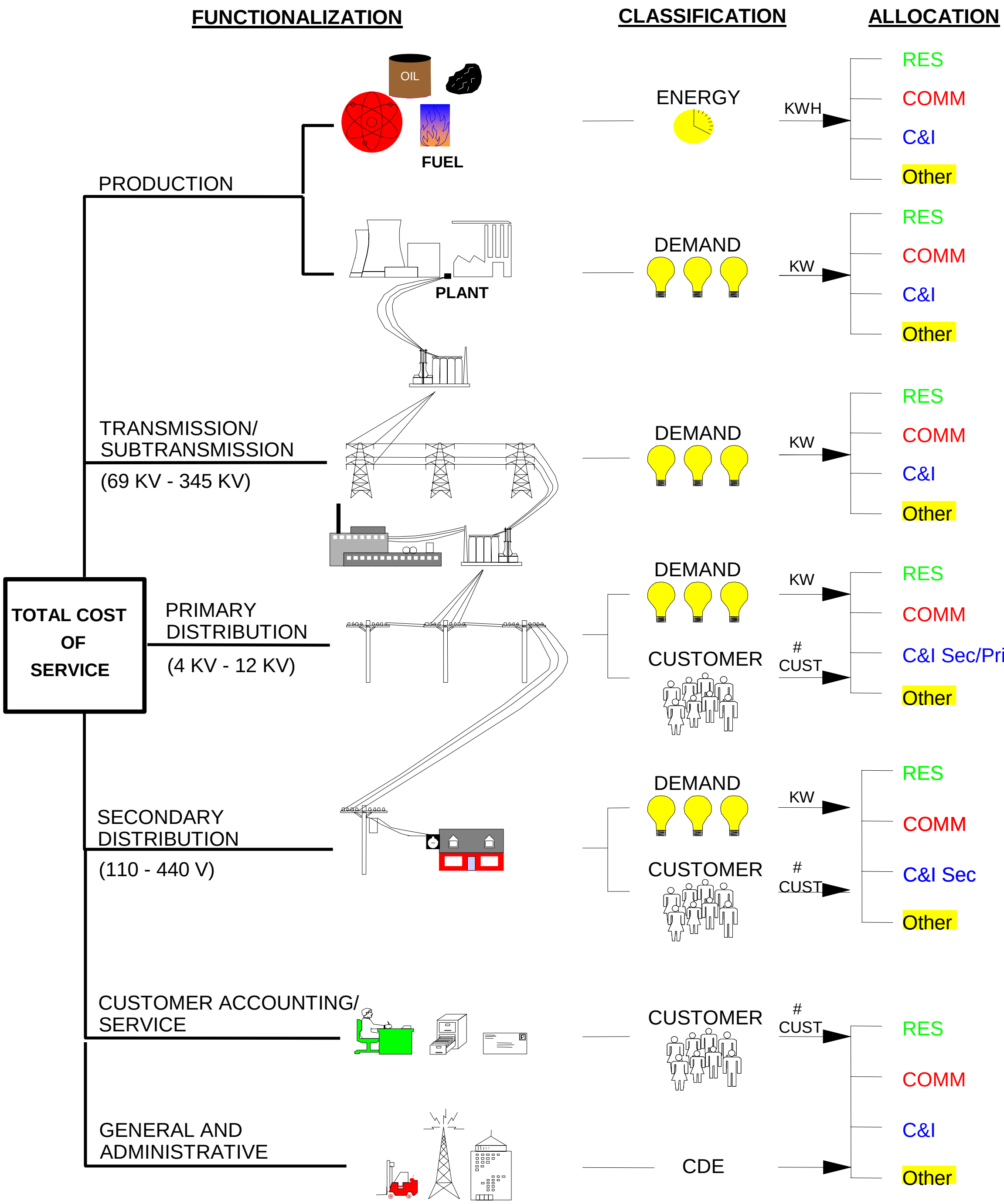
Satisfying customers' demand for electricity over time–providing **energy**–is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kilowatthours. To see one reason why this isn't so, consider 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 still 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 tomatoes producers and distributors, 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 kilowatthour) 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 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 (34,500 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 110/220 volts used to serve homes, barber shops 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 kilowatthour at home you're not only buying the energy itself but also the <u>service</u> of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like Large Power service customers–pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment.)

<u>Classification</u>

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 <u>peak</u> rate of usage during the year. If the utility anticipates a peak demand of 4,000 megawatts – 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 <u>peak</u> 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 expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kilowatthours generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned–and therefore the amount of fuel expense–is closely related to the amount of energy (number of kilowatthours) 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 a third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

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

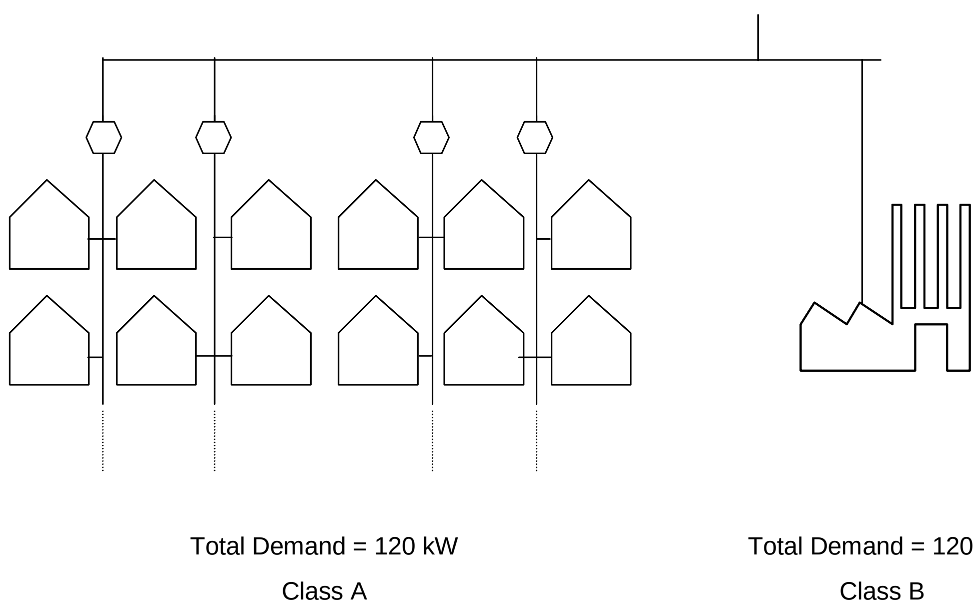
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), even though 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 also 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 kilowatthour (kWh). However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kilowatts (kW), than Customer 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.

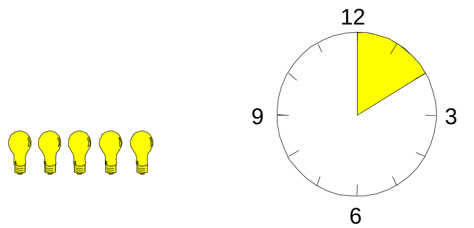
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

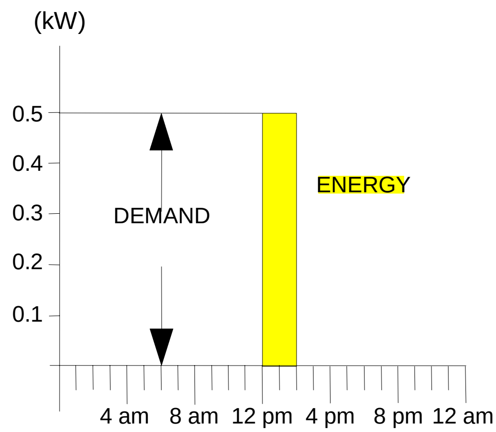
A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kilowatthours used 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

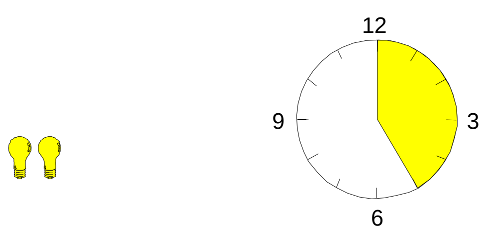


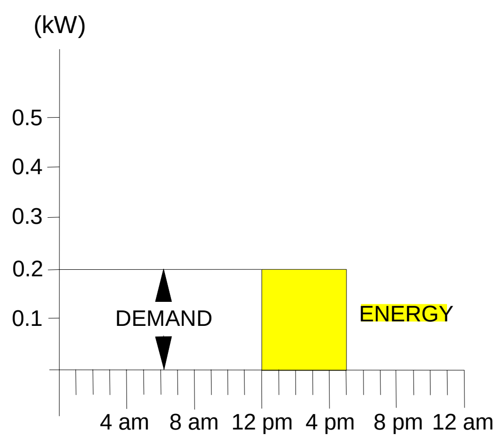


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

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 kilowatthour basis, than a customer with a low load factor, irrespective of size.

Consider also the analogy of a rental car which costs $40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be $2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the <u>average total</u> cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kilowatthour 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 industries generally have higher load factors than Residential or General Service customers, they are less costly to serve on a per-kilowatthour 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. The energy allocators for KCPL's retail customers are shown in Table 1.

TABLE 1
Energy Allocation Factor

Rate Class	Energy Generated (MWh) (1)	Allocation Factor (2)
Residential	2,664,695	29.73%
Small GS	486,738	5.43%
Medium GS	1,047,615	11.69%
Large GS	2,276,089	25.39%
Large Power	2,401,479	26.79%
Lighting	86,671	0.97%
Total	8,963,287	100.00%

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 shows the calculation of the factor for KCPL. (The selection and derivation of this factor is discussed in more detail beginning at page 18.)

Q DO THE RELATIONSHIPS BETWEEN THE ENERGY ALLOCATION FACTORS AND THE DEMAND ALLOCATION FACTORS TELL US ANYTHING ABOUT CLASS LOAD FACTOR?

A Yes. Recall that load factor is a measure of the consistency or uniformity of use of demand. Accordingly, customer classes' whose energy allocation factor is a larger percentage than their demand allocation have an above-average load factor, while customers whose demand allocation factor is higher than their energy allocation factor have a below-average load factor.

These relationships are merely the result of differences in how electricity is used. In the case of KCPL (as is true for essentially every other utility) the large GS and Large Power classes have above-average load factors, while the Residential and small GS customers have below-average load factors.

TABLE 2
Demand Allocation Factor
Production System

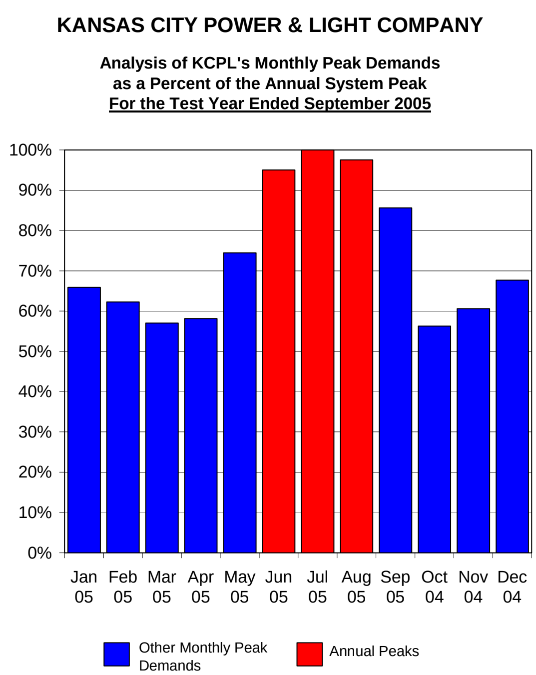
Rate Class	Production A&E (MW) (1)	Allocation Factor (2)
Residential	841	41.94%
Small GS	116	5.79%
Medium GS	239	11.90%
Large GS	426	21.22%
Large Power	385	19.16%
Lighting	---	0.00%
Total	2,007	100.00%

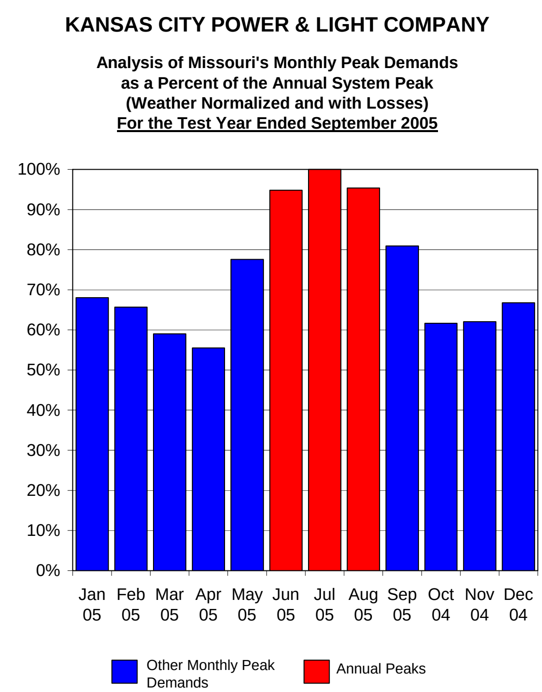
Utility System Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed, or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for total KCPL and Missouri KCPL are shown on Schedule 1, pages 1 and 2, respectively. For convenience, they are also shown here as Figure 4.

Figure 4





This shows the monthly system peak demands for the test year used in the study. The red bars show the months in which the highest peaks occurred.

This analysis clearly shows that summer peaks dominate the KCPL system. (This same information is presented in tabular form on Schedule 2.)

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' 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 cost. 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 coincident with the peaks selected for allocation. In the case of KCPL, this would be the months of June, July and August.

Q WHAT IS THE A&E METHOD?

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

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

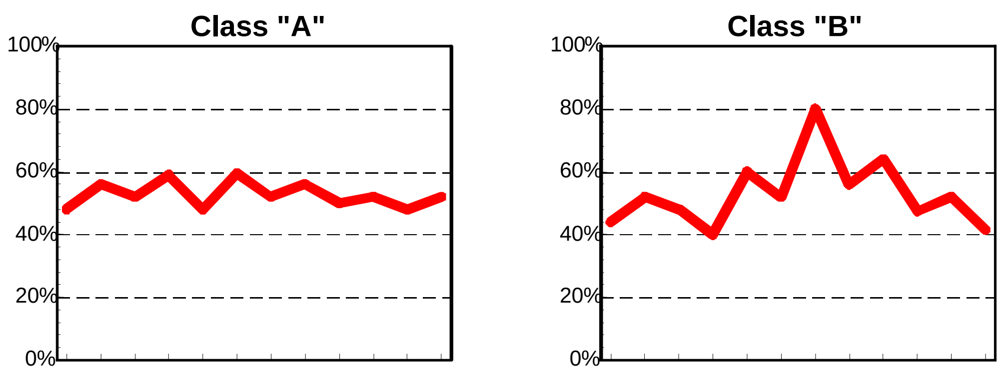
[1] NARUC Electric Utility Cost Allocation Manual, 1992, page 81.

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

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

Figure 5

Load Patterns



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[2] than Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment, resulting in higher maintenance cost.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in

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

proportion to the "peakiness" of the customer classes (measured by the class excess demands).

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

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

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

Schedule 3 shows the derivation of the demand allocation factor for generation using class non-coincident peak loads from the three summer peak months.

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

A Line 1 shows the average of the non-coincident peaks for each class in the three summer months. As explained previously, the summer months are selected because of their criticality in determining the need for generation capacity or firm purchased power. Line 2 shows the annual amount of energy required by each class. Line 3 is the average demand, in kilowatts, which is determined by dividing the annual energy in line 2 by the number of hours in a year. Line 4 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown on line 5, is equal to the non-coincident peak demand shown on line 1 minus the average demand that is shown on line 3. Line 6 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

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

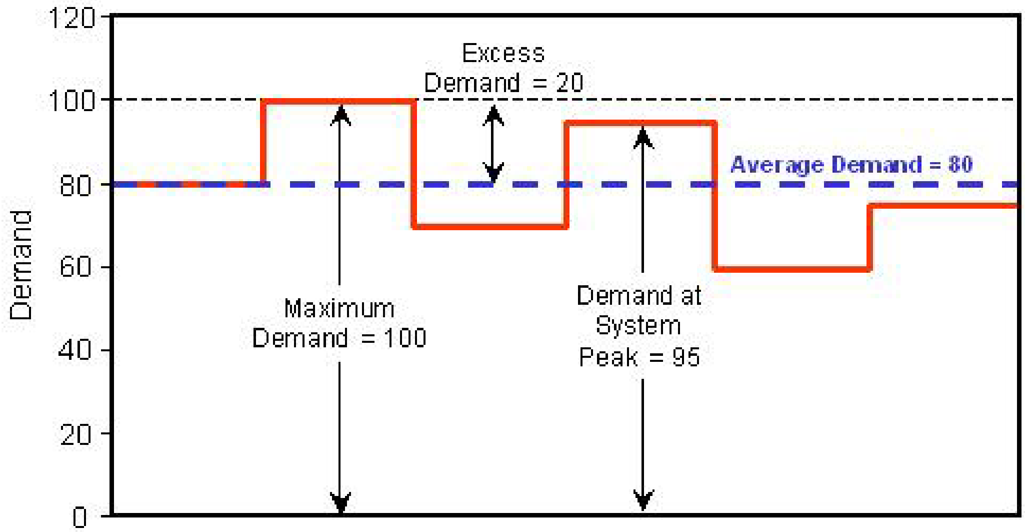
Q HOW DOES THIS DIFFER FROM THE ALLOCATOR KCPL HAS USED?

A KCPL used what it described as an "Average and Peak" allocation factor. It is constructed by multiplying each class' energy responsibility factor times the system load factor, and adding to that each class' percentage contribution to the annual system peak multiplied by the quantity one minus the load factor.

Both methods are a two-step process. In both methods, the first step is to weight the average demand by the system load factor. The second step is where the difference occurs. This is illustrated in Figure 6.

Figure 6

Components of Allocation Factor



Q PLEASE REFER TO FIGURE 6 AND EXPLAIN THE DIFFERENCES.

A Figure 6 is a simplified representation of a class load. The maximum demand of this particular class is represented as 100. Its contribution at the time of the system peak is 95, its average demand is 80, and the excess demand (the difference between its peak demand and its average demand) is 20.

The A&E method combines the class average demands with the class excess demands in order to construct an allocation factor that reflects average use as well as the excess of each class' peak demand over the average demand. The average and peak method, on the other hand, combines the average demand with the contribution to the system peak demand. As is evident from Figure 6, the average demand (80) is a component or sub-set of the contribution to system peak demand (95). Accordingly, when roughly equal weighting is given to the average demand and the contribution to system peak demand, the average demand is double counted. This has the effect of allocating significantly more costs to high load factor customers than is appropriate.

Q IS THE AVERAGE AND PEAK METHOD A REASONABLE ONE?

A No, it is not. As noted above, this allocation gives essentially equal weighting to annual energy consumption and contribution to system peak in the allocation of the investment in generation and transmission facilities. Since generation and transmission facilities must be designed to carry the peak loads imposed on them, the roughly equal weighting to energy consumption in the allocation factor is not related to cost of service at all.

Unlike the A&E method, which considers class individual peaks and class load factors, as well as diversity between class peaks and system peak, the average and peak method arbitrarily allocates about half of these costs on annual energy consumption.

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 4.

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

A Schedule 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 main elements of rate base. This is followed by revenues, expenses, operating income and, on line 19, the rate of return earned on service to each customer class under present rates. Line 20 shows the index of return which is developed by dividing the rate of return of each class by the overall rate of return of 7.42%.

Line 21 shows the dollar subsidy, or the difference between the revenues being produced by a class and the revenues required for the class to produce the average rate of return of 7.42%. Line 22 expresses this subsidy as the increase needed to equalize rates of return, which is simply the numbers on line 21 with the positive numbers made negative and the negative numbers made positive to indicate the direction of change in the revenues. In the context of no overall change in revenues, the cost of service study results indicate that individual classes would need to change in the range between +23% and -21%. Obviously, KCPL's rates are substantially out of line with cost of service.

Q OTHER THAN THE ALLOCATION OF THE GENERATION AND TRANSMISSION PLANT, HOW DOES YOUR STUDY DIFFER FROM THE ONE PRESENTED BY KCPL?

A There are also differences in terms of recognition of line losses, allocation of the primary distribution system, the allocation of a few administrative and general expense accounts, the allocation of off-system sales revenue and the allocation of income taxes.

Q PLEASE EXPLAIN HOW YOUR STUDY DIFFERS FROM KCPL'S IN TERMS OF RECOGNITION OF LINE LOSSES.

A In its study, KCPL failed to adjust some of the most important demand allocation factors (e.g., generation and transmission) to recognize losses from the customer's meter to the point where the allocation was being made. For example, in developing a demand allocation factor for generation, KCPL used loads at the customer level, and did not recognize the losses that are incurred in moving power from the generators to customers. The failure to recognize losses skews the results against those customers who take service at the higher voltages, and consequently have lower losses, and in favor of customers who take service at lower voltages. I have corrected this omission in my cost of service studies.

Q WHAT IS THE DIFFERENCE WITH RESPECT TO THE ALLOCATION OF THE PRIMARY DISTRIBUTION SYSTEM?

A KCPL allocated the demand-related portion of the primary distribution system using individual customer non-coincident peaks. While this is an appropriate basis for allocating the secondary distribution system, it fails to give appropriate recognition to the diversity among customers at the primary distribution level. I have changed the allocation of the demand-related primary distribution system from customer non-coincident peaks to class non-coincident peaks. This has the effect of reducing the amount of cost allocated to residential customers and increasing the cost allocated to other customers.

Q WHAT IS THE DIFFERENCE WITH RESPECT TO CERTAIN ADMINISTRATIVE AND GENERAL EXPENSE ACCOUNTS?

A In several instances, KCPL noted that cost causation was not clearly defined, and so it decided to just allocate these accounts using the energy allocation factor. These are Account Nos. 920 (office expense), 922 (administrative costs transferred – credit), 923 (outside services), 931 (rents), and a part of 930.2 (miscellaneous – other).

Arbitrarily defaulting to an energy allocation factor for these types of costs . . . when these costs have little or nothing to do with energy, is inappropriate. More typically, these accounts are allocated on some measure of the costs associated with all of the other elements of the system, such as salaries and wages or plant in service. I have allocated these accounts on salaries and wages to correct KCPL's misallocation.

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

A KCPL allocates what it has identified as profits from off-system sales on a rather novel methodology which attempts to allocate more profits to low load factor customers than to high load factor customers on the theory that the low load factor customers free up more capacity to facilitate off-system sales.

KCPL's particular allocation factor is unsupported. Furthermore, it does not give any consideration at all to sales from reserves that are paid for by all customers and carried for the benefit of all customers in proportion to customer loads, it does not recognize scheduled maintenance requirements or forced outage events, nor does it recognize specific class load patterns. It is a rather simplistic, broad brush and unique allocation formula. More typically, all of the revenues generated from off-system sales, including any imputed profit margin, would be allocated to customer classes on the basis of energy consumption. That is the approach I have utilized in my cost of service study.

Q WHAT IS THE DIFFERENCE IN THE TREATMENT IN INCOME TAXES?

A In its study, KCPL calculated income taxes based on taxable income. More typically in Missouri income taxes are allocated on rate base, and that is the approach which I have followed in my study. Whether taxes are allocated on rate base or calculated on taxable income the resulting increase or decrease in rates required to equal cost of service is the same. The only difference is how the income taxes are treated under the rates currently in effect. This affects rate of return slightly, but not the increase or decrease required to move rates to cost of service.

Q HAVE YOU PROVIDED THE FULL PRINTOUT OF YOUR CLASS COST OF SERVICE STUDY?

A Yes. I have included the full printout as Attachment 1 to my exhibits. Because KCPL has designated a few of the items in this study as Highly Confidential, I have designated Attachment 1 Highly Confidential in its entirety to avoid inadvertently disclosing anything that KCPL may choose to keep confidential.

Q DID YOU USE KCPL'S COST OF SERVICE MODEL TO PRODUCE YOUR CLASS COST OF SERVICE STUDY?

A No. The results of KCPL's allocation were replicated by utilizing the data contained in its cost of service model, but the results presented here are from our own cost of service model. Many of KCPL's allocation factors and functionalizations and classifications have been utilized, and the principal areas where I depart from KCPL have heretofore been explained in this testimony.

Q DID YOU PREPARE ANY OTHER CLASS COST OF SERVICE STUDIES?

A Yes. I prepared three other cost of service studies. Schedule 5 is a summary of the cost of service results if I use the four coincident peaks (which the Commission Staff used for jurisdictional purposes) as the allocation factor, Schedule 6 shows the summary using three coincident peaks and Schedule 7 is the summary using the single annual coincident peak.

Q ARE THE RESULTS OF ALL THESE STUDIES COMPARABLE?

A Yes. All these studies show that the Residential class is significantly below cost of service, while all other classes are well above cost of service.

Q THE RATES, WHEN EXPRESSED PER KILOWATTHOUR, CHARGED TO LARGE GS AND LARGE POWER CUSTOMERS ARE CURRENTLY LESS THAN THE RATES CHARGED TO RESIDENTIAL AND SMALL GS CUSTOMERS. DOES THE COST OF SERVICE STUDY INDICATE THAT THIS IS APPROPRIATE?

A Yes. Table 3 shows the cost-based revenue requirement for each KCPL class. Note that the cost, per unit, to serve the large GS and Large Power customers, is significantly less than the cost to serve the Residential and small GS customers. In fact, similar relationships hold on any electric utility system.

TABLE 3
Class Revenue Requirement
Average and Excess Method
(Dollars in Thousands)

Rate Class	Cost-Based Revenue (1)	Energy Sales (MWh) (2)	Cost per kWh (3)
Residential	$210,705	2,510,808	8.39¢
Small GS	35,293	458,655	7.69¢
Medium GS	56,294	987,312	5.70¢
Large GS	94,980	2,150,915	4.42¢
Large Power	81,599	2,319,462	3.52¢
Lighting	4,786	81,665	5.86¢
Total	$483,657	8,508,817	5.68¢

As previously discussed, the reasons for these differences are: (1) load factor, (2) delivery voltage, and (3) size.

The large GS and Large Power customers have higher load factors, as shown in Table 4. Consequently, the capital costs related to production and transmission are spread over a greater number of kilowatthours than is the case for lower load factor classes, resulting in lower costs per kWh and hence lower rates.

TABLE 4
Comparative Load Factors

Rate Class	Energy Generated (MWh) (1)	Production A&E (MW) (2)	Load Factor (3)
Residential	2,664,695	841	36%
Small GS	486,738	116	48%
Medium GS	1,047,615	239	50%
Large GS	2,276,089	426	61%
Large Power	2,401,479	385	71%
Lighting	86,671	---	N/M
Total	8,963,287	2,007	51%

In addition, these customers take service at a higher voltage level. This means that they do not cause the costs associated with lower voltage distribution. Losses incurred in providing service also are lower. Table 5 lists voltage level and composite loss percentages for the various classes. Losses are 6.13% at the secondary level and 3.71% at the primary level (for any customer served at the transmission level, the loss percentage would be lower).

TABLE 5
Energy Loss Factors

Rate Class	Percent of Sale by Voltage Level: Secondary[1] (1)	Percent of Sale by Voltage Level: Primary & Higher[2] (2)	Composite Loss Percentage (3)
Residential	100%	0%	6.13%
Small GS	100%	0%	6.12%
Medium GS	99%	1%	6.11%
Large GS	88%	12%	5.85%
Large Power	16%	84%	3.62%
Lighting	100%	0%	6.13%

[1]Secondary loss factor is 6.13%
[2]Primary loss factor is 3.71%
Substation loss factor is 2.48%
Transmission loss factor is 1.56%

The per capita sales to these classes are also much greater than to the other classes, as shown in Table 6. KCPL sells almost 2,000,000 and 25,000,000 kilowatthours per large GS and Large Power customer, respectively, but less than 11,000 kilowatthours per Residential customer, or between 180 and 2,300 times more per capita, as shown in Table 6. The customer-related costs to serve the former are not 180 to 2,500 times the customer-related costs to serve the Residential customer.

TABLE 6
Energy Sold Per Customer

Rate Class	Energy Sold (MWh) (1)	Number of Customers (2)	KWh Sold per Customer (3)
Residential	2,510,808	233,632	10,747
Small GS	458,655	25,800	17,777
Medium GS	987,312	4,653	212,188
Large GS	2,150,915	1,099	1,957,157
Large Power	2,319,462	93	24,940,452
Lighting	81,665	N/A	
Total	8,508,817	265,277	32,075

These differences in the service and usage characteristics–load factor, delivery voltage and size–result in a lower per unit cost to serve customers operating at a higher load factor, taking service at higher delivery voltage and purchasing a larger quantity of power and energy at a single delivery point**.**

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 basis used to establish the revenues collected from each customer class and to design rate schedules.

Although factors such as simplicity, gradualism and ease of administration may also be taken into account, 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.

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 other than cost factors, then some customers will pay the costs attributable to providing service to other customers–which is inherently inequitable.

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

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

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

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

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

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

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

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

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

Q DOES KCPL'S COST OF SERVICE STUDY SHOW SIGNIFICANT DIFFERENCES IN RATES OF RETURN AMONG CUSTOMER CLASSES?

A Yes. Even though it has many shortcomings which I have corrected, KCPL's class cost of service study shows, directionally, the same thing that my cost of service studies show: namely, that Residential customers are being undercharged, and other customer classes are being overcharged.

Q DID KCPL PROPOSE TO MAKE ANY REALIGNMENTS OF CLASS REVENUES IN AN EFFORT TO MOVE CLASSES CLOSER TO COST OF SERVICE?

A No. In a curious twist of logic, KCPL observes that no class cost of service study has been done for its system for over ten years, notes that 11.5% is a large increase and argues to postpone any interclass revenue realignment until after Iatan 2 is in service, or another four or five years.

Q DO YOU AGREE WITH KCPL'S PROPOSAL?

A No, I do not. The argument which KCPL makes for not doing anything is, in my view, actually a strong argument for doing something now. Admittedly, by any measure presented, class revenues are badly out of line with class costs. This circumstance has persisted (apparently) for a long time. The parties to the Regulatory Plan Stipulation specifically provided for KCPL to prepare and produce a class cost of service study in this case. That was not done with the intent that it would simply be ignored.

Furthermore, rates are so significantly out of line that it will take a considerable period of time to bring them back into alignment. Thus, it is imperative that movement toward cost of service be commenced in this case. While the amount of movement that is possible may be constrained by the overall amount of increase granted KCPL (if any), some movement needs to take place so that orderly progress toward the goal of cost-based rates can be made.

Q WHAT IMPACT DOES AN ACROSS-THE-BOARD INCREASE HAVE ON THE MAGNITUDE OF THE INTER-CLASS SUBSIDIES?

A This is illustrated on Schedule 8. For purposes of illustration, I applied a 10% across-the-board revenue increase, accounted for income taxes and recalculated the inter-class subsidies. Line 19 shows the change in the absolute value of the inter-class subsidies with an across-the-board increase. With the sole exception of the small general service class (which moves very slightly toward cost of service), an across-the-board increase makes the subsidies of every other class larger than at present rates. (The change in the subsidy is determined by comparing the numbers on lines 9 and 18.) Note that an across-the-board increase pushes the residential class further below cost and pushes the MGS, LGS and Large Power classes further above costs.

Q WHAT IS THE CONCLUSION TO BE DRAWN FROM THIS SCHEDULE?

A The conclusion is that an across-the-board increase would not maintain the status quo with respect to subsidies, but would, in fact, make matters worse.

Q HAVE YOU PREPARED RECOMMENDATIONS FOR THE ALLOCATION OF REVENUE ADJUSTMENTS (INCREASES OR DECREASES) AMONG CUSTOMER CLASSES?

A Yes, I have. This appears on Schedule 9.

Q PLEASE EXPLAIN SCHEDULE 9.

A Schedule 9 shows, in Column 1, the rate schedule revenues under present rates. Column 2 shows the required dollar changes and Column 3 shows the required percentage changes (as determined in the cost of service study) to fully align rates with costs.

Q YOU HAVE EXPRESSED WHY COST OF SERVICE SHOULD BE THE GOAL IN RATE DESIGN. IS IT ALWAYS POSSIBLE TO MOVE RATES EXACTLY TO COST OF SERVICE RESULTS, REGARDLESS OF THE LEVEL OF INCREASES WHICH MAY BE REQUIRED?

A No. It is more customary to move toward class cost of service results in a manner that recognizes the impacts of higher rates. The Residential class would require an increase of over 20% to move to cost. This is generally higher than would normally be imposed in a single step as a result strictly of inter-class rate realignments.

Q WHAT IS YOUR RECOMMENDATION?

A I recommend a realignment of class revenue that moves all classes closer to cost, constrained by the impact that results from any positive change in KCPL's revenue requirements. With this approach, the interclass revenue alignment can be larger at smaller overall increases. For impact reasons, the convergence toward cost of service would be moderated at higher revenue increases.

Q WHAT SPECIFICALLY WOULD YOU RECOMMEND?

A I would recommend that the Residential class receive an increase of 10% if the overall change in KCPL's revenues is zero. Other classes would receive a reduction in revenues equal to the dollar amount of the increase in the Residential class. The decrease would be in proportion to the subsidy that each customer class is currently paying. The larger the subsidy a class is paying, the larger the decrease it would receive.

If KCPL were to receive an overall increase of 5%, I would recommend increasing the Residential class 7.5% more than the average, and apportioning the reduction that results from this 7.5% increase in the same manner as described above. At this level of realignment, the Residential class increase would be a total of 12.5%.

If KCPL were to receive a 10% revenue increase I would recommend increasing the Residential class by 5% more than the average for realignment purposes, and apportioning the decrease to other classes in the same manner as described above. Under this scenario the total increase to the Residential class would be 15%. This approach gives recognition to class cost of service studies and also to rate impact concerns.

Q HAVE YOU ILLUSTRATED THIS RECOMMENDATION?

A Yes. This is illustrated on Schedule 9.

Q WHAT WOULD YOU RECOMMEND IF THE END RESULT IS A REDUCTION IN KCPL'S REVENUES?

A If there were a reduction in KCPL's revenues, I would maintain the Residential class at a 10% increase with the decreases that I have shown on Schedule 9 for the other classes. Whatever dollar amount of money that would be created by the decrease in

KCPL's revenues would be spread across all the non-residential classes in proportion to the revenue change which they would have seen at a zero change in revenues.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

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

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

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

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

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

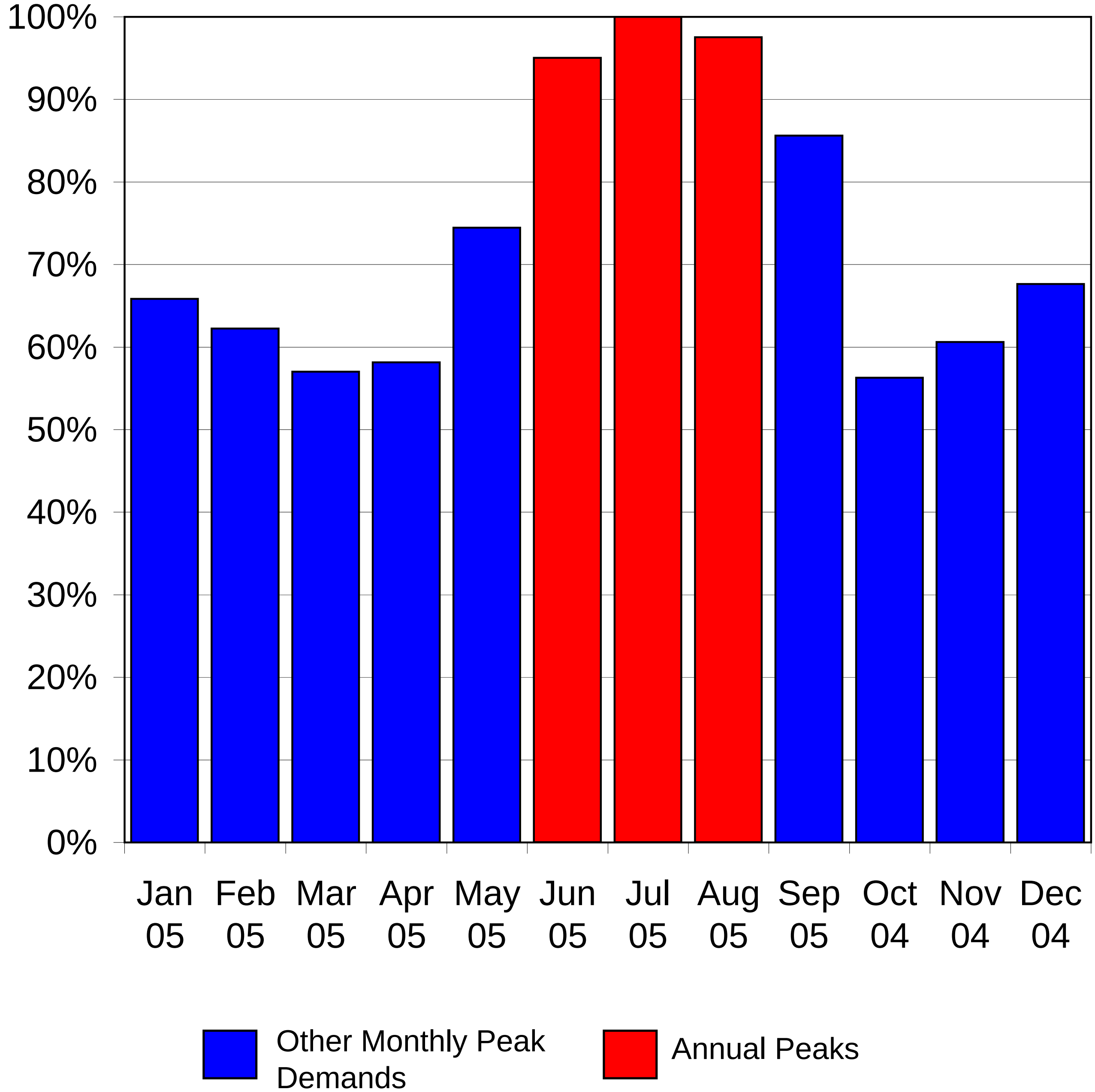
An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power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

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

KANSAS CITY POWER & LIGHT COMPANY

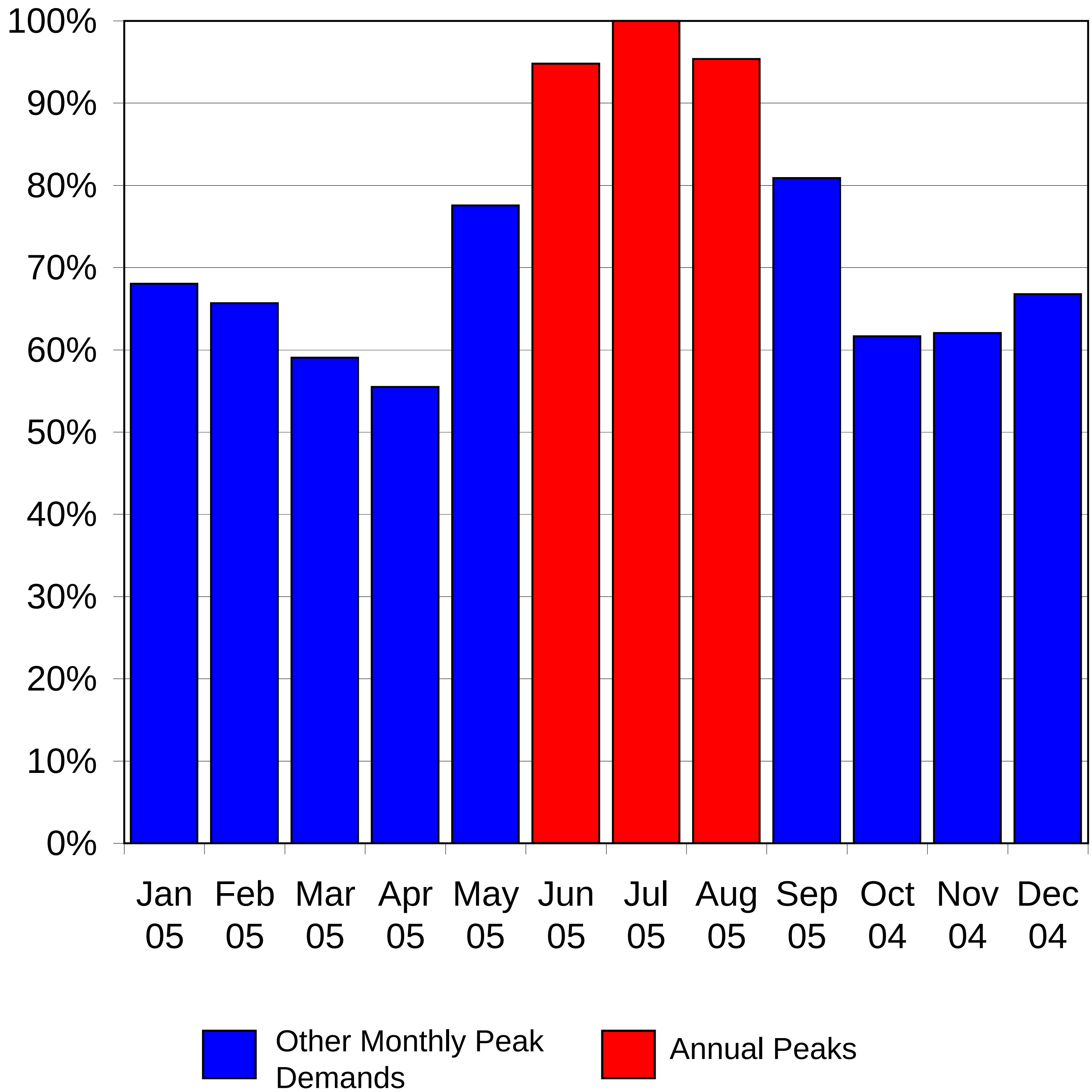
Analysis of KCPL's Monthly Peak Demands as a Percent of the Annual System Peak

For the Test Year Ended September 2005



KANSAS CITY POWER & LIGHT COMPANY

Analysis of Missouri's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
<u>For the Test Year Ended September 2005</u>



KANSAS CITY POWER & LIGHT COMPANY

Analysis of KCPL's Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended September 2005

Line	Description	Total Company MW (1)	Percent (2)
1	January 2005	2,313	66
2	February	2,186	62
3	March	2,003	57
4	April	2,042	58
5	May	2,615	74
6	June	3,338	95
7	July	3,512	100
8	August	3,426	98
9	September	3,007	86
10	October 2004	1,977	56
11	November	2,129	61
12	December	2,376	68

Source: 2004 and 2005 FERC Form 1s

KANSAS CITY POWER & LIGHT COMPANY

Analysis of Missouri's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
<u>For the Test Year Ended September 2005</u>

Line	Description	Missouri Jurisdiction MW (1)	Percent (2)
1	January 2005	1,365	68
2	February	1,318	66
3	March	1,185	59
4	April	1,114	56
5	May	1,557	78
6	June	1,902	95
7	July	2,007	100
8	August	1,914	95
9	September	1,623	81
10	October 2004	1,237	62
11	November	1,245	62
12	December	1,340	67

Source: Data Response 1-3
File 3a_3b_MO.xls and Tab Version 3

KANSAS CITY POWER & LIGHT COMPANY

Development of
Average and Excess Demand Allocator
Based on 3 NonCoincident Peaks
For the Test Year Ended September 2005

Line	Description	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)
1	Average of 3 NCPs (JJA) - kW	2,064,735	875,479	119,699	245,696	434,568	389,294
2	Energy Sales with Losses - MWh	8,876,616	2,664,695	486,738	1,047,615	2,276,089	2,401,479
3	Average Demand - kW	1,013,312	304,189	55,564	119,591	259,828	274,141
4	Average Demand - Percent	1.000000	0.300193	0.054834	0.118020	0.256414	0.270540
5	Class Excess Demand - kW	1,051,423	571,290	64,135	126,105	174,740	115,153
6	Class Excess Demand - Percent	1.000000	0.543349	0.060999	0.119937	0.166194	0.109521
	Allocator:						
7	Annual Load Factor * Average Demand	0.509918	0.153074	0.027961	0.060180	0.130750	0.137953
8	(1-LF) * Excess Demand	0.490082	0.266286	0.029894	0.058779	0.081449	0.053674
9	Average and Excess Demand Allocator	1.000000	0.419359	0.057855	0.118959	0.212199	0.191627

Notes:

Line 3 equals Line 2 ÷ 8.760
Line 5 equals Line 1 - Line 3

System Annual Load Factor 50.99% (8,876,616 MWh ÷ 2006.61 MW ÷ 8760 hours)
1 - Load Factor 49.01%

KANSAS CITY POWER & LIGHT COMPANY

Class Cost of Service Study at Present Rates for Missouri Customers
Average & Excess - 3NCP - Scenario
For the Test Year Ended September 30, 2005
(Dollars in Thousands)

Line	Description	Allocators	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Off Peak Lighting (7)	Other Lighting (8)
	Summary of Results									
	DEVELOPMENT OF RATE BASE									
1	PLANT IN SERVICE		$ 2,647,510	$ 1,190,798	$ 204,742	$ 318,141	$ 507,944	$ 411,442	$ -	$ 14,443
2	LESS: RESERVE FOR DEPRECIATION		1,209,961	537,883	90,678	144,075	234,029	195,704	-	7,592
3	NET PLANT IN SERVICE		1,437,549	652,915	114,065	174,066	273,915	215,737	-	6,850
4	RATE BASE ADDITIONS		70,755	27,469	4,478	8,218	15,387	14,556	-	646
5	RATE BASE DEDUCTIONS		336,272	147,299	26,698	40,242	65,569	54,706	-	1,758
6	TOTAL RATE BASE		1,172,031	533,085	91,844	142,042	223,734	175,588	-	5,738
	Operating Revenues:									
7	Adjusted Sales Revenues		483,656	171,390	36,586	62,431	108,729	98,464	-	6,057
8	Other Revenues		101,743	32,674	5,747	11,957	24,929	25,583	-	854
9	Total Operating Revenue		585,399	204,064	42,333	74,388	133,657	124,046	-	6,910
10	OPERATING EXPENSES									
11	OPERATION & MAINTENANCE		361,899	141,718	23,233	41,473	77,797	73,757	-	3,922
12	DEPRECIATION & AMORT EXPENSE		69,798	31,767	5,644	8,230	12,878	10,366	-	914
13	Interest on Customer Deposits		469	263	171	29	5	1	-	-
14	TAXES OTHER THAN INCOME TAX		34,369	15,466	2,630	4,106	6,588	5,365	-	214
15	KCMO Earnings Tax		867	394	68	105	166	130	-	4
16	Federal And State Income Taxes		31,075	14,237	2,483	3,775	5,881	4,540	-	159
17	TOTAL OPERATING EXPENSES		498,477	203,844	34,229	57,717	103,315	94,159	-	5,213
18	OPERATING INCOME		$ 86,922	$ 220	$ 8,104	$ 16,671	$ 30,342	$ 29,888	$ -	$ 1,697
19	RATE OF RETURN		7.42%	0.04%	8.82%	11.74%	13.56%	17.02%		29.57%
20	INDEX RATE OF RETURN		100	1	119	158	183	230		399
21	Subsidies	1.000000	$ -	$ (39,315)	$ 1,293	$ 6,137	$ 13,749	$ 16,865	$ -	$ 1,271
22	Change Needed to Equalize ROR		$ -	$ 39,315	$ (1,293)	$ (6,137)	$ (13,749)	$ (16,865)	$ -	$ (1,271)
23	Percent of Sales Revenue		0.00%	22.94%	-3.53%	-9.83%	-12.65%	-17.13%		-20.99%

KANSAS CITY POWER & LIGHT COMPANY

Class Cost of Service Study at Present Rates for Missouri Customers
4 Coincident Peak Scenario
For the Test Year Ended September 30, 2005
(Dollars in Thousands)

Line	Description	Allocators	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Off Peak Lighting (7)	Other Lighting (8)
	Summary of Results									
	DEVELOPMENT OF RATE BASE									
1	PLANT IN SERVICE		$ 2,647,510	$ 1,217,533	$ 193,462	$ 309,058	$ 505,154	$ 407,861	$ -	$ 14,443
2	LESS: RESERVE FOR DEPRECIATION		1,209,961	551,723	84,838	139,373	232,584	193,851	-	7,592
3	NET PLANT IN SERVICE		1,437,549	665,809	108,624	169,685	272,569	214,011	-	6,850
4	RATE BASE ADDITIONS		70,755	27,933	4,282	8,061	15,339	14,494	-	646
5	RATE BASE DEDUCTIONS		336,272	150,593	25,309	39,123	65,225	54,265	-	1,758
6	TOTAL RATE BASE		1,172,031	543,149	87,598	138,623	222,683	174,240	-	5,738
	Operating Revenues:									
7	Adjusted Sales Revenues		483,656	171,390	36,586	62,431	108,729	98,464	-	6,057
8	Other Revenues		101,743	32,904	5,650	11,879	24,905	25,552	-	854
9	Total Operating Revenue		585,399	204,294	42,236	74,310	133,633	124,016	-	6,910
10	OPERATING EXPENSES									
11	OPERATION & MAINTENANCE		361,899	143,672	22,408	40,809	77,593	73,495	-	3,922
12	DEPRECIATION & AMORT EXPENSE		69,798	32,467	5,348	7,992	12,805	10,272	-	914
13	Interest on Customer Deposits		469	263	171	29	5	1	-	-
14	TAXES OTHER THAN INCOME TAX		34,369	15,810	2,485	3,989	6,552	5,319	-	214
15	KCMO Earnings Tax		867	402	65	103	165	129	-	4
16	Federal And State Income Taxes		31,075	14,485	2,378	3,690	5,855	4,507	-	159
17	TOTAL OPERATING EXPENSES		498,477	207,098	32,856	56,612	102,975	93,723	-	5,213
18	OPERATING INCOME		$ 86,922	$ (2,804)	$ 9,380	$ 17,698	$ 30,658	$ 30,293	$ -	$ 1,697
19	RATE OF RETURN		7.42%	-0.52%	10.71%	12.77%	13.77%	17.39%		29.57%
20	INDEX RATE OF RETURN		100	(7)	144	172	186	234		399
21	Subsidies	1.000000	$ -	$ (43,085)	$ 2,883	$ 7,418	$ 14,143	$ 17,370	$ -	$ 1,271
22	Change Needed to Equalize ROR		$ -	$ 43,085	$ (2,883)	$ (7,418)	$ (14,143)	$ (17,370)	$ -	$ (1,271)
23	Percent of Sales Revenue		0.00%	25.14%	-7.88%	-11.88%	-13.01%	-17.64%		-20.99%

KANSAS CITY POWER & LIGHT COMPANY

Class Cost of Service Study at Present Rates for Missouri Customers
3 Coincident Peak Scenario
For the Test Year Ended September 30, 2005
(Dollars in Thousands)

Line	Description	Allocators	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Off Peak Lighting (7)	Other Lighting (8)
	Summary of Results									
	DEVELOPMENT OF RATE BASE									
1	PLANT IN SERVICE		$ 2,647,510	$ 1,204,788	$ 194,074	$ 311,248	$ 514,096	$ 408,860	$ -	$ 14,443
2	LESS: RESERVE FOR DEPRECIATION		1,209,961	545,125	85,155	140,507	237,214	194,368	-	7,592
3	NET PLANT IN SERVICE		1,437,549	659,663	108,920	170,742	276,882	214,493	-	6,850
4	RATE BASE ADDITIONS		70,755	27,712	4,293	8,099	15,494	14,511	-	646
5	RATE BASE DEDUCTIONS		336,272	149,023	25,384	39,393	66,327	54,388	-	1,758
6	TOTAL RATE BASE		1,172,031	538,351	87,828	139,448	226,050	174,616	-	5,738
	Operating Revenues:									
7	Adjusted Sales Revenues		483,656	171,390	36,586	62,431	108,729	98,464	-	6,057
8	Other Revenues		101,743	32,794	5,655	11,898	24,981	25,560	-	854
9	Total Operating Revenue		585,399	204,184	42,241	74,329	133,710	124,024	-	6,910
10	OPERATING EXPENSES									
11	OPERATION & MAINTENANCE		361,899	142,740	22,453	40,969	78,247	73,568	-	3,922
12	DEPRECIATION & AMORT EXPENSE		69,798	32,133	5,364	8,049	13,040	10,298	-	914
13	Interest on Customer Deposits		469	263	171	29	5	1	-	-
14	TAXES OTHER THAN INCOME TAX		34,369	15,646	2,493	4,017	6,667	5,332	-	214
15	KCMO Earnings Tax		867	398	65	103	167	129	-	4
16	Federal And State Income Taxes		31,075	14,367	2,384	3,711	5,938	4,516	-	159
17	TOTAL OPERATING EXPENSES		498,477	205,547	32,930	56,878	104,064	93,845	-	5,213
18	OPERATING INCOME		$ 86,922	$ (1,362)	$ 9,311	$ 17,451	$ 29,646	$ 30,180	$ -	$ 1,697
19	RATE OF RETURN		7.42%	-0.25%	10.60%	12.51%	13.11%	17.28%		29.57%
20	INDEX RATE OF RETURN		100	(3)	143	169	177	233		399
21	Subsidies	1.000000	$ -	$ (41,288)	$ 2,797	$ 7,109	$ 12,882	$ 17,229	$ -	$ 1,271
22	Change Needed to Equalize ROR		$ -	$ 41,288	$ (2,797)	$ (7,109)	$ (12,882)	$ (17,229)	$ -	$ (1,271)
23	Percent of Sales Revenue		0.00%	24.09%	-7.65%	-11.39%	-11.85%	-17.50%		-20.99%

KANSAS CITY POWER & LIGHT COMPANY

Class Cost of Service Study at Present Rates for Missouri Customers
1 Coincident Peak Scenario
For the Test Year Ended September 30, 2005
(Dollars in Thousands)

Line	Description	Allocators	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Off Peak Lighting (7)	Other Lighting (8)
	Summary of Results									
	DEVELOPMENT OF RATE BASE									
1	PLANT IN SERVICE		$ 2,647,510	$ 1,214,339	$ 198,465	$ 317,936	$ 507,861	$ 394,466	$ -	$ 14,443
2	LESS: RESERVE FOR DEPRECIATION		1,209,961	550,070	87,428	143,969	233,986	186,916	-	7,592
3	NET PLANT IN SERVICE		1,437,549	664,269	111,037	173,967	273,875	207,550	-	6,850
4	RATE BASE ADDITIONS		70,755	27,757	4,359	8,236	15,416	14,341	-	646
5	RATE BASE DEDUCTIONS		336,272	150,199	25,925	40,217	65,559	52,615	-	1,758
6	TOTAL RATE BASE		1,172,031	541,827	89,471	141,986	223,733	169,276	-	5,738
	Operating Revenues:									
7	Adjusted Sales Revenues		483,656	171,390	36,586	62,431	108,729	98,464	-	6,057
8	Other Revenues		101,743	32,877	5,693	11,956	24,928	25,437	-	854
9	Total Operating Revenue		585,399	204,267	42,279	74,387	133,656	123,900	-	6,910
10	OPERATING EXPENSES									
11	OPERATION & MAINTENANCE		361,899	143,438	22,774	41,458	77,791	72,516	-	3,922
12	DEPRECIATION & AMORT EXPENSE		69,798	32,383	5,479	8,225	12,876	9,922	-	914
13	Interest on Customer Deposits		469	263	171	29	5	1	-	-
14	TAXES OTHER THAN INCOME TAX		34,369	15,769	2,549	4,103	6,587	5,146	-	214
15	KCMO Earnings Tax		867	413	67	103	162	117	-	4
16	Federal And State Income Taxes		31,075	14,990	2,468	3,679	5,747	4,031	-	159
17	TOTAL OPERATING EXPENSES		498,477	207,256	33,510	57,596	103,169	91,733	-	5,213
18	OPERATING INCOME		$ 86,922	$ (2,990)	$ 8,769	$ 16,790	$ 30,487	$ 32,168	$ -	$ 1,697
19	RATE OF RETURN		7.42%	-0.55%	9.80%	11.83%	13.63%	19.00%		29.58%
20	INDEX RATE OF RETURN		100	(7)	132	159	184	256		399
21	Subsidies	1.000000	$ -	$ (43,173)	$ 2,134	$ 6,260	$ 13,894	$ 19,614	$ -	$ 1,272
22	Change Needed to Equalize ROR		$ -	$ 43,173	$ (2,134)	$ (6,260)	$ (13,894)	$ (19,614)	$ -	$ (1,272)
23	Percent of Sales Revenue		0.00%	25.19%	-5.83%	-10.03%	-12.78%	-19.92%		-21.00%

KANSAS CITY POWER & LIGHT COMPANY

Impact of an Across the Board 10% Increase
Average & Excess - 3NCP - Scenario
For the Test Year Ended September 30, 2005
(Dollars in Thousands)

Line	Description	Allocators	Missouri Retail (1)	Residential (2)	Small General Service (3)	Medium General Service (4)	Large General Service (5)	Large Power Service (6)	Off Peak Lighting (7)	Other Lighting (8)
	Summary of Results									
1	TOTAL RATE BASE		$ 1,172,031	$ 533,085	$ 91,844	$ 142,042	$ 223,734	$ 175,588	$ -	$ 5,738
	Operating Revenues:									
2	Adjusted Sales Revenues		483,656	171,390	36,586	62,431	108,729	98,464	-	6,057
3	Other Revenues		101,743	32,674	5,747	11,957	24,929	25,583	-	854
4	Total Operating Revenue		585,399	204,064	42,333	74,388	133,657	124,046	-	6,910
5	Operating Expenses at Current Rates		498,477	203,844	34,229	57,717	103,315	94,159	-	5,213
6	Operating Income at Current Rates		$ 86,922	$ 220	$ 8,104	$ 16,671	$ 30,342	$ 29,888	$ -	$ 1,697
7	Rate of Return at Current Rates		7.42%	0.04%	8.82%	11.74%	13.56%	17.02%		29.57%
8	Index at Current Rates		100	1	119	158	183	230		399
9	Subsidies at Current Rates	1.000000	$ -	$ (39,315)	$ 1,293	$ 6,137	$ 13,749	$ 16,865	$ -	$ 1,271
10	10% ATB Revenue Increase	10.00%	48,366	17,139	3,659	6,243	10,873	9,846	-	606
11	Operating Income Increase	1.634290	29,594							
12	Increase in Income Taxes	RATEBASE	18,771	8,538	1,471	2,275	3,583	2,812	-	92
13	Operating Revenue with ATB Increase		633,765	221,203	45,991	80,631	144,530	133,893	-	7,516
14	Operating Expenses with ATB Increase		517,249	212,382	35,700	59,992	106,898	96,971	-	5,305
15	Operating Income at 10% ATB Rates		$ 116,516	$ 8,821	$ 10,292	$ 20,639	$ 37,632	$ 36,922	$ -	$ 2,211
16	Rate of Return at 10% ATB Rates		9.94%	1.65%	11.21%	14.53%	16.82%	21.03%		38.52%
17	Index at 10% ATB Rates		100	17	113	146	169	212		388
18	Subsidies at 10% ATB Rates	1.000000	$ -	$ (44,175)	$ 1,161	$ 6,518	$ 15,389	$ 19,466	$ -	$ 1,640
19	Increase (Decrease) in Inter-Class Subsidies with an Across the Board Increase		$ -	$ 4,860	$ (132)	$ 382	$ 1,640	$ 2,600	$ -	$ 369

KANSAS CITY POWER & LIGHT COMPANY

Recommended Adjustments to Class Revenues
For the Test Year Ended September 2005
(Dollars in Thousands)

Line	Rate Classes	Current Sales Revenue	Change Needed to Equalize Rates of Return		Revenue Changes with No Change in Total Revenue		Revenue Changes with an Overall Increase of 5%		Revenue Changes with an Overall Increase of 10%	
			Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Residential	$ 171,390	$ 39,315	22.94%	$ 17,139	10.00%	$ 21,424	12.50%	$ 25,709	15.00%
2	Small General Service	36,586	(1,293)	-3.53%	(564)	-1.54%	1,407	3.84%	3,377	9.23%
3	Medium General Service	62,431	(6,137)	-9.83%	(2,675)	-4.29%	1,115	1.79%	4,905	7.86%
4	Large General Service	108,729	(13,749)	-12.65%	(5,994)	-5.51%	941	0.87%	7,876	7.24%
5	Large Power Service	98,464	(16,865)	-17.13%	(7,352)	-7.47%	(591)	-0.60%	6,170	6.27%
6	Lighting	6,057	(1,271)	-20.98%	(554)	-9.15%	(113)	-1.86%	329	5.43%
7	Total Missouri Retail	$ 483,657	$ -	0.00%	$ (0)	0.00%	$ 24,183	5.00%	$ 48,366	10.00%

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan	))))))))	**Case No. ER-2006-0314**

Attachment 1

to the Direct Testimony

of Maurice Brubaker

CONTAINS INFORMATION KCPL

HAS DESIGNATED "HIGHLY CONFIDENTIAL"

AND HAS BEEN FILED SEPARATELY