Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal 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**

Rebuttal Testimony 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

September 15, 2006

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 rebuttal 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 14th day of September 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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Rebuttal Testimony 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 63141-2000.

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

A Yes. I have previously filed direct and rebuttal testimony on revenue requirement issues and direct testimony on cost of service, revenue allocation and rate design issues.

Q ARE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN ANY OF THOSE PRIOR TESTIMONIES?

A Yes. This information is included in Appendix A to my direct testimony on revenue requirement issues.

Q HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESS JANICE PYATTE AND OPC WITNESS BARBARA MEISENHEIMER ON THE SUBJECT OF CLASS COST OF SERVICE?

A Yes.

Q DO YOU HAVE REBUTTAL TO THE POSITIONS OF THESE WITNESSES?

A Yes, I do. I disagree with the methods which these witnesses have used for the allocation of production and transmission fixed costs and with respect to the allocation of certain other components of the cost of service. The allocation of the generation and transmission fixed costs is the largest and most important of these issues, and I will address it first. Then, I will address some of the other differences in the allocations.

Q HAVE YOU REVIEWED THE TESTIMONY COMMISSION STAFF WITNESS JAMES BUSCH?

A Yes, I have. Mr. Busch proposes a revenue realignment based on the results of Staff's class cost of service study performed by Ms. Pyatte.

Q DO YOU HAVE ANY RESPONSE TO MR. BUSCH'S RECOMMENDATIONS?

A Yes. While I agree with the general direction of Mr. Busch's recommendations, I believe that he does not go far enough in recognizing interclass disparities. Also, as I will discuss in connection with my rebuttal to Staff Witness Pyatte, I believe that even if one were to accept Staff's allocation methodology for production and transmission costs, there are some inconsistencies and erroneous allocations of other costs in

Staff's study. If these were corrected, and Mr. Busch's methodology applied, a larger realignment of class revenues would occur.

Q PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A My rebuttal testimony may be summarized as follows:

1. The Average & Peak (A&P) allocation methods applied by both Staff and OPC are not explained as to methodology, supported as to theory or shown to be applicable to the KCPL system. These studies significantly over-allocate costs to large high load factor customers such as those that take service on the Large Power rate.

2. The study which OPC calls "time-of-use (TOU)" is not explained as to methodology, supported as to theory or shown to be applicable to the KCPL system, and allocates fixed costs even more disproportionately (than the A&P studies) to large high load factor customers such as those that take service on the Large Power rate.

3. Neither the A&P methods used by Staff and OPC nor the "TOU"" method advanced as an alternative by OPC are traditional, none are used in any other jurisdiction, and none have ever even been adopted by the Missouri PSC.

4. The Staff and OPC cost of service studies are internally inconsistent in that they allocate above average generation capacity costs to high load factor customers, but do not give them the benefit of the lower energy-related costs that correspond to the above average capital cost allocation.

5. The Average & Excess - 3 NCP study that I offered in my direct testimony is the most appropriate allocation method for the KCPL system and is the one that should be adopted by the Commission and used as a guide to distribute any revenue increase found appropriate.

6. In addition to the problems noted above, the OPC A&P study:

   a. Uses an incorrect (too high) load factor to weight the energy component of the A&P allocator. This appears just to be a mistake.

   b. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   c. Fails to recognize any customer-related component in the primary distribution system.

7. In addition to the above problems, OPC's "TOU" allocation study:

   a. Uses gross (undepreciated) installed capacity costs to develop the basis for the capacity allocation factor, rather than the revenue requirements on the current net investment in plant in service.

   b. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   c. Fails to recognize any customer-related component in the primary distribution system.

8. In addition to problems noted above, Staff's study:

   a. Develops a load factor for weighting the average component in the A&P study that uses demands that have not been adjusted for losses, and as a result overstates the load factor and the weighting given to energy.

   b. Allocates revenues from off-system sales using a demand allocation factor, which is inconsistent with the allocation on an energy basis of the expenses for the fuel and variable purchased power used to supply these sales.

   c. Allocates certain Administrative and General expense accounts on energy, rather than on the more conventionally used salaries and wages.

9. Adjusting the Staff's study only to correct the load factor, allocate the fuel cost portion of the revenue received from off-system sales on an energy basis to correspond with the allocation of the expenses, and adjusting the allocation of certain Administrative and General expenses would indicate that the Large Power Service class should receive a 6% decrease on a revenue neutral basis, even if Staff's generation and transmission allocation methodology is utilized.

Allocation of Generation and Transmission Capacity Costs

Q WHAT METHOD HAS STAFF USED FOR THE ALLOCATION OF GENERATION AND TRANSMISSION DEMAND-RELATED COSTS?

A Staff has used an A&P allocation method. In particular, Staff uses the 12 monthly non-coincident peak demands of each customer class along with each class's annual energy consumption. The energy component is weighted equal to the system annual load factor.

Q DOES STAFF EXPLAIN THE BASIS FOR SELECTING THIS ALLOCATION METHODOLOGY?

A No. Staff neither explains the derivation of the particular allocation factors, nor does it explain or attempt to justify why this particular method is appropriate for KCPL. Rather, Staff compares its 12-month NCP A&P method with KCPL's annual system peak and average allocation methodology. Staff also does not explain why it is appropriate to use class peak demands from every month of the year rather than just from the summer months.

Furthermore, Staff determines its weighting of monthly class peak demands by using a methodology that is described in a 1983 article that it simply attaches to its testimony. The author of the article is not presented as a witness in this proceeding, and Staff does not further attempt to explain the basis for the method, how the method works, or why it is appropriate to use in 2006 on the KCPL system.

Q DID YOU ADDRESS THE DEFECTS IN THE A&P METHODOLOGY IN YOUR DIRECT TESTIMONY ON COST OF SERVICE?

A Yes, I did. I explained in detail why the annual A&P method which KCPL proposed to use for class cost allocation was inappropriate, contrasted the A&P method to the Average & Excess (A&E) method which I propose, and explained why the A&E method was superior. Also, at pages 23-25 of that testimony, I showed how the A&P method actually double counts average demand and thereby significantly over-allocates costs to high load factor customers, like those on the Large Power rate. The methodology employed by Staff is even worse in this regard because it uses 12 monthly system peaks, which includes many months when the loads are significantly below the peak summer load. This use of 12 monthly peaks adds to the over-allocation of costs to high load factor, non-seasonal customers, such as those on the Large Power rate.

Q WHAT METHOD DID OPC USE FOR ALLOCATING GENERATION AND TRANSMISSION CAPACITY COSTS?

A OPC used a 12-month NCP A&P allocator (somewhat similar to Staff's) and also showed what it calls a "TOU" method.

Q WITNESS MEISENHEIMER REFERS TO THE FIRST OF HER ALLOCATION METHODS AS A "TRADITIONAL" STUDY. IS THAT AN ACCURATE DESCRIPTION?

A No, it is not. There is nothing traditional about either one of her studies. I am somewhat surprised by her statement because less than 12 months ago, in Case No. EO-2002-384, the Aquila class cost of service case, OPC stated in response to a data request, and confirmed on the record, that the so-called "traditional" method which it has proposed to use to allocate generation and transmission capacity costs in this case is, in fact, not used anywhere.

Q DOES MS. MEISENHEIMER SUPPORT OR EXPLAIN WHY SHE BELIEVES THE PARTICULAR METHODOLOGIES WHICH SHE HAS CHOSEN ARE APPROPRIATE?

A No, she does not. She does not provide any explanation or supporting reason for why either one of her allocation methods is appropriate.

Furthermore, she just calls her second study a "TOU" study but provides absolutely no description of the basis for the derivation of the allocation factors, the logic or theory supporting the use of this particular allocation method, or its applicability to the KCPL system. To simply call something a "TOU Study" is not meaningful because there is no conventional methodology or understanding that can be associated with the description: a "TOU Study."

Q WHAT IS THE SIGNIFICANCE OF THE FACT THAT A METHODOLOGY IS NOT USED IN OTHER JURISDICTIONS?

A Cost of service studies for electric systems have been performed for well over 50 years. This means that there has been a significant amount of analysis that has gone into the question of determining how best to ascertain cost-causation on electric systems, across a broad spectrum of utility circumstances. Methods that have not had the benefit of that analysis and withstood the test of time must be viewed with skepticism, and proponents of such methods bear a special burden of proving that they do a more accurate job of identifying cost-causation than do recognized methods, and are not merely ad hoc creations designed simply to support a particular result desired by the analyst.

Q HOW MUCH WEIGHTING DOES OPC'S A&P ALLOCATION METHOD GIVE TO SUMMER DEMANDS?

A Based on the information presented on Schedule BAM-DIR, page 3, the peak demands occurring during the three summer peak months have a weighting of **less**

than 17% in her A&P allocation factor. That means that loads at other times are weighted 83%, or nearly five times as much.

Q IS THIS WEIGHTING A REASONABLE ONE FOR SUMMER PEAK DEMANDS?

A No. This low weighting is fundamentally unreasonable. It is summer peak demands that drive the need for the addition of generation capacity and an allocation methodology which gives only 17% weighting to those summer peak demands cannot be regarded as reasonable. OPC's allocations skew the results so that high load factor customers are allocated a significant amount of costs that they are not responsible for causing.

Q TO DEVELOP THE WEIGHTING FOR THE DEMAND COMPONENT AND THE ENERGY COMPONENT OF OPC'S A&P ALLOCATION FACTOR, WHAT LOAD FACTOR DID OPC USE?

A OPC used a 62% load factor. The worksheet characterizes this as based on annual energy sales and annual system peak demand. It is not.

Q DID OPC USE ANNUAL ENERGY AND THE ANNUAL PEAK?

A No. The load factor which OPC has developed is erroneous. According to OPC's worksheet, the energy used is system (Missouri plus Kansas plus requirements wholesale) energy. However, the "annual system peak" used bears no relationship to the annual total company system peak. In fact, the demand number which OPC uses to calculate the load factor is approximately 600 megawatts (MW) below the total company peak. This is a major discrepancy. The system annual load factor is approximately 51%, not 62%.

This error overstates the load factor, thereby overstating the energy component of the A&P allocation factor. Thus, even if one were to accept OPC's method, the allocation factors are wrong. This, too, results in an over-allocation of costs to large high load factor customers such as those served under the Large Power rate.

Q YOU MENTIONED BEFORE THAT OPC'S A&P ALLOCATION METHOD WAS NOT USED IN ANY OTHER JURISDICTION. WHAT IS THE SITUATION WITH RESPECT TO WHAT OPC CALLS THE "TOU" STUDY?

A It is not used anywhere else either. This method is conceptually similar to the method that was advanced by Commission Staff in the previously referenced Aquila class cost of service case. In that case, Staff admitted that this methodology had not been used in any other state and, in fact, **has not ever** been adopted, even in Missouri.

This puts the "TOU" study in the same category as Staff's and OPC's A&P studies which I previously criticized, and pointed out have no precedent to support them and certainly no acceptance in the industry.

Q DOES MS. MEISENHEIMER EXPLAIN HOW SHE ALLOCATES CAPACITY AND ENERGY COSTS IN THE "TOU" STUDY?

A No, she does not. However, a review of her workpapers indicates that an hourly assignment of capacity costs of generation plants was made. It appears that a capacity component was identified for each plant. (I will discuss this in more detail later). Then, a production dispatch model was run to determine the output of each plant during each hour of the year. The dispatch level (output) of each plant, for each hour, was then totaled and divided into the identified capacity component. This per unit capacity component was then multiplied times the output of each plant in each hour in order to allocate capacity costs to each hour that a plant ran. This was repeated for each plant and a total capacity cost was developed for each hour. These hourly capacity costs were then allocated to customer classes based on class loads in each hour.

Q HAVE YOU BEEN ABLE TO ANALYZE THE RESULTS OF OPC'S CAPACITY COST ASSIGNMENT TO HOURS?

A Yes. Please refer to Schedule 1 COS-R attached to this testimony.

Q PLEASE EXPLAIN THIS GRAPH.

A This graph shows an hourly profile of the results of OPC's TOU capacity cost assignment. The average hourly load is represented by the blue line with the large squares. Each point on this chart for the load (left scale) is equal to the sum of the loads in each identified hour (i.e., 1:00 a.m., 2:00 p.m., etc.) of each day, divided by 365 days. Accordingly, this represents an average daily load profile.

The capacity charge line (red with pyramids) was created in a similar fashion. It shows the hourly assignment of capacity costs under OPC's approach. Note that the capacity cost per hour (right scale) in the middle of the night (4:00 AM) is almost as high as the capacity cost in the middle of the afternoon (5-6 PM), when the peaks occur. Given this profile of capacity cost assignments, OPC's "TOU" method cannot be described as cost-causation at all. There is no reasonable basis to believe that loads in the middle of the night cause installation of generation capacity. Rather, it is the peak loads occurring during the day, especially the highest ones that occur in the summer, that drives the need for capacity additions.

Rather than being "cost-causation," OPC's "TOU" allocation methodology is an <u>assignment</u> method which puts the same per kW capacity cost of a generation facility into every hour of the year that it runs.

Q HAS STAFF PREVIOUSLY CHARACTERIZED THIS TYPE OF COST ALLOCATION METHODOLOGY?

A Yes. It actually originated with Staff, and a form of it has been adopted by OPC. In the previously mentioned Aquila class cost of service case, Case No. EO-2002-384, Staff witness James Watkins testified that the methodology was not cost-causation at all, but rather was something developed many years ago in an effort to have data that might be used in developing time-of-use rates. Stretching the methodology to use it in allocating costs among customer classes extends it well beyond any reasonable use.

Q YOU MENTIONED THAT OPC IDENTIFIED A CAPACITY COMPONENT FOR EACH GENERATING PLANT. WHAT WAS THE BASIS FOR THAT CAPACITY COMPONENT?

A It is obvious from the workpapers that the amount used for the capacity component of each plant was the gross original cost of the plant. That is, the total nominal dollars spent to build the plant. It was not even reduced for accumulated reserve for depreciation. It is most unusual to use installed costs (depreciated or not) as a basis to represent and allocate capacity costs. More typically, an annual revenue requirement would be determined by giving consideration to investment net of accumulated deprecation, cost of capital, income tax expense and other fixed costs. Even if there were no other problems with OPC's study, this use of gross original cost is a serious flaw.

Q HOW DOES STAFF ALLOCATE FUEL AND VARIABLE PURCHASED POWER COSTS?

A On class energy requirements, adjusted for losses.

Q HOW DOES OPC ALLOCATE FUEL AND VARIABLE PURCHASED POWER COSTS?

A On class energy requirements, adjusted for losses.

Q DO YOU HAVE ANY DISAGREEMENT WITH THE ALLOCATION OF FUEL AND VARIABLE PURCHASED POWER COSTS ON THE BASIS OF CLASS ENERGY REQUIREMENTS, ADJUSTED FOR LOSSES?

A In the context of traditional studies like coincident peak and A&E, I do not. However, in the context of the non-traditional studies that both Staff and OPC have offered, all of which heavily weight the energy component in the allocation of fixed or demand-related generation costs, it is not appropriate.

Q PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO ALLOCATE ENERGY COSTS IN THIS FASHION WHEN USING STUDIES SUCH AS THOSE ADVANCED BY OPC AND STAFF?

A The OPC and Staff studies allocate significantly more generation fixed costs to high load factor customers than do the traditional studies. In other words, the higher the load factor of a class, the larger the share of the generation fixed costs that gets allocated to the class. If the costs allocated to classes under these methods were divided by the contribution of these classes to the system peak demand, or by the A&E demand, the result is a higher capital cost per kW for the higher load factor classes, and a lower capital cost per kW for the low load factor classes. Effectively, this means that the high load factor classes have been allocated an above average share of capital cost for generation, and the low load factor customer classes have been allocated a below average share.

Given these allocations of capital cost, it is inappropriate to allocate average fuel costs. Rather, the fuel cost allocation should recognize that the higher load factor customer classes should receive below average fuel cost to correspond to the above-average capital cost (similar to base load units) allocated to them, and the lower load factor classes should get an allocation of fuel costs that is above the average, corresponding to the lower than average capital cost (i.e., peaking units) allocated to them.

Q WHY WOULD IT BE APPROPRIATE TO RECOGNIZE A LOWER FUEL COST ALLOCATION TO THOSE CLASSES THAT ARE ALLOCATED A HIGHER CAPITAL COST?

A It is not only appropriate, but it is essential if the energy-weighted allocations of generation costs are employed. Failure to make this kind of distinction would give high load factor customers the worst of both worlds – above average capital costs and average energy costs; and the low load factor customers the best of both worlds – below average capital cost and average fuel cost.

Q HAVE YOU PREPARED ANY CALCULATIONS AND DEVELOPED A SCHEDULE TO ILLUSTRATE THIS?

A Yes, I have. Please refer to Schedule 2 COS-R attached to this testimony. This schedule compares the capacity costs per kW and the energy cost per kilowatthour (kWh) across classes for the traditional allocation methods, Staff's A&P method, OPC's A&P method and OPC's "TOU" method. To establish a common framework of costs for the analysis, so as to isolate the impacts just of allocation methodology, I used the total generation capacity costs and total generation energy costs from Staff's cost of service study and applied Staff and OPC demand and energy allocators to these total amounts. I then divided the results by the A&E capacity kilowatts (kW) and by the class megawatthours (MWh).

Q PLEASE EXPLAIN WHAT THIS SCHEDULE SHOWS.

A The first block of the schedule shows that under traditional allocation methods the capacity costs per kW and the energy costs per kWh allocated to each class are the same. The second block shows the allocation results under Staff's A&P method. Note that the impact is to allocate significantly more capital costs, in fact, 27% more, to the Large Power class than under the traditional approaches, which allocate average capacity costs. Note also that there is virtually no difference among classes as to the energy costs allocated. The differences that do exist are largely a result just of rounding, and the inclusion of minor items that may be allocated slightly differently. The third block shows similar results for OPC's study, except that the capital cost allocated to the LP class is even larger, and, once again, the energy cost is virtually identical.

The final block shows the OPC "TOU" study. Predictably, an even heavier allocation of capacity costs is made to the Large Power class, and even less is allocated to the Residential class. Once again, the energy costs across classes, while varying slightly, are nearly identical.

Q YOU INDICATED THAT THE ENERGY COSTS PER KWH ARE NOT MEANINGFUL DIFFERENT UNDER THESE ALLOCATIONS. HOW DIFFERENT ARE THE ENERGY COSTS OF THE DIFFERENT GENERATING FACILITIES?

A They are quite diverse. For example, the fuel cost for the Wolf Creek nuclear plant is less than 0.5¢ per kWh, the base load coal plants have fuel costs in the range of 0.8¢ to 1.4¢ per kWh, the combined cycle units have fuel costs in the range of 7¢, and the peaking units have fuel costs over 8¢ per kWh. (Note: These average fuel cost numbers are taken from KCPL's 2005 FERC Form 1 report.) Obviously, if some classes are allocated higher capacity costs than others, they should be entitled to at least an above-average share of the energy output from the higher capital cost, more fuel efficient, base load type generating units. None of the allocation methods advanced by Staff and OPC recognize this correspondence, and as a result over-allocate costs to high load factor customers

Q WHAT DO YOU BELIEVE SCHEDULE 2 COS-R SHOWS?

A I believe it demonstrates that the A&P and the "TOU" methods that have been sponsored in this case by Staff and OPC are highly non-symmetrical. They allocate capacity costs differentially across customer classes as a function of load pattern, but do virtually nothing to offset this higher allocation of capacity costs with a correspondingly (meaningfully) lower allocation of energy costs. Thus, I believe these studies are further flawed for this reason and are entitled to no weight.

Allocation of Certain Administrative and General Expenses

Q DO YOU HAVE ANY COMMENTS ON THE ALLOCATION OF ANY OF THE EXPENSES IN THE ADMINISTRATIVE AND GENERAL CATEGORY?

A Yes. In its study, Staff allocated certain administrative and general expense accounts on energy sales, rather than upon the more appropriate salaries and wages (i.e., payroll) or gross plant allocation factors. I address the problems with these allocations at page 28 of my direct testimony on cost of service and will only say here that there is no rationale for allocating these particular accounts on energy, it is not conventional to do so, and it should not be done in this case. Please note that this statement applies only to the Staff's studies and not to the OPC studies. OPC used payroll for most of the accounts and gross plant for one of the accounts.

Allocation of Certain Distribution Costs

Q WHAT IS THE LARGEST DIFFERENCE AMONG THE PARTIES WITH RESPECT TO THE ALLOCATION OF COSTS IN THE DISTRIBUTION ACCOUNTS?

A The largest difference among the parties is the issue of whether or not there is a customer component to the primary portion of the distribution system, namely Account 364 (Poles, Towers and Fixtures), Account 365 (Overhead Conductors and Devices), Account 366 (Underground Conduit) and Account 367 (Underground Conductors and Devices). KCPL, Staff and I all recognize the existence of a customer component in the primary portion of these accounts while OPC does not.

The general accepted industry practice is to recognize the customer component in the primary distribution system. The text and diagram at pages 11 and 12 of my direct testimony generally show the nature of the distribution system and explain why there is a customer component. Briefly, the more geographically dispersed the customers are, and the more of them that there are, the greater the extent of the primary distribution network needed to provide service. It takes much more primary network to serve 10,000 customers that each have a 10 kW load than it does to serve 20 customers that each have a 5,000 kW load.

Q DOES OPC EXPLAIN THE BASIS FOR IGNORING THE ALLOCATION OF DISTRIBUTION COSTS TO THE CUSTOMER COMPONENT?

A No. The only statement I can find is two sentences on page 7 of Ms. Meisenheimer's direct testimony. That language is:

> "For example, with the exception of service drops and meters, most of the facilities between the utility customer's point-of-service and the distribution substation are shared facilities. Since no portion of such facilities are directly related to the number of customers, the

> associated costs are best classified as demand-related, rather than customer-related."

Q DO THESE STATEMENTS PROVIDE A RATIONALE FOR IGNORING A CUSTOMER COMPONENT IN THE PRIMARY DISTRIBUTION SYSTEM?

A No. While it is true that many of these facilities are shared, in the sense that they are used to provide service to many customers, that says nothing about whether there is a customer component. The conclusion in the second sentence above simply does not follow from the previous assertions, and does not support the treatment that OCA gave to the primary distribution system.

Q ARE THERE OTHER ISSUES WITH RESPECT TO THE ALLOCATION OF DISTRIBUTION ACCOUNTS?

A Yes, there are other issues with respect to the types of demands used to allocate some of the investments, but in comparison to the other issues in this proceeding, they are relatively minor, and I will not discuss them.

Other Problems in Studies

Q WHAT WILL YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A I will address certain other problems, inconsistencies and/or errors that we have identified in Staff's and OPC's cost allocation studies, that I have not previously addressed.

Q DO YOU HAVE ANY COMMENTS OR ISSUES WITH RESPECT TO THE ALLOCATION OF REVENUES FROM OFF-SYSTEM SALES?

A Yes. Both Staff and OPC allocate 100% of the fuel and variable purchased power expenses that support these sales on an energy basis. However, they then allocate 100% of the revenues from these sales (the identified fuel and variable purchased power cost component plus the margin) on a demand basis. This is fundamentally inconsistent. If Staff and OPC desire to allocate the profit component on a demand basis, they should at least allocate the identified fuel and variable purchased power component of the sales revenue on an energy basis to offset the cost of fuel and variable purchased power that was allocated to classes on an energy basis. Failure to do so will clearly over-allocate costs to high load factor customers such as those served on the Large Power rate.

Q WHAT IS THE APPROXIMATE EFFECT OF CORRECTING FOR THIS INCONSISTENCY?

A The impact is to reduce the costs allocated to the Large Power class by approximately $1.3 million and to reduce the costs allocated to the Large General Service class by approximately $500,000. The costs allocated to the Residential class increase by approximately $1.7 million. The costs allocated to the Small General Service and Medium General Service classes change only in minor amounts.

Q IN STAFF'S STUDY, WHAT LOAD FACTOR WAS USED TO WEIGHT THE AVERAGE COMPONENT OF THE ALLOCATION FACTOR?

A Staff used a load factor of approximately 53.8%.

Q IS THIS CORRECT ANNUAL LOAD FACTOR?

A No. This load factor was developed by KCPL utilizing class contributions to annual system peak demand that had not been adjusted to the generation level to account for losses. As a result, the demand number in the denominator of the load factor calculation was understated and, consequently, the load factor was overstated. The correct annual load factor to use is the one after adjustment for losses in the demands and is 51% (see Schedule 3 attached to my direct testimony).

Q DOES MAKING THIS CORRECTION HAVE A LARGE IMPACT ON THE CLASSES?

A No. The difference is relatively minor in the case of the Staff's study. (Because the error made by OPC is significantly larger, that is not the case in the context of the OPC's studies.) The impact of correcting the Staff's annual load factor is to reduce costs allocated to the Large Power Service class by approximately $300,000, to reduce costs allocated to the Large General Service class by approximately $130,000. Costs allocated to the Residential class increase by approximately $400,000, and there is relatively little impact on the Small General Service and Medium General Service classes.

Q HAVE YOU DEVELOPED ANY SCHEDULES TO SHOW THE RESULTS OF MAKING THESE CORRECTIONS?

A Yes. Schedule 3.1 COS-R shows the impact of correcting Staff's study for the energy costs of sales.

Schedule 3.2 COS-R shows the impact of that correction plus the correction of the annual load factor.

Schedule 3.3 COS-R shows the effect of the two previous corrections plus a change in the allocation of certain Administrative and General expenses, which I discussed earlier in my rebuttal testimony.

As compared to Staff's filed study, the impact of these three adjustments is to reduce the costs allocated to the Large Power class by approximately $3 million, to reduce the costs allocated to the Large General Service class by approximately $1.2 million and to increase the costs allocated to the Residential class by approximately $3.7 million. There is only a small impact on the costs allocated to the Small General Service and the Medium General Service classes.

Q IF THESE ADJUSTMENTS WERE MADE TO STAFF'S COST OF SERVICE STUDY WOULD YOU SUPPORT STAFF'S COST OF SERVICE STUDY?

A No, I would not. For reasons previously discussed, I believe that the allocation methodology that Staff has chosen for production and transmission fixed costs substantially over-allocates costs to high load factor customers such as the Large Power Service class. Accordingly, I would not adopt Staff's study even if these changes were made. However, making these corrections does indicate that even with Staff's allocation of generation and transmission fixed costs, the Large Power service class and other non-residential classes are being charged rates even further above their cost of service.

Recommended Revenue Allocation

Q HAVE YOU REVIEWED THE TESTIMONY OF STAFF WITNESS BUSCH WITH RESPECT TO ALLOCATION OF ANY CHANGE IN REVENUES?

A Yes. Mr. Busch recommends making some movement toward class cost of service based on the results of Staff's cost of service study. Specifically, on a revenue neutral basis he proposes to decrease the revenues from each of the non-residential classes by an amount equal to the smallest decrease that Staff calculates would be appropriate to move any of the non-residential classes to cost of service. This turns out to be only 2.76%, which is driven by the Large General Service class. Even Staff's studies indicate decreases larger than this (up to nearly 10%) for other non-residential classes.

Q HAVING REVIEWED THE DIRECT TESTIMONY OF OTHER PARTIES, DO YOU HAVE ANY CHANGES IN YOUR RECOMMENDATIONS?

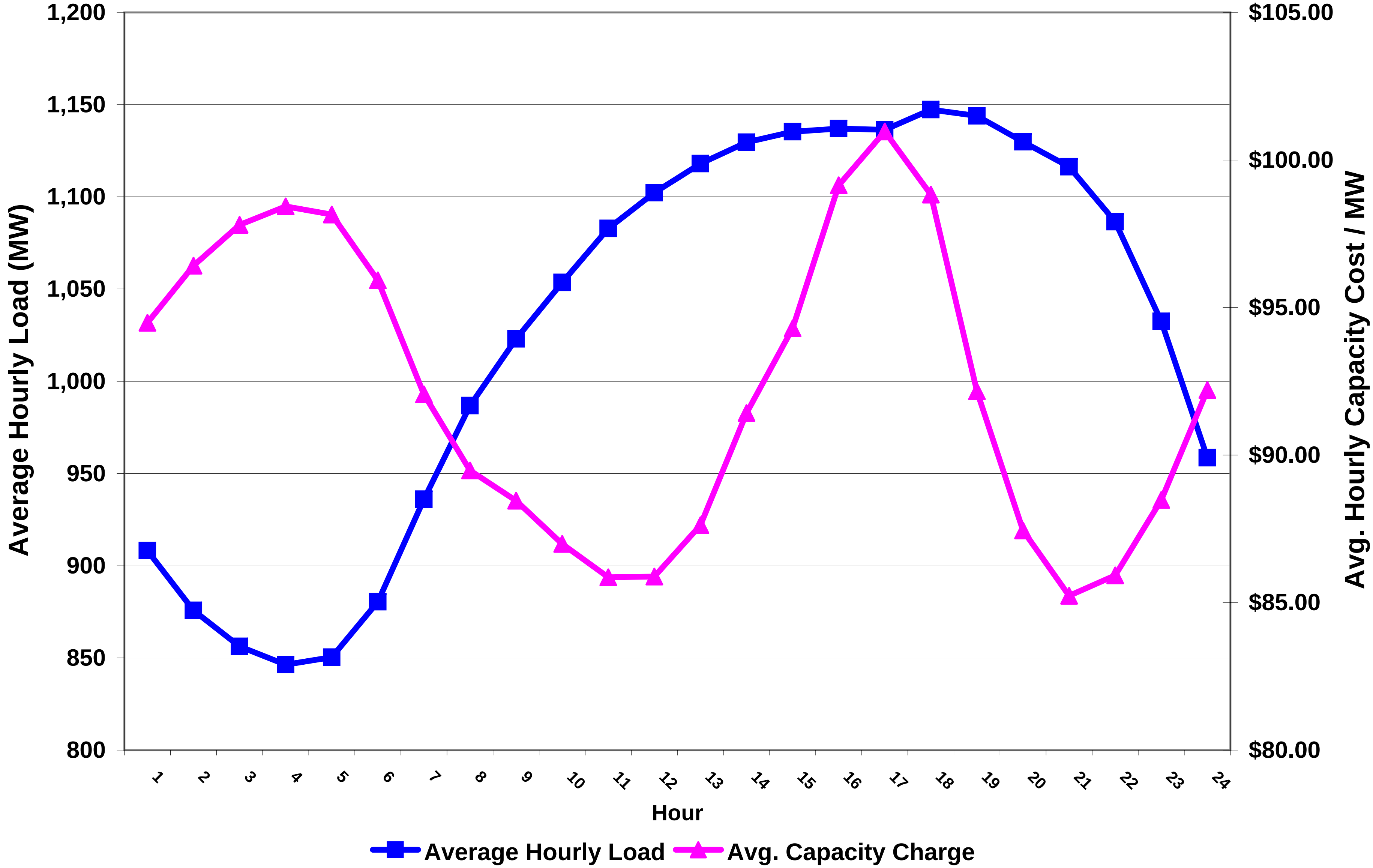
A No. I believe the recommendations which I made in my direct testimony concerning cost of service and revenue allocation issues continue to be appropriate. As a result, I believe the Commission should adopt the Average & Excess - 3 NCP cost of service methodology, and should adjust class revenues consistent with the guidelines which I set forth on Schedule 9 attached to my direct testimony on cost of service, revenue allocation and rate design.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY ON COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN?

A Yes, it does.

KANSAS CITY POWER & LIGHT COMPANY - MISSOURI

OPC'S HOURLY ASSIGNMENT OF GENERATION CAPITAL COSTS



Schedule 1 COS-R
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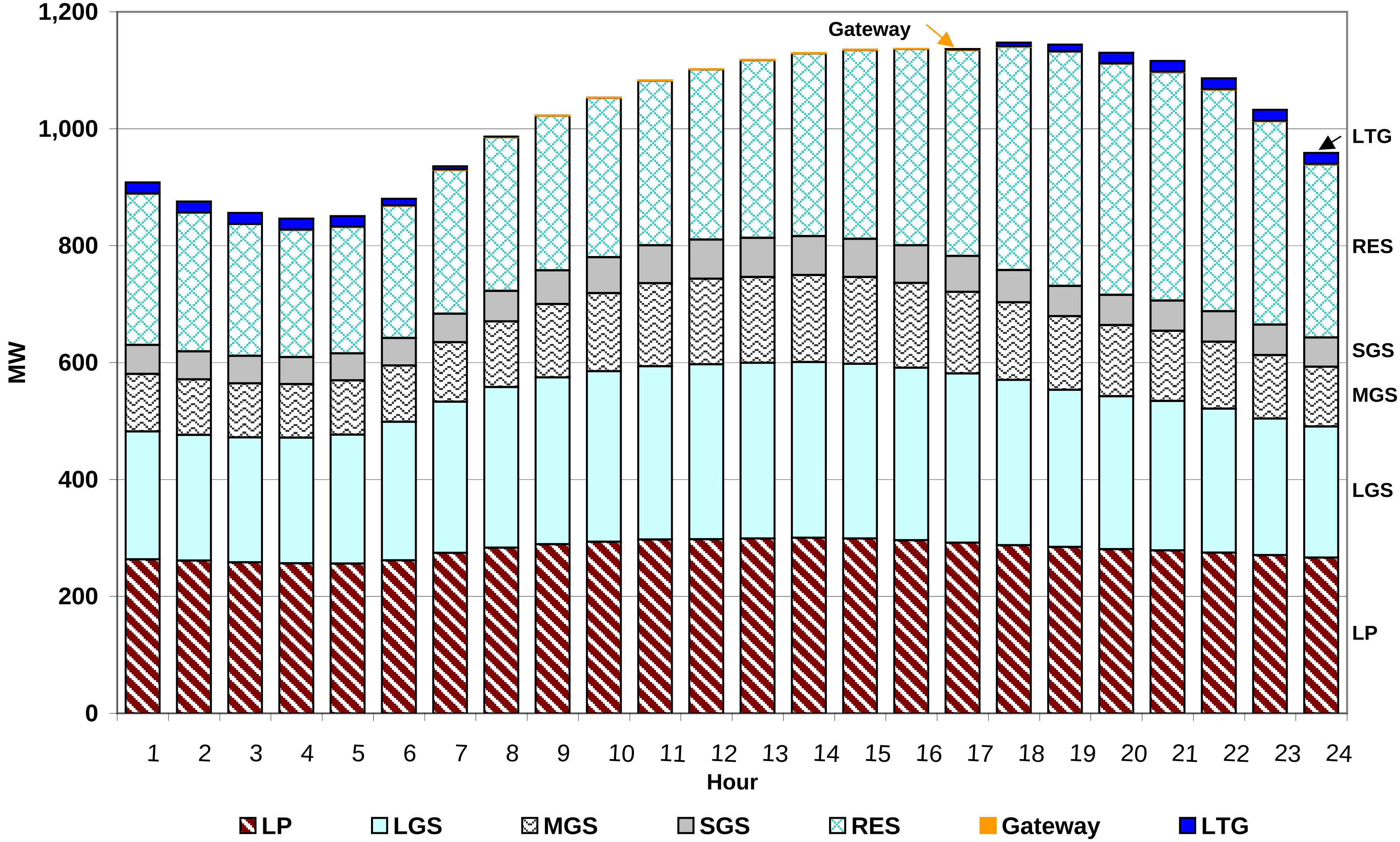
KANSAS CITY POWER & LIGHT COMPANY - MISSOURI

CLASS AVERAGE HOURLY LOAD FROM OPC TOU ALLOCATOR DATA



KANSAS CITY POWER & LIGHT - MISSOURI

COMPARISON OF STAFF'S AND OPC'S GENERATION CAPACITY AND ENERGY
CLASS REVENUE REQUIREMENTS WITH TRADITIONAL ALLOCATION METHODOLOGY

	Traditional Method				Staff COSS				OPC COSS				OPC TOU-COSS			
	Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.		Capacity Rev Req.		Energy Rev Req.	
Customer Class	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total MO Retail	108		1.90		108		1.90		108		1.90		108		1.90	
Residential	108	**0%**	1.90	**0%**	87	**-19%**	1.94	**2%**	84	**-22%**	1.89	**-1%**	77	**-29%**	1.97	**4%**
Small GS	108	**0%**	1.90	**0%**	106	**-2%**	1.94	**2%**	103	**-5%**	1.90	**0%**	101	**-6%**	1.90	**0%**
Medium GS	108	**0%**	1.90	**0%**	108	**0%**	1.94	**2%**	107	**-1%**	1.92	**1%**	106	**-2%**	1.93	**2%**
Large GS	108	**0%**	1.90	**0%**	125	**16%**	1.93	**2%**	125	**16%**	1.92	**1%**	129	**19%**	1.89	**-1%**
Large Power	108	**0%**	1.90	**0%**	137	**27%**	1.89	**0%**	140	**30%**	1.90	**0%**	152	**41%**	1.84	**-3%**

MOPSC STAFF FUNCTIONAL CLASS COST OF SERVICE STUDY - SUMMARY OF RESULTS
KANSAS CITY POWER & LIGHT COMPANY - 12 MONTHS ENDING SEPTEMBER 30, 2005
MOPSC CASE NO. ER-2006-0314

STAFF STUDY WITH ENERGY COST OF SALES ALLOCATED ON ENERGY WITH LOSSES

FUNCTIONAL CATEGORY	MISSOURI RETAIL	RESIDENTIAL	SMALL GENERAL SERVICE	MEDIUM GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
Production-Capacity	$217,406,900	$73,296,551	$12,261,753	$25,840,459	$53,375,957	$52,632,180	$0
Production-Energy	$161,960,634	$48,619,394	$8,880,906	$19,114,535	$41,528,981	$43,816,817	$0
Transmission	$22,457,045	$7,571,167	$1,266,578	$2,669,190	$5,513,469	$5,436,641	$0
Distribution Substations	$9,945,346	$4,371,840	$575,882	$1,179,271	$2,050,386	$1,767,967	$0
OH/UG Lines							
Pri-Customer Related	$14,648,988	$7,689,620	$2,547,488	$2,297,196	$1,808,593	$306,091	$0
Sec-Customer Related	$8,197,783	$4,410,867	$1,459,632	$1,310,621	$960,026	$56,638	$0
Pri-Demand Related	$31,031,435	$14,358,975	$2,216,676	$3,609,328	$7,086,815	$3,759,643	$0
Sec-Demand Related	$14,115,863	$7,445,682	$1,146,325	$1,854,852	$3,233,350	$435,654	$0
Line Transformers							
Sec-Customer Related	$5,886,637	$3,167,340	$1,048,128	$941,126	$689,372	$40,671	$0
Sec-Demand Related	$5,490,706	$3,493,205	$420,168	$552,928	$902,769	$121,637	$0
Services	$3,423,384	$1,817,375	$1,167,079	$322,945	$114,204	$1,780	$0
Meters & Recorders	$5,693,974	$3,249,775	$1,059,865	$723,381	$354,838	$306,115	$0
Company-Owned Lighting	$3,691,809	$0	$0	$0	$0	$0	$3,691,809
Meter Reading	$4,373,305	$3,732,156	$393,764	$82,953	$30,718	$133,714	$0
Customer Records & Collection	$10,200,785	$8,098,954	$1,181,363	$508,060	$410,928	$1,479	$0
Customer Assistance	$1,116,892	$269,897	$84,412	$120,796	$352,792	$288,995	$0
Sales Exp	$926,869	$486,537	$161,184	$145,348	$114,433	$19,367	$0
Uncollectible	$3,456,580	$2,998,237	$343,584	$114,758	$0	$0	$0
Other Cust Service	$4,336,006	$2,276,078	$754,040	$679,955	$535,332	$90,601	$0
Customer Deposits	$46,645	$26,136	$17,058	$2,863	$490	$97	$0
Sales-Related A&G Expenses	$16,298,282	$4,855,953	$887,040	$1,909,482	$4,159,921	$4,485,886	$0
Miscellaneous Assignments	$2,456,020	$1,395,749	$165,906	$209,937	$401,449	$282,979	$0
Income Taxes	$38,237,098	$16,956,426	$3,186,533	$4,495,701	$7,484,835	$6,113,603	$0
	$585,398,985	$220,587,916	$41,225,363	$68,685,685	$131,109,658	$120,098,554	$3,691,809
Reallocate Lighting Costs	$0	$1,399,963	$261,637	$435,914	$832,088	$762,206	($3,691,809)
TOTAL COST OF SERVICE	**$585,398,985**	**$221,987,879**	**$41,487,000**	**$69,121,600**	**$131,941,746**	**$120,860,760**	**$0**
CCOS %	100.00%	37.92%	7.09%	11.81%	22.54%	20.65%	0.00%
RATE REVENUE	$484,517,360	$171,390,199	$36,586,080	$62,437,672	$109,196,683	$98,849,995	$6,056,731
Reallocation of Lighting Revenues	$0	$2,296,760	$429,238	$715,155	$1,365,113	$1,250,465	($6,056,731)
TOTAL RATE REVENUE	**$484,517,360**	**$173,686,959**	**$37,015,318**	**$63,152,827**	**$110,561,796**	**$100,100,460**	**$0**
Economic Development Credits	($466,753)	($176,996)	($33,079)	($55,112)	($105,200)	($96,365)	$0
Interruptible (PLCC) Credits	($394,655)	($133,054)	($22,259)	($46,908)	($96,892)	($95,542)	$0
Revenue from Off-System Sales	$92,895,816	$29,584,154	$5,165,786	$11,002,029	$23,318,897	$23,824,950	$0
Miscellaneous Revenue	$8,847,217	$3,707,411	$779,455	$1,087,944	$1,831,730	$1,440,676	$0
TOTAL OPERATING REVENUE	**$585,398,985**	**$206,668,473**	**$42,905,222**	**$75,140,780**	**$135,510,331**	**$125,174,179**	**$0**
RATE REVENUE DEFICIENCY	**$0**	**$15,319,406**	**($1,418,222)**	**($6,019,181)**	**($3,568,584)**	**($4,313,418)**	**$0**
Required % Change							
to operating revenue	**0.00%**	**7.41%**	**-3.31%**	**-8.01%**	**-2.63%**	**-3.45%**	**0.00%**
to rate revenue	**0.00%**	**8.82%**	**-3.83%**	**-9.53%**	**-3.23%**	**-4.31%**	**0.00%**

Changed "Energy Cost of Sales" allocator to ENERGY1 - Run 1 of 3

MOPSC STAFF FUNCTIONAL CLASS COST OF SERVICE STUDY - SUMMARY OF RESULTS
KANSAS CITY POWER & LIGHT COMPANY - 12 MONTHS ENDING SEPTEMBER 30, 2005
MOPSC CASE NO. ER-2006-0314

STAFF STUDY WITH ENERGY COST OF SALES ALLOCATED ON ENERGY WITH LOSSES & CORRECTED LOAD FACTOR

FUNCTIONAL CATEGORY	MISSOURI RETAIL	RESIDENTIAL	SMALL GENERAL SERVICE	MEDIUM GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
Production-Capacity	$217,406,900	$73,785,114	$12,282,464	$25,851,539	$53,231,794	$52,255,989	$0
Production-Energy	$161,960,634	$48,619,394	$8,880,906	$19,114,535	$41,528,981	$43,816,817	$0
Transmission	$22,457,045	$7,621,633	$1,268,717	$2,670,335	$5,498,578	$5,397,782	$0
Distribution Substations	$9,945,346	$4,371,840	$575,882	$1,179,271	$2,050,386	$1,767,967	$0
OH/UG Lines							
Pri-Customer Related	$14,648,988	$7,689,620	$2,547,488	$2,297,196	$1,808,593	$306,091	$0
Sec-Customer Related	$8,197,783	$4,410,867	$1,459,632	$1,310,621	$960,026	$56,638	$0
Pri-Demand Related	$31,031,435	$14,358,975	$2,216,676	$3,609,328	$7,086,815	$3,759,643	$0
Sec-Demand Related	$14,115,863	$7,445,682	$1,146,325	$1,854,852	$3,233,350	$435,654	$0
Line Transformers							
Sec-Customer Related	$5,886,637	$3,167,340	$1,048,128	$941,126	$689,372	$40,671	$0
Sec-Demand Related	$5,490,706	$3,493,205	$420,168	$552,928	$902,769	$121,637	$0
Services	$3,423,384	$1,817,375	$1,167,079	$322,945	$114,204	$1,780	$0
Meters & Recorders	$5,693,974	$3,249,775	$1,059,865	$723,381	$354,838	$306,115	$0
Company-Owned Lighting	$3,691,809	$0	$0	$0	$0	$0	$3,691,809
Meter Reading	$4,373,305	$3,732,156	$393,764	$82,953	$30,718	$133,714	$0
Customer Records & Collection	$10,200,785	$8,098,954	$1,181,363	$508,060	$410,928	$1,479	$0
Customer Assistance	$1,116,892	$269,897	$84,412	$120,796	$352,792	$288,995	$0
Sales Exp	$926,869	$486,537	$161,184	$145,348	$114,433	$19,367	$0
Uncollectible	$3,456,580	$2,998,237	$343,584	$114,758	$0	$0	$0
Other Cust Service	$4,336,006	$2,276,078	$754,040	$679,955	$535,332	$90,601	$0
Customer Deposits	$46,645	$26,136	$17,058	$2,863	$490	$97	$0
Sales-Related A&G Expenses	$16,298,282	$4,855,953	$887,040	$1,909,482	$4,159,921	$4,485,886	$0
Miscellaneous Assignments	$2,456,020	$1,395,749	$165,906	$209,937	$401,449	$282,979	$0
Income Taxes	$38,237,098	$16,956,426	$3,186,533	$4,495,701	$7,484,835	$6,113,603	$0
	$585,398,985	$221,126,945	$41,248,214	$68,697,910	$130,950,604	$119,683,504	$3,691,809
Reallocate Lighting Costs	$0	$1,403,384	$261,782	$435,992	$831,079	$759,572	($3,691,809)
TOTAL COST OF SERVICE	**$585,398,985**	**$222,530,329**	**$41,509,996**	**$69,133,902**	**$131,781,683**	**$120,443,076**	**$0**
CCOS %	100.00%	38.01%	7.09%	11.81%	22.51%	20.57%	0.00%
RATE REVENUE	$484,517,360	$171,390,199	$36,586,080	$62,437,672	$109,196,683	$98,849,995	$6,056,731
Reallocation of Lighting Revenues	$0	$2,302,372	$429,476	$715,282	$1,363,457	$1,246,144	($6,056,731)
TOTAL RATE REVENUE	**$484,517,360**	**$173,692,571**	**$37,015,556**	**$63,152,954**	**$110,560,140**	**$100,096,139**	**$0**
Economic Development Credits	($466,753)	($177,429)	($33,097)	($55,122)	($105,073)	($96,032)	$0
Interruptible (PLCC) Credits	($394,655)	($133,941)	($22,296)	($46,928)	($96,631)	($94,859)	$0
Revenue from Off-System Sales	$92,895,816	$29,687,401	$5,170,163	$11,004,371	$23,288,431	$23,745,450	$0
Miscellaneous Revenue	$8,847,217	$3,716,240	$779,829	$1,088,145	$1,829,125	$1,433,878	$0
TOTAL OPERATING REVENUE	**$585,398,985**	**$206,784,842**	**$42,910,155**	**$75,143,419**	**$135,475,993**	**$125,084,576**	**$0**
RATE REVENUE DEFICIENCY	**$0**	**$15,745,487**	**($1,400,160)**	**($6,009,517)**	**($3,694,310)**	**($4,641,499)**	**$0**
Required % Change							
to operating revenue	**0.00%**	**7.61%**	**-3.26%**	**-8.00%**	**-2.73%**	**-3.71%**	**0.00%**
to rate revenue	**0.00%**	**9.07%**	**-3.78%**	**-9.52%**	**-3.34%**	**-4.64%**	**0.00%**
Changed LF to 50.99% - Run 2 of 3							

MOPSC STAFF FUNCTIONAL CLASS COST OF SERVICE STUDY - SUMMARY OF RESULTS
KANSAS CITY POWER & LIGHT COMPANY - 12 MONTHS ENDING SEPTEMBER 30, 2005
MOPSC CASE NO. ER-2006-0314

STAFF STUDY WITH ENERGY COST OF SALES ALLOCATED ON ENERGY WITH LOSSES, CORRECTED LOAD FACTOR, & REVISED ALLOCATION OF CERTAIN A&G EXPENSES

FUNCTIONAL CATEGORY	MISSOURI RETAIL	RESIDENTIAL	SMALL GENERAL SERVICE	MEDIUM GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE POWER SERVICE	LIGHTING
Production-Capacity	$228,004,745	$77,381,887	$12,881,193	$27,111,714	$55,826,662	$54,803,290	$0
Production-Energy	$162,727,214	$48,849,516	$8,922,941	$19,205,007	$41,725,543	$44,024,208	$0
Transmission	$22,977,594	$7,798,301		$2,732,232	$5,626,034	$5,522,901	$0
Distribution Substations	$10,061,076	$4,422,713	$582,583	$1,192,994	$2,074,245	$1,788,540	$0
OH/UG Lines							
Pri-Customer Related	$15,009,491	$7,878,857	$2,610,180	$2,353,728	$1,853,102	$313,623	$0
Sec-Customer Related	$8,382,909	$4,510,475	$1,492,594	$1,340,218	$981,706	$57,918	$0
Pri-Demand Related	$32,377,195	$14,981,690	$2,312,808	$3,765,856	$7,394,153	$3,922,689	$0
Sec-Demand Related	$14,686,208	$7,746,522	$1,192,641	$1,929,796	$3,363,992	$453,256	$0
Line Transformers							
Sec-Customer Related	$5,942,139	$3,197,203	$1,058,010	$949,999	$695,872	$41,054	$0
Sec-Demand Related	$5,542,474	$3,526,140	$424,129	$558,141	$911,280	$122,784	$0
Services	$3,437,303	$1,824,765	$1,171,825	$324,258	$114,668	$1,787	$0
Meters & Recorders	$5,908,967	$3,372,480	$1,099,883	$750,695	$368,236	$317,673	$0
Company-Owned Lighting	$3,864,538	$0	$0	$0	$0	$0	$3,864,538
Meter Reading	$4,636,565	$3,956,821	$417,467	$87,946	$32,567	$141,763	$0
Customer Records & Collection	$10,626,996	$8,437,346	$1,230,723	$529,288	$428,098	$1,541	$0
Customer Assistance	$1,245,042	$300,864	$94,098	$134,656	$393,270	$322,153	$0
Sales Exp	$1,014,177	$532,367	$176,367	$159,039	$125,212	$21,191	$0
Uncollectible	$3,662,833	$3,177,142	$364,086	$121,606	$0	$0	$0
Other Cust Service	$4,531,774	$2,378,841	$788,084	$710,655	$559,502	$94,691	$0
Customer Deposits	$46,645	$26,136	$17,058	$2,863	$490	$97	$0
Sales-Related A&G Expenses	$19,982	$5,953	$1,088	$2,341	$5,100	$5,500	$0
Miscellaneous Assignments	$2,456,020	$1,395,749	$165,906	$209,937	$401,449	$282,979	$0
Income Taxes	$38,237,098	$16,956,426	$3,186,533	$4,495,701	$7,484,835	$6,113,603	$0
	$585,398,985	$222,658,194	$41,488,322	$68,668,670	$130,366,017	$118,353,244	$3,864,538
Reallocate Lighting Costs	$0	$1,479,656	$275,707	$456,332	$866,336	$786,507	($3,864,538)
TOTAL COST OF SERVICE	**$585,398,985**	**$224,137,851**	**$41,764,029**	**$69,125,002**	**$131,232,354**	**$119,139,750**	**$0**
CCOS %	100.00%	38.29%	7.13%	11.81%	22.42%	20.35%	0.00%
RATE REVENUE	$484,517,360	$171,390,199	$36,586,080	$62,437,672	$109,196,683	$98,849,995	$6,056,731
Reallocation of Lighting Revenues	$0	$2,319,004	$432,104	$715,190	$1,357,773	$1,232,659	($6,056,731)
TOTAL RATE REVENUE	**$484,517,360**	**$173,709,203**	**$37,018,184**	**$63,152,862**	**$110,554,456**	**$100,082,654**	**$0**
Economic Development Credits	($466,753)	($178,711)	($33,299)	($55,115)	($104,635)	($94,993)	$0
Interruptible (PLCC) Credits	($394,655)	($133,941)	($22,296)	($46,928)	($96,631)	($94,859)	$0
Revenue from Off-System Sales	$92,895,816	$29,687,401	$5,170,163	$11,004,371	$23,288,431	$23,745,450	$0
Miscellaneous Revenue	$8,847,217	$3,716,240	$779,829	$1,088,145	$1,829,125	$1,433,878	$0
TOTAL OPERATING REVENUE	**$585,398,985**	**$206,800,192**	**$42,912,581**	**$75,143,334**	**$135,470,747**	**$125,072,130**	**$0**
RATE REVENUE DEFICIENCY	**$0**	**$17,337,659**	**($1,148,552)**	**($6,018,332)**	**($4,238,394)**	**($5,932,380)**	**$0**
Required % Change							
to operating revenue	**0.00%**	**8.38%**	**-2.68%**	**-8.01%**	**-3.13%**	**-4.74%**	**0.00%**
to rate revenue	**0.00%**	**9.98%**	**-3.10%**	**-9.53%**	**-3.83%**	**-5.93%**	**0.00%**

Allocated certain A&G expenses on salaries and wages, rather than energy - Run 3 of 3