Exhibit No.:	
Issues:	Revenue Requirement and Class Cost of Service Issues
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2011-0028
Date Testimony Prepared:	March 25, 2011

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	))))))	**Case No. ER-2011-0028** Tariff No. YE-2011-0116

Rebuttal Testimony and Schedules of

Maurice Brubaker

on Revenue Requirement and
Class Cost of Service Issues

On behalf of

Missouri Industrial Energy Consumers

March 25, 2011

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9371

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	))))))	**Case No. ER-2011-0028** Tariff No. YE-2011-0116

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

Affidavit of Maurice Brubaker

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

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

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2011-0028.

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

M E Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 24th day of March, 2011.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2013
Commission # 09706793

Maria E. Decker
Notary Public

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Rebuttal Testimony of Maurice Brubaker

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

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A Yes. I have previously filed direct testimony on revenue requirement, 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 ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC").

INTRODUCTION AND SUMMARY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A In my rebuttal testimony I will address the cost of service proposals put forth by the Staff of the Public Service Commission ("Staff"), the Office of Public Counsel ("OPC"), and the Missouri Department of Natural Resources ("MDNR"). I will also address certain changes that the Staff proposes to Ameren Missouri's fuel adjustment clause ("FAC") and Staff's proposal with respect to the recovery period for costs incurred in connection with Ameren Missouri's demand-side management ("DSM") program. The fact that I do not address every proposal advanced by other parties should not be construed as acquiescence in those proposals.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A They may be summarized as follows:

1. OPC's allocation of generation fixed, or demand-related, costs is premised on an average and peak ("A&P") allocation method that has been rejected by this and other commissions. It double counts energy consumption and over-allocates costs to high load factor customers, and should again be rejected.

2. Staff has developed an alternative Base, Intermediate and Peaking ("BIP") method that differs materially from the BIP method described in the NARUC Cost Allocation Manual and proposed for implementation in the Kansas City Power & Light Company ("KCPL") case. BIP is not an accepted method and should not be endorsed in this case.

3. Staff's actual implementation of BIP is based on development of a composite allocation factor that is constructed by looking at several different measures of class load responsibility. The alternative application proposed by Staff in this case produces results that are similar to traditional allocation methods.

4. Staff's proposal to change the length of the recovery period in the FAC from 12 months to eight months is unreasonable and should not be accepted.

5. Staff's proposal to capitalize and amortize new DSM costs over a six-year period is not supported and should be rejected. Instead, these balances should be amortized over a ten-year period. Similarly, MDNR's proposal to expense these costs should be rejected.

6. OPC's proposal to allocate the margin earned from OSS on a demand basis has previously been rejected by the Commission and should continue to be rejected in this case.

7. Staff's classification of generation system operation and maintenance ("O&M") expense is similar to Ameren Missouri's classification and should be rejected for the reasons explained in my direct testimony. OPC's allocation is closer to mine, but still contains inappropriate allocations of certain costs.

CLASS COST OF SERVICE ISSUES

Q HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESSES MICHAEL SCHEPERLE AND OPC WITNESSES RYAN KIND AND 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 fixed costs is the largest and most important of these issues, and I will address it first.

OPC's Study

Q WHAT METHOD HAS OPC USED FOR THE ALLOCATION OF GENERATION FIXED, OR DEMAND-RELATED, COSTS?

A OPC's recommended method is an A&P allocation method. In particular, OPC uses the four monthly coincident peak demands of each customer class along with each class's annual energy consumption. The energy component is weighted equal to the system's annual load factor. The result is to give only about 43% weighting to the contributions to the four monthly coincident peaks, and 57% weighting to annual energy consumption.

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

A No. While OPC explains the basis for the use of the four peaks, it does not explain or attempt to justify why this particular averaging method is appropriate for Ameren Missouri.

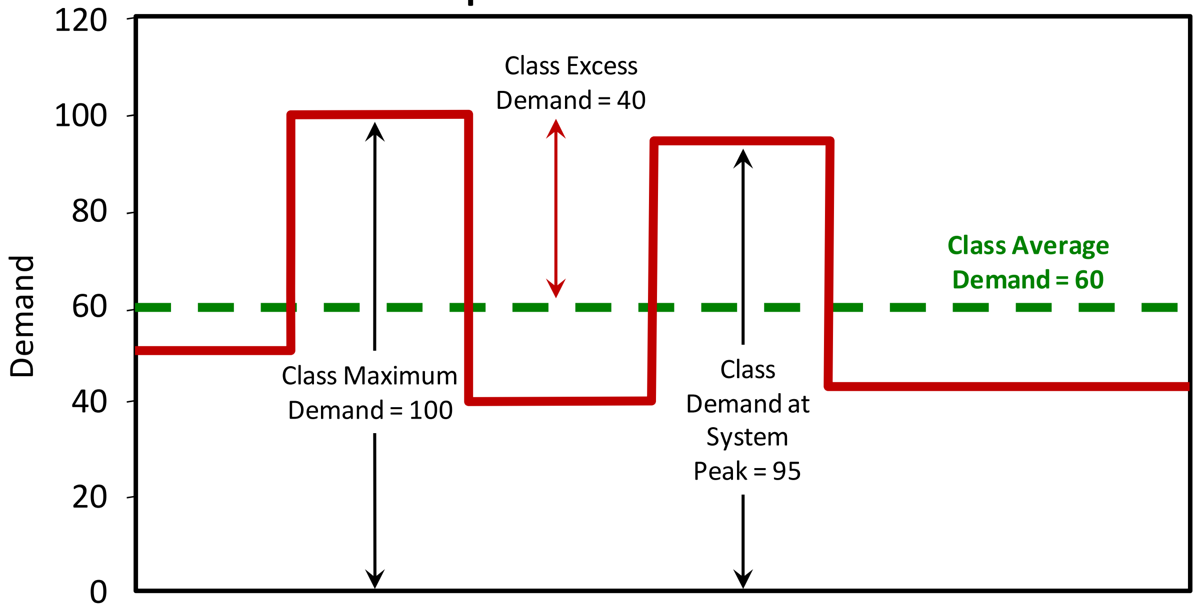
Q HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE AVERAGE AND EXCESS ("A&E") METHODOLOGY THAT YOU AND AMEREN MISSOURI USED IN YOUR CCOS STUDIES?

A OPC's A&P allocator is constructed by multiplying each class's energy responsibility factor (average demand) times the system load factor, and adding that result to each class's percentage contribution to the class peaks multiplied by the quantity one minus the load factor.

Both the A&P and A&E methods are two-step processes. 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 1.

Figure 1

Components of Allocation Factor



Q PLEASE REFER TO FIGURE 1 AND EXPLAIN THE DIFFERENCES.

A Figure 1 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 60, and the excess demand (the difference between its peak demand and its average demand) is 40.

As explained in more detail beginning at page 24 of my direct testimony on cost of service, the A&E method combines the class average demand with the class excess demand in order to construct an allocation factor that reflects average use as well as the excess of each class's maximum demand over its average demand. The A&E allocation factor is developed using the average demand (60) and the excess demand (40) for this class, along with the corresponding demands for all other classes. (This is shown in detail on Schedule MEB-COS-3 attached to my direct testimony on cost of service.)

OPC's A&P method, on the other hand, combines the average demand with the class monthly peak demands. As is evident from Figure 1, the average demand (60) is a component or sub-set of the class peak demand (100) and of the class load coincident with the system peak (95). Accordingly, in the A&P method when roughly equal weighting is given to the average demand and the contribution to system peak demand, the average demand is double-counted. This is a serious error, and has the effect of allocating significantly more costs to high load factor customers than is appropriate.

Q IS THE A&P METHOD A REASONABLE ONE TO USE?

A No, it is not. As noted above, this allocation gives more weighting to annual energy consumption than to the class peaks used in the allocation of the investment in generation facilities. Since generation facilities must be designed to carry the peak loads imposed on them, the heavy weighting given 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 A&P method arbitrarily allocates about half of these costs on annual energy consumption.

Q WHAT METHODOLOGY DID STAFF ADVOCATE FOR JURISDICTIONAL DEMAND ALLOCATION IN A RECENT KCPL RATE CASE, CASE NO. ER-2006-0314?

A In that case, KCPL had proposed a 12 monthly coincident peak allocation methodology for dividing costs between the Kansas retail jurisdiction, the resale jurisdiction and the Missouri retail jurisdiction. Staff witnesses presented extensive testimony demonstrating why summer peak demands were more important than demands in other months, and advocated a method which used only demands imposed on the system during the summer months.

Staff took a similar position in the current KCPL case, Case No. ER-2010-0355.

Q DO KCPL AND AMEREN MISSOURI HAVE A SIMILAR LOAD PATTERN?

A Yes. This is displayed graphically on Schedule MEB-COS-R-1. Clearly, the load patterns are quite similar, with dominant summer loads. Use of summer peak demands in the allocation is clearly as appropriate in the case of Ameren Missouri as it was in the case of KCPL.

Q ISN'T IT TRUE THAT THE STAFF'S ARGUMENTS IN THE KCPL CASE WERE IN THE CONTEXT OF JURISDICTIONAL, AND NOT CLASS, ALLOCATIONS?

A Yes. The issue arose first in the context of revenue requirements, i.e., when considering allocation of costs among jurisdictions. However, the same principles that justify the use of summer peak demands for jurisdictional allocation compel the use of that methodology when allocating among customer classes.

In fact, an appropriate identification of cost-causing peaks is even more important at the class level than at the jurisdictional level. This is because the differences among retail customer class load patterns are much greater than the differences between jurisdictional load patterns. Accordingly, a failure to appropriately distinguish these load characteristics at the class level would introduce even more distortions into the results than is true when the regulatory jurisdictions are viewed in total and compared one with another.

Q HAVE YOU REVIEWED OPC'S TREATMENT OF NON-FUEL GENERATION SYSTEM O&M EXPENSE?

A Yes. Mr. Kind states on pages 3 and 4 of his direct testimony that he followed the "commonly accepted practice in CCOS studies of having expenses follow plant" and then explained that this means that O&M costs are allocated in the same manner as the corresponding plant.

Q DID MR. KIND FOLLOW THIS TREATMENT FOR NON-FUEL GENERATION O&M EXPENSE?

A No, not entirely. From his workpapers it appears that he did apply this method for the allocation of non-fuel generation O&M expense associated with steam, nuclear and hydro facilities. However, for the category of other generation, he allocated a significant amount of the expenses on the energy factor rather than on the demand allocation factor.

I agree with his allocation of generation non-fuel O&M expenses for steam, nuclear and hydro facilities on the demand allocation factor, but disagree with his allocation of the other generation expenses for reasons I explained in my direct testimony on cost of service.

Q HOW DID MR. KIND ALLOCATE THE MARGIN EARNED FROM OSS?

A He allocated this margin based on class demand allocation factors, which is inconsistent with this Commission's recent findings that this margin should be allocated on the basis of class energy sales.

Staff's Study

Q WHAT METHOD DID COMMISSION STAFF USE FOR THE ALLOCATION OF GENERATION FIXED, OR DEMAND-RELATED, COSTS?

A Mr. Scheperle states that he has used something called the Base, Intermediate and Peaking ("BIP") method. In fact, however, Mr. Scheperle has applied what I think is best described as an alternative version of the BIP method. The BIP method described in the NARUC Cost Allocation Manual and as proposed to be implemented in the KCPL rate case, Case No. ER-2010-0355, develops separate allocation factors for different categories of plant. The BIP method is not an accepted method in the industry and rarely has been used, or even proposed. In fact, the principal proponent of the BIP method in the KCPL rate case was only able to identify one instance in the 30 years that he had been proposing the BIP method that it had been adopted by a public service commission.

Q HOW DOES MR. SCHEPERLE'S MODIFIED BIP DIFFER FROM THE BIP METHOD DESCRIBED IN THE NARUC COST ALLOCATION MANUAL AND AS PROPOSED FOR IMPLEMENTATION IN THE KCPL CASE?

A In Mr. Scheperle's alternate BIP application, he devises a composite allocation factor using a combination of class average demands, class 12 monthly non-coincident peak demands and class three summer month non-coincident peak demands. At each stage of the development of the allocation factor components, he subtracts the demands associated with the previously determined component from the total so as to avoid double counting. The resulting factor is applied to all generation fixed costs. Because of the way that the BIP allocation factor was constructed in this case, the end result is comparable to traditional allocation methods such as the A&E method.

Accordingly, while I disagree with the fundamental premise of BIP methods, Mr. Scheperle has implemented it in this case in a way that produces results consistent with generally accepted allocation methods.

Q HOW HAS STAFF CLASSIFIED GENERATION SYSTEM NON-FUEL O&M EXPENSES?

A Mr. Scheperle has essentially followed the classification proposed by Ameren Missouri. For reasons discussed in my direct testimony on cost of service, I disagree with this classification.

Symmetry of Fuel and Capital Cost Allocation

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 like A&P and others, which heavily weight energy 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 NON-TRADITIONAL STUDIES SUCH AS A&P AND OTHERS.

A These 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 of capital costs.

Given these allocations of capital cost, it would not be appropriate to use the same fuel costs for all classes. 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 heavily 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 PERFORMED ANY CALCULATIONS AND DEVELOPED A SCHEDULE TO ILLUSTRATE THIS?

A Yes, I have. Please refer to page 1 of Schedule MEB-COS-R-2 attached to this testimony. This schedule compares the capacity costs per kW and the energy costs per kilowatthour ("kWh") across classes for the traditional A&E allocation method and the A&P 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 my allocation factors (traditional) as well as OPC's demand and energy allocators to these total amounts. I then divided the results by the A&E capacity kW and by the class megawatthours ("MWh").

Q PLEASE EXPLAIN WHAT THIS SCHEDULE SHOWS.

A The top part 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 bottom part shows the allocation results under OPC's A&P method. Note that the impact is to allocate significantly more capital costs, in fact, 21% more to the Large Primary class and 45% more to the Large Transmission class than under the traditional approaches, which allocate average capacity costs to all classes. Note also that fuel costs per kWh are essentially the same for all classes.

Page 2 of Schedule MEB-COS-R-2 graphically shows the skewing under the A&P method.

Q YOU INDICATED THAT THE ENERGY COSTS PER KWH ARE THE SAME 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 Callaway nuclear unit is about 0.6¢ per kWh, the base load coal plants have fuel costs in the range of 1.4¢ to 1.9¢ per kWh, the more efficient peaking units have fuel costs of 4¢ to 7¢ per kWh, and other peakers have costs that are 12¢ and higher. (Note: These fuel costs are taken from AmerenUE's 2009 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, which would make their fuel cost per kWh lower than average. The allocation methods advanced by Staff and OPC do not recognize this correspondence, and as a result over-allocate costs to high load factor customers.

Q WHAT SHOULD BE CONCLUDED FROM SCHEDULE MEB-COS-R-2?

A This schedule clearly demonstrates that the non-traditional methods like A&P are highly non-symmetrical. They burden high load factor classes with above-average capacity costs, but do not allow them to benefit from the lower cost of energy that goes with the higher capacity costs. No theory supports this result and these flawed studies are entitled to no weight.

FUEL ADJUSTMENT CLAUSE

Q HAVE YOU REVIEWED THE COMMISSION STAFF REPORTS THAT ADDRESS FUEL AND PURCHASED POWER COST RECOVERY ISSUES?

A Yes.

Q DOES STAFF PROPOSE ANY CHANGE IN THE LENGTH OF RECOVERY IF ACTUAL FUEL COSTS DIFFER FROM FUEL COST IN BASE RATES?

A Yes. The FAC is discussed beginning at page 105 of the Staff's Revenue Requirement report. At page 118 of the report, Staff recommends reducing the recovery period from 12 months to eight months in order to "reduce regulatory lag."

Q DO YOU AGREE WITH THIS CHANGE?

A No, I do not. Staff has not provided any support for changing this 12-month period. The 12-month period for recovery/refund was developed as a joint recommendation of the parties in the case in which the FAC was first approved for Ameren Missouri. It has the benefit of moderating the adjustment by spreading out any recovery/refund over a full calendar year. Since there is no way to know in advance during what months of the calendar year over- or under-recoveries will occur, a 12-month recovery period is neutral and avoids concentrating this reconciliation in a shortened period where some classes could have a disproportionate share of usage.

Q STAFF OPPOSES AMEREN MISSOURI'S RECOMMENDATION TO REMOVE FROM THE CURRENT FAC THE LANGUAGE THAT EXCLUDES THE REVENUE FROM CONTRACT SALES TO MUNICIPALITIES FROM OSS REVENUES IN THE FAC. DO YOU AGREE WITH STAFF?

A No, I do not. As expressed in my direct testimony, we support Ameren Missouri's proposal to eliminate this exclusion. As has recently become clear, sales to municipalities are no longer priced on a cost of service basis, but rather on a competitive market basis because municipalities have a choice of generation suppliers. Recognizing this fact, it is reasonable to flow the revenue from all OSS through the FAC and to assign all of the fixed costs of the generation system to Missouri retail customers.

As I expressed in my direct testimony, should circumstances change in the future, this modification can be revisited.

RECOVERY OF COSTS ASSOCIATED WITH DSM EXPENDITURES

Q WHAT IS STAFF'S RECOMMENDATION FOR RECOVERY OF CAPITALIZED DSM EXPENDITURES?

A Page 45 of the Staff report presents the recommendation that the amortization period for all existing balances, as well as the balances added in this case, receive a six year amortization period.

Q DO YOU AGREE?

A No. As expressed in my direct testimony, it is appropriate to continue with the ten-year amortization for the initial group of expenditures and the six-year amortization that was stipulated to in the rate case for the second group of expenditures. For the additional expenditures being addressed in this case, it is appropriate to apply a ten-year amortization period, for the reasons discussed beginning at page 14 of my direct testimony on revenue requirement issues.

Q WHAT IS STAFF'S BASIS FOR THE SIX-YEAR AMORTIZATION OF ALL DSM EXPENDITURES?

A At page 45 of the Staff's Revenue Requirement report, this recommendation is attributed to Staff witness Rogers.

Q HAVE YOU REVIEWED MR. ROGERS' BASIS FOR THIS RECOMMENDATION?

A I looked for a justification, or even a discussion, attributed to Mr. Rogers (or any other Staff member) for this amortization period but could not find any such discussion. Accordingly, Staff has not supported its recommendation.

Q WHAT DOES MDNR PROPOSE FOR DSM COST RECOVERY?

A At page 11 of her testimony, MDNR witness Laura Wolfe proposes to expense DSM costs. She wants to "encourage" utilities to spend money on DSM and proposes expensing, pending the availability of a demand-side program investment mechanism ("DSIM") under the rules adopted by the Commission pursuant to the Missouri Energy Efficiency Act ("MEEA").

Q DO YOU AGREE WITH MDNR?

A No. For the reasons discussed beginning at page 14 of my direct testimony on revenue requirement issues, these costs should be capitalized and amortized over a ten-year period.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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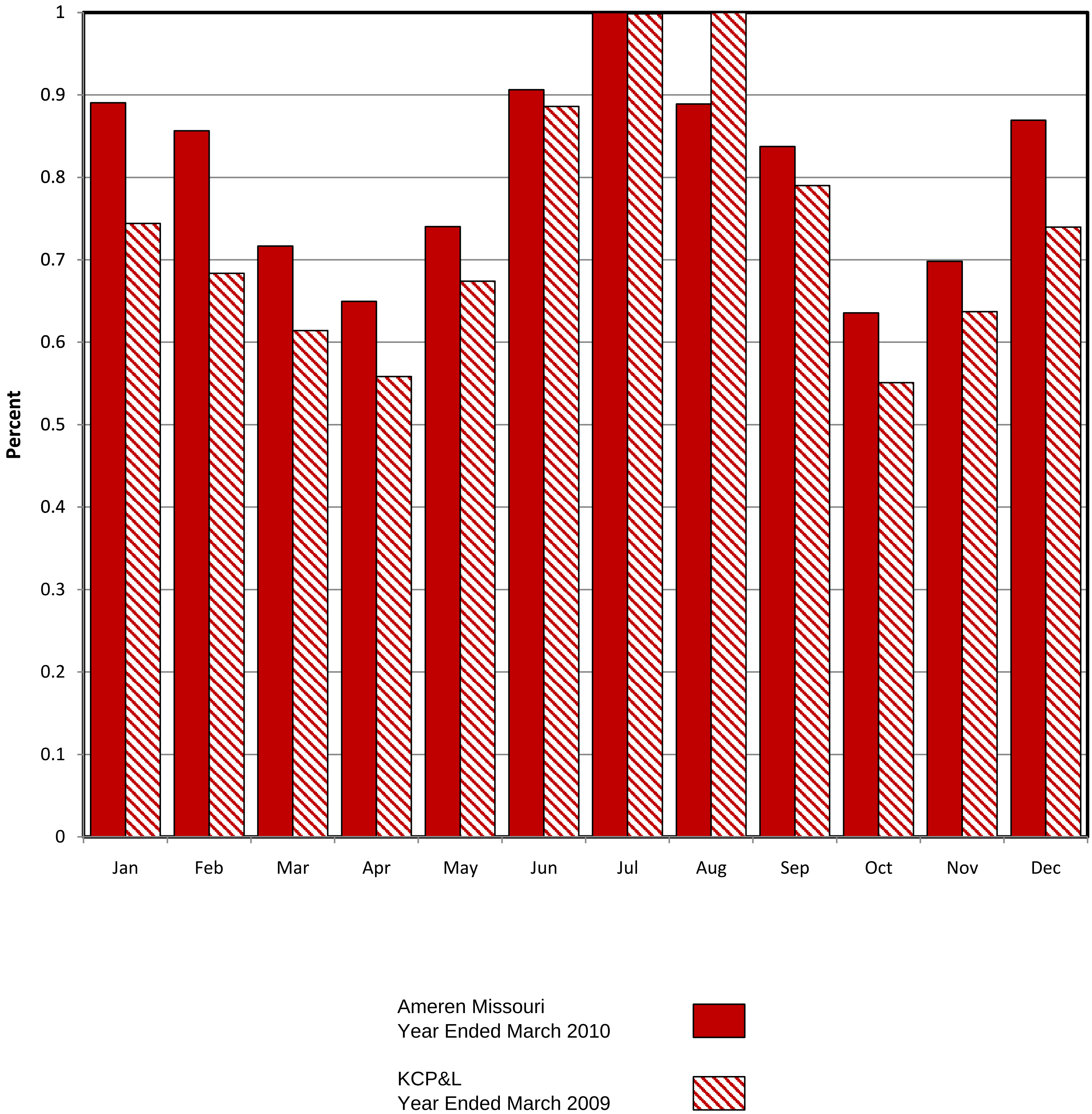
Ameren Missouri

Comparison of Ameren Missouri and Kansas City Power & Light Company
Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak



Schedule MEB-COS-R-1

AMEREN MISSOURI

CUSTOMER CLASS GENERATION CAPACITY COSTS PER KW AND ENERGY COSTS PER KWH UNDER TRADITIONAL METHODS MIEC AS COMPARED TO OPC PROPOSAL

MIEC COST OF SERVICE STUDY

	Traditional Avg. & Excess CCOS			
	Capacity Rev Req.		**Energy Rev Req.**	
Customer Class	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	124		2.88	
Res	124	**0%**	2.88	**0%**
SGS	124	**0%**	2.88	**0%**
LGS/SPS	124	**0%**	2.88	**0%**
LPS	124	**0%**	2.88	**0%**
LTS	124	**0%**	2.88	**0%**
Lighting	124	**0%**	2.88	**0%**

OFFICE OF PUBLIC COUNSEL COST OF SERVICE STUDY

	OPC Avg. and Peak CCOS			
	Capacity Rev Req.		**Energy Rev Req.**	
Customer Class	Capacity Costs $ per KW	% Difference From System Avg.	Energy Costs ¢ per kWh	% Difference From System Avg.
Total	124		2.88	
Res	115	**-7%**	2.90	**0%**
SGS	112	**-10%**	2.90	**0%**
LGS/SPS	129	**4%**	2.90	**0%**
LPS	150	**21%**	2.90	**0%**
LTS	180	**45%**	2.90	**0%**
Lighting[1]	N/A	**N/A**	N/A	**N/A**

[1] OPC Cost of Service Study did not allocate lighting costs to a Lighting class.

Ameren Missouri
Illustration of Skewed Allocation of Capital Costs and
Energy Costs Under OPC's Allocation Proposal.