Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Issues:	Cost of Service, Revenue Allocation, and Rate Design
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2008-0318

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	**))))))**	**Case No. ER-2008-0318**

Rebuttal Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation, and Rate Design

On Behalf of

Missouri Industrial Energy Consumers

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 8983
October 14, 2008

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

Affidavit of Maurice Brubaker

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

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by 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-2008-0318.

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

M. Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 13th day of October, 2008.

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

Tammy S. Klossner
Notary Public

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Rebuttal Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 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 fuel adjustment 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.

INTRODUCTION AND SUMMARY

Q ON WHOSE BEHALF ARE YOU PRESENTING THIS REBUTTAL TESTIMONY?

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

Q HAVE YOU REVIEWED THE TESTIMONY OF COMMISSION STAFF WITNESSES MICHAEL ENSRUD, DAVID ROOS AND JAMES WATKINS, 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 and transmission fixed costs is the largest and most important of these issues, and I will address it first.

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 Staff and OPC are not explained as to methodology, supported as to theory or shown to be applicable to the AmerenUE system. These studies significantly over-allocate costs to large high load factor customers such as those that take service on the Large Primary 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 AmerenUE 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 Primary rate.

3. Neither the A&P method used by Staff 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 - 1 NCP analysis that I offered in my direct testimony is the most appropriate allocation method for the AmerenUE system, and should be adopted by the Commission and used as a guide to distribute any revenue increase or decrease found appropriate.

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

    a. Uses an incorrect (too high) load factor to weight the energy component of the A&P allocator;

    b. Mis-allocates revenues from off-system sales; and

    c. Uses an unreasonably low weighting for the summer peak demand (10%) as compared to demands during other months (90%).

7. In addition to the above problems, OPC’s “TOU” allocation CCOS study:

    a. Mis-allocates revenues from off-system sales; and

    b. Relies on a calculation of hourly generation capacity costs, the accuracy and validity of which are highly suspect.

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

    a. Uses an unreasonably low weighting for the summer peak demand (10%), compared to demands during other months (90%);

    b. Mis-allocates revenues from off-system sales; and

    c. Allocates a significant amount of demand-related production function non-fuel operation and maintenance expense on energy.

ALLOCATION OF GENERATION AND TRANSMISSION CAPACITY COSTS

Q WHAT IS DISCUSSED IN THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A I discuss the allocation of generation and transmission capacity costs.

Staff Study

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's 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 AmerenUE. 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 peak summer month(s).

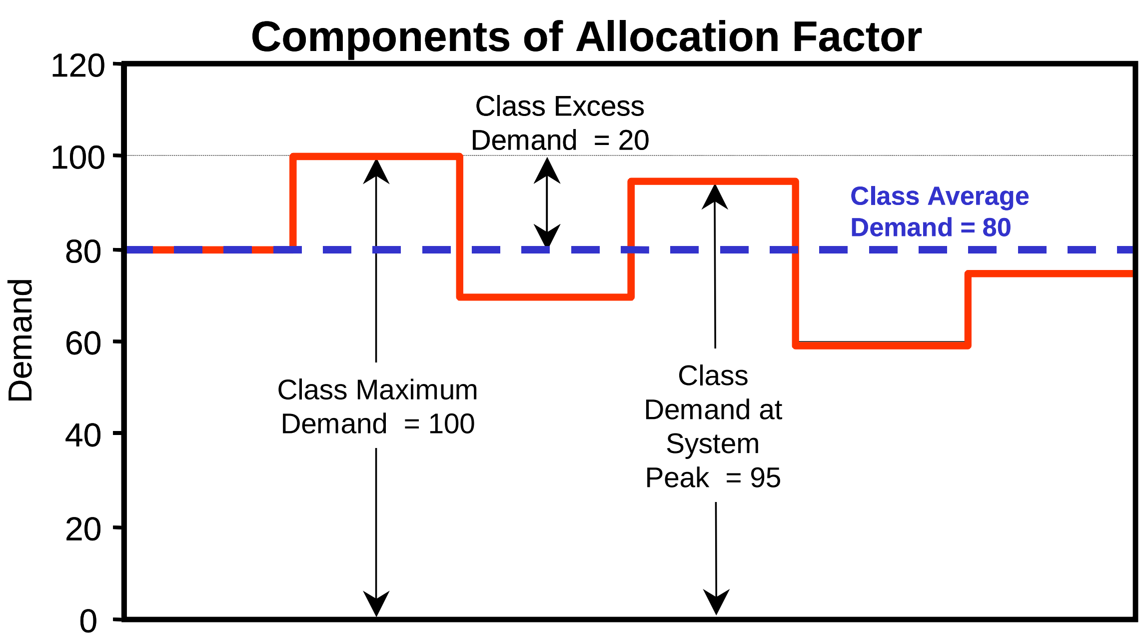
Furthermore, Staff determines its weighting of monthly class peak demands by using a methodology that is described in a 26-year old magazine article that it simply attaches to its testimony. In addition, Staff does not attempt to further explain the basis for the method, how the method works, or why it is appropriate to use in 2008 on the AmerenUE system.

Q HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE AVERAGE & EXCESS (A&E) METHODOLOGY THAT YOU USED IN YOUR CCOS STUDY?

A Staff's A&P allocator is constructed by multiplying each class's energy responsibility factor times the system load factor, and adding that result to each class's percentage contribution to the weighted 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



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 80, and the excess demand (the difference between its peak demand and its average demand) is 20.

As explained in more detail at page 25 of my September 11 direct testimony (Part 1), 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 from the average demand (80) and the excess demand (20).

Staff'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 (80) is a component or sub-set of the class peak demand (100). 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 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 essentially equal weighting to annual energy consumption and the class peaks used 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 A&P method arbitrarily allocates about half of these costs on annual energy consumption.

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

A Staff uses class demands from all 12 months, regardless of their magnitude, and weights them. However, I've presented information in my direct testimony that shows that the peak demand during a single summer month (August) was significantly higher than any other month during the year. The second highest peak demand occurred in July, and was more than 10% below the August peak. Although not explained in the testimony, the information presented in the Staff's workpapers shows that the peak demand occurring in August has a weighting of less than 10% in Staff's A&P allocation factor, which means that loads at other times are weighted 90%, or nine times as much.

A similar analysis of the two highest peak demands that occurred during August and July reveals that these peaks have a combined weighting of less than 15%, while the loads at other times are weighted over nearly six times as much

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

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 10% to 15% weighting to the highest summer peak demands cannot be regarded as reasonable. Staff'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 WHAT METHODOLOGY DID STAFF ADVOCATE FOR JURISDICTIONAL DEMAND ALLOCATION IN A RECENT KANSAS CITY POWER & LIGHT COMPANY (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.

Q DO KCPL AND AMERENUE 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 AmerenUE 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 between 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 IS THERE PRECEDENT TO SUPPORT THE STAFF'S A&P ALLOCATION METHOD?

A No. This became evident in the Aquila class cost of service case, Case No. EO-2002-384. The method which Staff uses in this (AmerenUE) case is the same as the method which OPC used in the Aquila case. In response to a data request in the Aquila case, OPC acknowledged that this particular methodology was not used anywhere to the best of its knowledge. I would concur with that conclusion.

OPC Studies

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

A OPC used a 4-month CP Average & Peak (A&P) allocator and also presented what it calls a "TOU" method.

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

A In regard to her A&P study she does not provide any explanation or supporting reason for why the use of this method is appropriate. As shown on Figure 1, the average demand is a component or sub-set of the contribution to the system peak(s) demand, so <u>OPC's method double-counts the average demand – just like Staff's method</u>.

Furthermore, Ms. Meisenheimer 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 AmerenUE 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 TO DEVELOP THE WEIGHTING FOR THE DEMAND COMPONENT AND THE ENERGY COMPONENT OF ITS A&P ALLOCATION FACTOR, WHAT LOAD FACTOR DID OPC USE?

A OPC used a 59.20% load factor. OPC's method of developing the system load factor produced a higher system load factor than what the Company produced.

Q DID OPC USE ANNUAL PEAK TO DEVELOP ITS LOAD FACTOR?

A No. The load factor which OPC has developed is erroneous. According to OPC's worksheet, the annual peak used is an average of the four monthly system peaks. This method of calculating the demand number which OPC uses to calculate the load factor is 850 megawatts (MW) below the total company peak. This is an error. The system annual load factor is approximately 53.36%, not 59.20%.

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 Primary rate.

Q HOW MUCH WEIGHT IS GIVEN TO SUMMER PEAK DEMANDS IN OPC'S STUDY?

A The summer peak demand is weighted only 10% in OPC's study.

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

A Only very generally. 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. 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 MEB-COS-R-2 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 a.m., etc.) of each day, divided by 365 days. Accordingly, this represents an average daily load profile.

The capacity cost 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 (2:00 a.m. - 5:00 a.m.), when demand is at its lowest is approximately 75% of the capacity cost in late afternoon (2:00 p.m. - 7:00 p.m.), when the peak is occurring.

MIEC witness Mr. David Stowe has performed a variety of analyses of the underlying data, and has found many anomalies that warrant further study. The anomalies in OPC's study that are identified by Mr. Stowe include illogical and unreasonable combinations of peak demand and capacity costs. Specifically, the OPC's data show the highest capacity costs occurs on a day with relatively low peak demands. The data also show that during the days of high peak demand, capacity costs are relatively low. The data even show that the capacity costs during thirteen weekend days, when peak demand is far below the annual peak, are higher than the capacity costs during the annual peak day. 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 or during weekends 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 drive 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 kilowatt (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 allocate costs among customer classes extends it well beyond any reasonable use.

<u>Symmetry of Fuel and Capital Cost Allocation</u>

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 Staff and OPC have offered, all of 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 STUDIES SUCH AS THOSE ADVANCED BY STAFF and OPC?

A These Staff and OPC 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 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 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 PERFORMED ANY CALCULATIONS AND DEVELOPED A SCHEDULE TO ILLUSTRATE THIS?

A Yes, I have. Please refer to Schedule MEB-COS-R-3 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, 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 my allocation factors (traditional) as well as the Staff and OPC 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 first block of the schedule shows that under traditional allocation methods both 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, 25% more, to the Large Primary class than under the traditional approaches, which allocate average capacity costs. Note also that fuel costs per kWh are the same for all classes.

The third block shows similar class capacity allocation results for OPC's A&P study. Note also that the energy-related costs are the same for all classes.

The final block shows the OPC "TOU" study. Predictably, an even heavier allocation of capacity costs (35% above the average) is made to the Large Primary class, and even less is allocated to the Residential class. The energy costs are once again the same for each class.

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 0.5¢ per kWh, the base load coal plants have fuel costs in the range of 1.2¢ to 1.6¢ per kWh, the more efficient peaking units have fuel costs of 7¢ to 15¢ per kWh, and other peakers have costs that are 25¢ and higher. (Note: These fuel costs are taken from AmerenUE's 2007 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. 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 SHOULD BE CONCLUDED FROM SCHEDULE MEB-COS-R-3?

A This schedule clearly 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 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.

Q HAS THIS ISSUE OF ALLOCATING A BELOW AVERAGE SHARE OF FUEL COSTS TO HIGHER LOAD FACTOR USERS RECENTLY BEEN ADDRESSED IN A MISSOURI RATE PROCEEDING?

A Yes. Staff witness Lena Mantle addressed this topic in her September 8, 2006 rebuttal testimony in a recent KCPL rate case, Case No. ER-2006-0314. Her testimony discussed planning principles and the relationship between load factors and generation mix. Her testimony clearly demonstrates that as capital cost increases (with higher load factor), energy cost decreases. While her testimony was in the context of jurisdictional allocations, the principle is the same at the class level. In fact, the recognition of the principles at the class level is even more critical since the differences between class load factors are much greater than the differences between jurisdictional load factors.

Importance of Precedent

Q IN EARLIER TESTIMONY, YOU POINTED OUT THAT MANY OF THE STUDIES BEING PROPOSED BY OTHER PARTIES IN THIS PROCEEDING ARE NOT USED IN OTHER JURISDICTIONS AND ARE NOT SUPPORTED BY PRECEDENT OR ACCEPTANCE IN THE INDUSTRY. WHAT IS THE SIGNIFICANCE OF THE FACT THAT A METHODOLOGY IS NOT USED IN OTHER JURISDICTIONS?

A Cost of service studies for electric systems has 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.

ALLOCATION OF REVENUE FROM OFF-SYSTEM SALES OF ENERGY

Q YOU INDICATED IN YOUR DIRECT TESTIMONY THAT IN A RECENT KCPL RATE CASE, CASE NO. ER-2006-0314, THE COMMISSION ADOPTED THE APPROACH OF ALLOCATING REVENUES FROM OFF-SYSTEM SALES ON THE BASIS OF AN ENERGY ALLOCATOR. IN THAT PROCEEDING, HOW DID STAFF AND THE OPC PROPOSE TO ALLOCATE REVENUE FROM OFF-SYSTEM SALES?

A Both Staff and the OPC supported the use of an energy allocator to allocate revenues from off-system sales. In fact, on page 38 of the KCPL Final Report and Order, Staff was quoted as saying that the use of the energy allocator to allocate off-system sales revenues “is the time-tested and widely accepted method for allocating such revenues in this state” of Missouri.

Q HAVE YOU EVALUATED THE IMPACT OF ADJUSTING STAFF’S COST OF SERVICE STUDY BY ALLOCATING OFF-SYSTEM SALES REVENUES ON AN ENERGY BASIS, AS OPPOSED TO A DEMAND BASIS?

A Yes, I have. Staff’s CCOS indicated that the Large Primary class had a revenue neutral deficiency of 2.90%. Schedule MEB-COS-R-4 shows the results of adjusting Staff’s study to allocate the margin on energy. This schedule indicates that after substituting the methodology for allocating off-system sales revenues, which Staff and OPC argued for in the KCPL case, the Large Primary class has a calculated revenue neutral deficiency of only 1.18%.

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 the OPC’s cost allocation studies, which I have not previously addressed.

Allocation of Non-Fuel Production O&M Expense

Q DID STAFF MAKE THE SAME ERROR AS THE COMPANY DID WITH RESPECT TO THE ALLOCATION OF CERTAIN NON-FUEL PRODUCTION O&M EXPENSES?

A Yes. Because Staff followed the same methodology as the Company, it designated a substantial portion of production function non-fuel operation and maintenance-related expenses as variable. As indicated in my direct testimony, it is more conventional to allocate these costs on an "expense follows plant" basis, that is to say, on a demand basis. The vast majority of these costs do not vary in any appreciable way with the number of kWhs generated, but occur as a function of operation and passage of time. OPC used the approach I used, but Staff did not.

Allocation of Certain Distribution Costs

Q HAVE YOU IDENTIFIED ANY POTENTIAL PROBLEMS IN THE WAY STAFF AND THE OPC ALLOCATE COSTS IN THE DISTRIBUTION ACCOUNTS?

A Both Staff and the OPC have proposed COS studies that recognize that there is a customer component to the primary and secondary distribution systems, namely Account 364 (Poles, Towers and Fixtures), Account 365 (Overhead Conductors and Devices), Account 366 (Underground Conduit) and Account 367 (Underground Conductors and Devices). Rather than perform their own studies, Staff and OPC have used the percentages developed in the zero intercept studies of Mr. Michael E. Vandas and used in Ameren's cost of service study.

As discussed in the direct testimony presented by Mr. Stowe and by me, the customer component in these studies is understated and the result is to over-allocate costs to Large Primary service customers.

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

A Yes, it does.

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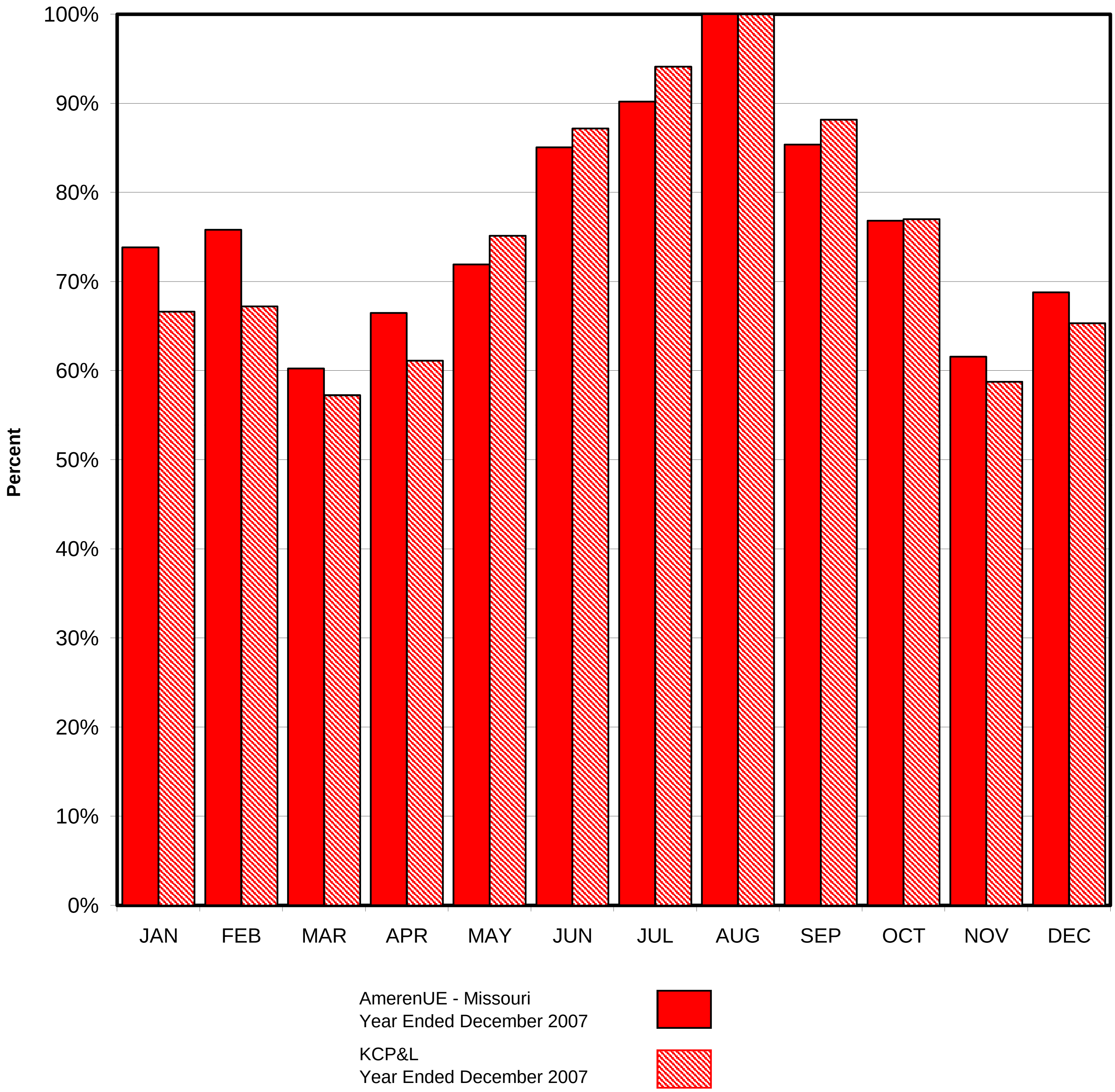
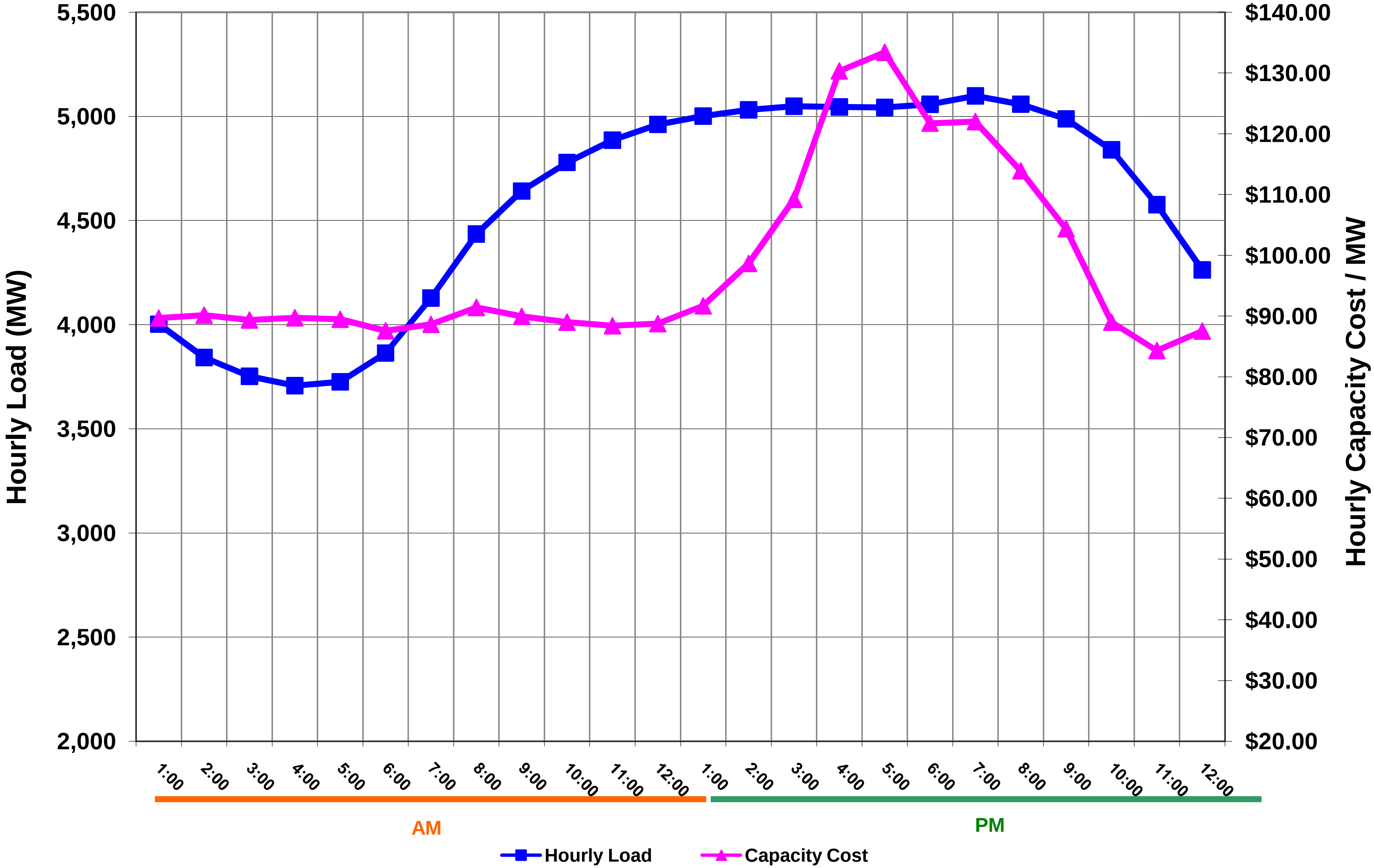
AmerenUE

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



AmerenUE

OPC'S HOURLY ASSIGNMENT OF GENERATION CAPACITY COSTS



Schedule MEB-COS-R-2

AmerenUE

Customer Class Generation Capacity Costs per KW and Energy Costs per kWh
Under a Traditional Method as Compared to Staff and OPC Proposals

	Traditional Method CCOS (MIEC)				Staff A&P 12NCP CCOS				OPC A&4P CCOS				OPC TOU-CCOS			
	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	89		2.21		89		2.21		89		2.21		89		2.21	
Res	89	**0%**	2.21	**0%**	75	**-16%**	2.21	**0%**	75	**-16%**	2.21	**0%**	71	**-20%**	2.21	**0%**
Small GS	89	**0%**	2.21	**0%**	85	**-4%**	2.21	**0%**	85	**-4%**	2.21	**0%**	79	**-11%**	2.21	**0%**
Large GS	89	**0%**	2.21	**0%**	99	**11%**	2.21	**0%**	99	**11%**	2.21	**0%**	100	**12%**	2.21	**0%**
Large PS	89	**0%**	2.21	**0%**	111	**25%**	2.21	**0%**	112	**26%**	2.21	**0%**	120	**35%**	2.21	**0%**
Trans.	89	**0%**	2.21	**0%**	135	**52%**	2.21	**0%**	137	**54%**	2.21	**0%**	163	**83%**	2.21	**0%**

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Staff Class Cost-Of-Service Results with Off-System Sales Margin Allocated on Energy

FUNCTIONAL CATEGORY			RES	SGS	LGS	LPS	LTS	Other	TOTAL
PRODUCTION	CAPACITY		$325,450,314	$88,175,133	$259,295,187	$79,670,385	$70,005,710	$0	$822,596,729
PRODUCTION	ENERGY		$324,490,477	$87,829,042	$291,029,240	$96,264,975	$91,768,667	$0	$891,382,403
TRANSMISSION	CAPACITY		$42,774,023	$11,588,882	$34,079,237	$10,471,100	$9,200,870	$0	$108,114,112
DISTRIBUTION	SUBSTATIONS	SUBSTATION DEMAND	$56,207,932	$13,274,789	$32,878,357	$8,325,265	$0	$0	$110,686,343
DISTRIBUTION	POLES AND CONDUCTORS	CUSTOMER	$48,717,329	$19,881,740	$2,962,218	$27,163	$0	$0	$71,588,451
DISTRIBUTION	POLES AND CONDUCTORS	PRIMARY DEMAND	$124,187,314	$24,352,941	$72,988,419	$11,347,945	$0	$0	$232,876,619
DISTRIBUTION	POLES AND CONDUCTORS	SECONDARY DEMAND	$35,106,527	$6,884,336	$15,176,302	$0	$0	$0	$57,167,165
DISTRIBUTION	TRANSFORMERS	SECONDARY CUSTOMER	$21,856,102	$5,946,333	$830,744	$0	$0	$0	$28,633,179
DISTRIBUTION	TRANSFORMERS	DEMAND	$13,971,497	$1,857,025	$4,234,182	$0	$0	$0	$20,062,704
DISTRIBUTION	SERVICES		$30,777,934	$6,070,957	$3,368,570	$0	$0	$0	$40,217,461
DISTRIBUTION	METERS		$14,887,445	$4,818,076	$2,765,326	$293,460	$12,948	$0	$22,777,255
	CUSTOMER DEPOSITS		($869,835)	($355,207)	($332,662)	$0	$0	$0	($1,557,704)
	METER READING		$16,595,462	$2,257,559	$300,101	$4,386	$104	$0	$19,157,612
	BILLING, SALES, SERVICE		$48,552,614	$6,604,840	$492,034	$3,008	$47	$0	$55,652,542
	ASSIGNED LGS/LPS/LTS		$0	$0	$323,426	$1,977	$31	$0	$325,434
	ASSIGNED RES/SGS		$1,982,510	$269,690	$0	$0	$0	$0	$2,252,200
	TOTAL		$1,104,687,647	$279,456,134	$720,390,680	$206,409,665	$170,988,378	$0	$2,481,932,505
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	$0
	TOTAL COST OF SERVICE		$1,104,687,647	$279,456,134	$720,390,680	$206,409,665	$170,988,378	$0	$2,481,932,505
	%		44.51%	11.26%	29.03%	8.32%	6.89%	0.00%	100%
	RATE REVENUE		$907,461,753	$241,523,515	$622,104,807	$162,634,458	$130,706,919	$28,667,613	$2,093,099,065
	Allocate Rate Revenues for Others		$12,759,718	$3,227,864	$8,320,888	$2,384,139	$1,975,005	($28,667,613)	$0
	Other		$34,291,278	$9,290,629	$27,320,801	$8,394,520	$7,376,196	$0	$86,673,424
	Margin From Off-System Sales		$91,261,594	$24,701,552	$81,850,760	$27,074,123	$25,809,555	$0	$250,697,584
									$0
	TOTAL REVENUE		$1,045,774,342	$278,743,559	$739,597,256	$200,487,240	$165,867,675	$0	$2,430,470,073
	%		43.03%	11.47%	30.43%	8.25%	6.82%	0.00%	100%
	REVENUE DEFICIENCY		$58,913,305	$712,575	($19,206,576)	$5,922,425	$5,120,704	$0	$51,462,432
	% CHANGE		**6.49%**	**0.30%**	**-3.09%**	**3.64%**	**3.92%**	**0.00%**	**2.46%**
	Less System Average increase		-2.46%	-2.46%	-2.46%	-2.46%	-2.46%		-2.46%
	Revenue Neutral % Change		**4.03%**	**-2.16%**	**-5.55%**	**1.18%**	**1.46%**	**0.00%**	**0.00%**