Exhibit No.:	
Issues:	Cost of Service, Revenue Allocation, and Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2011-0028
Date Testimony Prepared:	February 10, 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

Direct Testimony and Schedules of

Maurice Brubaker

**on Cost of Service, Revenue
Allocation and Rate Design**

On behalf of

Missouri Industrial Energy Consumers

February 10, 2011

BAI
BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9371

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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 direct 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 9th day of February, 2011.

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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<u>Direct 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 WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A 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 The purpose of my testimony is to present the results of an electric system class cost of service study for Ameren Missouri, to explain how the study should be used, and to recommend an appropriate allocation of any rate increase.

I also comment on Ameren Missouri's fuel adjustment clause ("FAC") and make suggestions for monitoring generation unit performance.

Q HOW IS YOUR TESTIMONY ORGANIZED?

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

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

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

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

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

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

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

4. Ameren Missouri utilizes, for its generation allocation, the A&E method using four class non-coincident peaks. While I believe use of the two predominant summer peaks is more conceptually correct, in this case the difference between the two allocation factors for every class is insignificant. To minimize differences, I have elected to use Ameren Missouri's generation allocation factor.

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

6. In order to better reflect cost-causation, I have changed Ameren Missouri's treatment of production non-fuel O&M expenses. Ameren Missouri allocates a significant proportion of non-fuel production O&M expense on energy. Since these expenses are more a function of the existence of the generation facilities and the passage of time, I have instead classified and allocated them as a demand-related cost.

7. I have calculated income taxes at current rates based on the taxable income of each class.

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

9. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6.

10. In light of the disturbing degradation in the performance of Ameren Missouri's major generating units, the Commission should require annual reporting of key performance indicators, such as heat rate, equivalent availability factor and equivalent forced outage rate. This is discussed in detail in the testimony of Jim Dauphinais that is being filed concurrently.

11. The Commission should carefully monitor these parameters and remain open to taking corrective action if necessary. Such corrective action could include a

modification of the sharing percentage in the FAC or a suspension of the FAC in its entirety.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

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

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

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

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

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

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

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, air conditioning, perhaps heating, and to operate various appliances. At any instant, several appliances may be operating (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and when reflects the second dimension of utility service – the rate of electricity use or **demand**. The demand imposed by customers is an especially important characteristic because the maximum demands determine how much capacity the utility is obligated to provide.

Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can safely be imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 9,000 megawatts ("MW") of electricity, the utility must have at least 9,000 MW of generation, plus additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and air conditioning systems cool our homes, schools, offices, and factories.

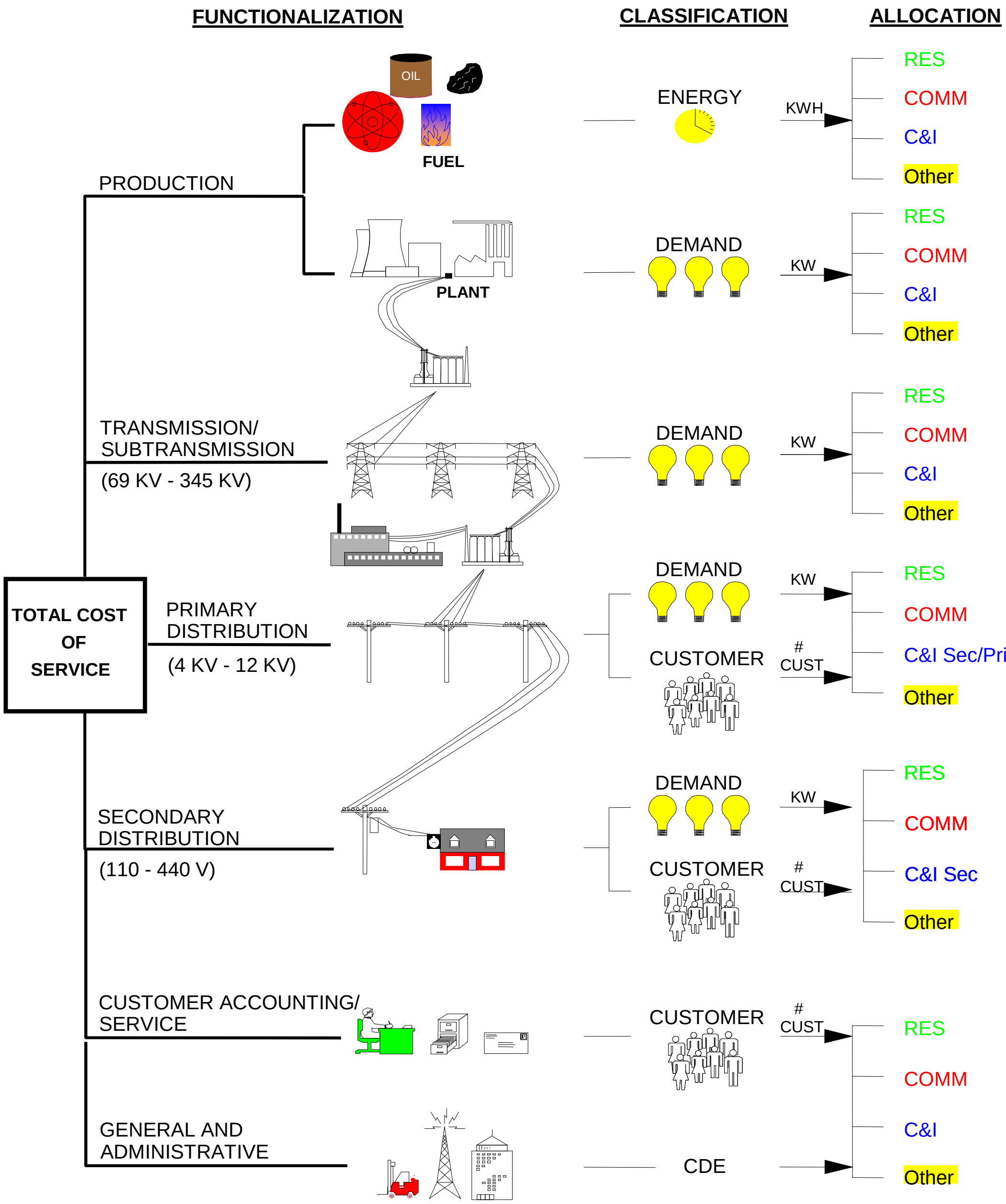
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kilowatthours ("kWh"). To see one reason why this isn't accurate, consider a more familiar commodity – tomatoes, for example.

The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the <u>service</u> of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

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

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

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

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

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

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

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

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but when you buy a kWh at home you're not only buying the energy itself but also the <u>service</u> of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like Large Transmission and Large Primary service customers – pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment, or pay separately for some services.)

<u>Classification</u>

Q WHAT IS CLASSIFICATION?

A Once the costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as **classification**. Costs are classified as demand-related, energy-related or customer-related.

Looking at the production function, the amount of production plant capacity required is primarily determined by the <u>peak</u> rate of usage during the year (i.e., the demand). If the utility anticipates a peak demand of 9,000 MW – it must install and/or contract for enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the <u>peak</u> demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the**

associated capital costs (which include return on investment, depreciation, fixed operation and maintenance expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kWhs generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kW) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned – and therefore the amount of fuel expense – is closely related to the amount of energy (number of kWhs) that customers use. Therefore, fuel expense is an energy-related cost.

Most other O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.

Customer-related costs are the third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

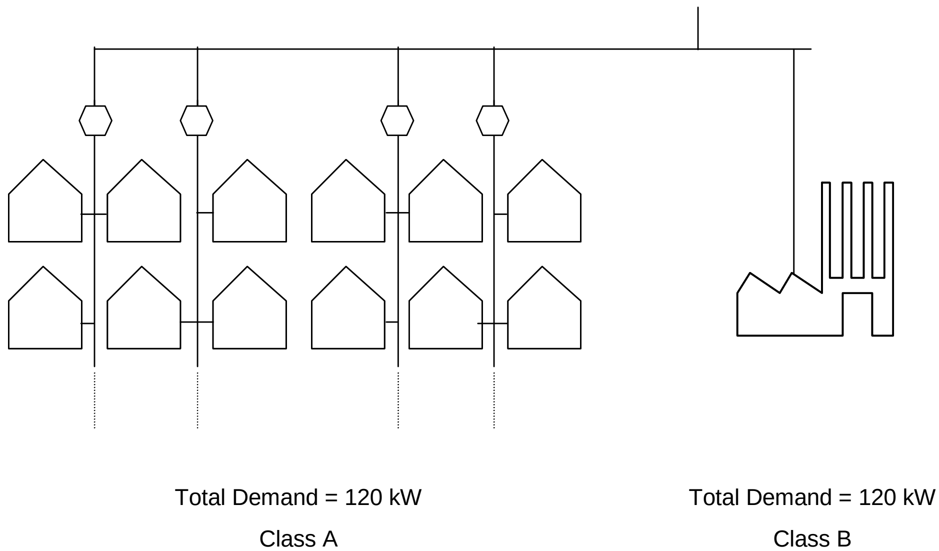
A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends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

Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kW load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2
Classification of Distribution Investment



Demand vs. Energy Costs

Q WHAT IS THE DISTINCTION BETWEEN DEMAND-RELATED COSTS AND ENERGY-RELATED COSTS?

A The difference between demand-related and energy-related costs explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3 compares the electrical requirements of two customers, A and B, each using 100-watt light bulbs.

Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy – 1,000 watthours or 1 kWh. However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kW, than Customer B who demanded only 200 watts per hour or 0.2 kW.

Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

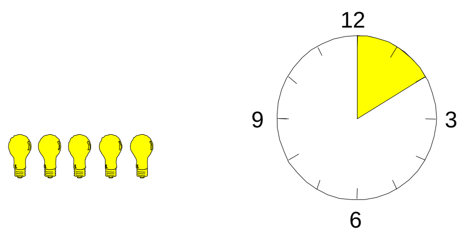
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

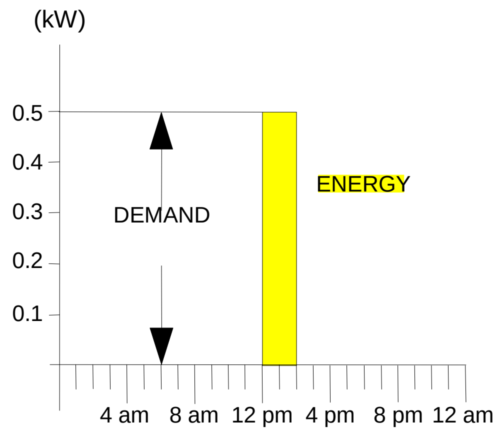
A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each kW of demand imposed on the system is much greater in the case of Customer B.

Figure 3

DEMAND VS. ENERGY

CUSTOMER A

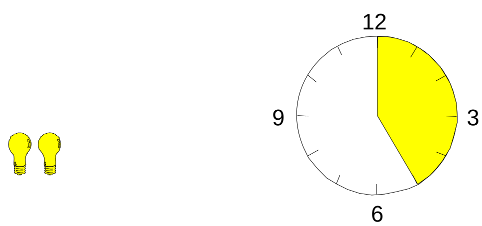


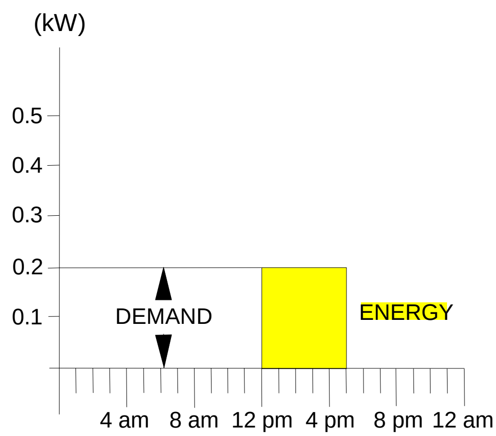


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

DEMAND: 500 watts = 0.5 kW

CUSTOMER B





ENERGY: 200 watts x 5 hours = 1,000 watthours = 1.0 kWh

DEMAND: 200 watts = 0.2 kW

Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kWh basis, than a customer with a low load factor, irrespective of size.

Consider also the analogy of a rental car which costs $40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be $2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the average total cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kWh will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industrial customers generally have higher load factors than residential or commercial customers, they are less costly to serve on a per-kWh basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

Allocation

Q WHAT IS ALLOCATION?

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

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. The energy allocators for Ameren Missouri's retail customers are shown in Table 1.

TABLE 1
Energy Allocation Factor

Rate Class	Energy Generated (MWh) (1)	Allocation Factor (2)
Residential	14,913,623	37.64%
Small GS	3,831,748	9.67%
Large GS/Small Primary	12,500,133	31.55%
Large Primary	3,958,728	9.99%
Large Transmission	4,170,226	10.52%
Lighting	250,005	0.63%
Total	39,624,464	100.00%

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 shows the calculation of the factor for Ameren Missouri. (The selection and derivation of this factor is discussed in more detail on pages 19 to 25.)

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

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

These relationships are merely the result of differences in how electricity is used. In the case of Ameren Missouri (as is true for essentially every other utility) the large customer classes have above-average load factors, while the Residential and Small GS customers have below-average load factors. (Load factors are presented in Table 4, which is discussed later.)

TABLE 2
Demand Allocation Factor
Production System

Rate Class	Production A&E (MW) (1)	Allocation Factor[2] (2)
Residential	3,710	46.68%
Small GS	867	10.91%
Large GS/Small Primary	2,258	28.41%
Large Primary	568	7.14%
Large Transmission	487	6.13%
Lighting	58	0.74%
Total	7,948[1]	100.00%

Notes:
[1]The 7,948 MW is the MO Jurisdictional peak.
[2]Column (2) is the A&E-4NCP allocation factor.

Q THE RATES, WHEN EXPRESSED PER KWH, CHARGED TO SMALL PRIMARY, LARGE PRIMARY AND LARGE TRANSMISSION CUSTOMERS ARE CURRENTLY LESS THAN THE RATES CHARGED TO OTHER CUSTOMERS. DOES THE COST OF SERVICE STUDY INDICATE THAT THIS IS APPROPRIATE?

A Yes. Table 3 shows the cost-based revenue requirement for each customer class. Note that the cost, per unit, to serve the Small Primary, Large Primary and Large Transmission customers is significantly less than the cost to serve the other customers. In fact, similar relationships hold true on any electric utility system.

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

Rate Class	Cost-Based Revenue (1)	Energy Sales (MWh) (2)	Cost per kWh (3)
Residential	$ 1,200,195	13,822,362	8.68¢
Small GS	259,679	3,551,371	7.31
Large GS/Small Primary	637,637	11,695,531	5.45
Large Primary	168,868	3,808,061	4.43
Large Transmission	132,452	4,119,018	3.22
Lighting	38,909	231,712	16.79
Total	$ 2,437,740	37,228,054	6.55¢

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

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

TABLE 4
Comparative Load Factors

Rate Class	Energy Generated (MWh) (1)	Production A&E (MW) (2)	Load Factor (3)
Residential	14,913,623	3,710	46%
Small GS	3,831,748	867	50%
Large GS/Small Primary	12,500,133	2,258	63%
Large Primary	3,958,728	568	80%
Large Transmission	4,170,226	487	98%
Lighting	250,005	58	49%
Total	39,624,464	7,948	57%

In addition, these customers take service at a higher voltage level. This means that they do not cause the costs associated with lower voltage distribution. Losses incurred in providing service also are lower. Table 5 lists voltage level and composite loss percentages for the various classes. Losses are 7.89% at the secondary level, 3.96% at the primary level and 1.24% at the transmission level.

TABLE 5
Energy Loss Factors

Rate Class	Percent of Sale By Voltage Level: Secondary (1)	Percent of Sale By Voltage Level: Primary & Higher (2)	Composite Loss Percentage (3)
Residential	100%	0%	7.89%
Small GS	100%	0%	7.89%
Large GS/Small Primary	67%	33%	6.88%
Large Primary	0%	100%	3.96%
Large Transmission	0%	100%	1.24%
Lighting	100%	0%	7.89%

Source: Ameren Missouri Cost of Service Study, A.F. 11 Worksheet.

The per capita sales to the Primary and Transmission classes are also much greater than to the other classes, as shown in Table 6. Ameren Missouri sells over 52 million kWhs per Large Primary customer, but only about 13,245 kWhs per Residential customer, or 3,900 times more per capita, as shown in Table 6. The customer-related costs to serve Large Primary customers are not 3,900 times the customer-related costs to serve the Residential customer.

TABLE 6
Energy Sold Per Customer

Rate Class	Energy Sold (MWh) (1)	Number of Customers (2)	KWh Sold per Customer (3)
Residential	13,822,362	1,043,559	13,245
Small GS	3,551,371	143,745	24,706
Large GS/Small Primary	11,695,531	10,775	1,085,386
Large Primary	3,808,061	73	52,165,216
Large Transmission	4,119,018	1	4,119,017,867
Lighting	231,712	55,793	4,153
Total	37,228,054	1,253,946	29,689

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

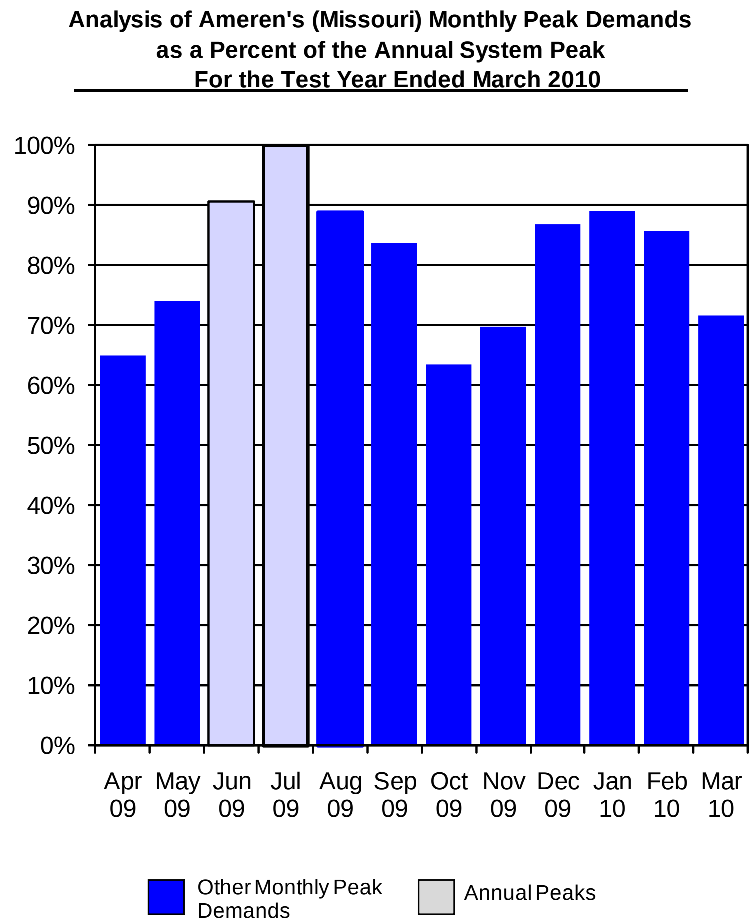
Utility System Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

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

Figure 4

AmerenUE



This shows the monthly system peak demands for the test year used in the study. The highlighted bar shows the month in which the highest peak occurred.

This analysis shows that summer peaks dominate the Ameren Missouri system. (This same information is presented in tabular form on Schedule MEB-COS-2.) This clearly shows that the system peak occurred in July, and was substantially higher than the monthly peaks occurring in the other months. The June peak was the closest, at 91% of the annual peak. The peaks in August and

September were 11% and 16%, respectively, lower than the annual peak. These lower loads simply are not representative of peak making weather and use of these lower demands as part of the allocation factor could distort the allocations and under-allocate costs to the most temperature sensitive loads.

Q WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?

A The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that caused the utility to incur capacity costs.

Q WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?

A As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class's contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then demands in all months may be important.

Q WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE AMEREN MISSOURI SYSTEM?

A As noted, the Ameren Missouri load pattern has predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission costs. Demands in other months are of much less significance, do not compel the addition of generation capacity to serve them and should not be used in determining the allocation of costs.

Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?

A The two most predominantly used allocation methods in the industry are the coincident peak method and the A&E demand method.

The coincident method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of Ameren Missouri, this would be one or more peaks occurring during the summer.

Q WHAT IS THE A&E METHOD?

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

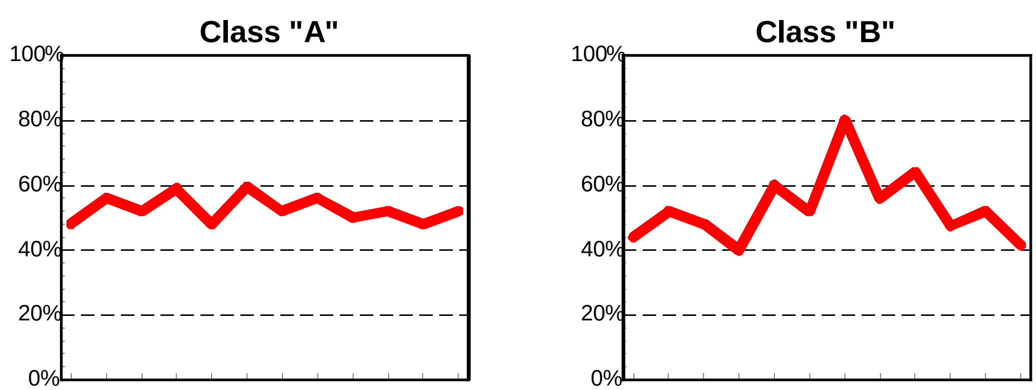
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability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

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

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

Figure 5

<u>Load Patterns</u>



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

[1] <u>NARUC Electric Utility Cost Allocation Manual</u>, 1992, page 81.

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

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

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

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

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

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

Based on test year load characteristics, I believe the most appropriate allocation would be A&E using June and July system peaks. The allocation factors for all classes under that approach are virtually identical to Ameren Missouri's A&E-4NCP allocation factors. (The Residential class is allocated slightly less costs with the A&E-4NCP method than with the A&E-2NCP method.) Because of the small difference, I have used Ameren Missouri's allocation factor in order to narrow the issues.

Schedule MEB-COS-3 shows the derivation of the demand allocation factor for generation using the four annual class non-coincident peaks.

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

A Line 2 shows the average of the four non-coincident peaks for each class. Line 3 shows the annual amount of energy required by each class. Line 4 is the average demand, in kWs, which is determined by dividing the annual energy in line 3 by the number of hours (8,760) in a year. Line 5 shows the percentage relationship between the average demand for each class and the total system.

The class excess demand, shown on line 6, is equal to the non-coincident peak demand shown on line 2 minus the average demand that is shown on line 4. Line 7 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

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

Making the Cost of Service Study – Summary

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

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

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

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

A The results are presented in Schedule MEB-COS-4. This cost of service study reflects results at present rates.

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

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

The next section shows the major elements of rate base, and line 32 shows the rate of return at present rates for each customer class based on this cost of service study and Ameren Missouri's claimed revenue requirements.

Q HOW DOES YOUR STUDY DIFFER FROM THE ONE PRESENTED BY AMEREN MISSOURI?

A There are differences in the classification of certain non-fuel generation O&M expenses.

In addition, I have calculated the income taxes at present rates based on the taxable income of each class, instead of allocating income taxes on rate base. This approach changes the rates of return at present rates, but (when applied consistently) does not change the amount of the increase or decrease required to move to cost of service.

Q PLEASE ELABORATE ON THE DIFFERENT TREATMENT OF INCOME TAXES.

A The changes fall in two categories. First is the amount of income taxes included in the class cost of service study, and second is the calculation of income taxes by customer class.

With respect to the amount included in the cost of service study, Ameren Missouri includes in its present rate class cost of service study the amount of income taxes associated with its operations if it receives the full amount of the increase that it has requested. As a result, it includes $208.4 million of income taxes in its present rate cost of service study shown in Schedule WMW-E1 and in other places. This amount includes roughly $100.1 million of income taxes that Ameren Missouri would not incur if it did not receive its requested $264 million rate increase. In my Schedule MEB-COS-4, total income taxes have been adjusted to the amount associated with present rates, which is approximately $108.3 million.

In terms of the amount of income tax attributable to individual customer classes, Ameren Missouri allocates income taxes to classes based on each class' rate base as a percentage of total rate base. This calculation essentially assumes that each customer class is producing the system average rate of return. However, the rates of return earned from the different classes are not equal, so Ameren's approach to allocating income taxes on rate base has the effect of over-allocating income taxes to classes whose rates of return are below average, and under-allocating income taxes to classes whose rates of return are above average. In my cost of service study, I have corrected for this problem by calculating income taxes separately for each customer class using a method that recognizes the appropriate income tax deductions for each class, and calculates the income tax obligation of each customer class as a function of its taxable income. This has the effect of increasing the income tax attributable to classes earning above system average rate of return, and reducing the income taxes charged to customers earning less than the system average rate of return.

Q WHAT IS THE ISSUE WITH RESPECT TO CERTAIN NON-FUEL GENERATION COSTS?

A Ameren Missouri has designated a substantial portion of its non-fuel generation operation and maintenance expenses as variable. This is the same approach it used in previous rate cases, including Case No. ER-2010-0036, Case No. ER-2008-0318 and many previous cases. In Data Request MIEC No. 5-04 in Case No. ER-2008-0318, Ameren Missouri was asked for the studies which it made to reach its conclusions supporting this particular separation of fixed and variable generation O&M expenses. Ameren Missouri responded by saying "There are no studies." It simply stated that it had been making the same division for a number of years.

Accordingly, Ameren Missouri has no support for the particular classification of non-fuel generation, operation and maintenance expenses that it has used in its study. It is more conventional to allocate these costs on an “expenses follows plant” basis, this 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 the existence of the plants, the hours of operation and the passage of time. In fact, Ameren Missouri schedules the maintenance on its coal and nuclear generation units on a “passage of time” basis, not on a “kWh generated” basis. My study incorporates this classification.

Q IS THERE AN ISSUE WITH RESPECT TO THE ALLOCATION OF TRANSMISSION COSTS?

A Ameren Missouri has allocated transmission costs using the 12 monthly coincident peaks. The transmission system must be built to meet the system peak demand, which occurs in the summer; not the average of the 12 monthly peak demands, some of which are significantly lower (28% and more) than the summer peak demand. In this respect, the transmission system is similar to the generation system, and should be allocated in a similar fashion.

Q HAVE YOU MODIFIED AMEREN MISSOURI’S CLASS COST OF SERVICE STUDY TO IMPLEMENT THIS CHANGE IN THE ALLOCATION OF TRANSMISSION COSTS?

A No. In looking at the difference in allocation factors and the dollar magnitude of change in class cost responsibility, I determined that the dollar amounts of change would not be material, and so in order to narrow the issues, I have simply used Ameren Missouri's allocation of transmission system costs.

Q WHAT ARE THE RESULTS OF MIEC'S COST OF SERVICE STUDY?

A As shown on line 32 of Schedule MEB-COS-4, at present rates all classes of service are producing a rate of return above the average, except for the Residential and Lighting classes.

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

A Yes. I have included the full printout of the cost of service study summarized on Schedule MEB-COS-4 as Attachment 1.

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

A It was the starting point. The results of Ameren Missouri's allocation first were replicated by utilizing the data contained in its cost of service model. Many of Ameren Missouri's allocation factors and functionalizations and classifications have been utilized. The principal areas where I depart from Ameren Missouri and use a different approach were incorporated into the allocations. They have previously been explained in this testimony.

ADJUSTMENT OF CLASS REVENUES

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

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

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

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

Electric rates also play a role in economic development, both with respect to job creation and job retention. This is particularly true in the case of industries where electricity is one of the largest components of the cost of production. Please see the testimony of Noranda witnesses for more elaboration on this issue.

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

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

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

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

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

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

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

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

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

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

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

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

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

Revenue Allocation

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

A As indicated on line 32 of Schedule MEB-COS-4, movement of all classes to cost of service will require an increase to the Residential and Lighting classes and a decrease to all other classes.

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

A This is shown on Schedule MEB-COS-5. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall increase in revenues. Note that the Residential class would require an increase of about $106 million, or 9.7%, in order to move to cost of service. The Lighting class would require an increase of $7.7 million, or almost 25%. All other classes would require a corresponding decrease. The decreases range from about 10.4% for the LGS/SPS class to 5% for the LTS class.

Q HOW DOES AMEREN MISSOURI PROPOSE TO ADJUST REVENUES?

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

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

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

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

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

Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.

A I have set forth my recommended revenue neutral adjustments on Schedule MEB-COS-6. I have expressed my recommendation in terms of a range of values, rather than as a specific amount. Given the relatively wide disparity in rates of return by customer class and the importance of moving toward cost of service while considering impacts, I believe that class increases on a revenue neutral basis within the range described on Schedule MEB-COS-6 would be reasonable.

FUEL ADJUSTMENT CLAUSE

Q ARE YOU FAMILIAR WITH AMEREN MISSOURI'S FAC?

A Yes.

Q HOW DO INCENTIVES TO BE EFFICIENT AND CONTROL COSTS CHANGE WHEN COST RECOVERY MOVES FROM BASE RATES TO AN FAC?

A The incentive to be efficient and control costs is less when a utility is allowed to pass-through all, or substantially all, of its incurred costs to its customers. When the utility must retain these costs and manage them in base rates, the incentive which the utility has is maximized because any increases or decreases in the level of costs are retained by stockholders.

Q CAN A UTILITY REALLY INFLUENCE ITS NET FUEL COSTS?

A Yes. There are many factors that influence the level of fuel and purchased power costs. Some of these are: (1) the skill of the utility in negotiating its fuel and purchased power contracts; (2) the skill of the utility in taking advantage of purchases and sales in the economy market; (3) the skill and diligence of a utility in maintaining its generation facilities and in restoring efficient units to service after unexpected outages; (4) the skill of the utility in planning and managing its maintenance outages; (5) the skill and success of the utility in hedging transactions for its fuel supplies; and (6) the management decisions regarding the type, size and timing of facilities added to the utility's generation portfolio. Clearly, there are many factors that influence the ultimate level of fuel costs incurred by a utility. Certainly, there are factors beyond the control of the utility, but there are many factors that the utility can manage.

Q **CAN YOU GIVE AN EXAMPLE OF WHERE, WITH AN FAC, THE INTEREST OF THE UTILITY'S CUSTOMERS AND ITS STOCKHOLDERS MAY DIVERGE, WHILE THEY WOULD BE CONGRUENT WITHOUT AN FAC?**

A Yes. Consider the circumstance where an efficient base load generating unit unexpectedly goes out of service. Assume that the utility can restore the unit to service more quickly if it spends $50,000 on overtime labor, expedited parts delivery, etc. Assume also that by expending these additional funds for maintenance, the utility would reduce fuel cost by $75,000. Clearly, the rational economic decision is to spend the extra dollars for maintenance in order to bring the unit back into service more quickly.

Consider now what happens under two different scenarios. If the utility does not have an FAC, it experiences the full cost of the additional maintenance, but it retains the full benefit of the reduced fuel cost, making it better off as a result of incurring this extra maintenance cost. With an FAC mechanism that allows the utility to pass-through all, or substantially all, of its fuel-related costs, foregoing the extra maintenance would benefit stockholders by $50,000, while the utility would be allowed to collect the additional fuel cost (or substantially all of it) from customers through the FAC. Should the utility choose this route, customers clearly would be worse off than if there had not been an FAC.

Q **AREN'T UTILITIES HELD TO A PRUDENCY STANDARD?**

A Yes, but it is very difficult to conduct a detailed audit of all of the decisions that go into a utility's procurement of fuel and purchased power, the maintenance of its generating fleet, and other factors that influence the level of these costs. The complexity of auditing the utility's generation function is overwhelming in comparison to the more limited analysis required for the Purchased Gas Adjustment (PGA) filings of the gas utilities. The number of decisions required to be investigated in the case of a PGA is relatively small. However, in the case of an electric utility, there are hourly transactions involving purchases and sales, decisions respecting acquisition of various kinds of fuel supplies in different markets, preventive maintenance practices, speed and cost of recovering from forced outages and similar decisions and actions. Thus, a rigorous audit of electric utility generation and purchased power costs is much more challenging and difficult to accomplish than a PGA audit.

Q ARE THERE OTHER CONCERNS THAT ARISE WHEN AN FAC REPLACES BASE RATE RECOVERY?

A Yes. In addition to the occurrence of specific events discussed above is the issue of the overall performance of the generation fleet. Efficient, low-cost generating depends upon a high level of performance from the nuclear and coal-fired generation facilities that are the low-cost producers of electricity. If the overall efficiency (usually measured by heat rate) degrades, the availability of the units decrease, or the forced outage rates increase, then customers will see higher costs than if unit performance were maintained or improved. The change in incentive noted above makes it important for the Commission to monitor key performance levels such as equivalent availability factor and equivalent forced outage rate.

Q ARE THESE PERFORMANCE MEASURES IN ADDITION TO WHAT IS ALREADY MONITORED?

A The availability factor and forced outage rate metrics would be an addition; however, providing periodic reports on unit heat rates is already a part of the reporting requirement.

Q IS MIEC OFFERING EVIDENCE WITH RESPECT TO THE PERFORMANCE OF AMEREN MISSOURI'S GENERATING UNITS?

A Yes. My colleague, Mr. Dauphinais, provides testimony setting forth the results of his review of these key metrics over time.

Q WHAT DO YOU CONCLUDE FROM MR. DAUPHINAIS' EVIDENCE?

A His evidence reveals disturbing trends in unit availability and in forced outage rates for Ameren Missouri's coal fleet. Over time, the forced outage rates have increased and the availability factors have decreased.

Q WHAT RECOMMENDATIONS DO YOU HAVE?

A I recommend that the Commission establish a procedure for routinely monitoring the heat rate, the equivalent availability factor and the equivalent forced outage rate of Ameren Missouri's generating units. In particular, I recommend that Ameren Missouri be required to report these statistics for its units (individually and fleet average) , as well as for peer units, on at least an annual basis. The report should be filed as soon after the conclusion of a calendar year as the necessary data can be processed and provided. The data should be filed with the Commission and made available not only to Commission Staff and the Office of Public Counsel, but also to interested parties who generally participate in Ameren Missouri PSC matters. The information should be the subject of a technical conference in conjunction with the first proposed change in the level of the FAC that occurs after the annual report is received.

Q DO YOU HAVE ANY RECOMMENDATIONS IN ADDITION TO MONITORING?

A Not at this time. Monitoring is, in my view, the most important thing that could be done at this point. If unit performance continues to deteriorate and if Ameren Missouri cannot provide a satisfactory explanation for the level of its unit performance, then the Commission should remain open to consideration of actions such as changing the sharing percentage in the FAC, or even revoking the right for Ameren Missouri to have an FAC.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

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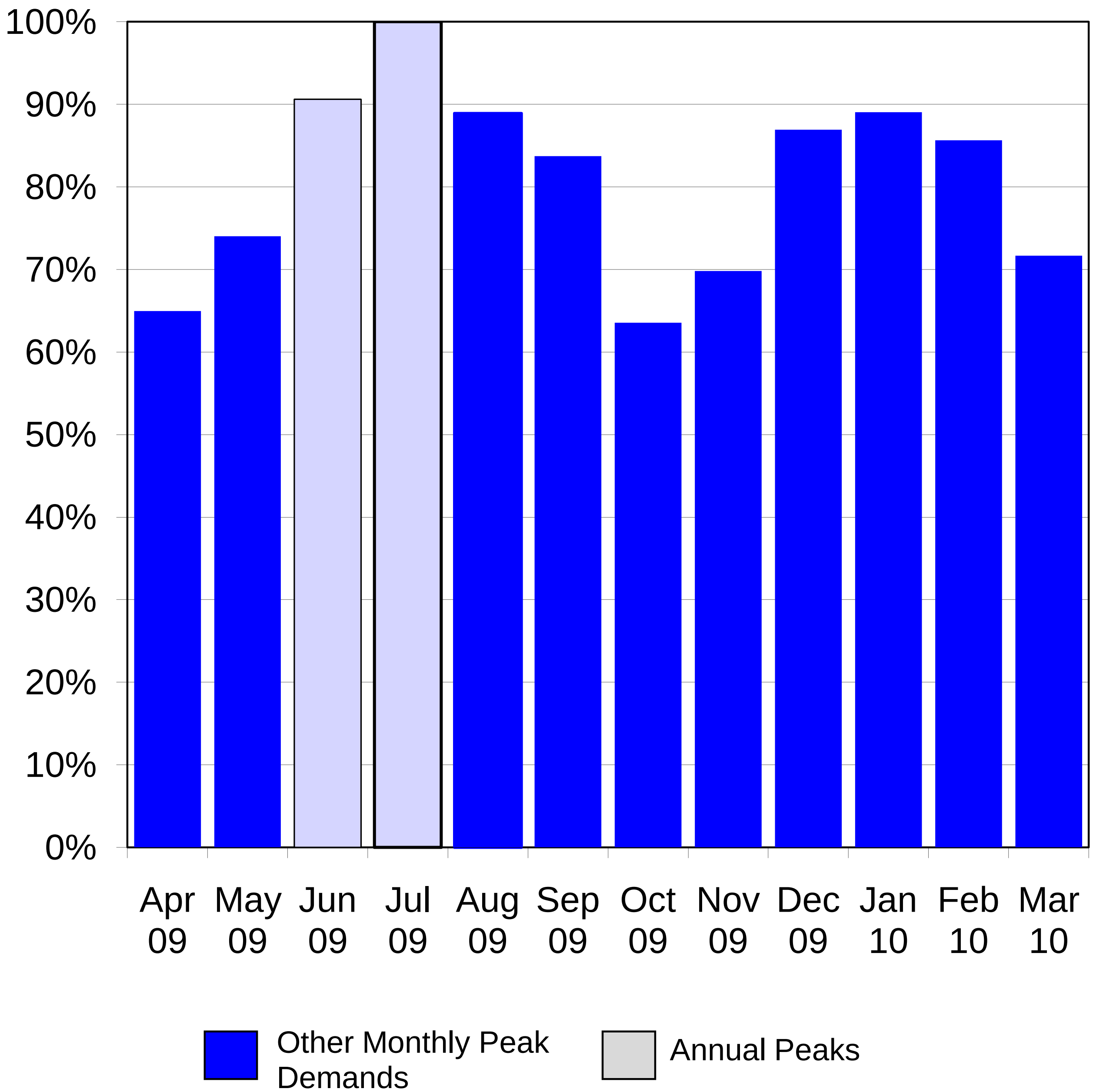
Ameren Missouri

Analysis of Ameren's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) For the Test Year Ended March 2010



Schedule MEB-COS-1

Ameren Missouri

Analysis of Ameren's Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) For the Test Year Ended March 2010

Line	Description	Total Company MW (1)	Percent (2)
1	January	7,077	89.0%
2	February	6,808	85.7%
3	March	5,697	71.7%
4	April	5,164	65.0%
5	May	5,883	74.0%
6	June	7,202	90.6%
7	July	7,948	100.0%
8	August	7,065	88.9%
9	September	6,655	83.7%
10	October	5,051	63.6%
11	November	5,549	69.8%
12	December	6,909	86.9%

Source: Ameren Missouri COS, System_CP Worksheet

Ameren Missouri

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended March 2010

Line	Description	Missouri Retail	Residential	Small General Service	Large General Service	Large Primary Service	Large Trans. Service	Lighting Service
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak	7,948						
2	Avg of 4 Highest Monthly NCP Values	8,067.5	3,779.8	882.0	2,286.9	571.6	487.8	59.5
3	Energy Sales with Losses - MWh	39,624,464	14,913,623	3,831,748	12,500,133	3,958,728	4,170,226	250,005
4	Average Demand - kW	4,523.3	1,702.5	437.4	1,427.0	451.9	476.1	28.5
5	Average Demand - Percent	100.0%	37.6%	9.7%	31.5%	10.0%	10.5%	0.6%
6	Class Excess Demand - kW	3,544.2	2,077.3	444.5	859.9	119.7	11.7	31.0
7	Class Excess Demand - Percent	100.0%	58.6%	12.5%	24.3%	3.4%	0.3%	0.9%
	Allocator:							
8	Annual Load Factor * Average Demand	0.569118	0.214201	0.055035	0.179537	0.056858	0.059896	0.003591
9	(1-LF) * Excess Demand	0.430882	0.252551	0.054045	0.104544	0.014550	0.001428	0.003763
10	Average and Excess Demand Allocator	1.000000	0.466752	0.109080	0.284081	0.071408	0.061324	0.007354

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

System Annual Load Factor	56.91%
1 - Load Factor	43.09%

Source: Ameren Missouri COS, A.F.1-4NCP Worksheet.

AMEREN MISSOURI

Electric Cost of Service Allocation Study
at Present Rates
Includes MIEC Classification Adjustments and MIEC's Alternative Income Tax Calculation

Line	Description	Missouri	Residential	Small Gen Serv	Large G.S./ Small Primary	Large Primary	Large Trans	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	BASE REVENUE	$ 2,437,740	$ 1,094,131	$ 280,137	$ 711,918	$ 181,019	$ 139,375	$ 31,160
2	OTHER REVENUE	71,988	40,263	6,911	16,441	4,171	3,558	645
3	LIGHTING REVENUE	-	-	-	-	-	-	-
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	389,344	146,722	37,697	122,978	38,947	41,027	1,972
5	RATE REVENUE VARIANCE	-	-	-	-	-	-	-
6	TOTAL OPERATING REVENUE	$ 2,899,072	$ 1,281,117	$ 324,745	$ 851,337	$ 224,136	$ 183,960	$ 33,777
7	TOTAL PROD, T&D, CUST, AND A&G EXP	1,791,698	808,103	184,008	501,346	145,815	131,152	21,274
8	TOTAL DEPR AND AMMORT EXPENSES	426,931	229,259	46,749	103,393	23,586	15,028	8,916
9	REAL ESTATE AND PROPERTY TAXES	135,868	70,858	15,082	33,611	8,104	5,689	2,524
10	INCOME TAXES: MIEC's Alternative Method	108,322	15,187	19,405	55,825	11,463	7,647	(1,204)
11	PAYROLL TAXES	23,610	12,010	2,524	6,027	1,562	1,049	437
12	FEDERAL EXCISE TAX	-	-	-	-	-	-	-
13	REVENUE TAXES	-	-	-	-	-	-	-
14	TOTAL OPERATING EXPENSES	$ 2,486,430	$ 1,135,417	$ 267,768	$ 700,201	$ 190,532	$ 160,565	$ 31,947
15	NET OPERATING INCOME	$ 412,642	$ 145,700	$ 56,977	$ 151,136	$ 33,605	$ 23,395	$ 1,830
16	GROSS PLANT IN SERVICE	14,123,637	7,367,710	1,564,609	3,499,664	840,651	589,474	261,530
17	RESERVES FOR DEPRECIATION	5,937,666	3,120,303	661,771	1,449,116	343,867	239,882	122,727
18	NET PLANT IN SERVICE	$ 8,185,971	$ 4,247,407	$ 902,838	$ 2,050,548	$ 496,783	$ 349,592	$ 138,803
19	MATERIALS & SUPPLIES - FUEL	371,450	139,979	35,965	117,326	37,157	39,142	1,881
20	MATERIALS & SUPPLIES -LOCAL	45,574	28,896	5,327	7,875	1,575	1	1,900
21	CASH WORKING CAPITAL	25,804	11,639	2,650	7,221	2,100	1,889	306
22	CUSTOMER ADVANCES & DEPOSITS	(19,537)	(23)	(16,017)	(3,498)	-	-	-
23	ACCUMULATED DEFERRED INCOME TAXES	(1,799,209)	(938,319)	(199,719)	(445,086)	(107,321)	(75,338)	(33,426)
24	TOTAL NET ORIGINAL COST RATE BASE	$ 6,810,054	$ 3,489,579	$ 731,044	$ 1,734,387	$ 430,294	$ 315,285	$ 109,463
25	RATE OF RETURN	6.059%	4.175%	7.794%	8.714%	7.810%	7.420%	1.671%

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATIONS BY MIEC
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($000's)

TITLE: GROSS PLANT IN SERVICE - PAGE 1

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1		PRODUCTION	A.F.1	$ 8,333,279	$ 3,889,578	$ 908,995	$ 2,367,325	$ 595,066	$ 511,029	$ 61,285
2										
3		TRANSMISSION								
4		LINES	A.F.2	$ 413,857	$ 192,494	$ 41,186	$ 116,047	$ 30,857	$ 31,374	$ 1,901
5		SUBSTATION	A.F.3	$ 276,880	$ 128,783	$ 27,554	$ 77,638	$ 20,644	$ 20,990	$ 1,272
6										
7		TOTAL TRANSMISSION		$ 690,737	$ 321,276	$ 68,740	$ 193,685	$ 51,500	$ 52,363	$ 3,172
8										
9		DISTRIBUTION PLANT								
10										
11	360	SUBSTATION LAND	A.F.8	$ 18,523	$ 9,405	$ 2,122	$ 5,479	$ 1,376	$ -	$ 141
12		OTHER LAND	A.F.5	$ 11,645	$ 5,913	$ 1,334	$ 3,444	$ 865	$ -	$ 89
13										
14	361-362	SUBSTATIONS	A.F.8	$ 725,597	$ 368,433	$ 83,128	$ 214,618	$ 53,893	$ -	$ 5,525
15										
16	364	POLES TOWERS FIXTURES								
17		CUSTOMER	A.F.4	$ 188,599	$ 156,956	$ 21,620	$ 1,621	$ 11	$ -	$ 8,392
18		HV	A.F.5a	$ 167,169	$ 84,860	$ 19,147	$ 49,432	$ 12,413	$ -	$ 1,317
19		PRIMARY	A.F.5b	$ 321,139	$ 163,063	$ 36,791	$ 94,987	$ 23,852	$ -	$ 2,445
20		SECONDARY	A.F.6	$ 163,726	$ 97,341	$ 21,963	$ 42,962	$ -	$ -	$ 1,460
21		LIGHTING-DIRECT	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22										
23		SUBTOTAL		$ 840,632	$ 502,220	$ 99,520	$ 189,002	$ 36,276	$ -	$ 13,614
24										
25	365	OVERHEAD CONDUCTOR								
26		CUSTOMER	A.F.4	$ 442,515	$ 368,270	$ 50,727	$ 3,803	$ 26	$ -	$ 19,689
27		HV	A.F.5a	$ 140,195	$ 71,167	$ 16,057	$ 41,456	$ 10,410	$ -	$ 1,104
28		PRIMARY	A.F.5b	$ 484,778	$ 246,153	$ 55,538	$ 143,388	$ 36,007	$ -	$ 3,691
29		SECONDARY	A.F.6	$ 25,451	$ 15,132	$ 3,414	$ 6,679	$ -	$ -	$ 227
30										
31		SUBTOTAL		$ 1,092,939	$ 700,722	$ 125,737	$ 195,325	$ 46,442	$ -	$ 24,712
32										
33	366	UNDERGROUND CONDUIT								
34		CUSTOMER	A.F.4	$ 181,175	$ 150,777	$ 20,769	$ 1,557	$ 11	$ -	$ 8,061
35		HV	A.F.5a	$ 7,545	$ 3,830	$ 864	$ 2,231	$ 560	$ -	$ 59
36		PRIMARY	A.F.5b	$ 54,362	$ 27,603	$ 6,228	$ 16,079	$ 4,038	$ -	$ 414
37		SECONDARY	A.F.6	$ 23,978	$ 14,256	$ 3,216	$ 6,292	$ -	$ -	$ 214
38										
39		SUBTOTAL		$ 267,060	$ 196,467	$ 31,077	$ 26,159	$ 4,609	$ -	$ 8,748
40										
41	367	UNDERGROUND CONDUCTORS								
42		CUSTOMER	A.F.4	$ 385,690	$ 320,979	$ 44,213	$ 3,314	$ 22	$ -	$ 17,161
43		HV	A.F.5a	$ 16,063	$ 8,154	$ 1,840	$ 4,750	$ 1,193	$ -	$ 127
44		PRIMARY	A.F.5b	$ 115,727	$ 58,762	$ 13,258	$ 34,230	$ 8,596	$ -	$ 881
45		SECONDARY	A.F.6	$ 51,045	$ 30,348	$ 6,847	$ 13,394	$ -	$ -	$ 455
46										
47		SUBTOTAL		$ 568,524	$ 418,243	$ 66,158	$ 55,688	$ 9,811	$ -	$ 18,624

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TITLE: GROSS PLANT IN SERVICE - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1										
2	368	LINE TRANSFORMERS								
3		CUSTOMER	A.F.15	$ 241,173	$ 210,182	$ 28,952	$ 2,039	$ -	$ -	$ -
4		SECONDARY	A.F.6	$ 181,426	$ 107,865	$ 24,337	$ 47,607	$ -	$ -	$ 1,618
5										
6		SUBTOTAL		$ 422,599	$ 318,047	$ 53,288	$ 49,646	$ -	$ -	$ 1,618
7										
8	369-1	OVERHEAD SERVICES								
9		CUSTOMER	A.F.15	$ 65,318	$ 56,925	$ 7,841	$ 552	$ -	$ -	$ -
10		SECONDARY	A.F.16	$ 94,979	$ 65,237	$ 14,174	$ 15,568	$ -	$ -	$ -
11										
12		SUBTOTAL		$ 160,298	$ 122,163	$ 22,016	$ 16,120	$ -	$ -	$ -
13										
14	369-2	UNDERGROUND SERVICES								
15		CUSTOMER	A.F.15	$ 131,307	$ 114,434	$ 15,763	$ 1,110	$ -	$ -	$ -
16		SECONDARY	A.F.16	$ 7,527	$ 5,170	$ 1,123	$ 1,234	$ -	$ -	$ -
17										
18		SUBTOTAL		$ 138,834	$ 119,604	$ 16,886	$ 2,344	$ -	$ -	$ -
19										
20	370	METERS	A.F.7	$ 108,173	$ 71,698	$ 21,031	$ 14,171	$ 1,100	$ 76	$ 96
21										
22	371	CUSTOMER INSTALLATIONS	DIRECT	$ 165	$ -	$ -	$ 82	$ 82	$ -	$ -
23										
24	373	STREET LIGHTING		113,064	0.000000	0.000000	0.000000	0.000000	0.000000	113,064
25										
26		SUBTOTAL - CUSTOMER DIST PLANT		$ 1,743,949	$ 1,450,222	$ 210,916	$ 28,167	$ 1,169	$ 76	$ 53,399
27		- DEMAND DIST PLANT		$ 2,724,104	$ 1,382,692	$ 311,383	$ 743,913	$ 153,285	$ -	$ 132,832
28										
29		DISTRIBUTION TOTAL		$ 4,468,053	$ 2,832,914	$ 522,298	$ 772,079	$ 154,454	$ 76	$ 186,230
30										
31		GENERAL PLANT	A.F.35	$ 577,224	$ 293,614	$ 61,713	$ 147,352	$ 38,199	$ 25,652	$ 10,695
32										
33				$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35				$ -	$ -	$ -	$ -	$ -	$ -	$ -
36										
37		SUBTOTAL PROD,T&D,GEN,COMMON PLANT		$ 14,069,293	$ 7,337,383	$ 1,561,747	$ 3,480,441	$ 839,219	$ 589,121	$ 261,382
38										
39		INTANGIBLE PLANT	A.F.35	$ 51,460	$ 26,176	$ 5,502	$ 13,137	$ 3,405	$ 2,287	$ 953
40		EE REGULATORY ASSET	DIRECT	$ 46,398	$ 26,285	$ 2,013	$ 17,194	$ 905	$ -	$ -
41		REGULATORY ACCOUNT (PENSION AND O	A.F.35	$ (43,515)	$ (22,134)	$ (4,652)	$ (11,108)	$ (2,880)	$ (1,934)	$ (806)
42										
43		TOTAL GROSS PLANT		$ 14,123,637	$ 7,367,710	$ 1,564,609	$ 3,499,664	$ 840,651	$ 589,474	$ 261,530

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($000's)

TITLE: GROSS PLANT IN SERVICE - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1										
2		MATERIALS & SUPPLIES - FUEL	A.F.11	$ 371,450	$ 139,979	$ 35,965	$ 117,326	$ 37,157	$ 39,142	$ 1,881
3		MATERIALS & SUPPLIES - LOCAL	A.F.18	$ 45,574	$ 28,896	$ 5,327	$ 7,875	$ 1,575	$ 1	$ 1,900
4		CASH WORKING CAPITAL	A.F.37	$ 25,804	$ 11,639	$ 2,650	$ 7,221	$ 2,100	$ 1,889	$ 306
5		CUSTOMER ADVANCES & DEPOSITS	A.F.12	$ (19,537)	$ (23)	$ (16,017)	$ (3,498)	$ -	$ -	$ -
6		ACCUM DEFERRED INCOME TAXES	A.F.19	$ (1,799,209)	$ (938,319)	$ (199,719)	$ (445,086)	$ (107,321)	$ (75,338)	$ (33,426)
7										
8		TOTAL GROSS RATE BASE		$ 12,747,719	$ 6,609,882	$ 1,392,815	$ 3,183,503	$ 774,162	$ 555,168	$ 232,190

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($000's)

TITLE: RESERVES FOR DEPRECIATION - PAGE 1

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1		PRODUCTION	A.F.1	$ 3,375,720	$ 1,575,626	$ 368,224	$ 958,977	$ 241,055	$ 207,012	$ 24,826
2										
3		TRANSMISSION								
4		LINES	A.F.2	$ 174,514	$ 81,170	$ 17,367	$ 48,934	$ 13,011	$ 13,230	$ 801
5		SUBSTATION	A.F.3	$ 73,844	$ 34,346	$ 7,349	$ 20,706	$ 5,506	$ 5,598	$ 339
6										
7		TOTAL TRANSMISSION		$ 248,358	$ 115,517	$ 24,716	$ 69,640	$ 18,517	$ 18,828	$ 1,141
8										
9		DISTRIBUTION PLANT								
10										
11	360	SUBSTATION LAND	A.F.8	$ 365	$ 185	$ 42	$ 108	$ 27	$ -	$ 3
12	321	OTHER LAND	A.F.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13										
14	361-362	SUBSTATIONS	A.F.8	$ 217,497	$ 110,437	$ 24,917	$ 64,331	$ 16,154	$ -	$ 1,656
15										
16	364	POLES TOWERS FIXTURES								
17		CUSTOMER	A.F.4	$ 149,740	$ 124,616	$ 17,165	$ 1,287	$ 9	$ -	$ 6,663
18		HV	A.F.5a	$ 132,726	$ 67,376	$ 15,202	$ 39,247	$ 9,856	$ -	$ 1,046
19		PRIMARY	A.F.5b	$ 254,971	$ 129,465	$ 29,211	$ 75,416	$ 18,938	$ -	$ 1,942
20		SECONDARY	A.F.6	$ 129,991	$ 77,285	$ 17,437	$ 34,110	$ -	$ -	$ 1,159
21		LIGHTING-DIRECT	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22										
23		SUBTOTAL		$ 667,428	$ 398,742	$ 79,015	$ 150,060	$ 28,802	$ -	$ 10,809
24										
25	365	OVERHEAD CONDUCTOR								
26		CUSTOMER	A.F.4	$ 128,496	$ 106,937	$ 14,730	$ 1,104	$ 7	$ -	$ 5,717
27		HV	A.F.5a	$ 40,709	$ 20,665	$ 4,663	$ 12,038	$ 3,023	$ -	$ 321
28		PRIMARY	A.F.5b	$ 140,768	$ 71,477	$ 16,127	$ 41,636	$ 10,455	$ -	$ 1,072
29		SECONDARY	A.F.6	$ 7,390	$ 4,394	$ 991	$ 1,939	$ -	$ -	$ 66
30										
31		SUBTOTAL		$ 317,363	$ 203,472	$ 36,511	$ 56,718	$ 13,486	$ -	$ 7,176
32										
33	366	UNDERGROUND CONDUIT								
34		CUSTOMER	A.F.4	$ 54,714	$ 45,534	$ 6,272	$ 470	$ 3	$ -	$ 2,434
35		HV	A.F.5a	$ 2,279	$ 1,157	$ 261	$ 674	$ 169	$ -	$ 18
36		PRIMARY	A.F.5b	$ 16,417	$ 8,336	$ 1,881	$ 4,856	$ 1,219	$ -	$ 125
37		SECONDARY	A.F.6	$ 7,241	$ 4,305	$ 971	$ 1,900	$ -	$ -	$ 65
38										
39		SUBTOTAL		$ 80,652	$ 59,332	$ 9,385	$ 7,900	$ 1,392	$ -	$ 2,642
40										
41	367	UNDERGROUND CONDUCTORS								
42		CUSTOMER	A.F.4	$ 120,355	$ 100,162	$ 13,797	$ 1,034	$ 7	$ -	$ 5,355
43		HV	A.F.5a	$ 5,012	$ 2,544	$ 574	$ 1,482	$ 372	$ -	$ 39
44		PRIMARY	A.F.5b	$ 36,113	$ 18,337	$ 4,137	$ 10,682	$ 2,682	$ -	$ 275
45		SECONDARY	A.F.6	$ 15,929	$ 9,470	$ 2,137	$ 4,180	$ -	$ -	$ 142
46										
47		SUBTOTAL		$ 177,409	$ 130,514	$ 20,645	$ 17,378	$ 3,061	$ -	$ 5,812

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($000's)

TITLE: RESERVES FOR DEPRECIATION - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1										
2	368	LINE TRANSFORMERS								
3		CUSTOMER	A.F.15	$ 79,600	$ 69,371	$ 9,556	$ 673	$ -	$ -	$ -
4		SECONDARY	A.F.6	$ 59,880	$ 35,601	$ 8,032	$ 15,713	$ -	$ -	$ 534
5										
6		SUBTOTAL		$ 139,480	$ 104,972	$ 17,588	$ 16,386	$ -	$ -	$ 534
7										
8	369-1	OVERHEAD SERVICES								
9		CUSTOMER	A.F.15	$ 80,609	$ 70,251	$ 9,677	$ 681	$ -	$ -	$ -
10		SECONDARY	A.F.16	$ 117,213	$ 80,508	$ 17,493	$ 19,212	$ -	$ -	$ -
11										
12		SUBTOTAL		$ 197,821	$ 150,759	$ 27,169	$ 19,893	$ -	$ -	$ -
13										
14	369-2	UNDERGROUND SERVICES								
15		CUSTOMER	A.F.15	$ 90,369	$ 78,757	$ 10,848	$ 764	$ -	$ -	$ -
16		SECONDARY	A.F.16	$ 5,180	$ 3,558	$ 773	$ 849	$ -	$ -	$ -
17										
18		SUBTOTAL		$ 95,549	$ 82,315	$ 11,621	$ 1,613	$ -	$ -	$ -
19										
20	370	METERS	A.F.7	$ 42,309	$ 28,043	$ 8,226	$ 5,543	$ 430	$ 30	$ 37
21										
22	371	CUSTOMER INSTALLATIONS	DIRECT	$ 153	$ -	$ -	$ 76	$ 76	$ -	$ -
23										
24	373	STREET LIGHTING		$ 62,250						$ 62,250
25										
26		SUBTOTAL - CUSTOMER DIST PLANT		$ 746,192	$ 623,671	$ 90,271	$ 11,556	$ 457	$ 30	$ 20,207
27		- DEMAND DIST PLANT		$ 1,252,084	$ 645,101	$ 144,849	$ 328,450	$ 62,973	$ -	$ 70,712
28										
29		DISTRIBUTION TOTAL		$ 1,998,276	$ 1,268,772	$ 235,120	$ 340,006	$ 63,429	$ 30	$ 90,918
30										
31		GENERAL PLANT	A.F.35	$ 291,601	$ 148,327	$ 31,176	$ 74,439	$ 19,297	$ 12,959	$ 5,403
32										
33				$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35				$ -	$ -	$ -	$ -	$ -	$ -	$ -
36										
37		SUBTOTAL PROD,T&D,GEN,COMMON PLANT		$ 5,913,955	$ 3,108,242	$ 659,236	$ 1,443,063	$ 342,298	$ 238,829	$ 122,288
38										
39		INTANGIBLE PLANT	A.F.35	$ 23,711	$ 12,061	$ 2,535	$ 6,053	$ 1,569	$ 1,054	$ 439
40		EE REGULATORY ASSET	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		REGULATORY ACCOUNT (PENSION AND O	A.F.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42										
43		TOTAL RESERVE FOR DEPRECIATION		$ 5,937,666	$ 3,120,303	$ 661,771	$ 1,449,116	$ 343,867	$ 239,882	$ 122,727

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TITLE: RESERVES FOR DEPRECIATION - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1										
2		MATERIALS & SUPPLIES - FUEL	A.F.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		MATERIALS & SUPPLIES - LOCAL	A.F.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		CASH WORKING CAPITAL	A.F.37	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5		CUSTOMER ADVANCES & DEPOSITS	A.F.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		ACCUM DEFERRED INCOME TAXES	A.F.19	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7										
8		RESERVES FOR DEPRECIATION		$ 5,937,666	$ 3,120,303	$ 661,771	$ 1,449,116	$ 343,867	$ 239,882	$ 122,727

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TITLE: NET ORIGINAL COST - PAGE 1

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1		PRODUCTION	A.F.1	$ 4,957,559	$ 2,313,953	$ 540,771	$ 1,408,348	$ 354,011	$ 304,017	$ 36,459
2										
3		TRANSMISSION								
4		LINES	A.F.2	$ 239,343	$ 111,324	$ 23,819	$ 67,112	$ 17,845	$ 18,144	$ 1,099
5		SUBSTATION	A.F.3	$ 203,036	$ 94,436	$ 20,206	$ 56,932	$ 15,138	$ 15,392	$ 932
6										
7		TOTAL TRANSMISSION		$ 442,379	$ 205,760	$ 44,024	$ 124,044	$ 32,983	$ 33,536	$ 2,032
8										
9		DISTRIBUTION PLANT								
10										
11	360	SUBSTATION LAND	A.F.8	$ 18,158	$ 9,220	$ 2,080	$ 5,371	$ 1,349	$ -	$ 138
12	321	OTHER LAND	A.F.5	$ 11,645	$ 5,913	$ 1,334	$ 3,444	$ 865	$ -	$ 89
13										
14	361-362	SUBSTATIONS	A.F.8	$ 508,100	$ 257,995	$ 58,210	$ 150,287	$ 37,739	$ -	$ 3,869
15										
16	364	POLES TOWERS FIXTURES								
17		CUSTOMER	A.F.4	$ 38,859	$ 32,339	$ 4,455	$ 334	$ 2	$ -	$ 1,729
18		HV	A.F.5a	$ 34,444	$ 17,485	$ 3,945	$ 10,185	$ 2,558	$ -	$ 271
19		PRIMARY	A.F.5b	$ 66,168	$ 33,598	$ 7,580	$ 19,571	$ 4,915	$ -	$ 504
20		SECONDARY	A.F.6	$ 33,734	$ 20,056	$ 4,525	$ 8,852	$ -	$ -	$ 301
21		LIGHTING-DIRECT	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22										
23		SUBTOTAL		$ 173,205	$ 103,478	$ 20,505	$ 38,942	$ 7,474	$ -	$ 2,805
24										
25	365	OVERHEAD CONDUCTOR								
26		CUSTOMER	A.F.4	$ 314,020	$ 261,334	$ 35,997	$ 2,698	$ 18	$ -	$ 13,972
27		HV	A.F.5a	$ 99,486	$ 50,502	$ 11,395	$ 29,418	$ 7,387	$ -	$ 784
28		PRIMARY	A.F.5b	$ 344,010	$ 174,676	$ 39,411	$ 101,752	$ 25,551	$ -	$ 2,620
29		SECONDARY	A.F.6	$ 18,061	$ 10,738	$ 2,423	$ 4,739	$ -	$ -	$ 161
30										
31		SUBTOTAL		$ 775,576	$ 497,250	$ 89,226	$ 138,608	$ 32,957	$ -	$ 17,536
32										
33	366	UNDERGROUND CONDUIT								
34		CUSTOMER	A.F.4	$ 126,460	$ 105,243	$ 14,497	$ 1,087	$ 7	$ -	$ 5,627
35		HV	A.F.5a	$ 5,267	$ 2,674	$ 603	$ 1,557	$ 391	$ -	$ 41
36		PRIMARY	A.F.5b	$ 37,945	$ 19,267	$ 4,347	$ 11,223	$ 2,818	$ -	$ 289
37		SECONDARY	A.F.6	$ 16,737	$ 9,951	$ 2,245	$ 4,392	$ -	$ -	$ 149
38										
39		SUBTOTAL		$ 186,409	$ 137,134	$ 21,692	$ 18,259	$ 3,217	$ -	$ 6,106
40										
41	367	UNDERGROUND CONDUCTORS								
42		CUSTOMER	A.F.4	$ 265,334	$ 220,817	$ 30,416	$ 2,280	$ 15	$ -	$ 11,806
43		HV	A.F.5a	$ 11,050	$ 5,610	$ 1,266	$ 3,268	$ 821	$ -	$ 87
44		PRIMARY	A.F.5b	$ 79,614	$ 40,425	$ 9,121	$ 23,548	$ 5,913	$ -	$ 606
45		SECONDARY	A.F.6	$ 35,116	$ 20,878	$ 4,711	$ 9,215	$ -	$ -	$ 313
46										
47		SUBTOTAL		$ 391,115	$ 287,729	$ 45,513	$ 38,311	$ 6,749	$ -	$ 12,812

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATIONS BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE EXCESS FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: NET ORIGINAL COST - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1										
2	368	LINE TRANSFORMERS								
3		CUSTOMER	A.F.15	$ 161,573	$ 140,811	$ 19,396	$ 1,366	$ -	$ -	$ -
4		SECONDARY	A.F.6	$ 121,546	$ 72,264	$ 16,305	$ 31,894	$ -	$ -	$ 1,084
5										
6		SUBTOTAL		$ 283,119	$ 213,075	$ 35,701	$ 33,260	$ -	$ -	$ 1,084
7										
8	369-1	OVERHEAD SERVICES								
9		CUSTOMER	A.F.15	$ (15,290)	$ (13,325)	$ (1,835)	$ (129)	$ -	$ -	$ -
10		SECONDARY	A.F.16	$ (22,233)	$ (15,271)	$ (3,318)	$ (3,644)	$ -	$ -	$ -
11										
12		SUBTOTAL		$ (37,523)	$ (28,596)	$ (5,154)	$ (3,773)	$ -	$ -	$ -
13										
14	369-2	UNDERGROUND SERVICES								
15		CUSTOMER	A.F.15	$ 40,938	$ 35,677	$ 4,914	$ 346	$ -	$ -	$ -
16		SECONDARY	A.F.16	$ 2,347	$ 1,612	$ 350	$ 385	$ -	$ -	$ -
17										
18		SUBTOTAL		$ 43,285	$ 37,289	$ 5,265	$ 731	$ -	$ -	$ -
19										
20	370	METERS	A.F.7	$ 65,863	$ 43,655	$ 12,805	$ 8,629	$ 670	$ 47	$ 58
21										
22	371	CUSTOMER INSTALLATIONS	DIRECT	$ 12	$ -	$ -	$ 6	$ 6	$ -	$ -
23										
24	373	STREET LIGHTING	A.F.29	$ 50,814	$ -	$ -	$ -	$ -	$ -	$ 50,814
25										
26		SUBTOTAL - CUSTOMER DIST PLANT		$ 997,757	$ 826,551	$ 120,645	$ 16,610	$ 713	$ 47	$ 33,192
27		- DEMAND DIST PLANT		$ 1,472,020	$ 737,591	$ 166,533	$ 415,463	$ 90,312	$ -	$ 62,120
28										
29		DISTRIBUTION TOTAL		$ 2,469,777	$ 1,564,142	$ 287,178	$ 432,073	$ 91,025	$ 47	$ 95,312
30										
31		GENERAL PLANT	A.F.35	$ 285,623	$ 145,287	$ 30,537	$ 72,913	$ 18,901	$ 12,693	$ 5,292
32										
33				$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35				$ -	$ -	$ -	$ -	$ -	$ -	$ -
36										
37		SUBTOTAL PROD,T&D,GEN,COMMON PLANT		$ 8,155,339	$ 4,229,141	$ 902,511	$ 2,037,378	$ 496,921	$ 350,293	$ 139,095
38										
39		INTANGIBLE PLANT		$ 27,749	$ 14,115	$ 2,967	$ 7,084	$ 1,836	$ 1,233	$ 514
40		EE REGULATORY ASSET	DIRECT	$ 46,398	$ 26,285	$ 2,013	$ 17,194	$ 905	$ -	$ -
41		REGULATORY ACCOUNT (PENSION AND O	A.F.35	$ (43,515)	$ (22,134)	$ (4,652)	$ (11,108)	$ (2,880)	$ (1,934)	$ (806)
42										
43		TOTAL NET PLANT		$ 8,185,971	$ 4,247,407	$ 902,838	$ 2,050,548	$ 496,783	$ 349,592	$ 138,803

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TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE EXCESS FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: NET ORIGINAL COST - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL	RESIDENTIAL	SMALL GEN SERVICE	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LARGE TRANSMISSION	LIGHTING
1		MATERIALS & SUPPLIES - FUEL	A.F.11	$ 371,450	$ 139,979	$ 35,965	$ 117,326	$ 37,157	$ 39,142	$ 1,881
2		MATERIALS & SUPPLIES - LOCAL	A.F.18	$ 45,574	$ 28,896	$ 5,327	$ 7,875	$ 1,575	$ 1	$ 1,900
3		CASH WORKING CAPITAL	A.F.37	$ 25,804	$ 11,639	$ 2,650	$ 7,221	$ 2,100	$ 1,889	$ 306
4		CUSTOMER ADVANCES & DEPOSITS	A.F.12	$ (19,537)	$ (23)	$ (16,017)	$ (3,498)	$ -	$ -	$ -
5		ACCUM DEFERRED INCOME TAXES	A.F.19	$ (1,799,209)	$ (938,319)	$ (199,719)	$ (445,086)	$ (107,321)	$ (75,338)	$ (33,426)
		TOTAL NET ORIGINAL COST RATE BASE		$ 6,810,054	$ 3,489,579	$ 731,044	$ 1,734,387	$ 430,294	$ 315,285	$ 109,463

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ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 1

			ALLOCATION		TOTAL MISSOURI		RESIDENTIAL		SMALL G. S.	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	TOTAL	LABOR	OTHER	LABOR	OTHER
1		OPERATING EXPENSES								
2										
3										
4		PRODUCTION								
5		OTHER	A.F.1	$ 201,182	$ 170,239	$ 371,421	$ 93,902	$ 79,460	$ 21,945	$ 18,570
6		VARIABLE	A.F.11	$ 7,519	$ 889,626	$ 897,146	$ 2,834	$ 335,252	$ 728	$ 86,136
7										
8		SUBTOTAL		$ 208,702	$ 1,059,866	$ 1,268,567	$ 96,736	$ 414,712	$ 22,673	$ 104,706
9										
10		SYSTEM REVENUE CREDITS								
11		INTERCHANGE SALES	A.F.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12		RENTALS	A.F.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13										
14		SUBTOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -
15										
16		TRANSMISSION								
17		LINES	A.F.2	$ 370	$ 4,869	$ 5,240	$ 172	$ 2,265	$ 37	$ 485
18		SUBSTATIONS	A.F.3	$ 6,302	$ 39,331	$ 45,633	$ 2,931	$ 18,294	$ 627	$ 3,914
19										
20		TOTAL TRANSMISSION EXPENSES		$ 6,672	$ 44,200	$ 50,872	$ 3,103	$ 20,558	$ 664	$ 4,399
21										
22										
23		DISTRIBUTION OPERATING EXPENSES								
24										
25										
26	582	SUBSTATIONS	A.F.8	$ 2,847	$ 1,407	$ 4,254	$ 1,446	$ 714	$ 326	$ 161
27										
28	583-1	OVERHEAD LINES								
29		CUSTOMER	A.F.22	$ 1,177	$ 349	$ 1,526	$ 978	$ 290	$ 135	$ 40
30		HV	A.F.23a	$ 467	$ 138	$ 605	$ 237	$ 70	$ 54	$ 16
31		PRIMARY	A.F.23b	$ 1,431	$ 424	$ 1,854	$ 726	$ 215	$ 164	$ 49
32		SECONDARY	A.F.24	$ 103	$ 31	$ 134	$ 54	$ 16	$ 13	$ 4
33		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35		SUBTOTAL		$ 3,178	$ 941	$ 4,120	$ 1,996	$ 591	$ 365	$ 108
36										
37	583-2	OVERHEAD TRANSFORMERS								
38		CUSTOMER	A.F.20	$ 1,045	$ (789)	$ 255	$ 910	$ (688)	$ 125	$ (95)
39		SECONDARY	A.F.21	$ 786	$ (594)	$ 192	$ 467	$ (353)	$ 105	$ (80)
40										
41		SUBTOTAL		$ 1,830	$ (1,383)	$ 447	$ 1,377	$ (1,041)	$ 231	$ (174)

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 1

			ALLOCATION	LARGE G. S. / SM PRI		L. PRIMARY		L. TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER
1		OPERATING EXPENSES									
2											
3											
4		PRODUCTION									
5		OTHER	A.F.1	$ 57,152	$ 48,362	$ 14,366	$ 12,157	$ 12,337	$ 10,440	$ 1,480	$ 1,252
6		VARIABLE	A.F.11	$ 2,375	$ 280,998	$ 752	$ 88,991	$ 792	$ 93,745	$ 38	$ 4,505
7											
8		SUBTOTAL		$ 59,527	$ 329,359	$ 15,118	$ 101,147	$ 13,130	$ 104,185	$ 1,518	$ 5,757
9											
10		SYSTEM REVENUE CREDITS									
11		INTERCHANGE SALES	A.F.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12		RENTALS	A.F.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13											
14		SUBTOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16		TRANSMISSION									
17		LINES	A.F.2	$ 104	$ 1,365	$ 28	$ 363	$ 28	$ 369	$ 2	$ 22
18		SUBSTATIONS	A.F.3	$ 1,767	$ 11,028	$ 470	$ 2,932	$ 478	$ 2,982	$ 29	$ 181
19											
20		TOTAL TRANSMISSION EXPENSES		$ 1,871	$ 12,394	$ 497	$ 3,295	$ 506	$ 3,351	$ 31	$ 203
21											
22											
23		DISTRIBUTION OPERATING EXPENSES									
24											
25											
26	582	SUBSTATIONS	A.F.8	$ 842	$ 416	$ 211	$ 105	$ -	$ -	$ 22	$ 11
27											
28	583-1	OVERHEAD LINES									
29		CUSTOMER	A.F.22	$ 10	$ 3	$ 0	$ 0	$ -	$ -	$ 55	$ 16
30		HV	A.F.23a	$ 138	$ 41	$ 35	$ 10	$ -	$ -	$ 4	$ 1
31		PRIMARY	A.F.23b	$ 423	$ 125	$ 106	$ 31	$ -	$ -	$ 11	$ 3
32		SECONDARY	A.F.24	$ 35	$ 10	$ -	$ -	$ -	$ -	$ 2	$ 0
33		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34											
35		SUBTOTAL		$ 606	$ 179	$ 141	$ 42	$ -	$ -	$ 71	$ 21
36											
37	583-2	OVERHEAD TRANSFORMERS									
38		CUSTOMER	A.F.20	$ 9	$ (7)	$ -	$ -	$ -	$ -	$ -	$ -
39		SECONDARY	A.F.21	$ 206	$ (156)	$ -	$ -	$ -	$ -	$ 7	$ (5)
40											
41		SUBTOTAL		$ 215	$ (163)	$ -	$ -	$ -	$ -	$ 7	$ (5)

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR	TOTAL MISSOURI OTHER	TOTAL MISSOURI TOTAL	RESIDENTIAL LABOR	RESIDENTIAL OTHER	SMALL G. S. LABOR	SMALL G. S. OTHER
1										
2	584-1	UNDERGROUND LINES								
3		CUSTOMER	A.F.26	$ 569	$ 1,347	$ 1,916	$ 476	$ 1,126	$ 66	$ 155
		HV	A.F.27a	$ 21	$ 51	$ 72	$ 11	$ 26	$ 2	$ 6
4		PRIMARY	A.F.27b	$ 155	$ 366	$ 520	$ 78	$ 186	$ 18	$ 42
5		SECONDARY	A.F.28	$ 71	$ 169	$ 240	$ 43	$ 101	$ 10	$ 23
6										
7		SUBTOTAL		$ 816	$ 1,932	$ 2,748	$ 608	$ 1,438	$ 95	$ 226
8										
9	584-2	UNDERGROUND TRANSFORMERS								
10		CUSTOMER	A.F.20	$ 416	$ (376)	$ 40	$ 363	$ (327)	$ 50	$ (45)
11		SECONDARY	A.F.21	$ 313	$ (283)	$ 30	$ 186	$ (168)	$ 42	$ (38)
12										
13		SUBTOTAL		$ 729	$ (658)	$ 71	$ 549	$ (495)	$ 92	$ (83)
14										
15	585	LIGHTING		$ 455	$ 206	$ 661	$ -	$ -	$ -	$ -
16										
17	586	METERS	A.F.7	$ 4,032	$ 1,174	$ 5,206	$ 2,672	$ 778	$ 784	$ 228
18										
19	587	CUSTOMER INSTALLATION	DIRECT	$ 1,450	$ 182	$ 1,632	$ (501)	$ (63)	$ -	$ -
20										
21		DIST OPERATING EXPENSE SUBTOTAL								
22		CUSTOMER A582-A587		$ 7,239	$ 1,704	$ 8,943	$ 5,399	$ 1,178	$ 1,159	$ 283
23		DEMAND A582-A587		$ 8,099	$ 2,096	$ 10,195	$ 2,747	$ 744	$ 733	$ 182
24										
25	580	SUPERVISION & ENGR								
26		CUSTOMER	A.F.30	$ 1,988	$ 211	$ 2,199	$ 1,483	$ 146	$ 318	$ 35
27		DEMAND	A.F.31	$ 2,225	$ 259	$ 2,484	$ 755	$ 92	$ 201	$ 23
28										
29		SUBTOTAL		$ 4,213	$ 470	$ 4,683	$ 2,238	$ 238	$ 520	$ 58
30										
31	581	DISPATCHING								
32		CUSTOMER	A.F.30	$ 1,945	$ 23	$ 1,968	$ 1,450	$ 16	$ 311	$ 4
33		DEMAND	A.F.31	$ 2,176	$ 29	$ 2,205	$ 738	$ 10	$ 197	$ 2
34										
35		SUBTOTAL		$ 4,121	$ 52	$ 4,173	$ 2,188	$ 26	$ 509	$ 6
36										
37	588	MISCELLANEOUS								
38		CUSTOMER	A.F.30	$ 3,834	$ 12,138	$ 15,972	$ 2,859	$ 8,390	$ 614	$ 2,018
39		DEMAND	A.F.31	$ 4,289	$ 14,931	$ 19,220	$ 1,455	$ 5,302	$ 388	$ 1,298
40										
41		SUBTOTAL		$ 8,123	$ 27,069	$ 35,192	$ 4,314	$ 13,692	$ 1,002	$ 3,316

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ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
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($000's)

TITLE: OPERATING EXPENSES - PAGE 2

			ALLOCATION	LARGE G. S. / SM PRI		L. PRIMARY		L. TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER
1											
2	584-1	UNDERGROUND LINES									
3		CUSTOMER	A.F.26	$ 5	$ 12	$ 0	$ 0	$ -	$ -	$ 23	$ 54
		HV	A.F.27a	$ 6	$ 15	$ 2	$ 4	$ -	$ -	$ 0	$ 0
4		PRIMARY	A.F.27b	$ 46	$ 108	$ 11	$ 27	$ -	$ -	$ 1	$ 3
5		SECONDARY	A.F.28	$ 18	$ 44	$ -	$ -	$ -	$ -	$ 1	$ 1
6											
7		SUBTOTAL		$ 75	$ 178	$ 13	$ 31	$ -	$ -	$ 25	$ 59
8											
9	584-2	UNDERGROUND TRANSFORMERS									
10		CUSTOMER	A.F.20	$ 4	$ (3)	$ -	$ -	$ -	$ -	$ -	$ -
11		SECONDARY	A.F.21	$ 82	$ (74)	$ -	$ -	$ -	$ -	$ 3	$ (3)
12											
13		SUBTOTAL		$ 86	$ (77)	$ -	$ -	$ -	$ -	$ 3	$ (3)
14											
15	585	LIGHTING		$ -	$ -	$ -	$ -	$ -	$ -	$ 455	$ 206
16											
17	586	METERS	A.F.7	$ 528	$ 154	$ 41	$ 12	$ 3	$ 1	$ 4	$ 1
18											
19	587	CUSTOMER INSTALLATION	DIRECT	$ 976	$ 122	$ 976	$ 122	$ -	$ -	$ -	$ -
20											
21		DIST OPERATING EXPENSE SUBTOTAL									
22		CUSTOMER A582-A587		$ 556	$ 158	$ 41	$ 12	$ 3	$ 1	$ 81	$ 72
23		DEMAND A582-A587		$ 2,773	$ 652	$ 1,341	$ 300	$ -	$ -	$ 504	$ 218
24											
25	580	SUPERVISION & ENGR									
26		CUSTOMER	A.F.30	$ 153	$ 20	$ 11	$ 1	$ 1	$ 0	$ 22	$ 9
27		DEMAND	A.F.31	$ 762	$ 81	$ 368	$ 37	$ -	$ -	$ 139	$ 27
28											
29		SUBTOTAL		$ 914	$ 100	$ 380	$ 39	$ 1	$ 0	$ 161	$ 36
30											
31	581	DISPATCHING									
32		CUSTOMER	A.F.30	$ 149	$ 2	$ 11	$ 0	$ 1	$ 0	$ 22	$ 1
33		DEMAND	A.F.31	$ 745	$ 9	$ 360	$ 4	$ -	$ -	$ 135	$ 3
34											
35		SUBTOTAL		$ 894	$ 11	$ 371	$ 4	$ 1	$ 0	$ 157	$ 4
36											
37	588	MISCELLANEOUS									
38		CUSTOMER	A.F.30	$ 294	$ 1,129	$ 22	$ 86	$ 2	$ 6	$ 43	$ 509
39		DEMAND	A.F.31	$ 1,468	$ 4,643	$ 710	$ 2,134	$ -	$ -	$ 267	$ 1,554
40											
41		SUBTOTAL		$ 1,763	$ 5,772	$ 732	$ 2,220	$ 2	$ 6	$ 310	$ 2,063

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AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR	TOTAL MISSOURI OTHER	TOTAL MISSOURI TOTAL	RESIDENTIAL LABOR	RESIDENTIAL OTHER	SMALL G. S. LABOR	SMALL G. S. OTHER
1										
2	589	RENTS								
3		CUSTOMER	A.F.30	$ -	$ 107	$ 107	$ -	$ 74	$ -	$ 18
4		DEMAND	A.F.31	$ -	$ 132	$ 132	$ -	$ 47	$ -	$ 11
5										
6		SUBTOTAL		$ -	$ 239	$ 239	$ -	$ 121	$ -	$ 29
7										
8		DIST OPERATING EXPENSE SUBTOTAL								
9		CUSTOMER A580-589		$ 15,006	$ 14,183	$ 29,189	$ 11,191	$ 9,804	$ 2,403	$ 2,358
10		DEMAND A580-589		$ 16,789	$ 17,446	$ 34,235	$ 5,695	$ 6,195	$ 1,520	$ 1,517
11										
12		TOTAL DIST OPERATING EXPENSES		$ 31,794	$ 31,630	$ 63,424	$ 16,886	$ 15,999	$ 3,924	$ 3,875
13										
14										
15		DISTRIBUTION MAINTENANCE EXPENSES								
16										
17										
18	591-592	SUBSTATIONS	A.F.8	$ 10,349	$ 8,317	$ 18,666	$ 5,255	$ 4,223	$ 1,186	$ 953
19										
20	593	OVERHEAD LINES								
21		CUSTOMER	A.F.22	$ 6,696	$ 24,241	$ 30,937	$ 5,561	$ 20,131	$ 766	$ 2,773
		HV	A.F.23a	$ 2,656	$ 9,617	$ 12,273	$ 1,348	$ 4,882	$ 304	$ 1,101
22		PRIMARY	A.F.23b	$ 8,136	$ 29,453	$ 37,589	$ 4,131	$ 14,955	$ 932	$ 3,374
23		SECONDARY	A.F.24	$ 586	$ 2,123	$ 2,709	$ 308	$ 1,115	$ 72	$ 261
24		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25										
26		SUBTOTAL		$ 18,074	$ 65,434	$ 83,508	$ 11,348	$ 41,082	$ 2,074	$ 7,509
27										
28	594	UNDERGROUND LINES								
29		CUSTOMER	A.F.26	$ 3,154	$ 5,370	$ 8,524	$ 2,636	$ 4,489	$ 363	$ 618
		HV	A.F.27a	$ 119	$ 203	$ 321	$ 60	$ 103	$ 14	$ 23
30		PRIMARY	A.F.27b	$ 857	$ 1,459	$ 2,316	$ 435	$ 741	$ 98	$ 167
31		SECONDARY	A.F.28	$ 395	$ 673	$ 1,068	$ 236	$ 403	$ 53	$ 91
32										
33		SUBTOTAL		$ 4,525	$ 7,705	$ 12,229	$ 3,368	$ 5,736	$ 528	$ 899
34										
35	595	LINE TRANSFORMERS								
36		CUSTOMER	A.F.20	$ 684	$ 359	$ 1,043	$ 596	$ 313	$ 82	$ 43
37		SECONDARY	A.F.21	$ 515	$ 270	$ 785	$ 306	$ 161	$ 69	$ 36
38										
39		SUBTOTAL		$ 1,199	$ 629	$ 1,828	$ 902	$ 474	$ 151	$ 79
40										
41	596	LIGHTING		$ 1,871	$ 1,246	$ 3,117	$ -	$ -	$ -	$ -
42										
43	597	METERS	A.F.7	$ 650	$ 99	$ 749	$ 431	$ 66	$ 126	$ 19
44										
45		DIST MAINTENANCE EXPENSE SUBTOTAL								
46		CUSTOMER A593-A597		$ 11,184	$ 30,069	$ 41,253	$ 9,224	$ 24,998	$ 1,338	$ 3,454
47		DEMAND A593-A597		$ 25,484	$ 53,360	$ 78,844	$ 12,080	$ 26,582	$ 2,728	$ 6,006

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 3

			ALLOCATION	LARGE G. S. / SM PRI		L. PRIMARY		L. TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER
1											
2	589	RENTS									
3		CUSTOMER	A.F.30	$ -	$ 10	$ -	$ 1	$ -	$ 0	$ -	$ 4
4		DEMAND	A.F.31	$ -	$ 41	$ -	$ 19	$ -	$ -	$ -	$ 14
5											
6		SUBTOTAL		$ -	$ 51	$ -	$ 20	$ -	$ 0	$ -	$ 18
7											
8		DIST OPERATING EXPENSE SUBTOTAL									
9		CUSTOMER A580-589		$ 1,152	$ 1,319	$ 85	$ 100	$ 6	$ 7	$ 168	$ 595
10		DEMAND A580-589		$ 5,747	$ 5,425	$ 2,780	$ 2,494	$ -	$ -	$ 1,045	$ 1,816
11											
12		TOTAL DIST OPERATING EXPENSES		$ 6,899	$ 6,744	$ 2,865	$ 2,594	$ 6	$ 7	$ 1,214	$ 2,411
13											
14											
15		DISTRIBUTION MAINTENANCE EXPENSES									
16											
17											
18	591-592	SUBSTATIONS	A.F.8	$ 3,061	$ 2,460	$ 769	$ 618	$ -	$ -	$ 79	$ 63
19											
20	593	OVERHEAD LINES									
21		CUSTOMER	A.F.22	$ 58	$ 208	$ 0	$ 1	$ -	$ -	$ 311	$ 1,127
		HV	A.F.23a	$ 786	$ 2,844	$ 197	$ 714	$ -	$ -	$ 21	$ 76
22		PRIMARY	A.F.23b	$ 2,406	$ 8,712	$ 604	$ 2,188	$ -	$ -	$ 62	$ 224
23		SECONDARY	A.F.24	$ 197	$ 714	$ -	$ -	$ -	$ -	$ 9	$ 33
24		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26		SUBTOTAL		$ 3,447	$ 12,478	$ 802	$ 2,903	$ -	$ -	$ 403	$ 1,461
27											
28	594	UNDERGROUND LINES									
29		CUSTOMER	A.F.26	$ 27	$ 46	$ 0	$ 0	$ -	$ -	$ 127	$ 216
		HV	A.F.27a	$ 35	$ 60	$ 9	$ 15	$ -	$ -	$ 1	$ 2
30		PRIMARY	A.F.27b	$ 253	$ 432	$ 64	$ 108	$ -	$ -	$ 7	$ 11
31		SECONDARY	A.F.28	$ 102	$ 174	$ -	$ -	$ -	$ -	$ 3	$ 6
32											
33		SUBTOTAL		$ 418	$ 711	$ 73	$ 124	$ -	$ -	$ 138	$ 235
34											
35	595	LINE TRANSFORMERS									
36		CUSTOMER	A.F.20	$ 6	$ 3	$ -	$ -	$ -	$ -	$ -	$ -
37		SECONDARY	A.F.21	$ 135	$ 71	$ -	$ -	$ -	$ -	$ 5	$ 2
38											
39		SUBTOTAL		$ 141	$ 74	$ -	$ -	$ -	$ -	$ 5	$ 2
40											
41	596	LIGHTING		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,871	$ 1,246
42											
43	597	METERS	A.F.7	$ 85	$ 13	$ 7	$ 1	$ 0	$ 0	$ 1	$ 0
44											
45		DIST MAINTENANCE EXPENSE SUBTOTAL									
46		CUSTOMER A593-A597		$ 176	$ 271	$ 7	$ 3	$ 0	$ 0	$ 439	$ 1,344
47		DEMAND A593-A597		$ 6,976	$ 15,466	$ 1,643	$ 3,643	$ -	$ -	$ 2,057	$ 1,663

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 4

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL G. S.	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	TOTAL	LABOR	OTHER	LABOR	OTHER
1										
2	590	SUPERVISION & ENGR								
3		CUSTOMER	A.F.32	$ 884	$ 138	$ 1,022	$ 729	$ 115	$ 106	$ 16
4		DEMAND	A.F.33	$ 2,014	$ 246	$ 2,260	$ 955	$ 122	$ 216	$ 28
5										
6		SUBTOTAL		$ 2,898	$ 384	$ 3,282	$ 1,684	$ 237	$ 321	$ 44
7										
8	598	MISCELLANEOUS								
9		CUSTOMER	A.F.32	$ 272	$ 670	$ 942	$ 224	$ 557	$ 32	$ 77
10		DEMAND	A.F.33	$ 619	$ 1,190	$ 1,808	$ 293	$ 593	$ 66	$ 134
11										
12		SUBTOTAL		$ 891	$ 1,860	$ 2,750	$ 517	$ 1,150	$ 99	$ 211
13		DIST MAINTENANCE EXPENSE SUBTOTAL								
14		CUSTOMER A590-A598		$ 12,339	$ 30,878	$ 43,217	$ 10,177	$ 25,671	$ 1,476	$ 3,546
15		DEMAND A590-A598		$ 28,117	$ 54,795	$ 82,912	$ 13,328	$ 27,297	$ 3,010	$ 6,168
16										
17		TOTAL MAINTENANCE OPERATING EXPENSE		$ 40,456	$ 85,673	$ 126,129	$ 23,505	$ 52,967	$ 4,486	$ 9,715
18										
19		TOTAL DISTRIBUTION EXPENSES		$ 72,251	$ 117,303	$ 189,554	$ 40,392	$ 68,966	$ 8,409	$ 13,589

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATION BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
AVERAGE & EXCESS - FOUR NONCOINCIDENT PEAKS
($000's)

TITLE: OPERATING EXPENSES - PAGE 4

			ALLOCATION	LARGE G. S. / SM PRI		L. PRIMARY		L. TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER
1											
2	590	SUPERVISION & ENGR									
3		CUSTOMER	A.F.32	$ 14	$ 1	$ 1	$ 0	$ 0	$ 0	$ 35	$ 6
4		DEMAND	A.F.33	$ 551	$ 71	$ 130	$ 17	$ -	$ -	$ 163	$ 8
5											
6		SUBTOTAL		$ 565	$ 72	$ 130	$ 17	$ 0	$ 0	$ 197	$ 14
7											
8	598	MISCELLANEOUS									
9		CUSTOMER	A.F.32	$ 4	$ 6	$ 0	$ 0	$ 0	$ 0	$ 11	$ 30
10		DEMAND	A.F.33	$ 169	$ 345	$ 40	$ 81	$ -	$ -	$ 50	$ 37
11											
12		SUBTOTAL		$ 174	$ 351	$ 40	$ 81	$ 0	$ 0	$ 61	$ 67
13		DIST MAINTENANCE EXPENSE SUBTOTAL									
14		CUSTOMER A590-A598		$ 194	$ 278	$ 8	$ 3	$ 1	$ 0	$ 484	$ 1,380
15		DEMAND A590-A598		$ 7,697	$ 15,882	$ 1,812	$ 3,741	$ -	$ -	$ 2,270	$ 1,708
16											
17		TOTAL MAINTENANCE OPERATING EXPENSE		$ 7,890	$ 16,159	$ 1,820	$ 3,744	$ 1	$ 0	$ 2,754	$ 3,088
18											
19		TOTAL DISTRIBUTION EXPENSES		$ 14,789	$ 22,904	$ 4,686	$ 6,337	$ 6	$ 7	$ 3,968	$ 5,499

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATIONS BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
($000's)

ADDITIONAL O&M EXPENSES - CONT.

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR	TOTAL MISSOURI OTHER	TOTAL MISSOURI TOTAL	RESIDENTIAL LABOR	RESIDENTIAL OTHER	SMALL G. S. LABOR	SMALL G. S. OTHER
1										
2										
3		CUSTOMER ACCOUNT EXPENSES								
4										
5	902	METER READING	A.F.7A	$88	$17,669	$17,757	$ 77	$ 15,375	$ 10	$ 2,019
6	905	MISCELLANEOUS	A.F.7A	$12	$186	$199	$ 11	$ 162	$ 1	$ 21
7	903	CUSTOMER RECORDS	A.F.40	$9,623	$6,484	$16,107	$ 7,619	$ 4,858	$ 547	$ 804
8	904	UNCOLLECTIBLE ACCOUNTS	A.F.13	$0	$5,912	$5,912	$ -	$ 5,438	$ -	$ 289
9	903	CREDIT AND COLLECTION	A.F.13	$2,987	$2,013	$5,000	$ 2,748	$ 1,852	$ 146	$ 98
10		INTEREST ON SURETY DEPOSITS	A.F.12	$ -	$ 687	$ 687	$ -	$ 1	$ -	$ 563
11										
12		SUBTOTAL		$12,710	$32,952	$45,663	$ 10,455	$ 27,687	$ 705	$ 3,795
13										
14	901	SUPERVISION	A.F.34	$ 1,889	$ 10	$ 1,899	$ 1,554	$ 8	$ 105	$ 1
15										
16		TOTAL CUSTOMER ACCOUNT EXPENSES		$14,599	$32,962	$47,562	$ 12,008	$ 27,695	$ 810	$ 3,796
17										
18										
19										
20										
21		CUSTOMER SERVICE & SALES EXPENSES								
22										
23	908-1&908	RCS	DIRECT	$ -	$ -	$0	$ -	$ -	$ -	$ -
24	908-916	CUSTOMER SERVICES & SALES	A.F.34	$ 4,655	$ 9,335	$13,990	$ 3,829	$ 7,843	$ 258	$ 1,075
25										
26		SUBTOTAL		4,655	9,335	$13,990	3,829	7,843	258	1,075
27										
28	907	SUPERVISION	A.F.38	$ 96	$ 9	$105	$ 79	$ 7	$ 5	$ 1
29										
30		TOTAL CUSTOMER SERVICE & SALES EXPENSES		4,751	9,343	$14,094	3,908	7,850	264	1,076
31										
32		TOTAL PROD, T&D,CUST EXPENSES		306,975	1,263,674	$1,570,649	156,148	539,781	32,820	127,566
33										
34										
35		A & G EXPENSES								
36										
37		EPRI	A.F.14	$ -	$ 3,759	$ 3,759	$ -	$ 1,647	$ -	$ 391
38		OTHER	A.F.35	$ 44,270	$ 173,019	$ 217,290	$ 22,519	$ 88,009	$ 4,733	$ 18,498
39										
39		SUBTOTAL		$ 44,270	$ 176,779	$ 221,049	$ 22,519	$ 89,656	$ 4,733	$ 18,889
40										
41		TOTAL PROD,T&D,CUST,A&G EXPENSES		$ 351,245	$ 1,440,453	$ 1,791,698	$178,666	$ 629,437	$ 37,553	$146,455
42										

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATIONS BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
($000's)

ADDITIONAL O&M EXPENSES - CONT.

LINE #	ACCT #	ITEM	ALLOCATION BASIS	LARGE G. S. LABOR	LARGE G. S. OTHER	L. PRIMARY LABOR	L. PRIMARY OTHER	L. TRANSMISSION LABOR	L. TRANSMISSION OTHER	LIGHTING LABOR	LIGHTING OTHER
1											
2											
3		CUSTOMER ACCOUNT EXPENSES									
4											
5	902	METER READING	A.F.7A	$ 1	$250	$ 0	$ 4	$ 0	$ 0	$ 0	$ 21
6	905	MISCELLANEOUS	A.F.7A	$ 0	$3	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
7	903	CUSTOMER RECORDS	A.F.40	$ 1,335	$786	$ 9	$ 5	$ 0	$ 0	$ 112	$ 30
8	904	UNCOLLECTIBLE ACCOUNTS	A.F.13	$ -	$185	$ -	$ -	$ -	$ -	$ -	$ -
9	903	CREDIT AND COLLECTION	A.F.13	$ 93	$63	$ -	$ -	$ -	$ -	$ -	$ -
10		INTEREST ON SURETY DEPOSITS	A.F.12	$ -	$123	$ -	$ -	$ -	$ -	$ -	$ -
11											
12		SUBTOTAL		$ 1,429	$1,410	$ 9	$ 9	$ 0	$ 0	$ 112	$ 51
13											
14	901	SUPERVISION	A.F.34	$ 212	$0	$ 1	$ 0	$ 0	$ 0	$ 17	$ 0
15											
16		TOTAL CUSTOMER ACCOUNT EXPENSES		$ 1,642	$1,411	$ 10	$ 9	$ 0	$ 0	$ 129	$ 51
17											
18											
19											
20											
21		CUSTOMER SERVICE & SALES EXPENSES									
22											
23	908-1&908	RCS	DIRECT	$ -	$0	$ -	$ -	$ -	$ -	$ -	$ -
24	908-916	CUSTOMER SERVICES & SALES	A.F.34	$ 524	$400	$ 3	$ 3	$ 0	$ 0	$ 41	$ 14
25											
26		SUBTOTAL		524	$400	3	3	0	0	41	14
27											
28	907	SUPERVISION	A.F.38	$ 11	$0	$ 0	$ 0	$ 0	$ 0	$ 1	$ 0
29											
30		TOTAL CUSTOMER SERVICE & SALES EXPENSES		534	$400	3	3	0	0	42	14
31											
32		TOTAL PROD, T&D,CUST EXPENSES		78,364	$366,468	20,314	110,792	13,642	107,543	5,687	11,524
33											
34											
35		A & G EXPENSES									
36											
37		EPRI	A.F.14	$ -	$1,046	$ -	$ 330	$ -	$ 310	$ -	$ 36
38		OTHER	A.F.35	$ 11,301	$44,168	$ 2,930	$ 11,450	$ 1,967	$ 7,689	$ 820	$ 3,206
39											
39		SUBTOTAL		$ 11,301	$45,213	$ 2,930	$ 11,779	$ 1,967	$ 7,999	$ 820	$ 3,242
40											
41		TOTAL PROD,T&D,CUST,A&G EXPENSES		$ 89,665	$411,681	$ 23,244	$122,571	$15,610	$115,542	$6,508	$14,766
42											

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATIONS BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
($000's)

ADDITIONAL O&M EXPENSES - CONT.

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL G. S.	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	TOTAL	LABOR	OTHER	LABOR	OTHER
1		DEPREC & AMORTIZATION EXPENSES								
2										
3										
4		DEPR-PRODUCTION PLANT	A.F.1	$ -	$ 210,990	$ 210,990	$ -	$ 98,480	$ -	$ 23,015
5		DEPR-COMMON PLANT	A.F.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		DEPR-TRANSMISSION PLANT	A.F.17	$ -	$ 15,603	$ 15,603	$ -	$ 7,257	$ -	$ 1,553
7		DEPR-DISTRIBUTION PLANT	A.F.18	$ -	$ 179,999	$ 179,999	$ -	$ 113,176	$ -	$ 20,007
8		DEPR-GENERAL PLANT	A.F.35	$ -	$ 20,339	$ 20,339	$ -	$ 10,346	$ -	$ 2,175
9										
10		SUBTOTAL		$ -	$ 426,931	$ 426,931	$ -	$ 229,259	$ -	$ 46,749
11										
12				$ -	$ -	$ -	$ -	$ -	$ -	$ -
13										
14		TOTAL DEPREC & AMORTIZ EXPENSES		$ -	$ 426,931	$ 426,931	$ -	$ 229,259	$ -	$ 46,749
15										
16										
17		OTHER								
18										
19										
20		REAL ESTATE & PROPERTY TAXES	A.F.19	$ -	$ 135,868	$ 135,868	$ -	$ 70,858	$ -	$ 15,082
21		INCOME/CITY EARNINGS TAXES	A.F.29	$ -	$ 108,322	$ 108,322	$ -	$ 55,506	$ -	$ 11,628
22		RETURN	A.F.29	$ -	$ 312,545	$ 312,545	$ -	$ 160,153	$ -	$ 33,551
23		PAYROLL TAXES	A.F.35	$ -	$ 23,610	$ 23,610	$ -	$ 12,010	$ -	$ 2,524
24		ENVIRONMENTAL TAX	A.F. 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25										
26		SUBTOTAL		$ -	$ 580,346	$ 580,346	$ -	$ 298,527	$ -	$ 62,785
27										
28		TOTAL OPERATING & OTHER EXPENSES		$ 351,245	$ 2,447,730	$ 2,798,975	$178,666	$1,157,223	$ 37,553	$255,989
29										
30										
31										
32										
33		TOTAL COST OF SERVICE		$ 351,245	$ 2,447,730	$ 2,798,975	$178,666	$1,157,223	$ 37,553	$255,989

AMEREN MISSOURI

ELECTRIC COST OF SERVICE ALLOCATION STUDY WITH MODIFICATIONS BY MIEC
TEST YEAR PERIOD: 12 MONTHS ENDED MARCH 2010
($000's)

ADDITIONAL O&M EXPENSES - CONT.

			ALLOCATION	LARGE G. S.		L. PRIMARY		L. TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER
1		DEPREC & AMORTIZATION EXPENSES									
2											
3											
4		DEPR-PRODUCTION PLANT	A.F.1	$ -	$59,938	$ -	$ 15,066	$ -	$ 12,939	$ -	$ 1,552
5		DEPR-COMMON PLANT	A.F.1	$ -	$0	$ -	$ -	$ -	$ -	$ -	$ -
6		DEPR-TRANSMISSION PLANT	A.F.17	$ -	$4,375	$ -	$ 1,163	$ -	$ 1,183	$ -	$ 72
7		DEPR-DISTRIBUTION PLANT	A.F.18	$ -	$33,887	$ -	$ 6,010	$ -	$ 3	$ -	$ 6,916
8		DEPR-GENERAL PLANT	A.F.35	$ -	$5,192	$ -	$ 1,346	$ -	$ 904	$ -	$ 377
9											
10		SUBTOTAL		$ -	$103,393	$ -	$ 23,586	$ -	$ 15,028	$ -	$ 8,916
11											
12				$ -	$0	$ -	$ -	$ -	$ -	$ -	$ -
13											
14		TOTAL DEPREC & AMORTIZ EXPENSES		$ -	$103,393	$ -	$ 23,586	$ -	$ 15,028	$ -	$ 8,916
15											
16											
17		OTHER									
18											
19											
20		REAL ESTATE & PROPERTY TAXES	A.F.19	$ -	$33,611	$ -	$ 8,104	$ -	$ 5,689	$ -	$ 2,524
21		INCOME/CITY EARNINGS TAXES	A.F.29	$ -	$27,588	$ -	$ 6,844	$ -	$ 5,015	$ -	$ 1,741
22		RETURN	A.F.29	$ -	$79,599	$ -	$ 19,748	$ -	$ 14,470	$ -	$ 5,024
23		PAYROLL TAXES	A.F.35	$ -	$6,027	$ -	$ 1,562	$ -	$ 1,049	$ -	$ 437
24		ENVIRONMENTAL TAX	A.F. 1	$ -	$0	$ -	$ -	$ -	$ -	$ -	$ -
25											
26		SUBTOTAL		$ -	$146,825	$ -	$ 36,259	$ -	$ 26,223	$ -	$ 9,727
27											
28		TOTAL OPERATING & OTHER EXPENSES		$ 89,665	$661,898	$ 23,244	$182,417	$15,610	$156,794	$6,508	$33,409
29											
30											
31											
32											
33		TOTAL COST OF SERVICE		$ 89,665	$661,898	$ 23,244	$182,417	$15,610	$156,794	$6,508	$33,409

Ameren Missouri

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using MIEC's Modified ECOS at Present Rates
($/Thousands)

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Adjusted Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Equal ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 1,094,131	$ 3,489,579	$ 145,700	4.175%	69	$ 211,444	$ 65,744	$ 106,064	9.7%
2	Small GS	280,137	731,044	56,977	7.794%	129	44,296	(12,681)	(20,458)	-7.3%
3	Large GS/Small Primary	711,918	1,734,387	151,136	8.714%	144	105,092	(46,044)	(74,281)	-10.4%
4	Large Primary	181,019	430,294	33,605	7.810%	129	26,073	(7,532)	(12,151)	-6.7%
5	Large Transmission	139,375	315,285	23,395	7.420%	122	19,104	(4,291)	(6,922)	-5.0%
6	Lighting	31,160	109,463	1,830	1.671%	28	6,633	4,803	7,749	24.9%
7	Total	$ 2,437,740	$ 6,810,054	$ 412,642	6.059%	100	$ 412,642	$ -	$ -	0.0%

AMEREN MISSOURI

Recommended Revenue Neutral Adjustments to Class Revenue* **($/Million)**

Line	**Rate Class**	**Dollar Adjustment Range**			**Percent Adjustment Range**		
		(1)		**(2)**	**(3)**		**(4)**
1	Residential	$ 26.5	-	$ 53.0	2.4%	-	4.8%
2	Small GS	(5.1)	-	(10.2)	-1.8%	-	-3.7%
3	Large GS/Primary	(18.6)	-	(37.1)	-2.6%	-	-5.2%
4	Large Primary	(3.0)	-	(6.1)	-1.7%	-	-3.4%
5	Large Transmission	(1.7)	-	(3.5)	-1.2%	-	-2.5%
6	Lighting	1.9	-	3.9	6.2%	-	12.4%
7	Total	$ -		$ -			

Note:

*Any rate increase granted will be applied as an equal percent to class revenues, and combined with these revenue-neutral adjustments to determine the total increase relative to current rates.