MIEC
504

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-2012-0166
Date Testimony Prepared:	July 19, 2012

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-2012-0166**
Tariff No. YE-2012-0370

Direct Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation and Rate Design

On behalf of

Missouri Industrial Energy Consumers

July 19, 2012

BRUBAKER & ASSOCIATES, INC.

MIEC Exhibit No. 504
Date 9-27-12 Reporter KF
File No. ER-2012-0166

Project 9553

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-2012-0166** Tariff No. YE-2012-0370

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 are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2012-0166.

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.

Maurice Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 18th day of July, 2012.

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

Maria E. Decker

Notary Public

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-2012-0166** Tariff No. YE-2012-0370

Table of Contents to the
<u>Direct Testimony of Maurice Brubaker</u>

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-2012-0166** Tariff No. YE-2012-0370

Table of Contents to the Direct Testimony of Maurice Brubaker (continued)

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-2012-0166** Tariff No. YE-2012-0370

Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, 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 ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

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

Q HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A Yes. I filed direct testimony on revenue requirement issues on July 6, 2012.

Q ARE YOUR QUALIFICATIONS CONTAINED IN THE JULY 6, 2012 TESTIMONY?

A Yes, they are contained in Appendix A to that testimony.

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.

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.

Next, 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.

The cost of service 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 that should be 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 modified Ameren Missouri's treatment of the non-labor component of production non-fuel operation and maintenance ("O&M") expenses. Ameren Missouri allocates a larger proportion of non-fuel production O&M expense on energy than I believe is appropriate. 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 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. Schedule MEB-COS-6 shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates, using Ameren Missouri's ECOS, with present rate income taxes allocated on taxable income for consistency of presentation with Schedule MEB-COS-5.

10. Ameren Missouri's equal percent across-the-board rate increase is completely inconsistent with the facts and, for two reasons, should not be adopted. First, it completely ignores the requirement to track and specifically assign energy efficiency ("EE") program costs and related charges by rate schedule so that the appropriate charges are borne by the users, and in order to ensure that customers who have opted-out of participation in the programs are not required

to bear the costs. Second, Ameren Missouri's allocation also ignores the very substantial differences in rate of return among classes under current rates.

11. My recommendation for allocating any amount of rate increase that is approved is set forth on Schedule MEB-COS-7 at several different levels of rate increase in order to illustrate the methodology. In addition to specific assignment of the EE revenue requirement by class, I am recommending a modest 2% revenue increase in Residential and Lighting classes because of their low rate of return, and a corresponding revenue neutral 1.75% decrease to all other customer classes. The combination of these two steps, along with an equal percentage increase for the portion of the rate increase that is not related to the EE revenue requirement will maintain fairness in the allocation of the EE revenue requirement and make a movement toward cost of service.

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 electricity used over time by a customer (i.e., energy measured in kilowatthours ("kWh")) <u>and</u> the rate of use (i.e., demand, a.k.a. "power" measured in 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 to 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. The utility must incur the cost of this pathway regardless of the customer's **demand** or **energy** requirements.

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.

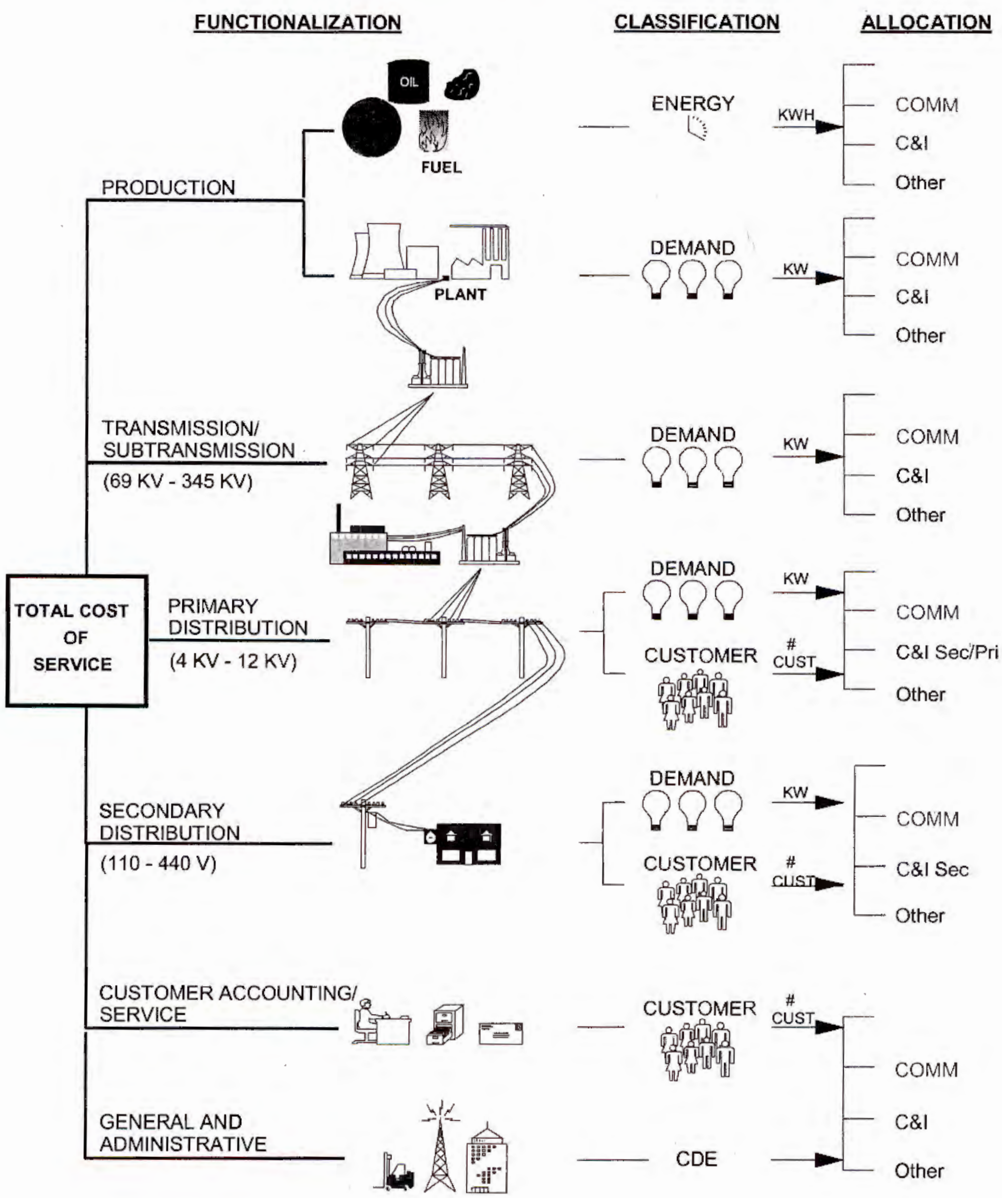
Generating units, transmission lines and substations and distribution lines and substations are rated according to their maximum capacity, which is the maximum amount of electrical demand that can safely be imposed on them. (They are not rated according to average annual demand; that is, the amount of 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 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 production. 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 service 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.)

Classification

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 peak 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 peak 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 O&M 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 construct a system's electrical pathways that comply with local or national safety and reliability codes, and to attach customers to that 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.

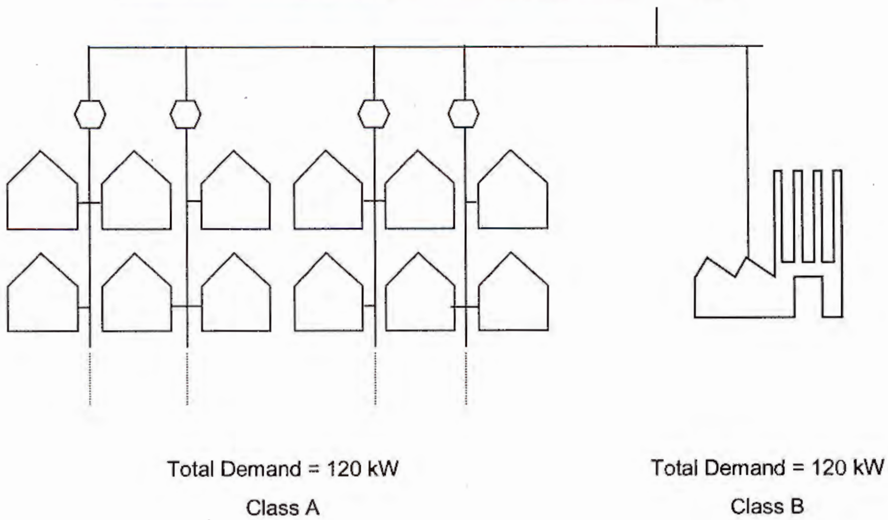
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kW load, having a total demand of 120 kW. This is the same total demand as is imposed 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 capacity of the system required by local or national safety and reliability codes, 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.

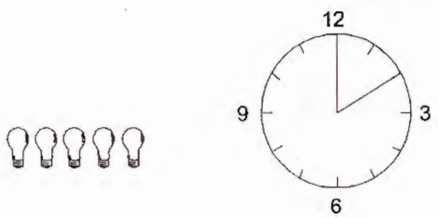
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

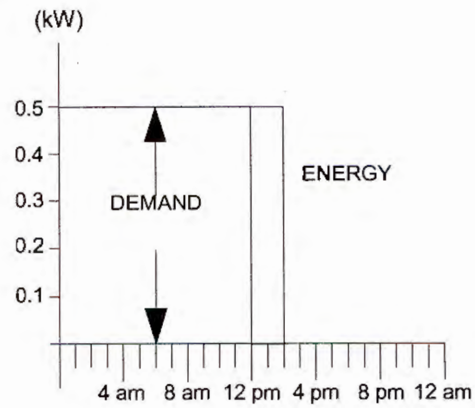
A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each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

Figure 3

DEMAND VS. ENERGY

CUSTOMER A

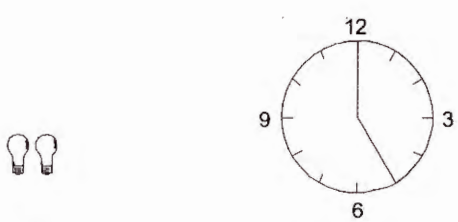


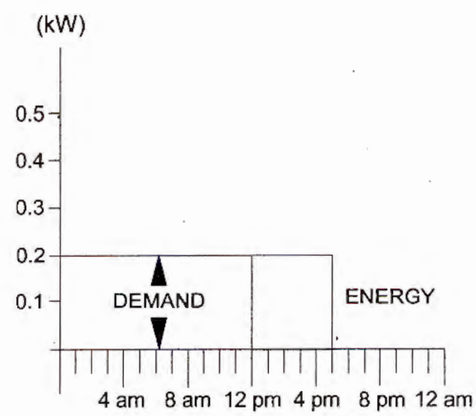


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

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 <u>average total</u> 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.

<u>Allocation</u>

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	14,636,832	37.13%
Small GS	3,783,089	9.60%
Large GS/Small Primary	12,598,059	31.96%
Large Primary	3,943,079	10.00%
Large Transmission	4,213,688	10.69%
Lighting	242,723	0.62%
Total	39,417,469	100.00%

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 below shows the calculation of the factor for Ameren Missouri. (The selection and derivation of this factor is discussed in more detail on pages 21 to 28.)

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	3,825	46.89%
Small GS	869	10.65%
Large GS/Small Primary	2,322	28.47%
Large Primary	589	7.23%
Large Transmission	493	6.04%
Lighting	59	0.72%
Total	8,156[1]	100.00%

Notes:
[1]The 8,156 MW is the Missouri 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	$ 1,271,139	13,543,438	9.39¢
Small GS	268,510	3,500,486	7.67
Large GS/Small Primary	686,500	11,767,949	5.83
Large Primary	177,851	3,787,202	4.70
Large Transmission	139,758	4,157,417	3.36
Lighting	36,399	224,591	16.21
Total	$ 2,580,158	36,981,084	6.98¢

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)	Production A&E (MW)	Load Factor
	(1)	(2)	(3)
Residential	14,636,832	3,825	44%
Small GS	3,783,089	869	50%
Large GS/Small Primary	12,598,059	2,322	62%
Large Primary	3,943,079	589	76%
Large Transmission	4,213,688	493	98%
Lighting	242,723	59	47%
Total	39,417,469	8,156	55%

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 8.07% at the secondary level, 4.12% at the primary level and 1.35% at the transmission level.

TABLE 5
Energy Loss Factors

Rate Class	Percent of Sale By Voltage Level: Secondary	Percent of Sale By Voltage Level: Primary & Higher	Composite Loss Percentage
	(1)	(2)	(3)
Residential	100%	0%	8.07%
Small GS	100%	0%	8.07%
Large GS/Small Primary	69%	31%	7.05%
Large Primary	0%	100%	4.12%
Large Transmission	0%	100%	1.35%
Lighting	100%	0%	8.07%

Source: Workpapers of Wilbon L. Cooper - Normal Billing Units.

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 13,000 kWhs per Residential customer, or 4,000 times more per capita, as shown in Table 6. The customer-related costs to serve Large Primary customers are not 4,000 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	13,543,438	1,037,189	13,058
Small GS	3,500,486	143,510	24,392
Large GS/Small Primary	11,767,949	10,071	1,168,481
Large Primary	3,787,202	72	52,600,030
Large Transmission	4,157,417	1	4,157,417,202
Lighting	224,591	55,560	4,042
Total	36,981,084	1,246,404	29,670

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.

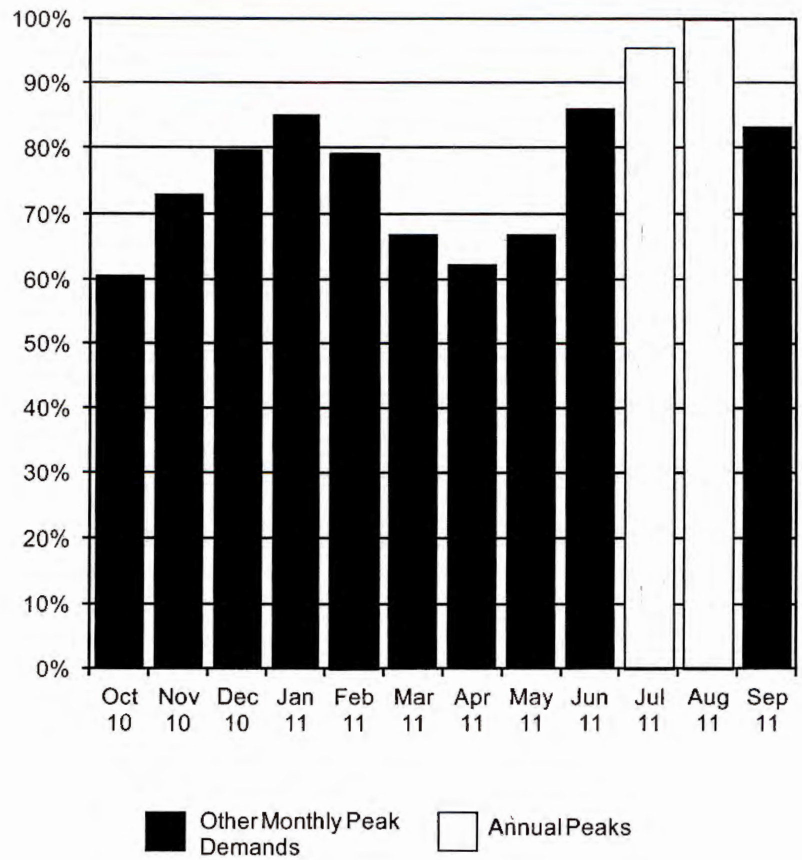
Utility System Characteristics

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
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 September 2011



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 August, and was substantially higher than the monthly peaks occurring in the other months. The July peak was the closest, at 95% of the annual peak. The peaks in June and January were 14% and 15%, 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 peak 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.

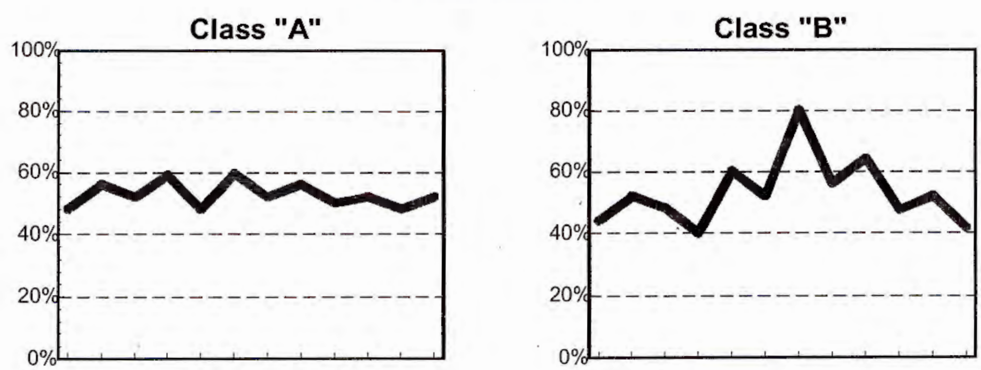
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability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

[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.

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

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in 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 July and August 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 "1" 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 25 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 $203.1 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 $142.9 million of income taxes that Ameren Missouri would not incur if it did not receive its requested $375.6 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 $60.2 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's 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 Missouri'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 the system average rate of return, and reducing the income taxes charged to customers earning less than the system average rate of return.

Q DO YOU TAKE ISSUE WITH ANY ELEMENTS OF AMEREN MISSOURI'S CLASS COST OF SERVICE STUDY?

A Yes. There are two areas where there are differences. The first is the allocation of transmission costs, and the second is the classification of certain non-fuel generation O&M expenses.

Q WHAT IS THE 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 (as much as 40% lower) 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 IS THE ISSUE WITH RESPECT TO THE CLASSIFICATION OF CERTAIN NON-FUEL GENERATION O&M EXPENSES?

A The issue involves the classification of non-labor generation costs (other than fuel and purchased power) between the "fixed" category and the "variable" category. The categories of costs, broadly speaking, are non-labor costs in the generation operations cost category and the generation maintenance category. Classification is important in cost of service studies because fixed costs are allocated on the production demand allocation factor, while variable costs are allocated on the production energy allocation factor. These factors are significantly different among classes, so the issue of classification is very important.

Q WHAT IS YOUR POSITION ON HOW THESE GENERATION COSTS OTHER THAN FUEL AND PURCHASED POWER SHOULD BE ALLOCATED?

A It is my position that the vast majority of these costs do not vary in any appreciable way with the number of kilowatthours generated, but occur primarily 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. I believe the most appropriate approach is to classify all of the generation O&M expense other than fuel and purchased power as a fixed cost. This is sometimes referred as the "expenses follow plant" basis. It is the basis that generally has been used in Missouri for classification and allocation of these costs.

Q TO WHAT EXTENT DOES AMEREN MISSOURI TAKE A DIFFERENT APPROACH?

A Historically, Ameren Missouri has classified significant amounts of both labor and non-labor costs as variable. In this case, Ameren Missouri has classified the labor component of generation O&M expense (except for fuel handling) as a fixed cost. This is consistent with the approach that I have used, and thus there is no longer a difference in the treatment of the labor component.

There does, however, remain some difference in the treatment of costs other than labor. Ameren Missouri has moved about 40% of these other costs that it previously classified as energy-related into the fixed cost category. Thus the remaining difference between my approach and Ameren Missouri's is approximately $97 million with respect to generation non-labor O&M expense other than fuel and purchased power.

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

A As shown on line 25 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 Attachment.

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 witness Kip Smith 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 misled 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 EE 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 EE or demand response 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.

The importance of this concept is underscored by the large dollar amount associated with EE programs that will be incorporated into the rates approved in this proceeding. The cost to be incorporated in rates for Ameren Missouri's new Missouri Energy Efficiency Investment Act ("MEEIA") programs is almost $80 million. This is a significant commitment of dollars and a large amount of the cost is for programs associated with residential customers. Cost-based rates for residential customers will provide higher rewards to customers who implement these programs. Failure to fully price the residential rates, and to reflect the cost of EE programs in the residential rate, will diminish the likelihood that these programs will be successful.

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 25 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 $101 million, or 8.6%, in order to move to cost of service. The Lighting class would require an increase of $2.0 million, or almost 6%. All other classes would require a corresponding decrease. The decreases range from 5.5% to 8.4%.

Q HAVE YOU PREPARED A SCHEDULE SIMILAR TO SCHEDULE MEB-COS-5, EXCEPT UTILIZING AMEREN MISSOURI'S CLASS COST OF SERVICE STUDY AND CALCULATING PRESENT RATE INCOME TAXES ON TAXABLE INCOME?

A Yes. This appears on Schedule MEB-COS-6. The results are very comparable to the results of my cost of service study shown on Schedule MEB-COS-5. The Residential and Lighting classes require an increase, while all of the other classes would require a decrease.

Q HOW DOES AMEREN MISSOURI PROPOSE TO ADJUST REVENUES?

A Ameren Missouri proposes 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 IN ITS CLASS COST OF SERVICE STUDY, HOW DID AMEREN MISSOURI TREAT THE EE REVENUE REQUIREMENT?

A In its class cost of service study, Ameren Missouri properly assigned the MEEIA-related EE costs by customer class. (As a result of the MEEIA proceeding, minor adjustments have been made to the amounts initially calculated by Ameren Missouri.) The amortizations required for pre-MEEIA EE programs were also appropriately assigned to the individual customer classes, consistent with their participation in Ameren Missouri's programs. The Unanimous Stipulation and Agreement in Ameren Missouri's MEEIA filing, Case No. EO-2012-0142, explicitly recognizes the appropriateness of class-specific assignments of these EE costs.

Q DO YOU THESE COSTS VARY SUBSTANTIALLY BY CUSTOMER CLASS?

A Yes. The costs range from approximately $59 million for the Residential class to "zero" dollars for the Large Transmission class.

Q WHY IS THE AMOUNT ATTRIBUTABLE TO THE LARGE TRANSMISSION CLASS ZERO?

A In accordance with the Commission's rules, the one customer in the Large Transmission class has opted out of participation in Ameren Missouri's EE programs.

Q HAVE CUSTOMERS IN OTHER CLASSES ALSO OPTED OUT?

A Yes. A number of customers in other classes also have opted out, which is one of the reasons that the relative amounts of costs associated with the business class customers are lower than for the Residential class. In addition, the residential programs themselves are more extensive, and cost more to implement, than do the business programs.

Q DOES AMEREN MISSOURI'S EQUAL PERCENT ACROSS-THE-BOARD INCREASE RECOGNIZE THESE CLASS DIFFERENCES?

A No. Ameren Missouri's equal percent across-the-board rate increase totally ignores these wide differences in responsibility for EE program costs. Burying these amounts in the overall revenue increase, and assigning the increase on an equal percentage basis, causes some classes to bear substantially more of these costs than they should, while others bear less than they should. For example, the equal percentage approach to the EE component of the requested rate increase assigns $48 million to the Residential class, when its responsibility for EE programs is $59 million.

On the other hand, it assigns approximately $6 million of cost to the Large Transmission Service class when, in fact, its actual responsibility for these costs is "zero." Also, the equal percent approach assigns $12 million to the Small General Service class while its responsibility for these costs is only $6 million.

Q DO YOU BELIEVE THAT AMEREN MISSOURI'S ACROSS-THE-BOARD INCREASE IS CONSISTENT WITH COST OF SERVICE?

A No. At a very minimum, even if no other changes were made in the allocation of the revenue increase, the EE revenue requirement must be assigned specifically to customer classes. To do otherwise would be to ignore the entire concept of class-specific assignments that follow cost of service and recognize the extent to which members of the various customer classes have opted out of these EE programs.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE ALLOCATION OF ANY AWARDED REVENUE INCREASE?

A As indicated above, a key part of my recommendation is to specifically assign the EE revenue requirements by customer class. As noted, this is consistent with the treatment of these costs in both Ameren Missouri's class cost of service study and my class cost of service study, as well as with the Unanimous Stipulation and Agreement in the MEEIA case.

Q HAVE YOU SUMMARIZED THESE ASSIGNMENTS IN YOUR SCHEDULES?

A Yes. My Schedule MEB-COS-7, consisting of five pages, illustrates my recommendations concerning the assignment and allocation of any awarded rate increase. The difference between the pages is the amount of overall increase that is assumed. The percentage increases range from 5% on page 1 through 14.6% (Ameren Missouri's request) on page 5 of the schedule. The assignment of EE revenue requirement dollars is shown in column 5 on each of the pages of this schedule.

Q PLEASE CONTINUE WITH THE EXPLANATION OF YOUR RECOMMENDED SPREAD OF ANY AWARDED REVENUE INCREASE.

A In addition to the specific assignment of the EE revenue requirement (shown in column 5 at Schedule MEB-COS-7), I am recommending some movement toward cost of service for all customer classes. In particular, I am proposing a gradual movement consistent with the stipulation in the prior rate proceeding that was approved by the Commission. Use of this methodology in a stipulation in the prior case certainly is not binding precedent, but I believe the methodology continues to be reasonable given the continuing class rate of return disparities in this case. Columns 2 through 4 develop this aspect of my proposal.

In particular, because the Residential and Lighting classes are producing a below average return, I recommend they first receive an increase of 2%, and that the approximately $24 million of revenue generated from this step be used to proportionately reduce the revenue responsibility of all of the other customer classes. The resulting "adjusted current revenues" is shown in column 4 on each of the pages of Schedule MEB-COS-7. After this step, then the specific assignment of the EE revenue requirement, which I previously discussed, is accomplished.

The final step (shown in column 6 of Schedule MEB-COS-7) is to distribute the remainder of the required increase to all classes on an equal percent basis.

The total revenue increase dollars by class are shown in column 7, and the resulting percentage increases are shown in column 8.

RATE DESIGN

Q HOW SHOULD THE EE COST BE REFLECTED IN RATES?

A The guidelines for the rate design and reflection of costs on customer bills are set forth in paragraph 10 of the Unanimous Stipulation and Agreement in Case No. EO-2012-0142. This paragraph specifies that each rate class's allocation of program costs and throughput disincentive will be reflected on the tariff sheets. It also provides that these MEEIA program costs are to be shown as a separate line item on the electric bills and labeled as "Energy Efficiency Investment Chg." In addition, for rate schedules that have demand metering and associated detail billing, the amortization of the pre-MEEIA charges will also be set out on the bill and designated as "Energy Efficiency Investment Chg."

It is important that the relevant amounts be included in the rate schedules and identified separately so that only customers who have not opted out of the programs are required to pay these costs. In other words, as in the current Ameren Missouri tariffs that were approved in the preceding rate case, ER-2011-0028, these charges are set forth separately so that customers who have opted out do not pay them.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

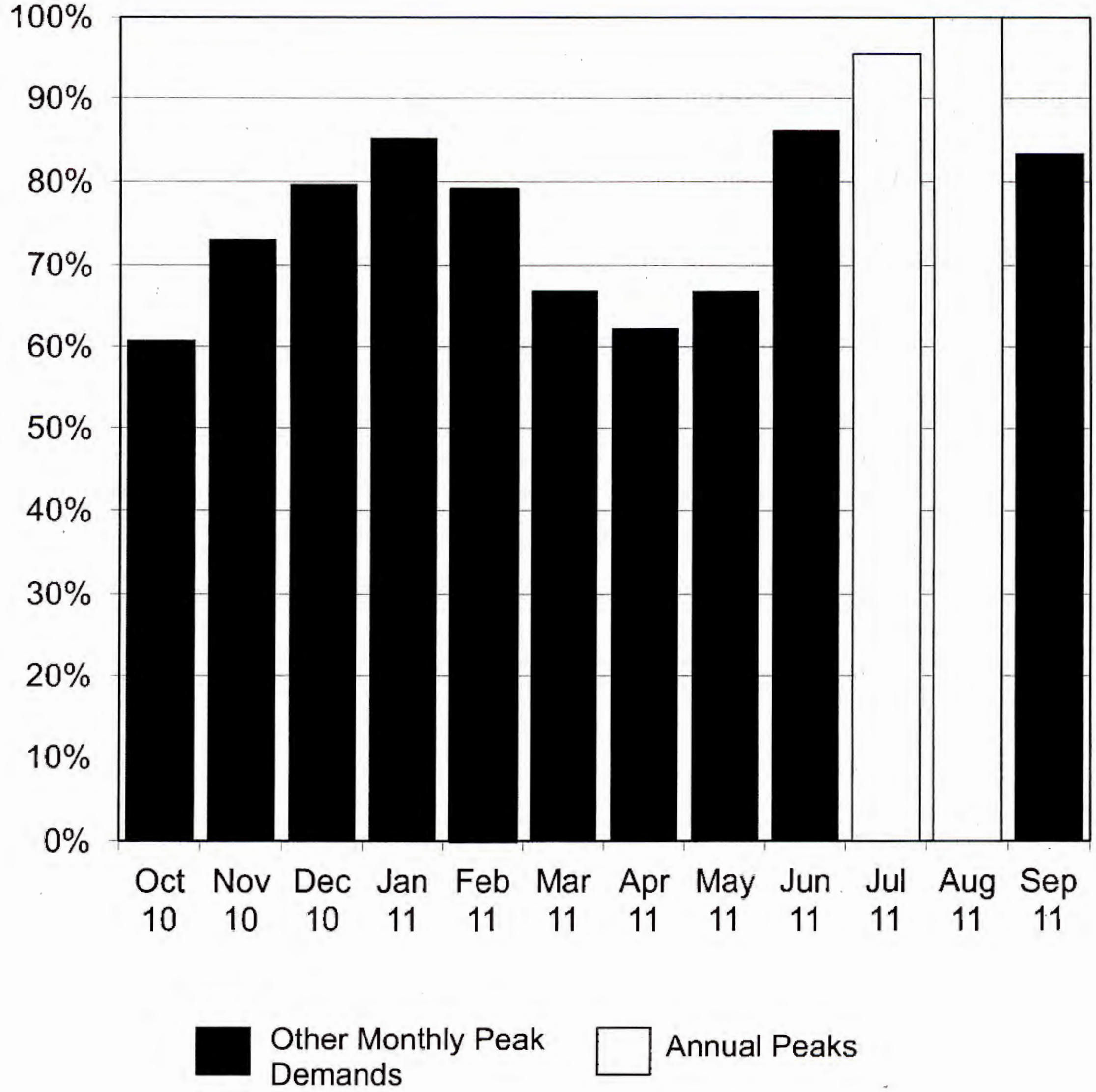
A Yes, it does.

\\Doc\Shares\ProlawDocs\TSK\9553\Testimony-BAI\219768.doc

AMEREN MISSOURI

Case No. ER-2012-0166

Analysis of Ameren's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) <u>For the Test Year Ended September 2011</u>



AMEREN MISSOURI
Case No. ER-2012-0166

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 September 2011

Line	Description	Total Company MW (1)	Percent (2)
1	January	6,947	85.2%
2	February	6,454	79.1%
3	March	5,464	67.0%
4	April	5,084	62.3%
5	May	5,462	67.0%
6	June	7,028	86.2%
7	July	7,787	95.5%
8	August	8,156	100.0%
9	September	6,801	83.4%
10	October	4,959	60.8%
11	November	5,964	73.1%
12	December	6,505	79.8%

Source: Ameren Missouri COS, System_CP Worksheet

AMEREN MISSOURI
Case No. ER-2012-0166

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended September 2011

Line	Description	Missouri Total (1)	Residential (2)	Small Gen. Service (3)	Large G.S./ Sm Primary (4)	Large Primary (5)	Large Transmission (6)	Lighting (7)
1	Missouri System Peak	8,156						
2	Avg of 4 Highest Monthly NCP Values	7,919.1	3,685	840	2,264	580	492	57
3	Energy Sales with Losses - MWh	39,417,469	14,636,832	3,783,089	12,598,059	3,943,079	4,213,688	242,723
4	Average Demand - kW	4,499.7	1,670.9	431.9	1,438.1	450.1	481.0	27.7
5	Average Demand - Percent	100.0%	37.1%	9.6%	32.0%	10.0%	10.7%	0.6%
6	Class Excess Demand - kW	3,419.4	2,014.2	408.6	826.2	130.1	10.9	29.3
7	Class Excess Demand - Percent	100.0%	58.9%	11.9%	24.2%	3.8%	0.3%	0.9%
	Allocator:							
8	Annual Load Factor * Average Demand	0.551704	0.204863	0.052950	0.176328	0.055189	0.058977	0.003397
9	(1-LF) * Excess Demand	0.448296	0.264073	0.053565	0.108324	0.017063	0.001424	0.003847
10	Average and Excess Demand Allocator	1.000000	0.468937	0.106515	0.284652	0.072252	0.060400	0.007244

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

System Annual Load Factor	55.17%
1 - Load Factor	44.83%

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

AMEREN MISSOURI
Case No. ER-2012-0166

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

Line	Description	Missouri Total (1)	Residential (2)	Small Gen. Service (3)	Large G.S./ Sm Primary (4)	Large Primary (5)	Large Transmission (6)	Lighting (7)
1	Base Revenue	$ 2,580,158	$ 1,170,105	$ 288,054	$ 749,850	$ 189,820	$ 147,949	$ 34,380
2	Other Revenue	68,583	38,657	6,658	15,873	3,763	3,078	555
3	Lighting Revenue	-	-	-	-	-	-	-
4	System, Off-Sys Sales & Disp of Allow	360,103	133,880	34,603	115,232	36,067	38,542	1,780
5	Rate Revenue Variance	-	-	-	-	-	-	-
6	Total Operating Revenue	$ 3,008,844	$ 1,342,642	$ 329,314	$ 880,954	$ 229,650	$ 189,568	$ 36,715
7	Total Prod, T&D, Cust and A&G Expense	$ 1,982,446	$ 908,325	$ 199,577	$ 557,773	$ 156,419	$ 139,809	$ 20,543
8	Total Depreciation and Ammortization Expenses	461,617	243,153	49,410	116,132	26,841	17,341	8,741
9	Real Estate and Property Taxes	142,152	74,466	15,498	35,478	8,288	5,826	2,597
10	Income Taxes: At Present Rates	60,209	(7,425)	13,893	39,528	8,271	5,741	201
11	Payroll Taxes	23,042	11,897	2,428	5,845	1,463	985	425
12	Federal Excise Taxes	-	-	-	-	-	-	-
13	Revenue Taxes	-	-	-	-	-	-	-
14	Total Operating Expenses	$ 2,669,466	$ 1,230,416	$ 280,806	$ 754,756	$ 201,281	$ 169,701	$ 32,507
15	Net Operating Income	$ 339,378	$ 112,226	$ 48,509	$ 126,198	$ 28,369	$ 19,867	$ 4,209
16	Gross Plant in Service	$ 14,610,042	$ 7,646,261	$ 1,587,513	$ 3,660,297	$ 854,696	$ 595,719	$ 265,557
17	Reserves for Depreciation	6,238,748	3,296,500	681,502	1,534,654	351,261	247,121	127,710
18	Net Plant in Service	$ 8,371,294	$ 4,349,761	$ 906,011	$ 2,125,643	$ 503,435	$ 348,598	$ 137,847
19	Materials & Supplies - Fuel	$ 260,508	$ 96,853	$ 25,033	$ 83,362	$ 26,092	$ 27,882	$ 1,287
20	Materials & Supplies - Local	170,308	108,482	19,556	30,290	5,016	3	6,961
21	Cash Working Capital	44,894	20,570	4,520	12,631	3,542	3,166	465
22	Customer Advances & Deposits	(19,448)	(10,815)	(4,742)	(3,617)	-	(125)	(149)
23	Accumulated Deferred Income Taxes	(2,017,383)	(1,056,796)	(219,937)	(503,492)	(117,621)	(82,674)	(36,862)
24	Total Net Original Cost Rate Base	$ 6,810,174	$ 3,508,054	$ 730,441	$ 1,744,816	$ 420,463	$ 296,850	$ 109,550
25	Rate of Return	4.983%	3.199%	6.641%	7.233%	6.747%	6.693%	3.842%

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: NET ORIGINAL COST - PAGE 1

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL (1)	RESIDENTIAL (2)	SMALL GEN SERVICE (3)	LARGE G.S./ SM PRIMARY (4)	LARGE PRIMARY (5)	LARGE TRANSMISSION (6)	LIGHTING (7)
1		PRODUCTION	A.F.1	$ 4,934,309	$ 2,313,878	$ 525,577	$ 1,404,561	$ 356,515	$ 298,033	$ 35,745
2										
3		TRANSMISSION								
4		LINES	A.F.2	$ 158,705	$ 70,339	$ 16,424	$ 47,321	$ 12,271	$ 12,077	$ 273
5		SUBSTATION	A.F.3	$ 320,495	$ 142,045	$ 33,168	$ 95,562	$ 24,781	$ 24,388	$ 551
6										
7		TOTAL TRANSMISSION		$ 479,200	$ 212,384	$ 49,593	$ 142,883	$ 37,052	$ 36,465	$ 824
8										
9		DISTRIBUTION PLANT								
10										
11	360	SUBSTATION LAND	A.F.8	$ 19,560	$ 9,981	$ 2,159	$ 5,889	$ 1,392	$ -	$ 140
12	321	OTHER LAND	A.F.5	$ 12,525	$ 6,520	$ 1,410	$ 3,846	$ 658	$ -	$ 91
13										
14	361-362	SUBSTATIONS	A.F.8	$ 564,299	$ 287,937	$ 62,274	$ 169,902	$ 40,148	$ -	$ 4,039
15										
16	364	POLES TOWERS FIXTURES								
17		CUSTOMER	A.F.4	$ 38,260	$ 31,838	$ 4,405	$ 309	$ 2	$ -	$ 1,706
18		HV	A.F.5a	$ 33,913	$ 17,302	$ 3,742	$ 10,205	$ 2,413	$ -	$ 251
19		PRIMARY	A.F.5b	$ 65,148	$ 33,912	$ 7,334	$ 20,003	$ 3,424	$ -	$ 476
20		SECONDARY	A.F.6	$ 33,215	$ 19,975	$ 4,320	$ 8,639	$ -	$ -	$ 280
21		LIGHTING-DIRECT	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22										
23		SUBTOTAL		$ 170,537	$ 103,028	$ 19,802	$ 39,156	$ 5,838	$ -	$ 2,713
24										
25	365	OVERHEAD CONDUCTOR								
26		CUSTOMER	A.F.4	$ 321,741	$ 267,736	$ 37,045	$ 2,600	$ 19	$ -	$ 14,342
27		HV	A.F.5a	$ 101,932	$ 52,005	$ 11,247	$ 30,674	$ 7,251	$ -	$ 755
28		PRIMARY	A.F.5b	$ 352,469	$ 183,474	$ 39,681	$ 108,219	$ 18,522	$ -	$ 2,574
29		SECONDARY	A.F.6	$ 18,505	$ 11,129	$ 2,407	$ 4,813	$ -	$ -	$ 156
30										
31		SUBTOTAL		$ 794,647	$ 514,343	$ 90,380	$ 146,306	$ 25,792	$ -	$ 17,827
32										
33	366	UNDERGROUND CONDUIT								
34		CUSTOMER	A.F.4	$ 130,418	$ 108,527	$ 15,016	$ 1,054	$ 8	$ -	$ 5,814
35		HV	A.F.5a	$ 5,432	$ 2,771	$ 599	$ 1,635	$ 386	$ -	$ 40
36		PRIMARY	A.F.5b	$ 39,132	$ 20,370	$ 4,406	$ 12,015	$ 2,056	$ -	$ 286
37		SECONDARY	A.F.6	$ 17,260	$ 10,380	$ 2,245	$ 4,489	$ -	$ -	$ 146
38										
39		SUBTOTAL		$ 192,243	$ 142,049	$ 22,266	$ 19,192	$ 2,450	$ -	$ 6,285
40										
41	367	UNDERGROUND CONDUCTORS								
42		CUSTOMER	A.F.4	$ 272,881	$ 227,077	$ 31,419	$ 2,205	$ 16	$ -	$ 12,164
43		HV	A.F.5a	$ 11,365	$ 5,798	$ 1,254	$ 3,420	$ 808	$ -	$ 84
44		PRIMARY	A.F.5b	$ 81,879	$ 42,621	$ 9,218	$ 25,139	$ 4,303	$ -	$ 598
45		SECONDARY	A.F.6	$ 36,115	$ 21,720	$ 4,697	$ 9,393	$ -	$ -	$ 305
46										
47		SUBTOTAL		$ 402,240	$ 297,216	$ 46,589	$ 40,157	$ 5,127	$ -	$ 13,151

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: NET ORIGINAL COST - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL (1)	RESIDENTIAL (2)	SMALL GEN SERVICE (3)	LARGE G.S./ SM PRIMARY (4)	LARGE PRIMARY (5)	LARGE TRANSMISSION (6)	LIGHTING (7)
1										
2	368	LINE TRANSFORMERS								
3		CUSTOMER	A.F.15	$ 162,193	$ 141,274	$ 19,547	$ 1,372	$ -	$ -	$ -
4		SECONDARY	A.F.6	$ 122,013	$ 73,379	$ 15,870	$ 31,734	$ -	$ -	$ 1,029
5										
6		SUBTOTAL		$ 284,206	$ 214,653	$ 35,418	$ 33,106	$ -	$ -	$ 1,029
7										
8	369-1	OVERHEAD SERVICES								
9		CUSTOMER	A.F.15	$ (18,307)	$ (15,945)	$ (2,206)	$ (155)	$ -	$ -	$ -
10		SECONDARY	A.F.16	$ (26,619)	$ (18,499)	$ (3,432)	$ (4,688)	$ -	$ -	$ -
11										
12		SUBTOTAL		$ (44,926)	$ (34,444)	$ (5,639)	$ (4,843)	$ -	$ -	$ -
13										
14	369-2	UNDERGROUND SERVICES								
15		CUSTOMER	A.F.15	$ 40,156	$ 34,977	$ 4,840	$ 340	$ -	$ -	$ -
16		SECONDARY	A.F.16	$ 2,302	$ 1,600	$ 297	$ 405	$ -	$ -	$ -
17										
18		SUBTOTAL		$ 42,458	$ 36,576	$ 5,136	$ 745	$ -	$ -	$ -
19										
20	370	METERS	A.F.7	$ 63,982	$ 41,849	$ 12,938	$ 8,430	$ 662	$ 46	$ 58
21										
22	371	CUSTOMER INSTALLATIONS	DIRECT	$ 6	$ -	$ -	$ 3	$ 3	$ -	$ -
23										
24	373	STREET LIGHTING	A.F.29	$ 49,887	$ -	$ -	$ -	$ -	$ -	$ 49,887
25										
26		SUBTOTAL - CUSTOMER DIST PLANT		$ 1,011,326	$ 837,333	$ 123,004	$ 16,154	$ 706	$ 46	$ 34,083
27		- DEMAND DIST PLANT		$ 1,540,338	$ 782,375	$ 169,728	$ 445,735	$ 81,364	$ -	$ 61,137
28										
29		DISTRIBUTION TOTAL		$ 2,551,664	$ 1,619,707	$ 292,732	$ 461,890	$ 82,070	$ 46	$ 95,220
30										
31		GENERAL PLANT	A.F.35	$ 281,976	$ 145,595	$ 29,711	$ 71,526	$ 17,898	$ 12,052	$ 5,195
32										
33				$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35				$ -	$ -	$ -	$ -	$ -	$ -	$ -
36										
37		SUBTOTAL PROD,T&D,GEN,COMMON PLANT		$ 8,247,150	$ 4,291,564	$ 897,613	$ 2,080,858	$ 493,535	$ 346,596	$ 136,984
38										
39		INTANGIBLE PLANT		$ 48,191	$ 24,883	$ 5,078	$ 12,224	$ 3,059	$ 2,060	$ 888
40		EE REGULATORY ASSET	EE tab	$ 77,311	$ 34,015	$ 3,464	$ 32,905	$ 6,927	$ -	$ -
41		REGULATORY ACCOUNT (PENSION A	A.F.35	$ (1,358)	$ (701)	$ (143)	$ (345)	$ (86)	$ (58)	$ (25)
42										
43		TOTAL NET PLANT		$ 8,371,294	$ 4,349,761	$ 906,011	$ 2,125,643	$ 503,435	$ 348,598	$ 137,847

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: NET ORIGINAL COST - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	MISSOURI TOTAL (1)	RESIDENTIAL (2)	SMALL GEN SERVICE (3)	LARGE G.S./ SM PRIMARY (4)	LARGE PRIMARY (5)	LARGE TRANSMISSION (6)	LIGHTING (7)
1		MATERIALS & SUPPLIES - FUEL	A.F.11	$ 260,508	$ 96,853	$ 25,033	$ 83,362	$ 26,092	$ 27,882	$ 1,287
2		MATERIALS & SUPPLIES - LOCAL	A.F.18	$ 170,308	$ 108,482	$ 19,556	$ 30,290	$ 5,016	$ 3	$ 6,961
3		CASH WORKING CAPITAL	A.F.37	$ 44,894	$ 20,570	$ 4,520	$ 12,631	$ 3,542	$ 3,166	$ 465
4		CUSTOMER ADVANCES & DEPOSITS	A.F.12	$ (19,448)	$ (10,815)	$ (4,742)	$ (3,617)	$ -	$ (125)	$ (149)
5		ACCUM DEFERRED INCOME TAXES	A.F.19	$ (2,017,383)	$ (1,056,796)	$ (219,937)	$ (503,492)	$ (117,621)	$ (82,674)	$ (36,862)
6										
7		TOTAL NET ORIGINAL COST RATE BASE		$ 6,810,174	$ 3,508,054	$ 730,441	$ 1,744,816	$ 420,463	$ 296,850	$ 109,550

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: OPERATING EXPENSES - PAGE 1

				TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	ALLOCATION BASIS	LABOR (1)	OTHER (2)	TOTAL (3)	LABOR (4)	OTHER (5)	LABOR (6)	OTHER (7)	LABOR (8)	OTHER (9)	LABOR (10)	OTHER (11)	LABOR (12)	OTHER (13)	LABOR (14)	OTHER (15)
1		OPERATING EXPENSES																
2																		
3																		
4		PRODUCTION																
5		OTHER	A.F.1/EE	196,454	202,265	398,718	92,124	100,320	20,925	19,129	55,921	56,653	14,194	14,678	11,866	10,255	1,423	1,230
6		VARIABLE	A.F.11	6,210	941,987	948,198	2,309	350,215	597	90,518	1,987	301,433	622	94,346	665	100,821	31	4,655
7																		
8		SUBTOTAL		202,664	1,144,252	1,346,916	94,433	450,534	21,522	109,647	57,908	358,086	14,816	109,024	12,531	111,075	1,454	5,885
9																		
10		SYSTEM REVENUE CREDITS																
11		OFF-SYSTEM SALES	A.F.11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12		RENTALS	A.F.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																		
14		SUBTOTAL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																		
16		TRANSMISSION																
17		LINES	A.F.2	393	5,042	5,436	174	2,235	41	522	117	1,503	30	390	30	384	1	9
18		SUBSTATIONS	A.F.3	5,591	41,379	46,971	2,478	18,339	579	4,282	1,667	12,338	432	3,199	425	3,149	10	71
19																		
20		TOTAL TRANSMISSION EXPENSES		5,985	46,422	52,406	2,652	20,574	619	4,804	1,784	13,841	463	3,589	455	3,532	10	80
21																		
22																		
23		DISTRIBUTION OPERATING EXPENSES																
24																		
25																		
26	582	SUBSTATIONS	A.F.8	2,785	1,469	4,254	1,421	750	307	162	839	442	198	105	-	-	20	11
27																		
28	583-1	OVERHEAD LINES																
29		CUSTOMER	A.F.22	1,019	291	1,309	846	241	117	33	8	2	0	0	-	-	48	14
30		HV	A.F.23a	405	116	521	207	59	45	13	122	35	29	8	-	-	3	1
31		PRIMARY	A.F.23b	1,245	355	1,600	648	185	140	40	382	109	65	19	-	-	9	3
32		SECONDARY	A.F.24	75	21	96	38	11	10	3	26	7	-	-	-	-	1	0
33		LIGHTING-DIRECT	A.F.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34																		
35		SUBTOTAL		2,744	783	3,527	1,738	496	312	89	538	154	94	27	-	-	61	17
36																		
37	583-2	OVERHEAD TRANSFORMERS																
38		CUSTOMER	A.F.20	1,568	244	1,812	1,366	213	189	29	13	2	-	-	-	-	-	-
39		SECONDARY	A.F.21	1,179	184	1,363	709	111	153	24	307	48	-	-	-	-	10	2
40																		
41		SUBTOTAL		2,747	428	3,175	2,075	323	342	53	320	50	-	-	-	-	10	2

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: OPERATING EXPENSES - PAGE 2

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	LARGE TRANSMISSION LABOR (12)	LARGE TRANSMISSION OTHER (13)	LIGHTING LABOR (14)	LIGHTING OTHER (15)
1																		
2	584-1	UNDERGROUND LINES																
3		CUSTOMER	A.F.26	$ 1,309	$ 1,087	$ 2,396	$ 1,094	$ 908	$ 151	$ 126	$ 11	$ 9	$ 0	$ 0	$ -	$ -	$ 53	$ 44
4		HV	A.F.27a	$ 50	$ 41	$ 91	$ 25	$ 21	$ 5	$ 5	$ 15	$ 12	$ 4	$ 3	$ -	$ -	$ 0	$ 0
5		PRIMARY	A.F.27b	$ 357	$ 297	$ 654	$ 186	$ 154	$ 40	$ 33	$ 110	$ 91	$ 19	$ 16	$ -	$ -	$ 3	$ 2
6		SECONDARY	A.F.28	$ 164	$ 136	$ 301	$ 100	$ 83	$ 21	$ 18	$ 42	$ 35	$ -	$ -	$ -	$ -	$ 1	$ 1
7																		
8		SUBTOTAL		$ 1,881	$ 1,561	$ 3,442	$ 1,405	$ 1,166	$ 218	$ 181	$ 177	$ 147	$ 22	$ 19	$ -	$ -	$ 57	$ 48
9																		
10	584-2	UNDERGROUND TRANSFORMERS																
11		CUSTOMER	A.F.20	$ 617	$ (414)	$ 203	$ 538	$ (361)	$ 74	$ (50)	$ 5	$ (4)	$ -	$ -	$ -	$ -	$ -	$ -
12		SECONDARY	A.F.21	$ 464	$ (312)	$ 153	$ 279	$ (187)	$ 60	$ (41)	$ 121	$ (81)	$ -	$ -	$ -	$ -	$ 4	$ (3)
13																		
14		SUBTOTAL		$ 1,082	$ (726)	$ 356	$ 817	$ (548)	$ 135	$ (90)	$ 126	$ (85)	$ -	$ -	$ -	$ -	$ 4	$ (3)
15																		
16	585	LIGHTING		$ 377	$ 365	$ 742	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 377	$ 365
17																		
18	586	METERS	A.F.7	$ 4,152	$ 13,326	$ 17,478	$ 2,716	$ 8,716	$ 840	$ 2,695	$ 547	$ 1,756	$ 43	$ 138	$ 3	$ 10	$ 4	$ 12
19																		
20	587	CUSTOMER INSTALLATION	DIRECT	$ 1,361	$ (67)	$ 1,294	$ (470)	$ 23	$ -	$ -	$ 916	$ (45)	$ 916	$ (45)	$ -	$ -	$ -	$ -
21																		
22		DIST OPERATING EXPENSE SUBTOTAL																
23		CUSTOMER A582-A587		$ 8,666	$ 14,533	$ 23,199	$ 6,559	$ 9,717	$ 1,371	$ 2,833	$ 584	$ 1,766	$ 43	$ 138	$ 3	$ 10	$ 105	$ 70
24		DEMAND A582-A587		$ 8,464	$ 2,606	$ 11,070	$ 3,143	$ 1,208	$ 783	$ 257	$ 2,879	$ 654	$ 1,231	$ 105	$ -	$ -	$ 429	$ 382
25																		
26	580	SUPERVISION & ENGR																
27		CUSTOMER	A.F.30	$ 1,877	$ 392	$ 2,269	$ 1,421	$ 262	$ 297	$ 76	$ 127	$ 48	$ 9	$ 4	$ 1	$ 0	$ 23	$ 2
28		DEMAND	A.F.31	$ 1,833	$ 70	$ 1,904	$ 681	$ 33	$ 170	$ 7	$ 624	$ 18	$ 267	$ 3	$ -	$ -	$ 93	$ 10
29																		
30		SUBTOTAL		$ 3,711	$ 462	$ 4,173	$ 2,102	$ 295	$ 467	$ 83	$ 750	$ 65	$ 276	$ 7	$ 1	$ 0	$ 116	$ 12
31																		
32	581	DISPATCHING																
33		CUSTOMER	A.F.30	$ 2,137	$ 125	$ 2,262	$ 1,617	$ 84	$ 338	$ 24	$ 144	$ 15	$ 11	$ 1	$ 1	$ 0	$ 26	$ 1
34		DEMAND	A.F.31	$ 2,087	$ 22	$ 2,109	$ 775	$ 10	$ 193	$ 2	$ 710	$ 6	$ 303	$ 1	$ -	$ -	$ 106	$ 3
35																		
36		SUBTOTAL		$ 4,223	$ 148	$ 4,371	$ 2,392	$ 94	$ 531	$ 27	$ 854	$ 21	$ 314	$ 2	$ 1	$ 0	$ 132	$ 4
37																		
38	588	MISCELLANEOUS																
39		CUSTOMER	A.F.30	$ 2,821	$ 15,275	$ 18,096	$ 2,135	$ 10,213	$ 446	$ 2,978	$ 190	$ 1,856	$ 14	$ 145	$ 1	$ 10	$ 34	$ 73
40		DEMAND	A.F.31	$ 2,755	$ 2,739	$ 5,494	$ 1,023	$ 1,270	$ 255	$ 270	$ 937	$ 687	$ 401	$ 110	$ -	$ -	$ 140	$ 401
41																		
42		SUBTOTAL		$ 5,576	$ 18,013	$ 23,589	$ 3,158	$ 11,483	$ 701	$ 3,247	$ 1,127	$ 2,543	$ 415	$ 255	$ 1	$ 10	$ 174	$ 475

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: OPERATING EXPENSES - PAGE 3

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	LARGE TRANSMISSION LABOR (12)	LARGE TRANSMISSION OTHER (13)	LIGHTING LABOR (14)	LIGHTING OTHER (15)
1																		
2	589	RENTS																
3		CUSTOMER	A.F.30	$ -	$ 392	$ 392	$ -	$ 262	$ -	$ 76	$ -	$ 48	$ -	$ 4	$ -	$ 0	$ -	$ 2
4		DEMAND	A.F.31	$ -	$ 70	$ 70	$ -	$ 33	$ -	$ 7	$ -	$ 18	$ -	$ 3	$ -	$ -	$ -	$ 10
5																		
6		SUBTOTAL		$ -	$ 462	$ 462	$ -	$ 294	$ -	$ 83	$ -	$ 65	$ -	$ 7	$ -	$ 0	$ -	$ 12
7																		
8		DIST OPERATING EXPENSE SUBTOTAL																
9		CUSTOMER A580-589		$ 15,500	$ 30,717	$ 46,217	$ 11,732	$ 20,539	$ 2,453	$ 5,988	$ 1,045	$ 3,732	$ 77	$ 291	$ 5	$ 20	$ 187	$ 147
10		DEMAND A580-589		$ 15,140	$ 5,507	$ 20,647	$ 5,621	$ 2,554	$ 1,400	$ 543	$ 5,150	$ 1,382	$ 2,201	$ 222	$ -	$ -	$ 767	$ 807
11																		
12		TOTAL DIST OPERATING EXPENSES		$ 30,640	$ 36,224	$ 66,864	$ 17,353	$ 23,092	$ 3,853	$ 6,531	$ 6,195	$ 5,114	$ 2,278	$ 513	$ 5	$ 20	$ 954	$ 954
13																		
14																		
15		DISTRIBUTION MAINTENANCE EXPENSES																
16																		
17																		
18	591-592	SUBSTATIONS	A.F.8	$ 10,466	$ 6,468	$ 16,934	$ 5,341	$ 3,300	$ 1,155	$ 714	$ 3,151	$ 1,947	$ 745	$ 460	$ -	$ -	$ 75	$ 46
19																		
20	593	OVERHEAD LINES																
21		CUSTOMER	A.F.22	$ 8,449	$ 23,974	$ 32,423	$ 7,013	$ 19,900	$ 970	$ 2,753	$ 68	$ 193	$ 1	$ 1	$ -	$ -	$ 397	$ 1,126
22		HV	A.F.23a	$ 3,359	$ 9,531	$ 12,890	$ 1,714	$ 4,863	$ 371	$ 1,052	$ 1,011	$ 2,868	$ 239	$ 678	$ -	$ -	$ 25	$ 71
23		PRIMARY	A.F.23b	$ 10,326	$ 29,301	$ 39,627	$ 5,375	$ 15,252	$ 1,162	$ 3,299	$ 3,170	$ 8,996	$ 543	$ 1,540	$ -	$ -	$ 75	$ 214
24		SECONDARY	A.F.24	$ 621	$ 1,761	$ 2,382	$ 312	$ 884	$ 81	$ 231	$ 217	$ 615	$ -	$ -	$ -	$ -	$ 11	$ 31
25		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26																		
27		SUBTOTAL		$ 22,754	$ 64,567	$ 87,321	$ 14,413	$ 40,899	$ 2,585	$ 7,335	$ 4,466	$ 12,673	$ 782	$ 2,219	$ -	$ -	$ 508	$ 1,441
28																		
29	594	UNDERGROUND LINES																
30		CUSTOMER	A.F.26	$ 3,249	$ 3,672	$ 6,920	$ 2,715	$ 3,069	$ 376	$ 425	$ 26	$ 30	$ 0	$ 0	$ -	$ -	$ 132	$ 149
31		HV	A.F.27a	$ 123	$ 139	$ 262	$ 83	$ 71	$ 14	$ 15	$ 37	$ 42	$ 9	$ 10	$ -	$ -	$ 1	$ 1
32		PRIMARY	A.F.27b	$ 886	$ 1,002	$ 1,888	$ 461	$ 522	$ 100	$ 113	$ 272	$ 308	$ 47	$ 53	$ -	$ -	$ 6	$ 7
33		SECONDARY	A.F.28	$ 408	$ 461	$ 869	$ 247	$ 279	$ 53	$ 60	$ 105	$ 118	$ -	$ -	$ -	$ -	$ 3	$ 4
34																		
35		SUBTOTAL		$ 4,666	$ 5,274	$ 9,940	$ 3,486	$ 3,940	$ 542	$ 613	$ 440	$ 498	$ 56	$ 63	$ -	$ -	$ 142	$ 161
36																		
37	595	LINE TRANSFORMERS																
38.		CUSTOMER	A.F.20	$ 650	$ 525	$ 1,174	$ 566	$ 457	$ 78	$ 63	$ 5	$ 4	$ -	$ -	$ -	$ -	$ -	$ -
39		SECONDARY	A.F.21	$ 489	$ 395	$ 883	$ 294	$ 237	$ 64	$ 51	$ 127	$ 103	$ -	$ -	$ -	$ -	$ 4	$ 3
40																		
41		SUBTOTAL		$ 1,139	$ 919	$ 2,058	$ 860	$ 694	$ 142	$ 115	$ 133	$ 107	$ -	$ -	$ -	$ -	$ 4	$ 3
42																		
43	596	LIGHTING		$ 2,060	$ 998	$ 3,058	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,060	$ 998
44																		
45	597	METERS	A.F.7	$ 616	$ 100	$ 716	$ 403	$ 65	$ 125	$ 20	$ 81	$ 13	$ 6	$ 1	$ 0	$ 0	$ 1	$ 0
46																		
47		DIST MAINTENANCE EXPENSE SUBTOTAL																
48		CUSTOMER A593-A597		$ 12,963	$ 28,270	$ 41,233	$ 10,697	$ 23,491	$ 1,549	$ 3,261	$ 181	$ 241	$ 7	$ 3	$ 0	$ 0	$ 529	$ 1,275
49		DEMAND A593-A597		$ 28,738	$ 50,055	$ 78,793	$ 13,806	$ 25,408	$ 3,000	$ 5,535	$ 8,090	$ 14,997	$ 1,582	$ 2,740	$ -	$ -	$ 2,261	$ 1,374

AMEREN MISSOURI
Case No. ER-2012-0166

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

TITLE: OPERATING EXPENSES - PAGE 4

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	LARGE TRANSMISSION LABOR (12)	LARGE TRANSMISSION OTHER (13)	LIGHTING LABOR (14)	LIGHTING OTHER (15)
1																		
2	590	SUPERVISION & ENGR																
3		CUSTOMER	A.F.32	$ 651	$ 133	$ 784	$ 537	$ 111	$ 78	$ 15	$ 9	$ 1	$ 0	$ 0	$ 0	$ 0	$ 27	$ 6
4		DEMAND	A.F.33	$ 1,443	$ 236	$ 1,678	$ 693	$ 120	$ 151	$ 26	$ 406	$ 71	$ 79	$ 13	$ -	$ -	$ 114	$ 6
5																		
6		SUBTOTAL		$ 2,094	$ 369	$ 2,462	$ 1,230	$ 230	$ 228	$ 41	$ 415	$ 72	$ 80	$ 13	$ 0	$ 0	$ 140	$ 12
7																		
8	598	MISCELLANEOUS																
9		CUSTOMER	A.F.32	$ 295	$ 741	$ 1,037	$ 244	$ 616	$ 35	$ 85	$ 4	$ 6	$ 0	$ 0	$ 0	$ 0	$ 12	$ 33
10		DEMAND	A.F.33	$ 655	$ 1,312	$ 1,967	$ 315	$ 666	$ 68	$ 145	$ 184	$ 393	$ 36	$ 72	$ -	$ -	$ 52	$ 36
11																		
12		SUBTOTAL		$ 951	$ 2,053	$ 3,004	$ 559	$ 1,282	$ 104	$ 231	$ 189	$ 399	$ 36	$ 72	$ 0	$ 0	$ 64	$ 69
13		DIST MAINTENANCE EXPENSE SUBTOTAL																
14		CUSTOMER A590-A598		$ 13,910	$ 29,144	$ 43,054	$ 11,478	$ 24,217	$ 1,662	$ 3,362	$ 194	$ 248	$ 8	$ 3	$ 0	$ 0	$ 568	$ 1,314
15		DEMAND A590-A598		$ 30,836	$ 51,603	$ 82,439	$ 14,814	$ 26,194	$ 3,219	$ 5,706	$ 8,681	$ 15,461	$ 1,697	$ 2,825	$ -	$ -	$ 2,426	$ 1,417
16																		
17		TOTAL MAINTENANCE OPERATING EXPENSE		$ 44,746	$ 80,747	$ 125,492	$ 26,291	$ 50,411	$ 4,881	$ 9,068	$ 8,875	$ 15,709	$ 1,705	$ 2,828	$ 0	$ 0	$ 2,993	$ 2,731
18																		
19		TOTAL DISTRIBUTION EXPENSES		$ 75,385	$ 116,971	$ 192,356	$ 43,645	$ 73,503	$ 8,734	$ 15,599	$ 15,070	$ 20,822	$ 3,983	$ 3,341	$ 6	$ 20	$ 3,948	$ 3,685

TITLE: OPERATING EXPENSES - PAGE 5

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	LARGE TRANSMISSION LABOR (12)	LARGE TRANSMISSION OTHER (13)	LIGHTING LABOR (14)	LIGHTING OTHER (15)
1																		
2																		
3		CUSTOMER ACCOUNT EXPENSES																
4																		
5	902	METER READING	A.F.7A	$ 89	$ 7,879	$ 7,968	$ 76	$ 6,776	$ 11	$ 938	$ 2	$ 137	$ 0	$ 17	$ 0	$ 2	$ 0	$ 9
6	905	MISCELLANEOUS	A.F.7A	$ 6	$ 192	$ 197	$ 5	$ 165	$ 1	$ 23	$ 0	$ 3	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
7	903	CUSTOMER RECORDS	A.F.40	$ 6,132	$ 7,568	$ 13,700	$ 4,855	$ 5,671	$ 349	$ 939	$ 850	$ 918	$ 5	$ 6	$ 0	$ 0	$ 72	$ 35
8	904	UNCOLLECTIBLE ACCOUNTS	A.F.13	$ -	$ 15,572	$ 15,572	$ -	$ 13,717	$ -	$ 903	$ -	$ 845	$ -	$ 63	$ -	$ -	$ -	$ 43
9	903	CREDIT AND COLLECTION	A.F.13	$ 1,904	$ 2,350	$ 4,253	$ 1,677	$ 2,070	$ 110	$ 136	$ 103	$ 128	$ 8	$ 9	$ -	$ -	$ 5	$ 7
10		INTEREST ON SURETY DEPOSITS	A.F.12	$ -	$ 722	$ 722	$ -	$ 402	$ -	$ 176	$ -	$ 134	$ -	$ -	$ -	$ 5	$ -	$ 6
11																		
12		SUBTOTAL		$ 8,130	$ 34,283	$ 42,413	$ 6,614	$ 28,800	$ 471	$ 3,115	$ 955	$ 2,166	$ 13	$ 95	$ 0	$ 7	$ 77	$ 100
13																		
14	901	SUPERVISION	A.F.34	$ 1,634	$ 9	$ 1,643	$ 1,329	$ 8	$ 95	$ 1	$ 192	$ 1	$ 3	$ 0	$ 0	$ 0	$ 15	$ 0
15																		
16		TOTAL CUSTOMER ACCOUNT EXPENSES		$ 9,764	$ 34,292	$ 44,056	$ 7,943	$ 28,808	$ 565	$ 3,116	$ 1,147	$ 2,166	$ 16	$ 95	$ 0	$ 7	$ 92	$ 100
17																		
18																		

AMEREN MISSOURI
Case No. ER-2012-0166

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

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	LARGE TRANSMISSION LABOR (12)	LARGE TRANSMISSION OTHER (13)	LIGHTING LABOR (14)	LIGHTING OTHER (15)
19		CUSTOMER SERVICE & SALES EXPENSES																
21	908-1&901	RCS	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	908-916	CUSTOMER SERVICES & SALES	A.F.34	$ 10,154	$ 5,584	$ 15,737	$ 8,260	$ 4,691	$ 588	$ 507	$ 1,193	$ 353	$ 17	$ 16	$ 0	$ 1	$ 96	$ 16
24		SUBTOTAL		$ 10,154	$ 5,584	$ 15,737	$ 8,260	$ 4,691	$ 588	$ 507	$ 1,193	$ 353	$ 17	$ 16	$ 0	$ 1	$ 96	$ 16
26	907-911	SUPERVISION	A.F.38	$ 30	$ 3	$ 33	$ 24	$ 3	$ 2	$ 0	$ 3	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
28		TOTAL CUSTOMER SERVICE & SALES EXPENSE		$ 10,183	$ 5,587	$ 15,770	$ 8,284	$ 4,694	$ 589	$ 508	$ 1,197	$ 353	$ 17	$ 16	$ 0	$ 1	$ 96	$ 16
30		TOTAL PROD, T&D,CUST EXPENSES		$ 303,982	$ 1,347,524	$ 1,651,505	$ 156,957	$ 578,113	$ 32,030	$ 133,673	$ 77,107	$ 395,270	$ 19,294	$ 116,065	$ 12,992	$ 114,636	$ 5,601	$ 9,767
33		A & G EXPENSES																
35		EPRI	A.F.14	$ -	$ 2,513	$ 2,513	$ -	$ 1,033	$ -	$ 260	$ -	$ 767	$ -	$ 222	$ -	$ 214	$ -	$ 17
36		OTHER	A.F.35	$ 43,253	$ 285,175	$ 328,428	$ 22,333	$ 149,888	$ 4,557	$ 29,058	$ 10,971	$ 73,657	$ 2,745	$ 18,092	$ 1,849	$ 10,118	$ 797	$ 4,362
38		SUBTOTAL		$ 43,253	$ 287,688	$ 330,941	$ 22,333	$ 150,921	$ 4,557	$ 29,317	$ 10,971	$ 74,425	$ 2,745	$ 18,314	$ 1,849	$ 10,333	$ 797	$ 4,379
40		TOTAL PROD,T&D,CUST,A&G EXPENSES		$ 347,234	$ 1,635,212	$ 1,982,446	$ 179,290	$ 729,035	$ 36,587	$ 162,990	$ 88,079	$ 469,694	$ 22,040	$ 134,379	$ 14,841	$ 124,969	$ 6,398	$ 14,145

TITLE: OPERATING EXPENSES - PAGE 6

LINE #	ACCT #	ITEM	ALLOCATION BASIS	TOTAL MISSOURI LABOR (1)	TOTAL MISSOURI OTHER (2)	TOTAL MISSOURI TOTAL (3)	RESIDENTIAL LABOR (4)	RESIDENTIAL OTHER (5)	SMALL GEN. SERVICE LABOR (6)	SMALL GEN. SERVICE OTHER (7)	LARGE G. S./SM PRIMARY LABOR (8)	LARGE G. S./SM PRIMARY OTHER (9)	LARGE PRIMARY LABOR (10)	LARGE PRIMARY OTHER (11)	LARGE TRANSMISSION LABOR (12)	LARGE TRANSMISSION OTHER (13)	LIGHTING LABOR (14)	LIGHTING OTHER (15)
1		DEPREC & AMORTIZATION EXPENSES																
4		DEPR-PRODUCTION PLANT	A.F.1	$ -	$ 230,672	$ 230,672	$ -	$ 108,170	$ -	$ 24,570	$ -	$ 65,661	$ -	$ 16,667	$ -	$ 13,933	$ -	$ 1,671
5		DEPR-COMMON PLANT	A.F.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		DEPR-TRANSMISSION PLANT	A.F.17	$ -	$ 16,797	$ 16,797	$ -	$ 7,445	$ -	$ 1,738	$ -	$ 5,008	$ -	$ 1,299	$ -	$ 1,278	$ -	$ 29
7		DEPR-DISTRIBUTION PLANT	A.F.18	$ -	$ 164,373	$ 164,373	$ -	$ 101,837	$ -	$ 17,857	$ -	$ 32,837	$ -	$ 5,716	$ -	$ 2	$ -	$ 6,124
8		DEPR-GENERAL PLANT	A.F.35	$ -	$ 49,775	$ 49,775	$ -	$ 25,701	$ -	$ 5,245	$ -	$ 12,626	$ -	$ 3,159	$ -	$ 2,127	$ -	$ 917
10		SUBTOTAL		$ -	$ 461,617	$ 461,617	$ -	$ 243,153	$ -	$ 49,410	$ -	$ 116,132	$ -	$ 26,841	$ -	$ 17,341	$ -	$ 8,741
12				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		TOTAL DEPREC & AMORTIZ EXPENSES		$ -	$ 461,617	$ 461,617	$ -	$ 243,153	$ -	$ 49,410	$ -	$ 116,132	$ -	$ 26,841	$ -	$ 17,341	$ -	$ 8,741
17		OTHER																
20		REAL ESTATE & PROPERTY TAXES	A.F.19	$ -	$ 142,152	$ 142,152	$ -	$ 74,466	$ -	$ 15,498	$ -	$ 35,478	$ -	$ 8,288	$ -	$ 5,826	$ -	$ 2,597
21		INCOME/CITY EARNINGS TAXES	A.F.29	$ -	$ 60,209	$ 60,209	$ -	$ (7,425)	$ -	$ 13,893	$ -	$ 39,528	$ -	$ 8,271	$ -	$ 5,741	$ -	$ 201
22		RETURN	A.F.29	$ -	$ 572,055	$ 572,055	$ -	$ 294,677	$ -	$ 61,357	$ -	$ 146,565	$ -	$ 35,319	$ -	$ 24,935	$ -	$ 9,202
23		PAYROLL TAXES	A.F.35	$ -	$ 23,042	$ 23,042	$ -	$ 11,897	$ -	$ 2,428	$ -	$ 5,845	$ -	$ 1,463	$ -	$ 985	$ -	$ 425
24		ENVIRONMENTAL TAX	A.F. 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		SUBTOTAL		$ -	$ 797,458	$ 797,458	$ -	$ 373,615	$ -	$ 93,176	$ -	$ 227,415	$ -	$ 53,341	$ -	$ 37,486	$ -	$ 12,425
28		TOTAL OPERATING & OTHER EXPENSES		$ 347,234	$ 2,894,287	$ 3,241,521	$ 179,290	$ 1,345,803	$ 36,587	$ 305,576	$ 88,079	$ 813,242	$ 22,040	$ 214,560	$ 14,841	$ 179,796	$ 6,398	$ 35,311
33		TOTAL COST OF SERVICE		$ 347,234	$ 2,894,287	$ 3,241,521	$ 179,290	$ 1,345,803	$ 36,587	$ 305,576	$ 88,079	$ 813,242	$ 22,040	$ 214,560	$ 14,841	$ 179,796	$ 6,398	$ 35,311

AMEREN MISSOURI
Case No. ER-2012-0166

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
(Dollars in Thousands)

Line	Rate Class	Base 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)	Percent Increase (9)
1	Residential	$ 1,170,105	$3,508,054	$ 112,226	3.199%	64	$ 174,820	$ 62,594	$ 101,034	8.6%
2	Small Gen. Service	288,054	730,441	48,509	6.641%	133	36,401	(12,108)	(19,543)	-6.8%
3	Large G.S. / Sm Primary	749,850	1,744,816	126,198	7.233%	145	86,951	(39,247)	(63,349)	-8.4%
4	Large Primary	189,820	420,463	28,369	6.747%	135	20,953	(7,415)	(11,969)	-6.3%
5	Large Transmission	147,949	296,850	19,867	6.693%	134	14,793	(5,074)	(8,190)	-5.5%
6	Lighting	34,380	109,550	4,209	3.842%	77	5,459	1,250	2,018	5.9%
7	Total	$ 2,580,158	$6,810,174	$ 339,378	4.983%	100	$ 339,378	$ -	$ -	0.0%

AMEREN MISSOURI
Case No. ER-2012-0166

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using Ameren's ECOS and Present Rate Income Taxes Allocated on Taxable Income
(Dollars in 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)	Percent Increase (9)
1	Residential	$ 1,170,105	$3,507,841	$ 118,036	3.365%	68	$ 174,810	$ 56,774	$ 91,639	7.8%
2	Small Gen. Service	288,054	730,419	49,132	6.727%	135	36,400	(12,732)	(20,551)	-7.1%
3	Large G.S. / Sm Primary	749,850	1,744,893	124,085	7.111%	143	86,955	(37,130)	(59,931)	-8.0%
4	Large Primary	189,820	420,524	26,700	6.349%	127	20,956	(5,744)	(9,271)	-4.9%
5	Large Transmission	147,949	296,952	17,079	5.751%	115	14,798	(2,281)	(3,681)	-2.5%
6	Lighting	34,380	109,545	4,347	3.968%	80	5,459	1,113	1,796	5.2%
7	Total	$ 2,580,158	$6,810,174	$ 339,378	4.983%	100	$ 339,378	$ -	$ -	0.0%

AMEREN MISSOURI
Case No. ER-2012-0166

Spread of 5% Revenue Increase Using Ameren's Class EE Revenue Requirement and Non-EE Revenue Allocation Based on Method Stipulated in Prior Ameren MO Case (ER- 2011-0028)
(Dollars in Thousands)

			Revenue Adjustment						
Line	Rate Class	Current Revenue	2% Increase Residential & Lighting	1.75% Decr. All Other Classes	Adjusted Current Revenues	EE Revenue Requirement	Non-EE Remainder of 5% Increase Applied to All Classes	Total Revenue Increase	Percent Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 1,170,105	$ 23,402		$ 1,193,507	$ 58,750	$ 11,314	$ 93,467	7.99%
2	Small Gen. Service	288,054		(5,044)	283,009	6,216	2,683	3,855	1.34%
3	Large G.S. / Sm Primary	749,850		(13,131)	736,719	31,989	6,984	25,842	3.45%
4	Large Primary	189,820		(3,324)	186,496	7,593	1,768	6,037	3.18%
5	Large Transmission	147,949		(2,591)	145,358	-	1,378	(1,213)	-0.82%
6	Lighting	34,380	688		35,068	-	332	1,020	2.97%
7	Total	$ 2,580,158	$ 24,090	$ (24,090)	$ 2,580,158	$ 104,548	$ 24,459	$ 129,008	5.00%

AMEREN MISSOURI
Case No. ER-2012-0166

Spread of 7% Revenue Increase Using Ameren's Class EE Revenue Requirement
and Non-EE Revenue Allocation Based on Method Stipulated in Prior Ameren MO Case (ER- 2011-0028)
(Dollars in Thousands)

			Revenue Adjustment						
Line	Rate Class	Current Revenue	2% Increase Residential & Lighting	1.75% Decr. All Other Classes	Adjusted Current Revenues	EE Revenue Requirement	Non-EE Remainder of 7% Increase Applied to All Classes	Total Revenue Increase	Percent Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 1,170,105	$ 23,402		$ 1,193,507	$ 58,750	$ 35,184	$ 117,337	10.03%
2	Small Gen. Service	288,054		(5,044)	283,009	6,216	8,343	9,515	3.30%
3	Large G.S. / Sm Primary	749,850		(13,131)	736,719	31,989	21,718	40,576	5.41%
4	Large Primary	189,820		(3,324)	186,496	7,593	5,498	9,767	5.15%
5	Large Transmission	147,949		(2,591)	145,358	-	4,285	1,694	1.15%
6	Lighting	34,380	688		35,068	-	1,034	1,721	5.01%
7	Total	$ 2,580,158	$ 24,090	$ (24,090)	$ 2,580,158	$ 104,548	$ 76,063	$ 180,611	7.00%

AMEREN MISSOURI
Case No. ER-2012-0166

Spread of 10% Revenue Increase Using Ameren's Class EE Revenue Requirement and Non-EE Revenue Allocation Based on Method Stipulated in Prior Ameren MO Case (ER- 2011-0028)
(Dollars in Thousands)

Line	Rate Class	Current Revenue	Revenue Adjustment: 2% Increase Residential & Lighting	Revenue Adjustment: 1.75% Decr. All Other Classes	Adjusted Current Revenues	EE Revenue Requirement	Non-EE Remainder of 10% Increase Applied to All Classes	Total Revenue Increase	Percent Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 1,170,105	$ 23,402		$ 1,193,507	$ 58,750	$ 70,990	$ 153,142	13.09%
2	Small Gen. Service	288,054		(5,044)	283,009	6,216	16,833	18,005	6.25%
3	Large G.S. / Sm Primary	749,850		(13,131)	736,719	31,989	43,820	62,678	8.36%
4	Large Primary	189,820		(3,324)	186,496	7,593	11,093	15,362	8.09%
5	Large Transmission	147,949		(2,591)	145,358	-	8,646	6,055	4.09%
6	Lighting	34,380	688		35,068	-	2,086	2,773	8.07%
7	Total	$ 2,580,158	$ 24,090	$ (24,090)	$ 2,580,158	$ 104,548	$ 153,467	$ 258,016	10.00%

AMEREN MISSOURI
Case No. ER-2012-0166

Spread of 12% Revenue Increase Using Ameren's Class EE Revenue Requirement and Non-EE Revenue Allocation Based on Method Stipulated in Prior Ameren MO Case (ER- 2011-0028)

(Dollars in Thousands)

			Revenue Adjustment						
Line	Rate Class	Current Revenue	2% Increase Residential & Lighting	1.75% Decr. All Other Classes	Adjusted Current Revenues	EE Revenue Requirement	Non-EE Remainder of 12% Increase Applied to All Classes	Total Revenue Increase	Percent Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 1,170,105	$ 23,402		$ 1,193,507	$ 58,750	$ 94,860	$ 177,012	15.13%
2	Small Gen. Service	288,054		(5,044)	283,009	6,216	22,494	23,665	8.22%
3	Large G.S. / Sm Primary	749,850		(13,131)	736,719	31,989	58,554	77,412	10.32%
4	Large Primary	189,820		(3,324)	186,496	7,593	14,823	19,092	10.06%
5	Large Transmission	147,949		(2,591)	145,358	-	11,553	8,962	6.06%
6	Lighting	34,380	688		35,068	-	2,787	3,475	10.11%
7	Total	$ 2,580,158	$ 24,090	$ (24,090)	$ 2,580,158	$ 104,548	$ 205,071	$ 309,619	12.00%

AMEREN MISSOURI
Case No. ER-2012-0166

Spread of 14.6% Revenue Increase Using Ameren's Class EE Revenue Requirement
and Non-EE Revenue Allocation Based on Method Stipulated in Prior Ameren MO Case (ER- 2011-0028)
(Dollars in Thousands)

			Revenue Adjustment						
Line	Rate Class	Current Revenue	2% Increase Residential & Lighting	1.75% Decr. All Other Classes	Adjusted Current Revenues	EE Revenue Requirement	Non-EE Remainder of 14.6% Increase Applied to All Classes	Total Revenue Increase	Percent Increase
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 1,170,105	$ 23,402		$ 1,193,507	$ 58,750	$ 125,364	$ 207,517	17.7%
2	Small Gen. Service	288,054		(5,044)	283,009	6,216	29,727	30,899	10.7%
3	Large G.S. / Sm Primary	749,850		(13,131)	736,719	31,989	77,384	96,242	12.8%
4	Large Primary	189,820		(3,324)	186,496	7,593	19,589	23,859	12.6%
5	Large Transmission	147,949		(2,591)	145,358	-	15,268	12,677	8.6%
6	Lighting	34,380	688		35,068	-	3,683	4,371	12.7%
7	Total	$ 2,580,158	$ 24,090	$ (24,090)	$ 2,580,158	$ 104,548	$ 271,016	$ 375,565	14.6%