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-2014-0258
Date Testimony Prepared:	December 19, 2014

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 Revenues for Electric Service	**)))))**	**Case No. ER-2014-0258**

Direct Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation and Rate Design

On behalf of

Missouri Industrial Energy Consumers

December 19, 2014

BRUBAKER & ASSOCIATES, INC.

Project 9913

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 Revenues for Electric Service	)))))	**Case No. ER-2014-0258**

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-2014-0258.

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

M E Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 18th day of December, 2014.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2017
Commission # 13706793

Maria E. Decker
Notary Public

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Table of Contents to the
Direct Testimony of Maurice Brubaker

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OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	**)))))**	**Case No. ER-2014-0258**

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

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

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"), including Noranda Aluminum, Inc. ("Noranda").

INTRODUCTION AND SUMMARY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A One 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.

The second purpose is to explain, in light of Noranda's circumstances, why additional factors need to be considered. I also explain and demonstrate that keeping Noranda on the system at its requested rate is a better deal for other customers than a shutdown of the smelter.

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 are then followed by recommendations with respect to the allocation of revenues.

The final section addresses the Noranda rate proposal and explains why serving Noranda at a rate less than fully allocated embedded cost is a better deal for the other customers than if the smelter shuts down.

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 major 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 also have calculated income taxes at current rates based on the taxable income of each class in order to recognize Ameren Missouri's actual total income tax liability at current rates, and the responsibility of each class for that liability.

8. The results of my class cost of service study are summarized on Schedule MEB-COS-4.

9. For purposes of implementing the revenue increase approved by the Commission in this case, all of the charges in the Large Primary Service Rate and the Large Transmission Service Rate, except for the Low-Income Pilot

Program Charge and the Energy Efficiency Program Charges should receive the overall system average percentage increase.

10. The rate applicable to Noranda should be set at $32.50/MWh with annual increases of 1% thereafter, regardless of whether Ameren Missouri has filed a rate case.

11. The Commission should approve the proposed Service to Aluminum Smelters ("SAS") Rate that is set forth on Schedule MEB-COS-5. Other customers will be better off than if Noranda shuts down.

12. Service Classification No. 12(M), Large Transmission Service Rate, should remain in place and available, but with the charges increased by the system average percentage increase as previously noted.

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.

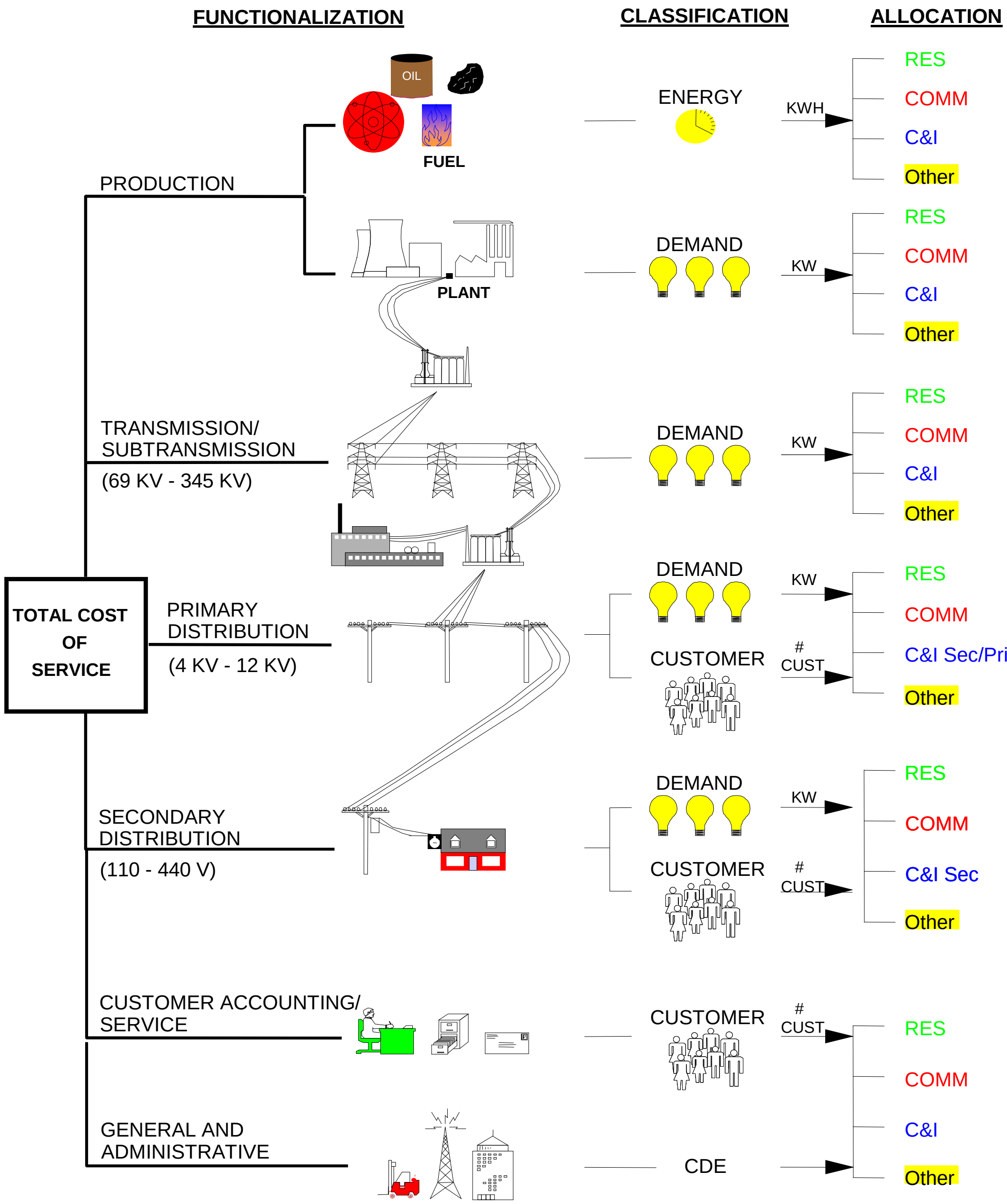
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWh. To see one reason why this isn't accurate, consider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



<u>A CLOSER LOOK AT THE COST OF SERVICE STUDY</u>

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.

<u>Functionalization</u>

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.

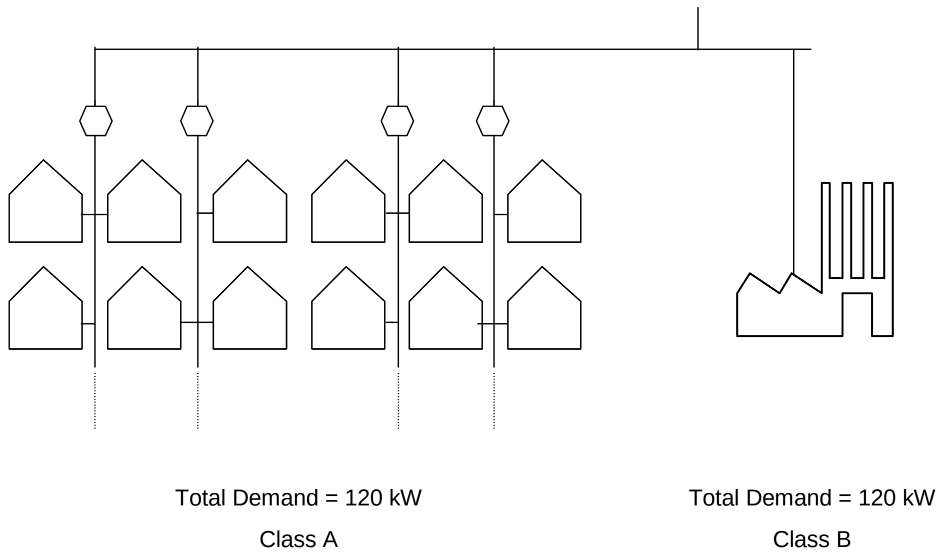
A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to construct a system's electrical pathways that comply with local or national safety and reliability codes, and to attach customers to that system, regardless of their demand or energy requirements. 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
<u>Classification of Distribution Investment</u>



<u>Demand vs. Energy Costs</u>

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.

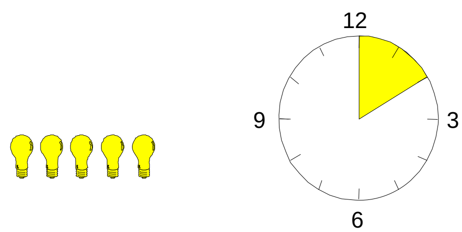
Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

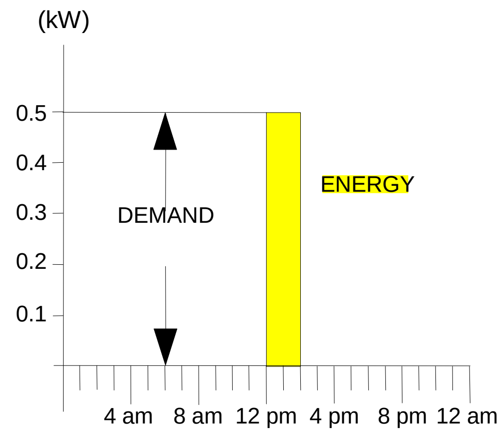
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

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

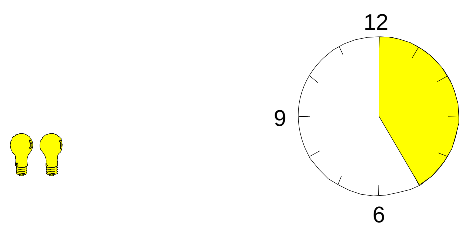


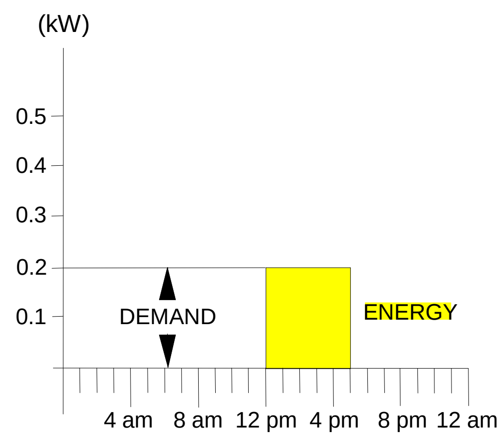


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

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.

Allocation

Q WHAT IS ALLOCATION?

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

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

TABLE 1
Energy Allocation Factor

Rate Class	Energy Generated (MWh) (1)	Allocation Factor (2)
Residential	14,404,516	36.74%
Small GS	3,742,505	9.55%
Large GS/Small Primary	12,470,694	31.81%
Large Primary	4,093,616	10.44%
Large Transmission	4,255,279	10.85%
Lighting	237,509	0.61%
Total	39,204,119	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 22 to 29.)

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	3,454	45.34%
Small GS	813	10.67%
Large GS/Small Primary	2,213	29.05%
Large Primary	590	7.74%
Large Transmission	495	6.50%
Lighting	53	0.70%
Total	7,618[1]	100.00%

Notes:
[1] The 7,618 MW is the MO Jurisdictional peak.
[2] Column (2) is the A&E-4NCP allocation factor.

Q THE RATES, WHEN EXPRESSED PER KWH, CHARGED TO LARGE GS/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 Large GS/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	$ 1,299,258	13,381,143	9.71 ¢
Small GS	290,265	3,468,350	8.37
Large GS/Small Primary	742,548	11,648,737	6.37
Large Primary	201,848	3,920,375	5.15
Large Transmission	166,007	4,198,453	3.95
Lighting	37,873	219,766	17.23
Total	$ 2,737,799	36,836,823	7.43 ¢

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

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

TABLE 4
Comparative Load Factors

Rate Class	Energy Generated (MWh) (1)	Production A&E (MW) (2)	Load Factor (3)
Residential	14,404,516	3,454	48%
Small GS	3,742,505	813	53%
Large GS/Small Primary	12,470,694	2,213	64%
Large Primary	4,093,616	590	79%
Large Transmission	4,255,279	495	98%
Lighting	237,509	53	51%
Total	39,204,119	7,618	59%

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 Sales By Voltage Level: Secondary (1)	Percent of Sales By Voltage Level: Primary & Higher (2)	Composite Loss Percentage (3)
Residential	100%	0%	8.07%
Small GS	100%	0%	8.07%
Large GS/Small Primary	69%	31%	7.07%
Large Primary	0%	100%	4.12%
Large Transmission	0%	100%	1.35%
Lighting	100%	0%	8.07%

Source: Workpapers of James R. Pozzo
Ameren Missouri Cost of Service Study, kWh's 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 56 million kWhs per Large Primary customer, but only about 13,000 kWhs per Residential customer, or 4,300 times more per capita, as shown in Table 6. The customer-related costs to serve a Large Primary customer are not 4,300 times the customer-related costs to serve a Residential customer.

TABLE 6

Energy Sold Per Customer

Rate Class	Energy Sold (MWh) (1)	Number of Customers (2)	kWh Sold per Customer (3)
Residential	13,381,143	1,043,482	12,824
Small GS	3,468,350	145,755	23,796
Large GS/Small Primary	11,648,737	10,248	1,136,684
Large Primary	3,920,375	70	56,005,357
Large Transmission	4,198,453	1	4,198,452,991
Lighting	219,766	55,029	3,994
Total	36,836,823	1,254,585	29,362

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.

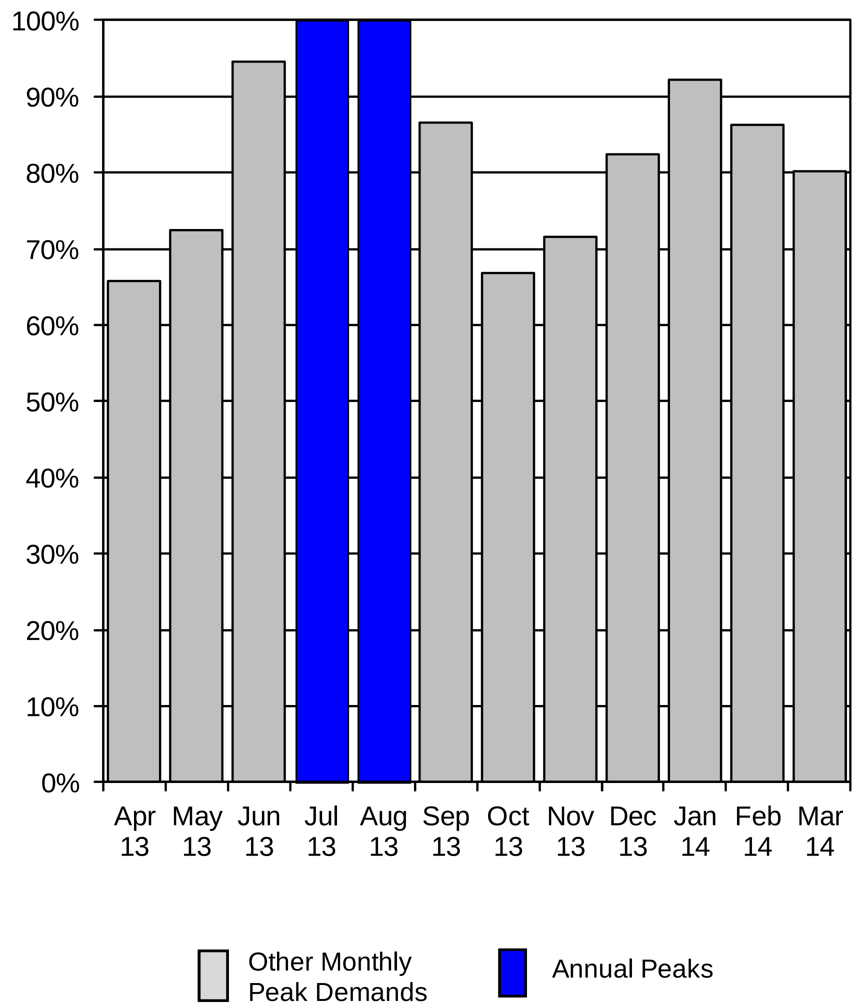
Utility System Load Characteristics

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, they are 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)
<u>For the Test Year Ended March 2014</u>



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.) The system peak occurred in July, with a nearly identical peak demand in August. The peaks in June and January were 95% and 92%, respectively, of the annual peak. The monthly peaks occurring in the other months were substantially lower. 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.

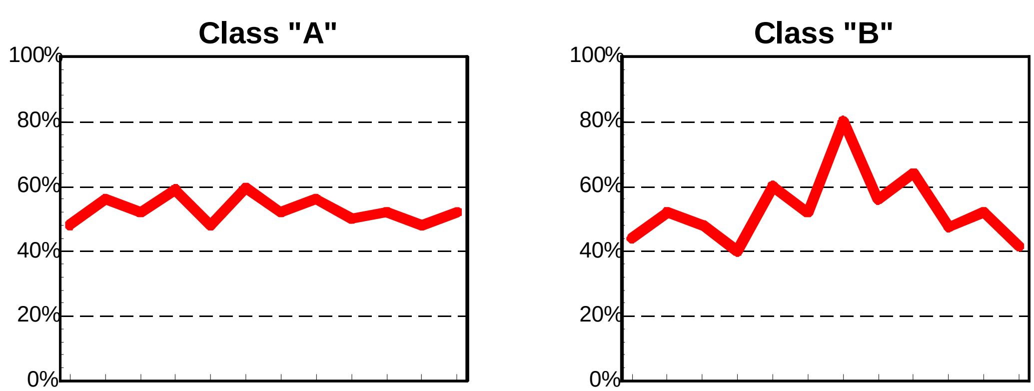
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability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

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[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 time of occurrence of the 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 major 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 $213.7 million of income taxes in its present rate cost of service study shown in Schedule WMW-1 and in other places. This amount includes roughly $100.7 million of income taxes that Ameren Missouri would not incur if it did not receive its requested $264.1 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 $113.1 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 WHERE ARE THE RESULTS OF MIEC'S COST OF SERVICE STUDY SHOWN?

A The results at present rates are summarized on Schedule MEB-COS-4.

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 witnesses for more elaboration on this issue.

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

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

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

A When rates are based on cost, each customer pays what it costs the utility to provide service to that customer; no more and no less. If rates are based on anything other than cost factors, then some customers will pay the costs attributable to providing service to other customers – which in most cases is 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 Energy Efficiency ("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 based on an under-priced rate, the 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 rate is 6¢ per kWh.

The importance of this concept is underscored by the large dollar amount associated with EE programs that will be incorporated into Ameren Missouri's Integrated Resource Plan. The costs expended pursuant to the Missouri Energy Efficiency Investment Act ("MEEIA") are expected to approach $150 million over the next three years. 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.

Q ARE THERE CIRCUMSTANCES WHERE IT IS APPROPRIATE TO CONSIDER FACTORS OTHER THAN COST-BASED ALLOCATION?

A Yes, when retention or attraction of load requires a discount and when other customers are better off if that load is served. The impact on the state's economy may also be a factor to be considered.

Revenue Allocation

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

A Large Primary Service customers and Lighting customers are relatively close to the system average rate of return, while the Residential class is below, and the Small General Service and Large General Service/Small Primary classes are above the system average rate of return.

Q WHAT IS YOUR RECOMMENDED REVENUE ALLOCATION METHOD?

A I recommend that the revenues from Large Primary Service customers be increased by the overall system average percentage increase and that each charge within the Large Primary Service class except for the Low-Income Pilot Program Charge and the Energy Efficiency Program Charges receive the overall system average percentage increase.

As discussed further in the following section of my testimony, the Large Transmission Service Rate would remain in place with the charges except for the Low-Income Pilot Program Charge being increased by the system average percentage increase.

RATE FOR SERVICE TO NORANDA

Q WHAT IS COVERED IN THIS SECTION OF YOUR TESTIMONY?

A Through separate witnesses, Noranda is requesting an adjustment in rates and the adoption of a seven-year rate plan which it believes is necessary to maintain the viability of the New Madrid Aluminum Smelter. The reasons for that circumstance, and the support for the specific rate plan that is requested, are contained in the testimony of the Noranda witnesses.

Q PLEASE BRIEFLY SUMMARIZE THE RATE THAT NORANDA IS REQUESTING.

A Noranda is requesting a rate of $32.50/MWh to be established at the conclusion of this case. This rate would escalate by 1% on each annual anniversary of the effective date of this new rate, through the end of the seven-year term requested for the rate. I present an exemplar tariff to define these terms.

I also provide a quantification of the total impact to Ameren Missouri's ratepayers (other than Noranda) as a result of the proposed Service to Aluminum Smelters ("SAS") rate, as compared to the impact on other customers were the Noranda smelter to shut down and cease taking electric service. I present the latter analysis using a range of values for costs that might be avoided and revenues that might be gained were Noranda not taking electricity at the New Madrid smelter. These values are supported by my colleague, Mr. James Dauphinais.

Q WHAT IS THE RATE SCHEDULE UNDER WHICH NORANDA CURRENTLY TAKES SERVICE?

A Noranda currently takes service under Service Classification No. 12(M) ("SC No. 12(M)"), the Large Transmission Service rate.

Q WHAT IS THE AVERAGE RATE PER KILOWATTHOUR ("KWH") TO NORANDA UNDER SC NO. 12(M)?

A Under the final rates approved in Ameren Missouri's most recent rate case (Case No. ER-2012-0166) and Noranda's test year volumes in this case, the average base rate revenue paid to Ameren Missouri is $37.95/MWh, or 3.795¢/kWh. This is the composite effect of the customer charge, demand charge, energy charge and other charges in the tariff. Test year base rate revenues were approximately $159.3 million. The current Fuel Adjustment Charge ("FAC") of $4.40/MWh brings the total Ameren Missouri cost to $42.35/MWh on a test year basis.[3]

Q HAVE YOU DEVELOPED A SAMPLE TARIFF TO EFFECTUATE NORANDA'S RATE REQUEST?

A Yes. Schedule MEB-COS-5 is the illustrative (EXEMPLAR) tariff I am proposing for this purpose. In order to allow the existing SC No. 12(M) to remain available to other customers (Noranda is currently the only customer), and for possible future use by Noranda, I have left SC No. 12(M) unchanged and created Service Classification No. 10(M) ("SC No. 10(M)"), which I previously described as Service to Aluminum Smelters, or SAS.

The tariff also recognizes the Low-Income Pilot Program that is being conducted. Noranda currently pays $1,500/month toward this pilot program and that charge would continue. In addition, provision has been made to allow that number to grow in the event that the program is expanded. The not-to-exceed amount under this provision is stated as the current $1,500/month plus 100 times the monthly

[3]Based on test year usage, current base rates and current FAC, and the approximately $1.50/MWh paid to Associated Electric Cooperative to wheel power to the smelter, the "all-in" delivered cost is $43.85/MWh.

low-income program cost that would be paid by a residential customer consuming 1,500 kWh of energy per month.

Except as explicitly provided otherwise, the terms and conditions of the SAS tariff would be the same as those in existing SC No. 12(M).

Q HAVE YOU CALCULATED THE DOLLAR REDUCTION IN BASE RATE REVENUES THAT WOULD BE ASSOCIATED WITH IMPLEMENTATION OF NORANDA'S RATE REQUEST?

A Yes. This calculation is summarized on Schedule MEB-COS-6.

Q PLEASE EXPLAIN THIS SCHEDULE.

A The average rate paid by Noranda under SC No. 12(M) that was approved in Case No. ER-2012-0166, at Noranda's test year kWh consumption in this case, is $37.95/MWh as shown on line 1. Comparing that to the $32.50/MWh rate indicates a difference of $5.45/MWh, as shown on line 3. Line 4 shows Noranda's test year MWh and line 5 shows the $22.9 million base rate adjustment which is determined by multiplying the figure on line 3 times the MWh shown on line 4.

Q DO YOU HAVE A RECOMMENDATION FOR HOW TO ADJUST BASE RATES OF OTHER CUSTOMER CLASSES TO IMPLEMENT THIS RATE ADJUSTMENT?

A Yes. I believe that the most reasonable way would be by means of an equal percentage increase applied to the test year base rate revenues of the other major customer classes. This approach treats all classes the same way and maintains the interclass revenue relationships established in the Final Order in Case No. ER-2012-0166.

The base rate revenues that are to be adjusted are taken from the testimony of Ameren Missouri witness James Pozzo, and include base rate revenue charges other than energy efficiency and low income revenues surcharges. This approach incorporates the recommendation of Commission Staff witness Michael Scheperle in Case No. EC-2014-0224.

Q HAVE YOU PERFORMED THIS CALCULATION?

A Yes. It appears on Schedule MEB-COS-7. Column 1 shows the applicable test year base rate revenues of each class and Column 2 shows the adjustment. The adjustment is developed by multiplying the test year base rate revenues in Column 1 times 0.8946%. This is the amount necessary to recover the $22.9 million base rate revenue decrease associated with Noranda's rate request.

Q DOES NORANDA CURRENTLY PAY ANY OTHER CHARGES THAT IT WOULD NOT PAY UNDER ITS RATE REQUEST?

A Yes. Noranda also pays an FAC which, as previously noted, currently is $4.40/MWh. That amount may change between now and the time that the rate adjustment is implemented. However, whatever FAC revenue reduction occurs when the rate adjustment is implemented will be picked up automatically through the operation of the FAC. (At current rates, FAC payments by Noranda amount to approximately $18.5 million per year.) At the level of the current FAC, the combination of the reduction in base revenues and in FAC revenues is approximately $41.4 million per year.[4]

[4]If the FAC remains at its current level, the average revenue change to the other major rate classes, considering both base rates and the FAC, would be 1.53%.

Q ARE RATES THAT ARE DESIGNED TO RETAIN AT-RISK LOADS TYPICALLY PRICED BELOW FULLY ALLOCATED EMBEDDED COST OF SERVICE?

A Yes. The concept behind a load retention rate is to keep on the system a load that otherwise might not be served if the rate to be charged were the fully allocated embedded cost.

The basis for such a rate is typically a price at or above incremental cost so that other customers are benefitted as compared to the customer not being served.

Q HAVE YOU CALCULATED WHAT THE NET REVENUE LOSS WOULD BE IF NORANDA WERE NOT OPERATING THE SMELTER?

A Yes. Based on the estimated reductions in Ameren Missouri's Actual Net Energy Costs ("ANEC") that would occur were Noranda not to be served (provided to me by my colleague Mr. Dauphinais), I have calculated that the net revenue loss if the smelter were not served would be between approximately $54 million per year and $60 million per year, as shown on Schedule MEB-COS-8, and the average percentage increase to other customers would range from 2.01% to 2.22%.[5]

Q HOW DO THESE AMOUNTS COMPARE TO THE REDUCTION IN REVENUES UNDER THE REQUESTED RATE PLAN WHEREIN THE SMELTER CONTINUES AS A RETAIL CUSTOMER OF AMEREN MISSOURI BUT AT A RATE LOWER THAN WHAT IT CURRENTLY PAYS?

A In the scenario where the smelter remains as a retail customer of Ameren Missouri but at a lower rate, the calculated revenue reduction was $22.9 million in base revenues and $18.5 million in FAC, for a total of $41.4 million, which would produce a

[5]If a 48-month period were used, and the early 2014 polar vortex inappropriately included, the revenue loss would be lower.

1.53% increase to other customers as shown in Schedule MEB-COS-9. Obviously, this impact on other customers is substantially less than the impact other customers would experience if the smelter were to shut down. Accordingly, serving the smelter at the requested rate is beneficial to other customers, as compared to a shut down of the smelter.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications 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 PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission ("FERC"), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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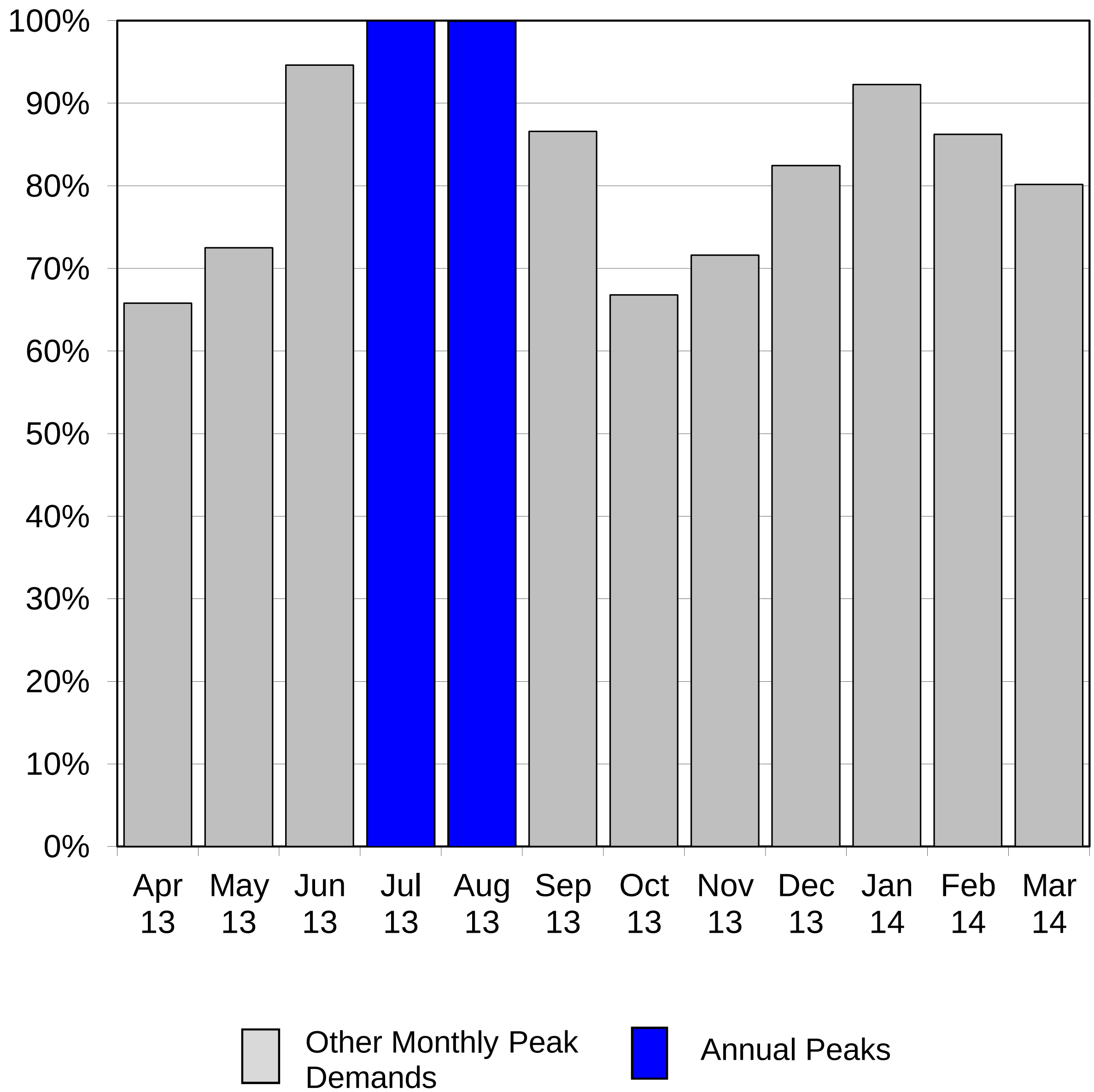
AMEREN MISSOURI

Case No. ER-2014-0258

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 March 2014</u>



Schedule MEB-COS-1

AMEREN MISSOURI
Case No. ER-2014-0258

Analysis of Ameren's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended March 2014

Line	Description	Total Company MW (1)	Percent (2)
1	January	7,027	92.2%
2	February	6,568	86.2%
3	March	6,106	80.1%
4	April	5,012	65.8%
5	May	5,523	72.5%
6	June	7,206	94.6%
7	July	7,618	100.0%
8	August	7,615	100.0%
9	September	6,596	86.6%
10	October	5,088	66.8%
11	November	5,454	71.6%
12	December	6,281	82.4%

Source: Ameren Missouri COS, System_CP Worksheet

AMEREN MISSOURI
Case No. ER-2014-0258

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended March 2014

Line	Description	Missouri Total	Residential	Small Gen. Service	Large G.S./ Sm Primary	Large Primary	Large Transmission	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Missouri System Peak	7,618						
2	Avg of 4 Highest Monthly NCP Values	7,937	3,637	852	2,293	602	496	56
3	Energy Sales with Losses - MWh	39,204,119	14,404,516	3,742,505	12,470,694	4,093,616	4,255,279	237,509
4	Average Demand - kW	4,475.4	1,644.4	427.2	1,423.6	467.3	485.8	27.1
5	Average Demand - Percent	100.0%	36.7%	9.5%	31.8%	10.4%	10.9%	0.6%
6	Class Excess Demand - kW	3,461.5	1,992.9	424.9	869.4	134.7	10.7	28.9
7	Class Excess Demand - Percent	100.0%	57.6%	12.3%	25.1%	3.9%	0.3%	0.8%
	Allocator:							
8	Annual Load Factor * Average Demand	0.587471	0.215851	0.056081	0.186872	0.061343	0.063765	0.003559
9	(1-LF) * Excess Demand	0.412529	0.237511	0.050639	0.103607	0.016052	0.001275	0.003445
10	Average and Excess Demand Allocator	1.000000	0.453362	0.106720	0.290479	0.077395	0.065040	0.007004

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

System Annual Load Factor	58.75%
1 - Load Factor	41.25%

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

AMEREN MISSOURI
Case No. ER-2014-0258

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	$ 2,737,799	$ 1,230,497	$ 302,850	$ 804,460	$ 202,782	$ 159,333	$ 37,876
2	Other Revenue	80,601	45,242	7,407	18,269	4,760	4,082	841
3	Lighting Revenue	-	-	-	-	-	-	-
4	System, Off-Sys Sales & Disp of Allow	234,414	86,233	22,405	74,656	24,506	25,474	1,140
5	Rate Revenue Variance	-	-	-	-	-	-	-
6	Total Operating Revenue	$ 3,052,814	$ 1,361,973	$ 332,662	$ 897,384	$ 232,049	$ 188,889	$ 39,857
7	Total Prod, T&D, Cust and A&G Expense	1,819,741	806,802	185,771	516,163	151,645	139,838	19,522
8	Total Depreciation and Ammortization Expenses	529,416	269,918	57,564	136,762	33,329	22,508	9,336
9	Real Estate and Property Taxes	143,851	73,655	15,929	36,466	8,916	6,298	2,588
10	Income Taxes: At Present Rates	113,085	30,426	17,095	53,108	7,869	2,896	1,689
11	Payroll Taxes	21,430	10,727	2,264	5,590	1,454	1,023	372
12	Federal Excise Taxes	-	-	-	-	-	-	-
13	Revenue Taxes	-	-	-	-	-	-	-
14	Total Operating Expenses	$ 2,627,523	$ 1,191,529	$ 278,622	$ 748,089	$ 203,214	$ 172,562	$ 33,507
15	Net Operating Income	$ 425,291	$ 170,444	$ 54,040	$ 149,295	$ 28,835	$ 16,327	$ 6,350
16	Gross Plant in Service	15,919,092	8,145,648	1,758,883	4,044,477	988,945	695,657	285,480
17	Reserves for Depreciation	6,796,331	3,523,775	756,035	1,689,034	402,370	283,081	142,036
18	Net Plant in Service	$ 9,122,760	$ 4,621,874	$ 1,002,848	$ 2,355,444	$ 586,575	$ 412,576	$ 143,444
19	Materials & Supplies - Fuel	375,572	138,160	35,896	119,612	39,264	40,814	1,826
20	Materials & Supplies - Local	187,831	117,600	22,559	34,255	5,874	3	7,541
21	Cash Working Capital	39,362	17,452	4,018	11,165	3,280	3,025	422
22	Customer Advances & Deposits	(22,563)	(8,909)	(5,375)	(6,233)	(957)	-	(1,089)
23	Accumulated Deferred Income Taxes	(2,385,054)	(1,221,198)	(264,101)	(604,603)	(147,826)	(104,417)	(42,910)
24	Total Net Original Cost Rate Base	$ 7,317,909	$ 3,664,978	$ 795,845	$ 1,909,640	$ 486,210	$ 352,001	$ 109,235
25	Rate of Return	5.812%	4.651%	6.790%	7.818%	5.931%	4.638%	5.813%

AMEREN MISSOURI
Case No. ER-2014-0258

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	$ 5,235,601	$ 2,373,622	$ 558,742	$ 1,520,835	$ 405,207	$ 340,526	$ 36,670
2										
3		TRANSMISSION								
4		LINES	A.F.2	$ 380,331	$ 173,226	$ 38,412	$ 108,318	$ 30,071	$ 29,460	$ 844
5		SUBSTATION	A.F.3	$ 273,033	$ 124,356	$ 27,576	$ 77,760	$ 21,587	$ 21,148	$ 606
6										
7		TOTAL TRANSMISSION		$ 653,364	$ 297,582	$ 65,988	$ 186,078	$ 51,658	$ 50,608	$ 1,451
8										
9		DISTRIBUTION PLANT								
10										
11	360	SUBSTATION LAND	A.F.8	$ 22,381	$ 11,101	$ 2,651	$ 6,807	$ 1,658	$ -	$ 163
12	321	OTHER LAND	A.F.5	$ 14,298	$ 7,247	$ 1,731	$ 4,441	$ 773	$ -	$ 107
13										
14	361-362	SUBSTATIONS	A.F.8	$ 657,284	$ 326,020	$ 77,862	$ 199,900	$ 48,703	$ -	$ 4,798
15										
16	364	POLES TOWERS FIXTURES								
17		CUSTOMER	A.F.4	$ 32,215	$ 26,795	$ 3,743	$ 263	$ 2	$ -	$ 1,413
18		HV	A.F.5a	$ 28,555	$ 14,166	$ 3,383	$ 8,681	$ 2,116	$ -	$ 208
19		PRIMARY	A.F.5b	$ 54,855	$ 27,803	$ 6,640	$ 17,037	$ 2,966	$ -	$ 409
20		SECONDARY	A.F.6	$ 27,967	$ 16,405	$ 3,918	$ 7,402	$ -	$ -	$ 241
21		LIGHTING-DIRECT	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22										
23		SUBTOTAL		$ 143,592	$ 85,169	$ 17,684	$ 33,383	$ 5,084	$ -	$ 2,272
24										
25	365	OVERHEAD CONDUCTOR								
26		CUSTOMER	A.F.4	$ 353,246	$ 293,807	$ 41,039	$ 2,885	$ 20	$ -	$ 15,494
27		HV	A.F.5a	$ 111,913	$ 55,520	$ 13,260	$ 34,022	$ 8,294	$ -	$ 817
28		PRIMARY	A.F.5b	$ 386,983	$ 196,139	$ 46,843	$ 120,190	$ 20,924	$ -	$ 2,886
29		SECONDARY	A.F.6	$ 20,317	$ 11,918	$ 2,846	$ 5,377	$ -	$ -	$ 175
30										
31		SUBTOTAL		$ 872,459	$ 557,384	$ 103,989	$ 162,475	$ 29,238	$ -	$ 19,373
32										
33	366	UNDERGROUND CONDUIT								
34		CUSTOMER	A.F.4	$ 158,293	$ 131,658	$ 18,390	$ 1,293	$ 9	$ -	$ 6,943
35		HV	A.F.5a	$ 6,592	$ 3,271	$ 781	$ 2,004	$ 489	$ -	$ 48
36		PRIMARY	A.F.5b	$ 47,496	$ 24,073	$ 5,749	$ 14,752	$ 2,568	$ -	$ 354
37		SECONDARY	A.F.6	$ 20,949	$ 12,289	$ 2,935	$ 5,545	$ -	$ -	$ 181
38										
39		SUBTOTAL		$ 233,331	$ 171,290	$ 27,855	$ 23,593	$ 3,066	$ -	$ 7,526
40										
41	367	UNDERGROUND CONDUCTORS								
42		CUSTOMER	A.F.4	$ 292,490	$ 243,274	$ 33,981	$ 2,389	$ 16	$ -	$ 12,829
43		HV	A.F.5a	$ 12,181	$ 6,043	$ 1,443	$ 3,703	$ 903	$ -	$ 89
44		PRIMARY	A.F.5b	$ 87,762	$ 44,482	$ 10,623	$ 27,257	$ 4,745	$ -	$ 655
45		SECONDARY	A.F.6	$ 38,710	$ 22,707	$ 5,423	$ 10,245	$ -	$ -	$ 334
46										
47		SUBTOTAL		$ 431,144	$ 316,506	$ 51,471	$ 43,595	$ 5,664	$ -	$ 13,907

AMEREN MISSOURI
Case No. ER-2014-0258

Electric Cost of Service Allocation Study
at Present Rates
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(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	$ 162,584	$ 141,439	$ 19,756	$ 1,389	$ -	$ -	$ -
4		SECONDARY	A.F.6	$ 122,307	$ 71,746	$ 17,135	$ 32,371	$ -	$ -	$ 1,056
5										
6		SUBTOTAL		$ 284,891	$ 213,184	$ 36,891	$ 33,760	$ -	$ -	$ 1,056
7										
8	369-1	OVERHEAD SERVICES								
9		CUSTOMER	A.F.15	$ (26,384)	$ (22,953)	$ (3,206)	$ (225)	$ -	$ -	$ -
10		SECONDARY	A.F.16	$ (38,365)	$ (26,491)	$ (5,176)	$ (6,699)	$ -	$ -	$ -
11										
12		SUBTOTAL		$ (64,750)	$ (49,444)	$ (8,382)	$ (6,924)	$ -	$ -	$ -
13										
14	369-2	UNDERGROUND SERVICES								
15		CUSTOMER	A.F.15	$ 38,111	$ 33,154	$ 4,631	$ 326	$ -	$ -	$ -
16		SECONDARY	A.F.16	$ 2,185	$ 1,508	$ 295	$ 381	$ -	$ -	$ -
17										
18		SUBTOTAL		$ 40,295	$ 34,662	$ 4,926	$ 707	$ -	$ -	$ -
19										
20	370	METERS	A.F.7	$ 58,824	$ 33,325	$ 12,064	$ 10,690	$ 1,065	$ 47	$ 1,633
21										
22	371	CUSTOMER INSTALLATIONS	DIRECT	$ (3)	$ -	$ -	$ (1)	$ (1)	$ -	$ -
23										
24	373	STREET LIGHTING	A.F.29	$ 46,703	$ -	$ -	$ -	$ -	$ -	$ 46,703
25										
26		SUBTOTAL - CUSTOMER DIST PLANT		$ 1,069,379	$ 880,499	$ 130,398	$ 19,010	$ 1,111	$ 47	$ 38,313
27		- DEMAND DIST PLANT		$ 1,671,071	$ 825,948	$ 198,344	$ 493,415	$ 94,138	$ -	$ 59,225
28										
29		DISTRIBUTION TOTAL		$ 2,740,449	$ 1,706,448	$ 328,742	$ 512,425	$ 95,250	$ 47	$ 97,538
30										
31		GENERAL PLANT	A.F.35	$ 331,179	$ 165,777	$ 34,985	$ 86,385	$ 22,476	$ 15,805	$ 5,751
32										
33				$ -	$ -	$ -	$ -	$ -	$ -	$ -
34										
35				$ -	$ -	$ -	$ -	$ -	$ -	$ -
36										
37		SUBTOTAL PROD,T&D,GEN,COMMON PLANT		$ 8,960,594	$ 4,543,428	$ 988,457	$ 2,305,723	$ 574,590	$ 406,986	$ 141,410
38										
39		INTANGIBLE PLANT		$ 131,687	$ 65,918	$ 13,911	$ 34,349	$ 8,937	$ 6,285	$ 2,287
40		EE REGULATORY ASSET	EE tab	$ 45,040	$ 19,817	$ 2,018	$ 19,170	$ 4,036	$ -	$ -
41		REGULATORY ACCOUNT (PENSION	A.F.35	$ (14,561)	$ (7,289)	$ (1,538)	$ (3,798)	$ (988)	$ (695)	$ (253)
42										
43		TOTAL NET PLANT		$ 9,122,760	$ 4,621,874	$ 1,002,848	$ 2,355,444	$ 586,575	$ 412,576	$ 143,444

AMEREN MISSOURI
Case No. ER-2014-0258

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	$ 375,572	$ 138,160	$ 35,896	$ 119,612	$ 39,264	$ 40,814	$ 1,826
2		MATERIALS & SUPPLIES - LOCAL	A.F.18	$ 187,831	$ 117,600	$ 22,559	$ 34,255	$ 5,874	$ 3	$ 7,541
3		CASH WORKING CAPITAL	A.F.37	$ 39,362	$ 17,452	$ 4,018	$ 11,165	$ 3,280	$ 3,025	$ 422
4		CUSTOMER ADVANCES & DEPOSIT	A.F.12	$ (22,563)	$ (8,909)	$ (5,375)	$ (6,233)	$ (957)	$ -	$ (1,089)
5		ACCUM DEFERRED INCOME TAXES	A.F.19	$ (2,385,054)	$ (1,221,198)	$ (264,101)	$ (604,603)	$ (147,826)	$ (104,417)	$ (42,910)
6										
7		TOTAL NET ORIGINAL COST RATE BASE		$ 7,317,909	$ 3,664,978	$ 795,845	$ 1,909,640	$ 486,210	$ 352,001	$ 109,235

AMEREN MISSOURI
Case No. ER-2014-0258

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

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	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	$ 200,928	$ 135,321	$ 336,249	$ 91,093	$ 61,349	$ 21,443	$ 14,441	$ 58,366	$ 39,308	$ 15,551	$ 10,473	$ 13,068	$ 8,801	$ 1,407	$ 948
6		VARIABLE	A.F.11	$ 4,754	$ 918,177	$ 922,931	$ 1,749	$ 337,766	$ 454	$ 87,756	$ 1,514	$ 292,420	$ 497	$ 95,990	$ 517	$ 99,780	$ 23	$ 4,464
7																		
8		SUBTOTAL		$ 205,683	$ 1,053,498	$ 1,259,181	$ 92,842	$ 399,115	$ 21,897	$ 102,198	$ 59,880	$ 331,728	$ 16,048	$ 106,463	$ 13,585	$ 108,582	$ 1,430	$ 5,412
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	$ 305	$ 6,132	$ 6,437	$ 139	$ 2,793	$ 31	$ 619	$ 87	$ 1,746	$ 24	$ 485	$ 24	$ 475	$ 1	$ 14
18		SUBSTATIONS	A.F.3	$ 6,197	$ 55,364	$ 61,561	$ 2,823	$ 25,216	$ 626	$ 5,592	$ 1,765	$ 15,768	$ 490	$ 4,377	$ 480	$ 4,288	$ 14	$ 123
19																		
20		TOTAL TRANSMISSION EXPENSES		$ 6,502	$ 61,495	$ 67,997	$ 2,961	$ 28,009	$ 657	$ 6,211	$ 1,852	$ 17,514	$ 514	$ 4,862	$ 504	$ 4,763	$ 14	$ 137
21																		
22																		
23		DISTRIBUTION OPERATING EXPENSES																
24																		
25																		
26	582	SUBSTATIONS	A.F.8	$ 2,710	$ 1,486	$ 4,196	$ 1,344	$ 737	$ 321	$ 176	$ 824	$ 452	$ 201	$ 110	$ -	$ -	$ 20	$ 11
27																		
28	583-1	OVERHEAD LINES																
29		CUSTOMER	A.F.22	$ 1,012	$ 264	$ 1,276	$ 839	$ 219	$ 117	$ 31	$ 8	$ 2	$ 0	$ 0	$ -	$ -	$ 48	$ 12
30		HV	A.F.23a	$ 396	$ 103	$ 499	$ 196	$ 51	$ 47	$ 12	$ 120	$ 31	$ 29	$ 8	$ -	$ -	$ 3	$ 1
31		PRIMARY	A.F.23b	$ 1,246	$ 325	$ 1,570	$ 631	$ 164	$ 151	$ 39	$ 387	$ 101	$ 67	$ 18	$ -	$ -	$ 9	$ 2
32		SECONDARY	A.F.24	$ 28	$ 7	$ 35	$ 5	$ 1	$ 4	$ 1	$ 17	$ 4	$ -	$ -	$ -	$ -	$ 1	$ 0
33		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34																		
35		SUBTOTAL		$ 2,682	$ 699	$ 3,380	$ 1,672	$ 436	$ 319	$ 83	$ 533	$ 139	$ 97	$ 25	$ -	$ -	$ 61	$ 16
36																		
37	583-2	OVERHEAD TRANSFORMERS																
38		CUSTOMER	A.F.20	$ 1,521	$ 303	$ 1,824	$ 1,323	$ 263	$ 185	$ 37	$ 13	$ 3	$ -	$ -	$ -	$ -	$ -	$ -
39		SECONDARY	A.F.21	$ 1,144	$ 228	$ 1,372	$ 671	$ 134	$ 160	$ 32	$ 303	$ 60	$ -	$ -	$ -	$ -	$ 10	$ 2
40																		
41		SUBTOTAL		$ 2,665	$ 531	$ 3,195	$ 1,994	$ 397	$ 345	$ 69	$ 316	$ 63	$ -	$ -	$ -	$ -	$ 10	$ 2

AMEREN MISSOURI
Case No. ER-2014-0258

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

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	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																		
2	584-1	UNDERGROUND LINES																
3		CUSTOMER	A.F.26	$ 396	$ 795	$ 1,191	$ 330	$ 664	$ 46	$ 93	$ 3	$ 7	$ 0	$ 0	$ -	$ -	$ 16	$ 32
4		HV	A.F.27a	$ 15	$ 31	$ 46	$ 8	$ 15	$ 2	$ 4	$ 5	$ 9	$ 1	$ 2	$ -	$ -	$ 0	$ 0
5		PRIMARY	A.F.27b	$ 109	$ 220	$ 330	$ 55	$ 112	$ 13	$ 27	$ 34	$ 68	$ 6	$ 12	$ -	$ -	$ 1	$ 2
6		SECONDARY	A.F.28	$ 50	$ 101	$ 151	$ 30	$ 59	$ 7	$ 14	$ 13	$ 26	$ -	$ -	$ -	$ -	$ 0	$ 1
7																		
8		SUBTOTAL		$ 570	$ 1,147	$ 1,717	$ 423	$ 850	$ 68	$ 137	$ 55	$ 110	$ 7	$ 14	$ -	$ -	$ 17	$ 35
9																		
10	584-2	UNDERGROUND TRANSFORMERS																
11		CUSTOMER	A.F.20	$ 682	$ (93)	$ 589	$ 593	$ (81)	$ 83	$ (11)	$ 6	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -
12		SECONDARY	A.F.21	$ 513	$ (70)	$ 443	$ 301	$ (41)	$ 72	$ (10)	$ 136	$ (18)	$ -	$ -	$ -	$ -	$ 4	$ (1)
13																		
14		SUBTOTAL		$ 1,195	$ (163)	$ 1,032	$ 894	$ (122)	$ 155	$ (21)	$ 142	$ (19)	$ -	$ -	$ -	$ -	$ 4	$ (1)
15																		
16	585	LIGHTING		$ 308	$ 388	$ 696	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 308	$ 388
17																		
18	586	METERS	A.F.7	$ 4,113	$ 13,881	$ 17,994	$ 2,330	$ 7,864	$ 844	$ 2,847	$ 748	$ 2,523	$ 74	$ 251	$ 3	$ 11	$ 114	$ 385
19																		
20	587	CUSTOMER INSTALLATION	DIRECT	$ 1,134	$ (596)	$ 538	$ (392)	$ 206	$ -	$ -	$ 763	$ (401)	$ 763	$ (401)	$ -	$ -	$ -	$ -
21																		
22		DIST OPERATING EXPENSE SUBTOTAL																
23		CUSTOMER A582-A587		$ 7,724	$ 15,150	$ 22,874	$ 5,416	$ 8,929	$ 1,275	$ 2,996	$ 778	$ 2,533	$ 75	$ 251	$ 3	$ 11	$ 178	$ 430
24		DEMAND A582-A587		$ 7,653	$ 2,222	$ 9,875	$ 2,849	$ 1,439	$ 777	$ 295	$ 2,602	$ 333	$ 1,068	$ (252)	$ -	$ -	$ 357	$ 406
25																		
26	580	SUPERVISION & ENGR																
27		CUSTOMER	A.F.30	$ 1,962	$ 292	$ 2,254	$ 1,376	$ 172	$ 324	$ 58	$ 198	$ 49	$ 19	$ 5	$ 1	$ 0	$ 45	$ 8
28		DEMAND	A.F.31	$ 1,944	$ 43	$ 1,987	$ 724	$ 28	$ 197	$ 6	$ 661	$ 6	$ 271	$ (5)	$ -	$ -	$ 91	$ 8
29																		
30		SUBTOTAL		$ 3,906	$ 335	$ 4,241	$ 2,099	$ 200	$ 521	$ 63	$ 858	$ 55	$ 290	$ (0)	$ 1	$ 0	$ 136	$ 16
31																		
32	581	DISPATCHING																
33		CUSTOMER	A.F.30	$ 1,808	$ 152	$ 1,959	$ 1,267	$ 89	$ 298	$ 30	$ 182	$ 25	$ 17	$ 3	$ 1	$ 0	$ 42	$ 4
34		DEMAND	A.F.31	$ 1,791	$ 22	$ 1,813	$ 667	$ 14	$ 182	$ 3	$ 609	$ 3	$ 250	$ (3)	$ -	$ -	$ 84	$ 4
35																		
36		SUBTOTAL		$ 3,599	$ 174	$ 3,772	$ 1,934	$ 104	$ 480	$ 33	$ 791	$ 29	$ 267	$ (0)	$ 1	$ 0	$ 125	$ 8
37																		
38	588	MISCELLANEOUS																
39		CUSTOMER	A.F.30	$ 2,402	$ 16,343	$ 18,745	$ 1,684	$ 9,632	$ 396	$ 3,231	$ 242	$ 2,732	$ 23	$ 271	$ 1	$ 12	$ 55	$ 464
40		DEMAND	A.F.31	$ 2,380	$ 2,396	$ 4,776	$ 886	$ 1,552	$ 242	$ 318	$ 809	$ 359	$ 332	$ (272)	$ -	$ -	$ 111	$ 438
41																		
42		SUBTOTAL		$ 4,782	$ 18,739	$ 23,521	$ 2,570	$ 11,184	$ 638	$ 3,550	$ 1,051	$ 3,092	$ 355	$ (1)	$ 1	$ 12	$ 166	$ 902

AMEREN MISSOURI
Case No. ER-2014-0258

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

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	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																		
2	589	RENTS																
3		CUSTOMER	A.F.30	$ -	$ 422	$ 422	$ -	$ 249	$ -	$ 83	$ -	$ 71	$ -	$ 7	$ -	$ 0	$ -	$ 12
4		DEMAND	A.F.31	$ -	$ 62	$ 62	$ -	$ 40	$ -	$ 8	$ -	$ 9	$ -	$ (7)	$ -	$ -	$ -	$ 11
5																		
6		SUBTOTAL		$ -	$ 484	$ 484	$ -	$ 289	$ -	$ 92	$ -	$ 80	$ -	$ (0)	$ -	$ 0	$ -	$ 23
7																		
8		DIST OPERATING EXPENSE SUBTOTAL																
9		CUSTOMER A580-589		$ 13,895	$ 32,358	$ 46,253	$ 9,743	$ 19,071	$ 2,293	$ 6,398	$ 1,399	$ 5,410	$ 134	$ 537	$ 6	$ 24	$ 320	$ 918
10		DEMAND A580-589		$ 13,768	$ 4,745	$ 18,513	$ 5,126	$ 3,073	$ 1,398	$ 630	$ 4,681	$ 711	$ 1,921	$ (538)	$ -	$ -	$ 642	$ 867
11																		
12		TOTAL DIST OPERATING EXPENSES		$ 27,663	$ 37,103	$ 64,766	$ 14,869	$ 22,145	$ 3,691	$ 7,028	$ 6,080	$ 6,122	$ 2,055	$ (1)	$ 6	$ 24	$ 962	$ 1,785
13																		
14																		
15		DISTRIBUTION MAINTENANCE EXPENSES																
16																		
17																		
18	591-592	SUBSTATIONS	A.F.8	$ 10,016	$ 4,643	$ 14,659	$ 4,968	$ 2,303	$ 1,186	$ 550	$ 3,046	$ 1,412	$ 742	$ 344	$ -	$ -	$ 73	$ 34
19																		
20	593	OVERHEAD LINES																
21		CUSTOMER	A.F.22	$ 5,523	$ 22,890	$ 28,413	$ 4,578	$ 18,974	$ 639	$ 2,650	$ 45	$ 186	$ 0	$ 1	$ -	$ -	$ 260	$ 1,078
22		HV	A.F.23a	$ 2,160	$ 8,954	$ 11,115	$ 1,072	$ 4,442	$ 256	$ 1,061	$ 657	$ 2,722	$ 160	$ 664	$ -	$ -	$ 16	$ 65
23		PRIMARY	A.F.23b	$ 6,796	$ 28,166	$ 34,962	$ 3,444	$ 14,276	$ 823	$ 3,409	$ 2,111	$ 8,748	$ 367	$ 1,523	$ -	$ -	$ 51	$ 210
24		SECONDARY	A.F.24	$ 153	$ 632	$ 785	$ 28	$ 117	$ 24	$ 101	$ 94	$ 388	$ -	$ -	$ -	$ -	$ 6	$ 27
25		LIGHTING-DIRECT	A.F.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26																		
27		SUBTOTAL		$ 14,632	$ 60,643	$ 75,275	$ 9,122	$ 37,809	$ 1,742	$ 7,222	$ 2,906	$ 12,044	$ 528	$ 2,188	$ -	$ -	$ 333	$ 1,380
28																		
29	594	UNDERGROUND LINES																
30		CUSTOMER	A.F.26	$ 1,872	$ 814	$ 2,686	$ 1,563	$ 679	$ 218	$ 95	$ 15	$ 7	$ 0	$ 0	$ -	$ -	$ 76	$ 33
31		HV	A.F.27a	$ 72	$ 31	$ 103	$ 36	$ 16	$ 9	$ 4	$ 22	$ 10	$ 5	$ 2	$ -	$ -	$ 1	$ 0
32		PRIMARY	A.F.27b	$ 518	$ 225	$ 743	$ 263	$ 114	$ 63	$ 27	$ 161	$ 70	$ 28	$ 12	$ -	$ -	$ 4	$ 2
33		SECONDARY	A.F.28	$ 237	$ 103	$ 340	$ 140	$ 61	$ 33	$ 14	$ 62	$ 27	$ -	$ -	$ -	$ -	$ 2	$ 1
34																		
35		SUBTOTAL		$ 2,699	$ 1,173	$ 3,873	$ 2,001	$ 870	$ 323	$ 140	$ 260	$ 113	$ 33	$ 15	$ -	$ -	$ 82	$ 36
36																		
37	595	LINE TRANSFORMERS																
38		CUSTOMER	A.F.20	$ 442	$ 216	$ 659	$ 385	$ 188	$ 54	$ 26	$ 4	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
39		SECONDARY	A.F.21	$ 333	$ 163	$ 496	$ 195	$ 95	$ 47	$ 23	$ 88	$ 43	$ -	$ -	$ -	$ -	$ 3	$ 1
40																		
41		SUBTOTAL		$ 775	$ 379	$ 1,154	$ 580	$ 284	$ 100	$ 49	$ 92	$ 45	$ -	$ -	$ -	$ -	$ 3	$ 1
42																		
43	596	LIGHTING		$ 1,748	$ 516	$ 2,263	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,748	$ 516
44																		
45	597	METERS	A.F.7	$ 727	$ 147	$ 874	$ 412	$ 83	$ 149	$ 30	$ 132	$ 27	$ 13	$ 3	$ 1	$ 0	$ 20	$ 4
46																		
47		DIST MAINTENANCE EXPENSE SUBTOTAL																
48		CUSTOMER A593-A597		$ 8,565	$ 24,067	$ 32,632	$ 6,938	$ 19,925	$ 1,061	$ 2,802	$ 196	$ 222	$ 14	$ 4	$ 1	$ 0	$ 356	$ 1,115
49		DEMAND A593-A597		$ 22,032	$ 43,434	$ 65,465	$ 10,146	$ 21,424	$ 2,440	$ 5,190	$ 6,240	$ 13,419	$ 1,303	$ 2,545	$ -	$ -	$ 1,903	$ 856

AMEREN MISSOURI
Case No. ER-2014-0258

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

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	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																		
2	590	SUPERVISION & ENGR																
3		CUSTOMER	A.F.32	$ 360	$ 149	$ 508	$ 291	$ 123	$ 45	$ 17	$ 8	$ 1	$ 1	$ 0	$ 0	$ 0	$ 15	$ 7
4		DEMAND	A.F.33	$ 925	$ 268	$ 1,193	$ 426	$ 132	$ 102	$ 32	$ 262	$ 83	$ 55	$ 16	$ -	$ -	$ 80	$ 5
5																		
6		SUBTOTAL		$ 1,284	$ 417	$ 1,702	$ 717	$ 256	$ 147	$ 49	$ 270	$ 84	$ 55	$ 16	$ 0	$ 0	$ 95	$ 12
7																		
8	598	MISCELLANEOUS																
9		CUSTOMER	A.F.32	$ 265	$ 661	$ 926	$ 214	$ 547	$ 33	$ 77	$ 6	$ 6	$ 0	$ 0	$ 0	$ 0	$ 11	$ 31
10		DEMAND	A.F.33	$ 681	$ 1,193	$ 1,874	$ 314	$ 588	$ 75	$ 143	$ 193	$ 369	$ 40	$ 70	$ -	$ -	$ 59	$ 23
11																		
12		SUBTOTAL		$ 946	$ 1,854	$ 2,800	$ 528	$ 1,135	$ 108	$ 219	$ 199	$ 375	$ 41	$ 70	$ 0	$ 0	$ 70	$ 54
13		DIST MAINTENANCE EXPENSE SUBTOTAL																
14		CUSTOMER A590-A598		$ 9,189	$ 24,877	$ 34,066	$ 7,444	$ 20,595	$ 1,138	$ 2,896	$ 210	$ 229	$ 15	$ 4	$ 1	$ 0	$ 382	$ 1,152
15		DEMAND A590-A598		$ 23,638	$ 44,895	$ 68,533	$ 10,885	$ 22,145	$ 2,618	$ 5,364	$ 6,695	$ 13,871	$ 1,398	$ 2,631	$ -	$ -	$ 2,042	$ 884
16																		
17		TOTAL MAINTENANCE OPERATING EXPENSE		$ 32,827	$ 69,772	$ 102,599	$ 18,329	$ 42,740	$ 3,756	$ 8,260	$ 6,905	$ 14,100	$ 1,413	$ 2,635	$ 1	$ 0	$ 2,423	$ 2,037
18																		
19		TOTAL DISTRIBUTION EXPENSES		$ 60,490	$ 106,875	$ 167,365	$ 33,197	$ 64,885	$ 7,448	$ 15,289	$ 12,985	$ 20,221	$ 3,468	$ 2,634	$ 7	$ 24	$ 3,386	$ 3,822

AMEREN MISSOURI
Case No. ER-2014-0258

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 5

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	BASIS	LABOR	OTHER	TOTAL	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER	LABOR	OTHER
				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1																		
2																		
3		CUSTOMER ACCOUNT EXPENSES																
4																		
5	902	METER READING	A.F.7A	$ 103	$ 8,660	$ 8,763	$ 89	$ 7,491	$ 12	$ 987	$ 2	$ 170	$ 0	$ 2	$ 0	$ 0	$ 0	$ 10
6	905	MISCELLANEOUS	A.F.7A	$ (18)	$ 93	$ 75	$ (16)	$ 80	$ (2)	$ 11	$ (0)	$ 2	$ (0)	$ 0	$ (0)	$ 0	$ (0)	$ 0
7	903	CUSTOMER RECORDS	A.F.40	$ 4,601	$ 6,483	$ 11,083	$ 3,680	$ 4,901	$ 264	$ 811	$ 598	$ 735	$ 4	$ 5	$ 0	$ 0	$ 54	$ 30
8	904	UNCOLLECTIBLE ACCOUNTS	A.F.13	$ -	$ 14,693	$ 14,693	$ -	$ 13,644	$ -	$ 504	$ -	$ 277	$ -	$ -	$ -	$ -	$ -	$ 269
9	903	CREDIT AND COLLECTION	A.F.13	$ 1,428	$ 2,013	$ 3,441	$ 1,326	$ 1,869	$ 49	$ 69	$ 27	$ 38	$ -	$ -	$ -	$ -	$ 26	$ 37
10		INTEREST ON SURETY DEPOSITS	A.F.12	$ -	$ 722	$ 722	$ -	$ 285	$ -	$ 172	$ -	$ 200	$ -	$ 31	$ -	$ -	$ -	$ 35
11																		
12		SUBTOTAL		$ 6,113	$ 32,664	$ 38,778	$ 5,079	$ 28,270	$ 323	$ 2,554	$ 626	$ 1,421	$ 4	$ 38	$ 0	$ 0	$ 80	$ 381
13																		
14	901	SUPERVISION	A.F.34	$ 1,978	$ 8	$ 1,986	$ 1,643	$ 7	$ 104	$ 1	$ 203	$ 0	$ 1	$ 0	$ 0	$ 0	$ 26	$ 0
15																		
16		TOTAL CUSTOMER ACCOUNT EXPENSES		$ 8,091	$ 32,673	$ 40,764	$ 6,722	$ 28,277	$ 428	$ 2,555	$ 829	$ 1,422	$ 5	$ 38	$ 0	$ 0	$ 106	$ 381
17																		
18																		
19		CUSTOMER SERVICE & SALES EXPENSES																
20																		
21	08-1&90	RCS	DIRECT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	908-916	CUSTOMER SERVICES & SALES	A.F.34	$ 14,587	$ 9,421	$ 24,008	$ 12,120	$ 8,154	$ 771	$ 737	$ 1,494	$ 410	$ 10	$ 11	$ 0	$ 0	$ 192	$ 110
23																		
24		SUBTOTAL		$ 14,587	$ 9,421	$ 24,008	$ 12,120	$ 8,154	$ 771	$ 737	$ 1,494	$ 410	$ 10	$ 11	$ 0	$ 0	$ 192	$ 110
25																		
26	907-911	SUPERVISION	A.F.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27																		
28		TOTAL CUSTOMER SERVICE & SALES EXPENS		$ 14,587	$ 9,421	$ 24,008	$ 12,120	$ 8,154	$ 771	$ 737	$ 1,494	$ 410	$ 10	$ 11	$ 0	$ 0	$ 192	$ 110
29																		
30		TOTAL PROD, T&D,CUST EXPENSES		$ 295,353	$ 1,263,962	$ 1,559,315	$ 147,843	$ 528,439	$ 31,200	$ 126,989	$ 77,040	$ 371,295	$ 20,045	$ 114,008	$ 14,096	$ 113,369	$ 5,129	$ 9,862
31																		
32																		
33		A & G EXPENSES																
34																		
35		EPRI	A.F.14	$ -	$ 13,922	$ 13,922	$ -	$ 7,128	$ -	$ 1,542	$ -	$ 3,529	$ -	$ 863	$ -	$ 609	$ -	$ 250
36		OTHER	A.F.35	$ 50,715	$ 195,790	$ 246,505	$ 25,386	$ 98,006	$ 5,357	$ 20,683	$ 13,228	$ 51,070	$ 3,442	$ 13,288	$ 2,420	$ 9,344	$ 881	$ 3,400
37																		
38		SUBTOTAL		$ 50,715	$ 209,712	$ 260,427	$ 25,386	$ 105,134	$ 5,357	$ 22,224	$ 13,228	$ 54,599	$ 3,442	$ 14,151	$ 2,420	$ 9,953	$ 881	$ 3,650
39																		
40		TOTAL PROD,T&D,CUST,A&G EXPENSES		$ 346,068	$ 1,473,674	$ 1,819,741	$ 173,229	$ 633,573	$ 36,557	$ 149,213	$ 90,269	$ 425,895	$ 23,487	$ 128,158	$ 16,516	$ 123,322	$ 6,010	$ 13,512

AMEREN MISSOURI
Case No. ER-2014-0258

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 6

			ALLOCATION	TOTAL MISSOURI			RESIDENTIAL		SMALL GEN. SERVICE		LARGE G. S./SM PRIMARY		LARGE PRIMARY		LARGE TRANSMISSION		LIGHTING	
LINE #	ACCT #	ITEM	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		DEPREC & AMORTIZATION EXPENSES																
2																		
3																		
4		DEPR-PRODUCTION PLANT	A.F.1	$ -	$ 279,401	$ 279,401	$ -	$ 126,670	$ -	$ 29,818	$ -	$ 81,160	$ -	$ 21,624	$ -	$ 18,172	$ -	$ 1,957
5		DEPR-COMMON PLANT	A.F.1	$ -	$ 14,168	$ 14,168	$ -	$ 6,234	$ -	$ 635	$ -	$ 6,030	$ -	$ 1,270	$ -	$ -	$ -	$ -
6		DEPR-TRANSMISSION PLANT	A.F.17	$ -	$ 22,622	$ 22,622	$ -	$ 10,303	$ -	$ 2,285	$ -	$ 6,443	$ -	$ 1,789	$ -	$ 1,752	$ -	$ 50
7		DEPR-DISTRIBUTION PLANT	A.F.18	$ -	$ 159,152	$ 159,152	$ -	$ 99,644	$ -	$ 19,114	$ -	$ 29,025	$ -	$ 4,977	$ -	$ 3	$ -	$ 6,390
8		DEPR-GENERAL PLANT	A.F.35	$ -	$ 54,072	$ 54,072	$ -	$ 27,067	$ -	$ 5,712	$ -	$ 14,104	$ -	$ 3,670	$ -	$ 2,581	$ -	$ 939
9																		
10		SUBTOTAL		$ -	$ 529,416	$ 529,416	$ -	$ 269,918	$ -	$ 57,564	$ -	$ 136,762	$ -	$ 33,329	$ -	$ 22,508	$ -	$ 9,336
11																		
12				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13																		
14		TOTAL DEPREC & AMORTIZ EXPENSES		$ -	$ 529,416	$ 529,416	$ -	$ 269,918	$ -	$ 57,564	$ -	$ 136,762	$ -	$ 33,329	$ -	$ 22,508	$ -	$ 9,336
15																		
16																		
17		OTHER																
18																		
19																		
20		REAL ESTATE & PROPERTY TAXES	A.F.19	$ -	$ 143,851	$ 143,851	$ -	$ 73,655	$ -	$ 15,929	$ -	$ 36,466	$ -	$ 8,916	$ -	$ 6,298	$ -	$ 2,588
21		INCOME/CITY EARNINGS TAXES	A.F.29	$ -	$ 113,085	$ 113,085	$ -	$ 30,426	$ -	$ 17,095	$ -	$ 53,108	$ -	$ 7,869	$ -	$ 2,896	$ -	$ 1,689
22		RETURN	A.F.29	$ -	$ 588,726	$ 588,726	$ -	$ 294,848	$ -	$ 64,026	$ -	$ 153,631	$ -	$ 39,116	$ -	$ 28,318	$ -	$ 8,788
23		PAYROLL TAXES	A.F.35	$ -	$ 21,430	$ 21,430	$ -	$ 10,727	$ -	$ 2,264	$ -	$ 5,590	$ -	$ 1,454	$ -	$ 1,023	$ -	$ 372
24		ENVIRONMENTAL TAX	A.F. 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25																		
26		SUBTOTAL		$ -	$ 867,092	$ 867,092	$ -	$ 409,656	$ -	$ 99,314	$ -	$ 248,795	$ -	$ 57,355	$ -	$ 38,535	$ -	$ 13,437
27																		
28		TOTAL OPERATING & OTHER EXPENSES		$ 346,068	$ 2,870,182	$ 3,216,249	$ 173,229	$ 1,313,147	$ 36,557	$ 306,090	$ 90,269	$ 811,451	$ 23,487	$ 218,843	$ 16,516	$ 184,365	$ 6,010	$ 36,285
29																		
30																		
31																		
32																		
33		TOTAL COST OF SERVICE		$ 346,068	$ 2,870,182	$ 3,216,249	$ 173,229	$ 1,313,147	$ 36,557	$ 306,090	$ 90,269	$ 811,451	$ 23,487	$ 218,843	$ 16,516	$ 184,365	$ 6,010	$ 36,285

SERVICE CLASSIFICATION NO. 10(M)
SERVICE TO ALUMINUM SMELTERS ("SAS") RATE

RATE BASED ON MONTHLY METER READINGS

This rate is optionally available to aluminum smelters who otherwise qualify to take service under Service Classification No. 12(M).

The rate shall initially be $32.50/MWh upon approval. Thereafter, the rate will increase by 1% of the then current rate value upon the annual anniversaries of the initial effective date of this Service Classification.

Except as provided below with respect to low-income program charges, no other charges shall apply to service under this Service Classification.

Low-Income Program Charge If Company is conducting a low-income program, customer will pay a monthly charge not-to-exceed $1,500 plus 100 times the monthly amount paid by a residential customer using 1,500 kWh of energy per month.

OTHER PROVISIONS

The provisions in paragraphs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 12 in Service Classification 12(M), Large Transmission Service Rate, shall also apply; provided that use of the SAS rate shall not cause a change in the term of the existing contract between Customer and Ameren Missouri.

AMEREN MISSOURI
Case No. ER-2014-0258

Base Rate Revenue Change
Attributable to Rate Adjustment

Line	Description	Amount (1)
1	Revenue per kWh under SC 12(M) approved in Case No. ER-2012-0166 and Noranda's Test Year kWh Purchases in Case No. ER-2014-0258	$37.95 per MWh
2	Requested Rate	$32.50 per MWh
3	Difference	$5.45
4	Noranda's Test Year MWh	4,198,453
5	Amount of Adjustment ($000)	$22,882

AMEREN MISSOURI
Case No. ER-2014-0258

Revenue-Neutral Adjustment to Base Rate Revenues of Other Major Customer Classes

Line	Class	Test Year Base Rate Revenue[1] (000) (1)	Adjustment[2] (000) (2)
1	Residential	$1,218,848	$10,905
2	Small General Service	301,617	2,698
3	Large General Service	572,000	5,117
4	Small Primary Service	225,172	2,014
5	Large Primary Service	202,147	1,808
6	Lighting	37,876	339
7	MSD	73	1
8	Total	$2,557,734	$22,882

(1) From direct testimony of Ameren Missouri witness Jim Pozzo in ER-2014-0258. Base rates less energy efficiency and low income revenues.
(2) 0.8946%

AMEREN MISSOURI
Case No. ER-2014-0258

Net Revenue Loss from Smelter Shutdown

Line	Description	36-Month Average[1] (1)	36-Month Average[2] (2)	48-Month Average[3] (3)
1	Revenue Loss ($/MWh)	$42.35	$42.35	$42.35
2	Reduction in Actual Net Energy Costs (ANEC) ($/MWh)	$28.03	$29.39	$31.74
3	Net Loss ($/MWh)	$14.32	$12.96	$10.61
4	MWh Sales to Noranda	4,198,453	4,198,453	4,198,453
5	Net Dollar Loss ($000)	$60,122	$54,412	$44,546
6	Percent Increase to Other Customers[4]	2.22%	2.01%	1.64%

[1] Polar Vortex excluded and ARR Revenue and Market Price Reductions included.
[2] Polar Vortex excluded and ARR Revenue and Market Price Reductions excluded.
[3] Polar Vortex included and ARR Revenue and Market Price Reductions excluded.
[4] Line 5 ÷ $2,710,675,000

AMEREN MISSOURI
Case No. ER-2014-0258

Impact of Noranda Rate Proposal on Other Customers
(Dollars in Thousands)

Line	Class	Present Base Revenue (1)	Present FAC Revenue (2)	Present Total Revenue (3)	Additional Base Rate Revenue (4)	Additional FAC Revenue (5)	Additional Total Amount (6)	Additional Total % of Present Total (7)
1	Residential	$1,218,848	$62,852	$1,281,700	$10,905	$7,536	$18,441	1.44%
2	Small General Service	301,617	16,313	317,930	2,698	1,956	4,654	1.46%
3	Large General Service	572,000	38,412	610,412	5,117	4,606	9,723	1.59%
4	Small Primary Service	225,172	16,749	241,921	2,014	2,074	4,088	1.69%
5	Large Primary Service	202,147	17,602	219,749	1,808	2,180	3,988	1.81%
6	Lighting	37,876	1,013	38,890	339	121	460	1.18%
7	MSD	73	0	73	1	0	1	1.39%
8	Total	$2,557,734	$152,941	$2,710,675	$22,882	$18,473	$41,355	1.53%

AMEREN MISSOURI
Case No. ER-2014-0258

FAC Revenue

Line	Class	FAC $/MWh[1] (1)	MWh[2] (2)	Present FAC Revenue (3)	Additional FAC Revenue (4)
1	Residential	$ 4.70	13,372,844	$ 62,852,365	$ 7,535,910
2	Small General Service	$ 4.70	3,470,807	16,312,793	1,955,881
3	Large General Service	$ 4.70	8,172,762	38,411,982	4,605,543
4	Small Primary Service	$ 4.55	3,681,032	16,748,697	2,074,348
5	Large Primary Service	$ 4.55	3,868,532	17,601,821	2,180,008
6	Lighting	$ 4.70	215,587	1,013,259	121,488
7	MSD	$ 4.70	27	127	15
8	Subtotal		32,781,591	$ 152,941,043	$ 18,473,193
9	Large Transmission Service	$ 4.40	4,198,453	18,473,193	
10	Total		36,980,044	$ 171,414,237	

[1] Rider FAC effective date of September 24, 2014

[2] Schedule JRP-7 of Ameren witness Jim Pozzo in ER-2014-0258.