No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Revised Direct Testimony
Issues:	Cost of Service, Revenue Allocation, and Rate Design
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2010-0036

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service	))))))	**Case No. ER-2010-0036** Tariff Nos. YE-2010-0054 and YE-2010-0055

Revised Direct Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation and Rate Design

On behalf of

Missouri Industrial Energy Consumers

January 6, 2010
Revised February 3, 2009

BAI
BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9187

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

Affidavit of Maurice Brubaker

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

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

2. Attached hereto and made a part hereof for all purposes are my revised direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2010-0036.

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 3rd day of February, 2010.

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

Tammy S Klossner
Notary Public

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Revised Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my direct testimony on revenue requirement issues.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

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

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of an electric system class cost of service study for AmerenUE, to explain how the study should be used, and to recommend an appropriate allocation of any rate increase. I also address the rate design for any Environmental Cost Recovery Mechanism (ECRM) that may be approved and the payment terms for non-residential customers.

Q HOW IS YOUR TESTIMONY ORGANIZED?

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

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

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

This revised direct testimony corrects an inconsistency in the treatment of income taxes that was present in the January 6, 2010 filing.

SUMMARY

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

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

2. AmerenUE 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 AmerenUE. These are the coincident peak methodology and the average and excess (A&E) methodology.

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

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

6. In order to better reflect cost-causation, I have changed AmerenUE's cost of service methodology in several respects:

   (1) AmerenUE allocates transmission costs using 12 monthly coincident peaks. Since the transmission system must be built to meet the maximum demands, I have used the same allocation factor as is applicable for generation plant.

   (2) AmerenUE allocates a significant proportion of non-fuel production O&M expense on energy. Since these expenses are more a function of the existence of the generation facilities and the passage of time, I have instead classified and allocated them as a demand-related cost.

   (3) AmerenUE allocates the margin on off-system sales on a demand basis. I have changed the allocation to reflect the more appropriate energy-based allocation which the Commission has previously approved for this purpose.

   (4) I have modified AmerenUE's allocation of general and intangible plant to reflect a more appropriate allocation.

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

8. The results of my class cost of service study, incorporating both the change in methodology that I have applied and the adjustments to fuel expense, other O&M expense and depreciation expense sponsored by other MIEC witnesses are summarized on Schedule MEB-COS-4. Schedule MEB-COS-5 shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates.

9. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6. In addition, this schedule shows the additional adjustment required to move the Large Transmission rate to cost of service.

10. Because of the unique circumstances faced by aluminum smelters, MIEC supports moving the Large Transmission class to its cost of service at this time. The adjustment required to effect this movement is spread on an equal percentage basis to all remaining customer classes.

11. Page 1 of Schedule MEB-COS-7 shows the class adjustments required to implement an overall increase of $137 million, which is consistent with MIEC's recommended expense adjustments and proposed return on equity. Other pages of Schedule MEB-COS-7 illustrate the distribution of both smaller and larger amounts of increase.

12. Schedules MEB-COS-8 and MEB-COS-9 show an alternative method for adjusting rates and allocating any rate increase.

13. Any increase found appropriate for Rate 11 (Large Primary Service) should be applied as a uniform percentage increase to the existing charges in the tariff.

14. The payment terms for non-residential customers should be extended to 21 days, the same that applies to residential customers.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

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

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

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

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

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

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

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

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

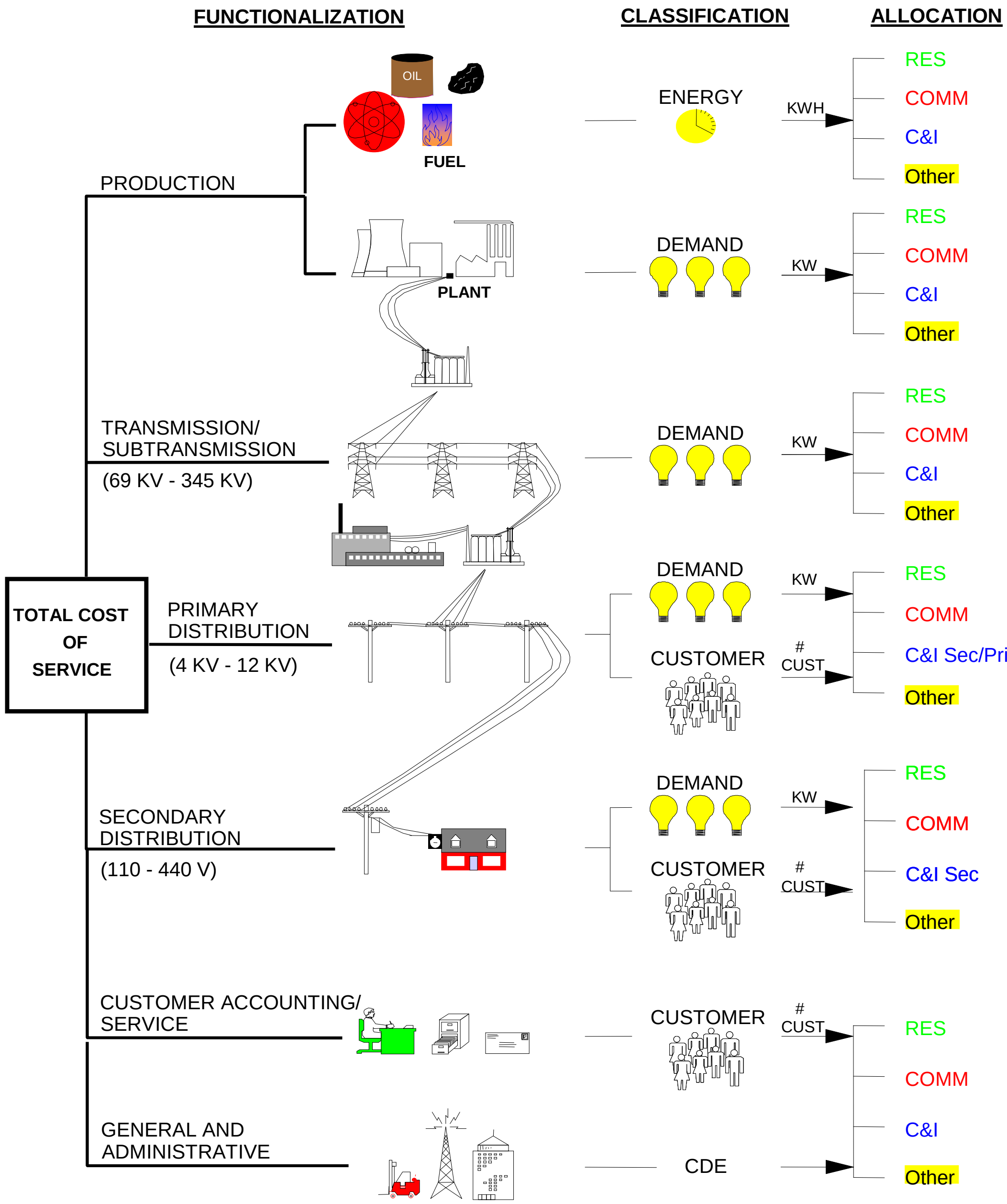
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so, consider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

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

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

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

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

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

Referring to Figure 1, at the top level there is generation. The next level is the extra high voltage transmission and subtransmission system (69,000 volts to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution – 4,160 to 12,000 volts. Finally, the voltage is stepped down by pole 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. If the utility anticipates a peak demand of 9,000 megawatts – 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 operation and maintenance expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kWhs generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

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

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

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

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

Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

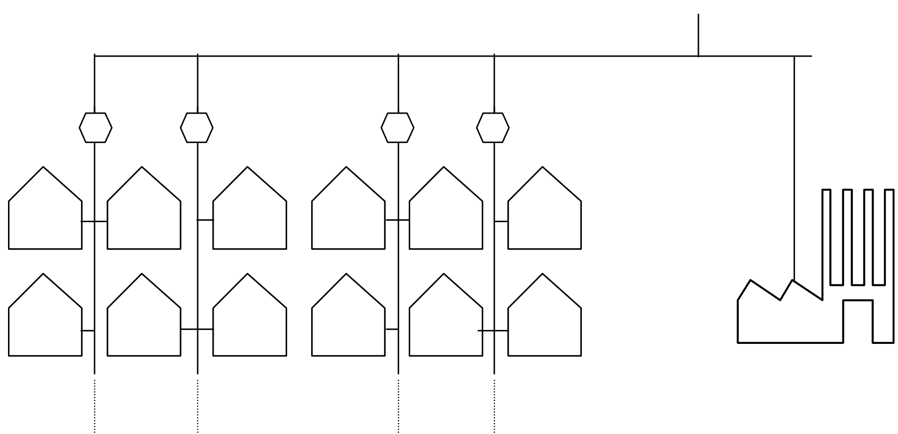
Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

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

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

Figure 2

<u>Classification of Distribution Investment</u>



Total Demand = 120 kW

Class A

Total Demand = 120 kW

Class B

Demand vs. Energy Costs

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

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

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

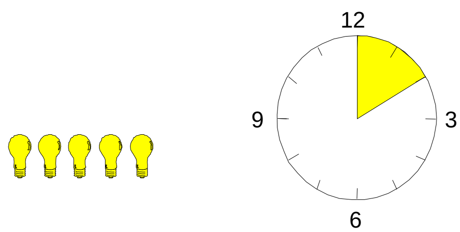
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

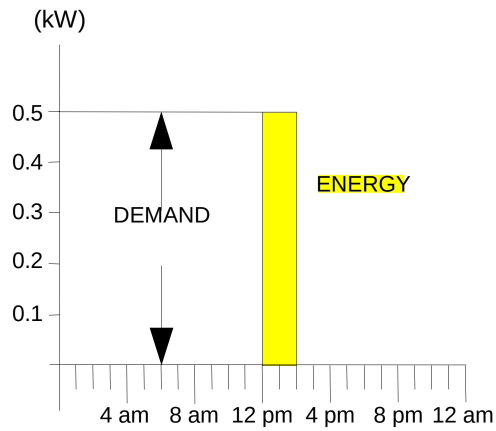
A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each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

Figure 3

DEMAND VS. ENERGY

CUSTOMER A

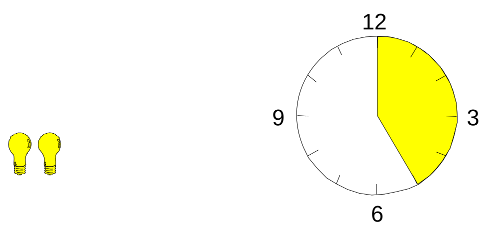


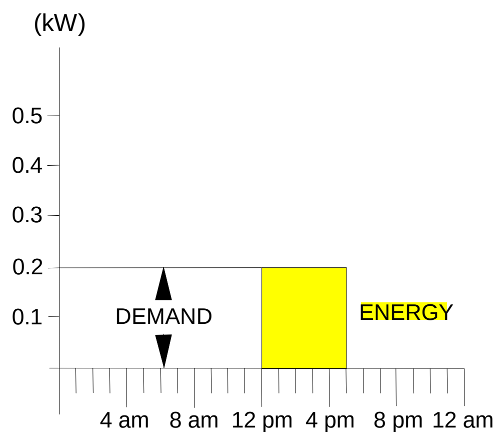


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

DEMAND: 500 watts = 0.5 kW

CUSTOMER B





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

DEMAND: 200 watts = 0.2 kW

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

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

<u>Allocation</u>

Q WHAT IS ALLOCATION?

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

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

TABLE 1
Energy Allocation Factor

Rate Class	Energy Generated (MWh) (1)	Allocation Factor (2)
Residential	14,828,434	37.02%
Small GS	3,908,409	9.76%
Large GS/Small Primary	12,901,145	32.21%
Large Primary	4,246,561	10.60%
Large Transmission	4,170,226	10.41%
Total	40,054,775	100.00%

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 shows the calculation of the factor for AmerenUE. (The selection and derivation of this factor is discussed in more detail on pages 20 to 26.)

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 AmerenUE (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	3,839	46.65%
Small GS	906	11.01%
Large GS/Small Primary	2,356	28.63%
Large Primary	641	7.79%
Large Transmission	487	5.92%
Total	8,228[1]	100.00%

Notes:
[1]The 8,228 MW is the MO Jurisdictional peak.
[2]Column (2) is the A&E-4NCP allocation factor.

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

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

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

Rate Class	Cost-Based Revenue (1)	Energy Sales (MWh) (2)	Cost per kWh (3)
Residential	$1,106,762	13,743,406	8.62¢
Small GS	240,899	3,622,422	6.46
Large GS/Small Primary	580,324	12,073,913	4.38
Large Primary	160,054	4,084,939	3.74
Large Transmission	117,556	4,119,018	2.55
Total	$2,205,595	37,643,698	5.86¢

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	14,828,434	3,839	44%
Small GS	3,908,409	906	49%
Large GS/Small Primary	12,901,145	2,356	62%
Large Primary	4,246,561	641	75%
Large Transmission	4,170,226	487	97%
Total	40,054,775	8,228	55%

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

TABLE 5
Energy Loss Factors

Rate Class	Percent of Sale By Voltage Level		Composite Loss Percentage
	Secondary (1)	Primary & Higher (2)	(3)
Residential	100%	0%	7.89%
Small GS	100%	0%	7.89%
Large GS/Small Primary	68%	32%	6.85%
Large Primary	0%	100%	3.96%
Large Transmission	0%	100%	1.24%

The per capita sales to the Primary and Transmission classes are also much greater than to the other classes, as shown in Table 6. AmerenUE sells almost 61,000,000 kWhs per Large Primary customer, but only about 13,000 kWhs per Residential customer, or 4,700 times more per capita, as shown in Table 6. The customer-related costs to serve Large Primary customers are not 4,700 times the customer-related costs to serve the Residential customer.

TABLE 6
Energy Sold Per Customer

Rate Class	Energy Sold (MWh) (1)	Number of Customers (2)	KWh Sold per Customer (3)
Residential	13,743,406	1,033,561	13,297
Small GS	3,622,422	141,513	25,598
Large GS/Small Primary	12,073,913	10,548	1,144,619
Large Primary	4,084,939	67	60,592,420
Large Transmission	4,119,018	1	4,119,017,867
Total	37,643,698	1,185,690	31,748

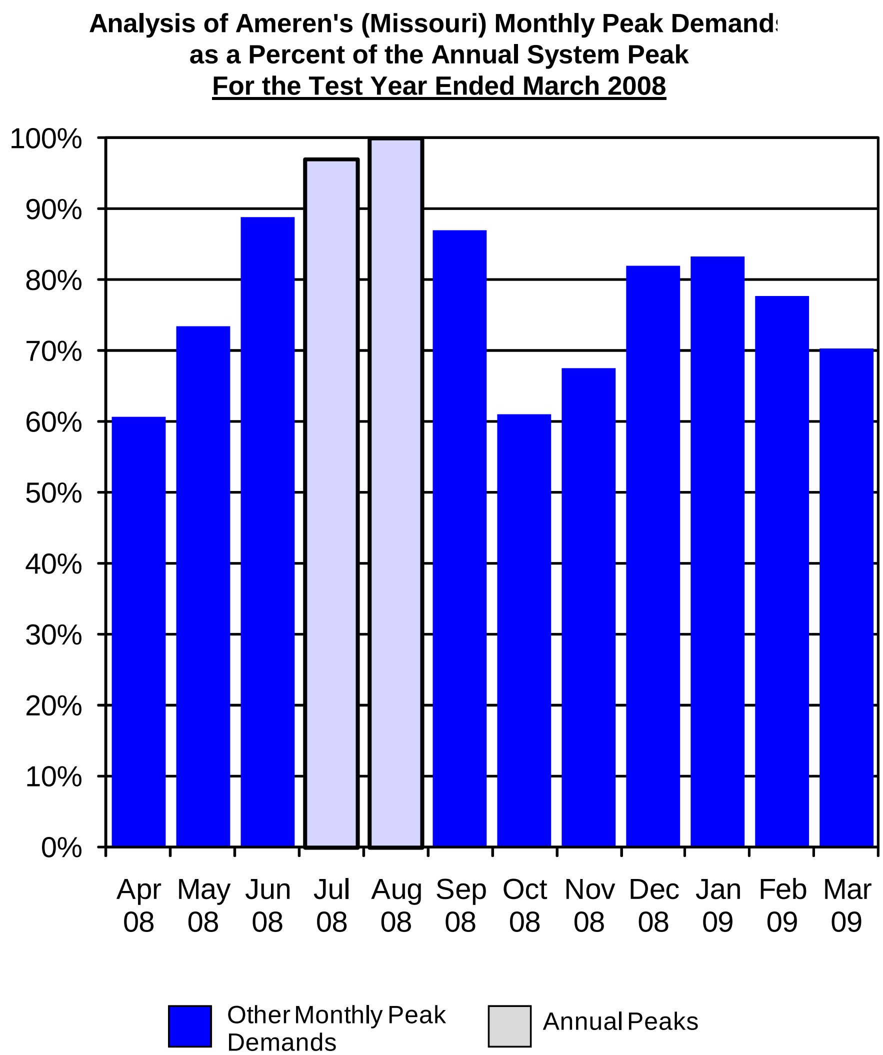
These differences in the service and usage characteristics – load factor, delivery voltage and size – result in a lower per unit cost to serve customers operating at a higher load factor, taking service at higher delivery voltage and purchasing a larger quantity of power and energy at a single delivery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

Utility System Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

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

Figure 4
AmerenUE



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

This analysis shows that summer peaks dominate the AmerenUE system. (This same information is presented in tabular form on Schedule MEB-COS-2.) This clearly shows that the system peak occurred in August, and was substantially higher than the monthly peaks occurring in the other months. The July peak was close, at 97% of the annual peak. The peaks in June and September were 11% and 13%, respectively, lower than the annual peak. These lower loads simply are not representative of peak making weather and use of these lower demands as part of the allocation factor could distort the allocations and under-allocate costs to the most temperature sensitive loads.

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

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

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

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

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

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

Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?

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

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

Q WHAT IS THE A&E METHOD?

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

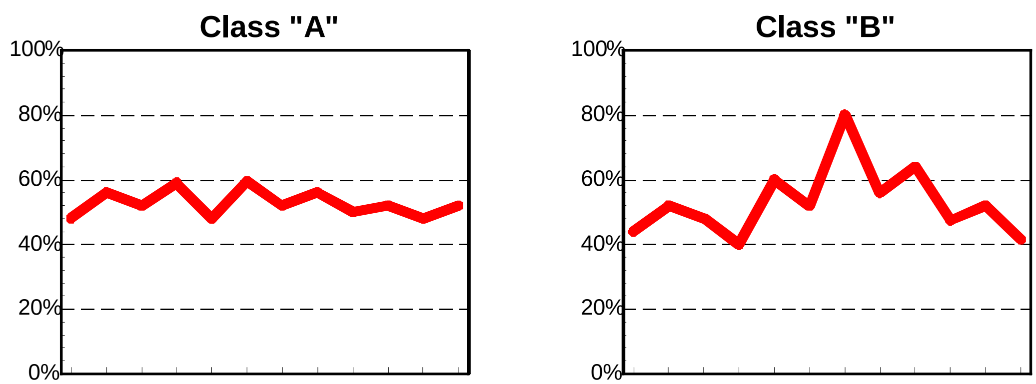
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability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

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

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

Figure 5

<u>Load Patterns</u>



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

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

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

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

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

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

A First, in order to reflect cost-causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has 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 study, using the demands during the peak summer months, or a version of an A&E cost of service study that uses class non-coincident peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I will make my recommendations based on the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

Based on test year load characteristics, I believe the most appropriate allocation would be A&E using July and August system peaks. The allocation factors for all classes under that approach are virtually identical to AmerenUE's A&E-4NCP allocation factors. (The Residential class is allocated slightly less costs with the A&E-4NCP method, and the other classes are allocated slightly more.) Because of the small difference, I have used AmerenUE'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 kilowatts, 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 excess demand, shown on line 6, is equal to the non-coincident peak demand shown on line 2 minus the average demand that is shown on line 4. Line 7 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

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

Making the Cost of Service Study – Summary

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

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

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

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

A The results are presented in Schedule MEB-COS-4. In this cost of service study, which reflects results at present rates, I have incorporated the adjustments of fuel expense, other O&M expense and depreciation expense sponsored by MIEC witnesses, along with the related income tax effects.

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, including MIEC's adjustments to expenses.

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

Q OTHER THAN THE USE OF DIFFERENT REVENUE REQUIREMENT ELEMENTS, HOW DOES YOUR STUDY DIFFER FROM THE ONE PRESENTED BY AMERENUE?

A There also are differences in the allocation of the transmission system, the classification of certain non-fuel generation O&M expenses, the allocation of off-system sales revenue, and a minor difference in the allocation of general and intangible plant.

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 WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF TRANSMISSION COSTS?

A AmerenUE 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 (30% and more) than the summer peak demand. In this respect, the transmission system is similar to the generation system, and should be allocated in a similar fashion.

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

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

Accordingly, AmerenUE has no support for the particular classification of non-fuel generation, operation and maintenance expenses that it has used in its study. It is more conventional to allocate these costs on an "expenses follows plant" basis, this is to say, on a demand basis. The vast majority of these costs do not vary in any appreciable way with the number of kWhs generated, but occur as a function of the existence of the plants, the hours of operation and the passage of time. My study incorporates this classification.

Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF OFF-SYSTEM SALES?

A AmerenUE has allocated the revenues from off-system sales on the basis of class demand. It then estimates the cost of fuel and purchased power associated with making these sales. These estimated costs are allocated to customers on demand, while the balance of the fuel expense is allocated on energy. The end result of these calculations is to allocate the estimated net margin on the basis of class demands.

AmerenUE's approach, which requires this estimate of the fuel and purchased power costs associated with the power produced for purposes of off-system sales, is at odds with the treatment of these sales and the associated expenses in the fuel adjustment clause. In the FAC, all of the fuel and purchased power expense associated both with native load and off-system sales, as well as a credit for 100% of the off-system sales, are established on a per kWh basis. This approach recognizes that the preponderance of these sales are non-firm, and also recognizes that the attempted separation of costs between that incurred for purposes of native load and that incurred for purposes of off-system sales requires numerous assumptions and is subject to error.

The more traditional approach is to allocate the revenues from off-system sales to customer classes on the basis of class kWh requirements. This would make the allocation of the revenues consistent with the allocation of the underlying costs. (This method was recently adopted in a KCP&L rate case, Case No. ER-2006-0314.)

Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF GENERAL AND INTANGIBLE PLANT?

A AmerenUE has allocated these investments on the basis of the total of the operating labor contained in the production, distribution, transmission and customer account functions. On the theory that the general plant relates to the plant in other functions, I have allocated these costs on the basis of the related production, transmission, and distribution plant.

Q ARE THESE ADJUSTMENTS WHICH YOU HAVE MADE TO AMERENUE'S CLASS COST OF SERVICE STUDY CONSISTENT WITH THE ADJUSTMENTS WHICH YOU MADE IN AMERENUE'S PREVIOUS RATE CASE, CASE NO. ER-2008-0318?

A Yes, they are. The only differences are: (1) the relatively minor adjustment to the allocation of general and intangible plant which I did not make in that case, and (2) the calculation of income taxes based on the taxable income of each class. All of the other adjustments were made previously.

Q WHAT ARE THE RESULTS OF THIS COST OF SERVICE STUDY?

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

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 on Schedule MEB-COS-4 as Attachment 1.

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

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

Adjustment of Class Revenues

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Revenue Allocation

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

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

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

A This is shown on Schedule MEB-COS-5. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall increase in revenues. Note that the Residential class would require an increase of about $130 million, or 13%, in order to move to cost of service. All other classes would require a corresponding decrease. The decreases range from about 4% for the Small GS class to 16% for the Large Transmission class.

Q HOW DOES AMERENUE PROPOSE TO ADJUST REVENUES?

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

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

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

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

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

Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.

A My specific proposal is shown on Schedule MEB-COS-6. Column 1 shows class revenues at current rates. Column 2 shows the first step of my proposed cost of service adjustment. This adjustment moves classes roughly 20% of the way toward cost of service. This 20% movement was selected because it makes a reasonable step in the right direction without imposing too disruptive of a revenue increase on the Residential class. An overall increase of about 2.6% on the Residential class is a relatively modest step, but at least it is a step in the right direction.

While some will want to talk about the impact on the Residential class of this increase, it is also important not to lose sight of the fact that by not moving all the way to cost of service, the other customer classes are continuing to bear more of the burden of the revenue responsibility than they should. My recommendation of moving 20% of the way toward cost of service, which limits the Residential class increase to 2.6% (as compared to the 13% increase required to move all the way to cost of service) is relatively moderate, and must be considered in light of the fact that other classes are being asked to continue to provide part of the revenue responsibility that rightly should be shouldered by the Residential class.

Q WHAT ELSE IS SHOWN ON SCHEDULE MEB-COS-6?

A Column 3 shows an adjustment to move the Large Transmission class to its cost of service, rather than 20% toward its cost of service. The only customer taking service on this rate, Noranda Aluminum Company, is submitting separate testimony in which it outlines the unique circumstances facing the aluminum industry and other factors pertinent to Noranda's operation of its smelter in Southeastern Missouri.

Because of the unique circumstances faced by aluminum smelters, MIEC supports moving the Large Transmission class to its cost of service at this time. The adjustment required to effect this movement is spread on an equal percentage basis to all remaining customer classes.

Q PLEASE CONTINUE WITH YOUR EXPLANATION OF SCHEDULE MEB-COS-6.

A Column 4 shows the total of the cost of service adjustments that are being made, and column 5 shows the adjusted current revenues which take into account the cost of service adjustments to current revenues. Finally, column 6 shows the percentage that each class represents of the adjusted current revenues. This would be the basis for distributing whatever amount of revenue increase AmerenUE is granted by the Commission.

Q HAVE YOU PREPARED SCHEDULES TO ILLUSTRATE THE OVERALL IMPACT OF YOUR RECOMMENDATION IN THE CONTEXT OF VARIOUS LEVELS OF POTENTIAL RATE INCREASE?

A Yes. These all appear in Schedule MEB-COS-7. Page 1 shows the increases by customer class based on MIEC's overall revenue increase of $137 million. Page 2 illustrates the increases assuming an overall increase of $100 million, while pages 3 and 4 illustrate the distribution of larger amounts of revenue increase.

Q IF, INSTEAD OF YOUR APPROACH, THE COMMISSION CHOOSES TO ESTABLISH A RATE LEVEL FOR LTS INDEPENDENT OF THE AMOUNT OF OVERALL REVENUE INCREASE, HAVE YOU PREPARED AN EXAMPLE TO ILLUSTRATE HOW THIS APPROACH COULD BE IMPLEMENTED?

A Yes. This is shown on Schedule MEB-COS-8 and Schedule MEB-COS-9.

Q PLEASE EXPLAIN THE APPROACH SET FORTH ON THESE SCHEDULES.

A Schedule MEB-COS-8 shows a cost of service adjustment for all classes other than LTS. The objective here is to move 20% of the way to cost of service. These adjustments are made to revenues at current rates in order to determine the adjusted revenues at current rates, which form the basis for the distribution of revenue adjustments.

Schedule MEB-COS-9 shows how to combine the cost of service adjustments with the target revenue level for LTS, and the overall rate increase that is granted. For purposes of illustration, I have used a $200 million overall rate increase.

This approach allows the Commission to establish an appropriate revenue level for Rate LTS by taking into account all of the evidence that is available to it, and without regard to the results of a particular cost of service study. At the same time, appropriate cost of service adjustments can be made for other customer classes as well.

Rate Design for Rate 11

Q DO YOU HAVE ANY CONCERNS WITH RESPECT TO THE DESIGN OF PROPOSED RATE 11 – THE LARGE PRIMARY SERVICE RATE?

A The Company has proposed an equal percentage increase to all values within the rate. I agree with this approach and would recommend that it be followed in the implementation of the final rate design in this matter.

Payment Terms

Q DO YOU HAVE ANY ADDITIONAL ISSUES REGARDING THE COST OF SERVICE STUDY AND THE TERMS AND CONDITIONS OF THE RATES?

A Yes. The concern arises from the current allocation of cash working capital. It is my understanding that the cash working capital requirement of AmerenUE is calculated using a lead-lag study. The lead-lag study incorporates a revenue lag which measures the amount of time from when electric service is supplied until payment is made by the customer. The payment periods are not the same for all customer classes. Residential customers have 21 days to pay their bills before their bills are considered delinquent, but business customers have only 10 days to pay their bills before those bills are considered delinquent. Provisions for the 21-day payment period for residential customers can be found in the Commission Rules under 4 CSR 240-13.020 (7). Provisions for the 10-day payment period for business customers are not specified in the rules, but are found in AmerenUE's tariff.

Q DOES THE LEAD-LAG STUDY DIFFERENTIATE BETWEEN THE PAYMENT PERIODS OF THE CUSTOMERS?

A No. Even though business customers are required to pay in half the time residential customers pay, the revenue lag for the lead-lag study is an overall lag with all payment periods combined into one revenue lag. Customer classes which are required to pay in 10 days impose a lower cash working capital requirement, but are not differentiated from customer classes which are allowed to pay 21 days after the bill is rendered. It is not reasonable to require business customers to pay within 10 days, but not recognize that fact in the cash working capital calculation used in the class cost of service study.

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that business customers be allowed to pay their bills in the same time frame as the residential customers. In other words, all customers would be required to pay their electric bill within 21 days without being considered delinquent.

<u>Rate Design for Environmental Cost Recovery Mechanism</u>

Q IN YOUR REVENUE REQUIREMENT TESTIMONY, IN WHICH YOU OPPOSED THE ADOPTION OF AN ECRM, YOU INDICATED THAT IN YOUR RATE DESIGN TESTIMONY YOU WOULD ADDRESS THE APPROPRIATE COST RECOVERY MECHANISM, IF THE COMMISSION DECIDES TO ADOPT AN ECRM. DO YOU HAVE A RECOMMENDATION?

A Yes. My recommendation is that, if the Commission decides to implement an ECRM, the charges be divided into fixed and variable cost categories.

The variable category would include any purchased emission allowances or chemicals that are used directly in the combustion process or in the process of pollutant removal, and which vary directly as a function of the energy generated in the generating unit. These amounts would be offset by any revenues from the sale of allowances. All other cost items, including other O&M expense, depreciation, taxes and return are fixed costs and would be in that category.

Q HOW WOULD THESE COSTS BE LEVIED TO CUSTOMERS?

A It would be appropriate to levy the charges associated with the variable costs on a kWh basis, adjusted for losses. The fixed costs should be collected as a percentage of base rate revenues.

Q USING AMERENUE'S CLAIMED ENVIRONMENTAL COSTS IN CURRENT RATES, WHAT ARE THE ECRM BASE RATE VALUES?

A They will be as follows:

TABLE 7
ECRM Base Costs at Present Rates

Description	Variable Costs (¢/kWh) (1)	Fixed Costs (Percent of Present Base Rate Revenue) (2)
Base Rates	0.000266	2.439

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

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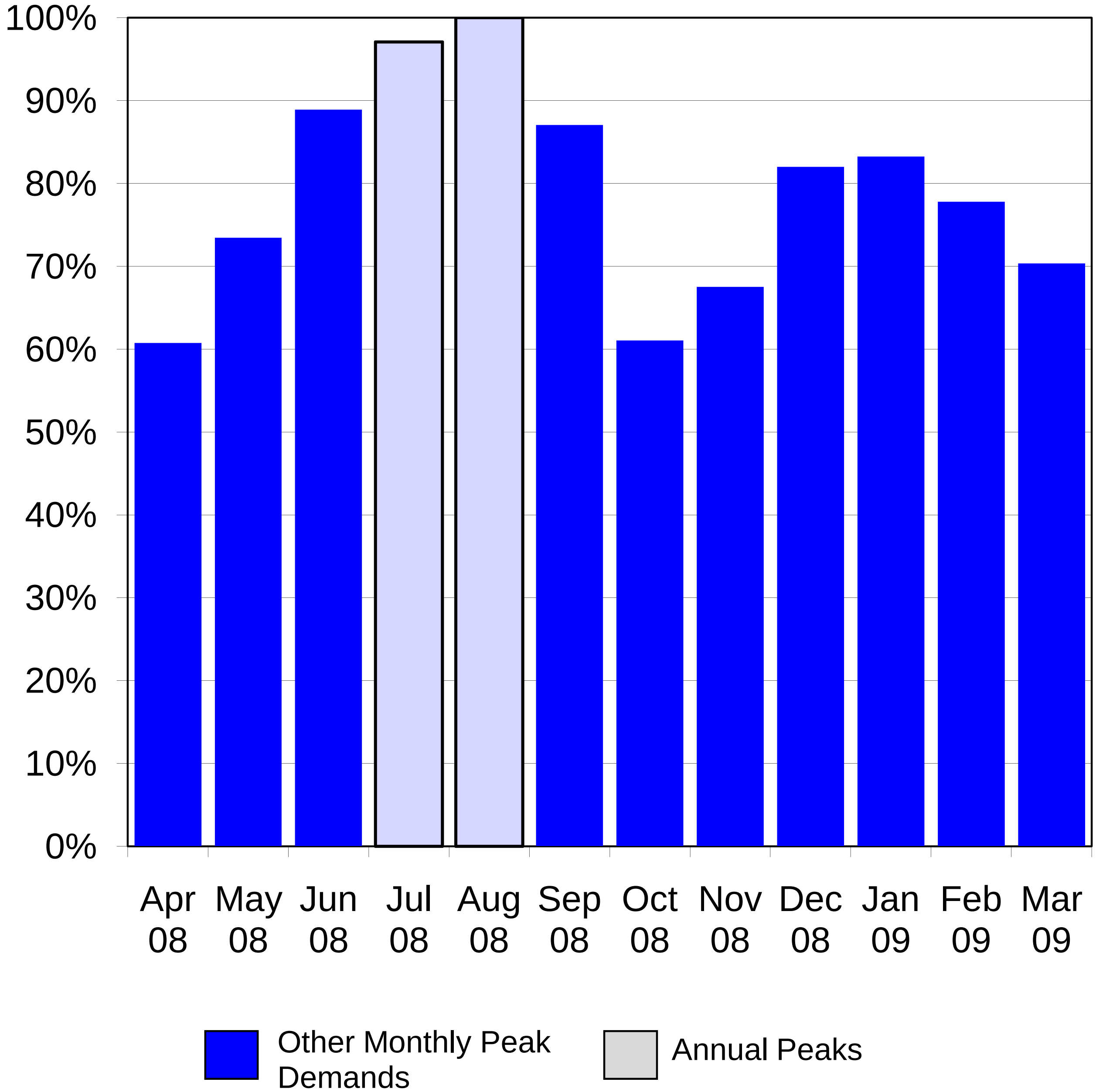
AmerenUE

Analysis of Ameren's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak For the Test Year Ended March 2009



Schedule MEB-COS-1

AmerenUE

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 2009

Line	Description	Total Company MW (1)	Percent (2)
1	January	6,850	83.3
2	February	6,400	77.8
3	March	5,788	70.3
4	April	4,997	60.7
5	May	6,043	73.4
6	June	7,315	88.9
7	July	7,988	97.1
8	August	8,228	100.0
9	September	7,165	87.1
10	October	5,025	61.1
11	November	5,554	67.5
12	December	6,749	82.0

Source: AmerenUE COS, System_CP Worksheet

AmerenUE

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended March 2009

Line	Description	Missouri Retail	Residential	Small General Service	Large General Service	Large Primary Service	Large Trans. Service
		(1)	(2)	(3)	(4)	(5)	(6)
1	Missouri System Peak	8,227,926					
2	Avg of 4 Highest Monthly NCP Values	8,386,375	3,931,844	925,569	2,393,739	647,426	487,797
3	Energy Sales with Losses - MWh	39,980,377	14,766,375	3,904,012	12,890,041	4,249,723	4,170,226
4	Average Demand - kW	4,563,970	1,685,659	445,663	1,471,466	485,128	476,053
5	Average Demand - Percent	1.000000	0.369341	0.097648	0.322409	0.106295	0.104307
6	Class Excess Demand - kW	3,822,405	2,246,185	479,905	922,273	162,298	11,744
7	Class Excess Demand - Percent	1.000000	0.587636	0.125551	0.241281	0.042460	0.003072
	Allocator:						
8	Annual Load Factor * Average Demand	0.554693	0.204871	0.054165	0.178838	0.058961	0.057858
9	(1-LF) * Excess Demand	0.445307	0.261679	0.055909	0.107444	0.018908	0.001368
10	Average and Excess Demand Allocator	1.000000	0.466549	0.110073	0.286282	0.077869	0.059226

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

System Annual Load Factor	55.47%
1 - Load Factor	44.53%

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

AmerenUE

Electric Cost of Service Allocation Study
at Present Rates
Includes MIEC Expense Adjustments and Associated Income Tax Adjustments

Line	Description	Missouri (1)	Residential (2)	Small Gen Serv (3)	Large G.S./ Small Primary (4)	Large Primary (5)	Large Trans (6)
1	BASE REVENUE	$ 2,205,595	$ 977,137	$ 251,620	$ 664,928	$ 172,754	$ 139,156
2	OTHER REVENUE	$ 60,511	$ 34,858	$ 6,185	$ 13,785	$ 3,470	$ 2,213
3	LIGHTING REVENUE	$ 31,252	$ 16,433	$ 3,528	$ 7,933	$ 2,034	$ 1,324
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 309,518	$ 114,436	$ 30,189	$ 99,755	$ 32,851	$ 32,287
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 2,606,876	$ 1,142,865	$ 291,521	$ 786,400	$ 211,110	$ 174,980
7	TOTAL PROD, T&D, CUST, AND A&G EXP	$ 1,794,748	$ 830,655	$ 187,590	$ 502,738	$ 149,513	$ 124,254
8	TOTAL DEPR AND AMMORT EXPENSES	$ 376,408	$ 207,652	$ 43,418	$ 90,629	$ 21,951	$ 12,759
9	MIEC ADJUSTMENTS (O&M Exp.)	$ (72,123)	$ (39,095)	$ (8,140)	$ (17,883)	$ (4,486)	$ (2,519)
10	MIEC ADJUSTMENTS (Deprec.Exp.)	$ (77,278)	$ (42,480)	$ (8,913)	$ (18,686)	$ (4,532)	$ (2,667)
11	MIEC ADJUSTMENTS (Net Fuel Exp.)	$ (46,131)	$ (17,078)	$ (4,501)	$ (14,858)	$ (4,891)	$ (4,803)
12	REAL ESTATE AND PROPERTY TAXES	$ 109,467	$ 58,578	$ 12,524	$ 27,323	$ 6,789	$ 4,252
13	INCOME TAXES (Calculated using Alternative Method)	$ 37,260	$ (28,618)	$ 8,524	$ 41,278	$ 6,852	$ 9,225
14	INCOME TAXES ASSOCIATED w/ADJUSTMENTS (Tax rate = 38.42713%)						
15	INCOME TAX ADJ. (O&M Exp.)	$ 27,715	$ 15,023	$ 3,128	$ 6,872	$ 1,724	$ 968
16	INCOME TAX ADJ. (Deprec. Exp.)	$ 29,696	$ 16,324	$ 3,425	$ 7,181	$ 1,742	$ 1,025
17	INCOME TAX ADJ. (Net Fuel Exp.)	$ 17,727	$ 6,563	$ 1,730	$ 5,710	$ 1,879	$ 1,846
18	PAYROLL TAXES	$ 21,484	$ 11,183	$ 2,352	$ 5,544	$ 1,500	$ 904
19	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -
20	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -
21	TOTAL OPERATING EXPENSES	$ 2,218,972	$ 1,018,706	$ 241,136	$ 635,847	$ 178,040	$ 145,243
22	NET OPERATING INCOME	$ 387,904	$ 124,159	$ 50,385	$ 150,553	$ 33,070	$ 29,737
23	GROSS PLANT IN SERVICE	$ 12,585,208	$ 6,734,601	$ 1,439,890	$ 3,141,330	$ 780,529	$ 488,858
24	RESERVES FOR DEPRECIATION	$ 5,527,036	$ 2,969,598	$ 634,265	$ 1,374,326	$ 336,412	$ 212,436
25	NET PLANT IN SERVICE	$ 7,058,172	$ 3,765,003	$ 805,625	$ 1,767,004	$ 444,118	$ 276,423
26	MATERIALS & SUPPLIES - FUEL	$ 313,702	$ 116,134	$ 30,610	$ 101,040	$ 33,258	$ 32,660
27	MATERIALS & SUPPLIES -LOCAL	$ 53,164	$ 35,198	$ 6,509	$ 9,661	$ 1,737	$ 59
28	CASH WORKING CAPITAL	$ (8,335)	$ (3,858)	$ (871)	$ (2,335)	$ (694)	$ (577)
29	CUSTOMER ADVANCES & DEPOSITS	$ (18,455)	$ (9,263)	$ (4,665)	$ (3,402)	$ (1,125)	$ -
30	ACCUMULATED DEFERRED INCOME TAXES	$ (1,396,804)	$ (747,458)	$ (159,810)	$ (348,649)	$ (86,629)	$ (54,257)
31	TOTAL NET ORIGINAL COST RATE BASE	$ 6,001,444	$ 3,155,755	$ 677,398	$ 1,523,319	$ 390,665	$ 254,308
32	RATE OF RETURN	6.464%	3.934%	7.438%	9.883%	8.465%	11.693%

Notes:
Off-System Sales Revenue Allocated on Energy.
Non-Fuel Production O&M Expenses Classified as Fixed O&M Expenses.
Transmission Plant and Expense Allocated using A&E-4NCP.
Intangible and General Plant Allocated using Factors Derived from Plant (A.F. 19) Rather than Expenses (i.e., A.F.35).
Income Taxes Calculated on the Taxable Income of Each Class.

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

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Adjusted Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 977,137	$ 3,155,755	$ 124,159	3.934%	61	$ 203,973	$ 79,814	$ 129,625	13.3%
2	Small GS	251,620	677,398	50,385	7.438%	115	43,784	(6,601)	(10,721)	-4.3%
3	Large GS/Small Primary	664,928	1,523,319	150,553	9.883%	153	98,460	(52,093)	(84,603)	-12.7%
4	Large Primary	172,754	390,665	33,070	8.465%	131	25,251	(7,820)	(12,700)	-7.4%
5	Large Transmission	139,156	254,308	29,737	11.693%	181	16,437	(13,300)	(21,600)	-15.5%
6	Total	$ 2,205,595	$ 6,001,444	$ 387,904	6.464%	100	387,904.0	$ 0	$ 0	0.0%

Source: Schedule MEB-COS-4

GRCF 1.624092

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Recommended Cost of Service Adjustments
Using MIEC's Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues	Move 20% Toward Cost Of Service	Adjust LTS to Cost Of Service	Total Cost of Service Adjustment	Adjusted Current Revenue	Percent of Adjusted Current Revenue
		(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	$ 977.1	$ 25.9	$ 8.2	$ 34.1	$ 1,011.2	45.21%
2	Small GS	251.6	(2.1)	2.1	(0.0)	251.6	11.25%
3	Large GS/Small Primary	664.9	(16.9)	5.6	(11.4)	653.6	29.22%
4	Large Primary	172.8	(2.5)	1.4	(1.1)	171.7	7.67%
5	Large Transmission	139.2	(4.3)	(17.3)	(21.6)	117.6	5.26%
6	Subtotal	$ 2,205.6	$ -	$ -	$ -	$ 2,205.6	98.60%
7	Lighting	31.3				31.3	1.40%
8	Total	$ 2,236.9				$ 2,236.9	100.00%

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Illustration of How a $137 Million Rate Increase Would be Allocated ($ in Millions)

Line	Rate Class	Current Revenues	Cost of Service Adjustment	Share of Rate Increase	Total Rate Change		Revenues After Increase
					Amount	Percent	
		(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	$ 977.1	$ 34.1	$ 61.9	$ 96.0	9.83%	$ 1,073.2
2	Small GS	251.6	(0.0)	15.4	15.4	6.11%	267.0
3	Large GS/Small Primary	664.9	(11.4)	40.0	28.7	4.31%	693.6
4	Large Primary	172.8	(1.1)	10.5	9.4	5.45%	182.2
5	Large Transmission	139.2	(21.6)	7.2	(14.4)	-10.35%	124.8
6	Subtotal	$ 2,205.6	$ -	$ 135.1	$ 135.1	6.12%	$ 2,340.7
7	Lighting	31.3		1.9	1.9	6.12%	33.2
8	Total	$ 2,236.9	$ -	$ 137.0	$ 137.0	6.12%	$ 2,373.9

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Illustration of How a $100 Million Rate Increase Would be Allocated ($ in Millions)

Line	Rate Class	Current Revenues (1)	Cost of Service Adjustment (2)	Share of Rate Increase (3)	Total Rate Change: Amount (4)	Total Rate Change: Percent (5)	Revenues After Increase (6)
1	Residential	$ 977.1	$ 34.1	$ 45.2	$ 79.3	8.12%	$ 1,056.4
2	Small GS	251.6	(0.0)	11.2	11.2	4.45%	262.8
3	Large GS/Small Primary	664.9	(11.4)	29.2	17.9	2.69%	682.8
4	Large Primary	172.8	(1.1)	7.7	6.6	3.81%	179.3
5	Large Transmission	139.2	(21.6)	5.3	(16.3)	-11.75%	122.8
6	Subtotal	$ 2,205.6	$ -	$ 98.6	$ 98.6	4.47%	$ 2,304.2
7	Lighting	31.3		1.4	1.4	4.47%	32.7
8	Total	$ 2,236.9	$ -	$ 100.0	$ 100.0	4.47%	$ 2,336.9

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Illustration of How a $200 Million Rate Increase Would be Allocated ($ in Millions)

Line	Rate Class	Current Revenues (1)	Cost of Service Adjustment (2)	Share of Rate Increase (3)	Total Rate Change Amount (4)	Total Rate Change Percent (5)	Revenues After Increase (6)
1	Residential	$ 977.1	$ 34.1	$ 90.4	$ 124.5	12.74%	$ 1,101.6
2	Small GS	251.6	(0.0)	22.5	22.5	8.92%	274.1
3	Large GS/Small Primary	664.9	(11.4)	58.4	47.1	7.08%	712.0
4	Large Primary	172.8	(1.1)	15.3	14.3	8.25%	187.0
5	Large Transmission	139.2	(21.6)	10.5	(11.1)	-7.97%	128.1
6	Subtotal	$ 2,205.6	$ -	$ 197.2	$ 197.2	8.94%	$ 2,402.8
7	Lighting	31.3		2.8	2.8	8.94%	34.1
8	Total	$ 2,236.9	$ -	$ 200.0	$ 200.0	8.94%	$ 2,436.9

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Illustration of How a $300 Million Rate Increase Would be Allocated ($ in Millions)

Line	Rate Class	Current Revenues (1)	Cost of Service Adjustment (2)	Share of Rate Increase (3)	Total Rate Change: Amount (4)	Total Rate Change: Percent (5)	Revenues After Increase (6)
1	Residential	$ 977.1	$ 34.1	$ 135.6	$ 169.7	17.37%	$ 1,146.9
2	Small GS	251.6	(0.0)	33.7	33.7	13.39%	285.3
3	Large GS/Small Primary	664.9	(11.4)	87.7	76.3	11.47%	741.2
4	Large Primary	172.8	(1.1)	23.0	21.9	12.69%	194.7
5	Large Transmission	139.2	(21.6)	15.8	(5.8)	-4.19%	133.3
6	Subtotal	$ 2,205.6	$ -	$ 295.8	$ 295.8	13.41%	$ 2,501.4
7	Lighting	31.3		4.2	4.2	13.41%	35.5
8	Total	$ 2,236.9	$ -	$ 300.0	$ 300.0	13.41%	$ 2,536.9

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Recommended Cost of Service Adjustments
Excluding Rate LTS
Using MIEC's Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move RES 20% Toward Cost Of Service (2)	Adjusted Current Revenue (3)	Percent of Adjusted Current Revenue (4)
1	Residential	$ 977.1	$ 25.9	$ 1,003.1	47.82%
2	Small GS	251.6	(2.6)	249.0	11.87%
3	Large GS/Small Primary	664.9	(20.3)	644.6	30.73%
4	Large Primary	172.8	(3.0)	169.7	8.09%
5	Lighting	31.3	-	31.3	1.49%
6	Total	$ 2,097.7	$ -	$ 2,097.7	100.00%

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Illustration of How a $200 Million Rate Increase Would be Allocated, Assuming That Rate LTS Revenues Are Set at a Specific Level of $111 Million ($ in Millions)

Line	Rate Class	Current Revenues (1)	Cost of Service Adjustment (2)	Share of Rate Change[1] (3)	Total Rate Change: Amount (4)	Total Rate Change: Percent (5)	Revenues After Increase (6)
1	Residential	$ 977.1	$ 25.9	$ 109.1	$ 135.0	13.8%	$ 1,112.2
2	Small GS	251.6	(2.6)	27.1	24.5	9.7%	276.1
3	Large GS/Small Primary	664.9	(20.3)	70.1	49.8	7.5%	714.7
4	Large Primary	172.8	(3.0)	18.5	15.4	8.9%	188.2
6	Lighting	31.3	-	3.4	3.4	10.9%	34.7
7	Subtotal	2,097.7	$ -	228.2	228.2	10.9%	2,325.9
8	LTS	139.2	-	(28.2)	(28.2)	-20.2%	$ 111.0
9	Total	$ 2,236.9	$ -	$ 200.0	$ 200.0	8.9%	$ 2,436.9

[1] Increase of $200 + LTS Reduction of $28.2.