Exhibit No.:	
Issues:	Cost of Service/Revenue Allocation/Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2024-0319
Date Testimony Prepared:	December 17, 2024

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	**)))))**	**Case No. ER-2024-0319**

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers

December 17, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11700

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	)	**Case No. ER-2024-0319**

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

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on her 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-2024-0319.

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

Maurice Brubaker

Maurice Brubaker

Subscribed and sworn to before me this 16th day of December 2024.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2027
Commission # 15024862

Tammy S Klossner

Notary Public

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

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In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	**Case No. ER-2024-0319**

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 the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor's Degree in Electrical Engineering from the Missouri University of Science and Technology (previously Missouri School of Mines and Metallurgy and the University of Missouri at Rolla), a Master of Science Degree in Engineering from Washington University, and a Master's Degree of Business Administration, also from Washington University. I have been a consultant in the field of utility contracts, rates and regulation since 1970. I have testified on a number of subjects including planning, reliability, cost of service, revenue allocation and rate design.

I have testified in over 30 utility jurisdictions, including Missouri. I have submitted testimony on many occasions, including in more than 180 cases during the past 20 years. Additional information is included in Appendix A to my 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"), a non-profit corporation that represents the interests of large consumers in Missouri rate matters.

I. INTRODUCTION AND SUMMARY

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to support an appropriate cost of service method and to support a more meaningful movement toward class cost of service than has been proposed by Ameren Missouri ("AMO").

Q IS MIEC SPONSORING ANY OTHER WITNESSES?

A Yes. My colleague, Jessica York, is filing testimony on cost of service and revenue allocation. My colleague, Chris Walters, filed testimony on cost of capital on December 3, 2024.

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.

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. AMO 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 AMO. These are the coincident peak methodology and the average and excess ("A&E") methodology.

4. AMO utilizes, for its generation allocation, the A&E method using four class non-coincident peaks. A reasonable alternative would be A&E using four coincident peaks. As shown in Ms. York's testimony, the difference in 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 or demands coincident with system peaks.

6. I recommend that in adjusting rates all classes should be moved one-third of the way toward cost of service.

7. For purposes of implementing the final rates in this case, all of the charges in the LPS Rate, except for the Low-Income Pilot Program Charge, should receive the same percentage change.

<u>II. COST OF SERVICE PROCEDURES</u>

<u>Overview</u>

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.

<u>Electricity Fundamentals</u>

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:

- With limited exceptions, it cannot be economically 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 of 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 kilowatts ("kW")) are important, and both vary significantly from class to class.

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.

Second, 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 kW 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.

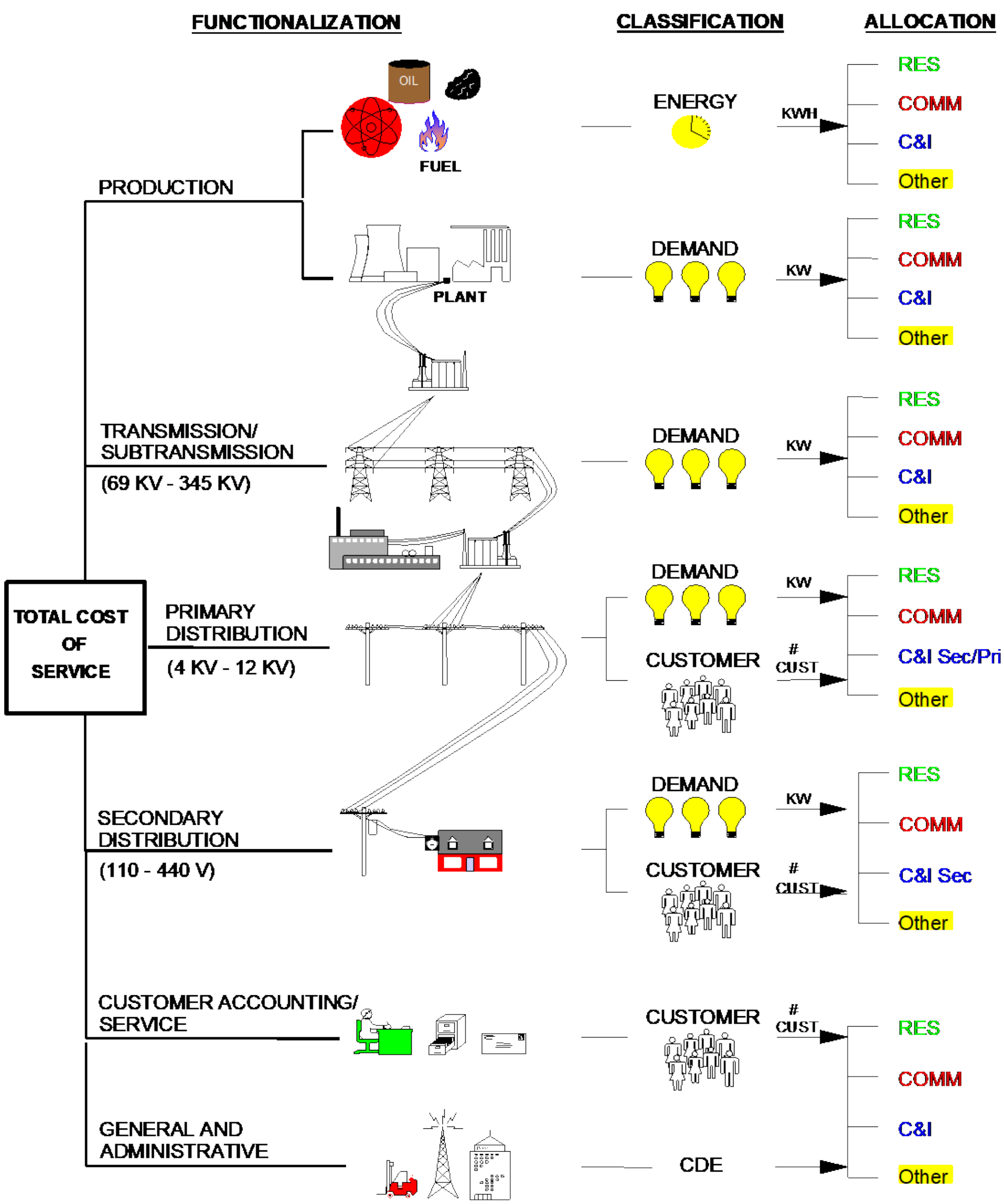
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWh. To see one reason why this isn't accurate, consider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

The tomatoes we buy at the supermarket, say for about $2.00 a pound, might originally come from Florida, where they are grown, 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 kW demands whenever they occur.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



III. 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, distribution, 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 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 door 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 costs to the utility are avoided. (Actually, the reason the utility does not bear these costs is that they are borne by the customer who must invest in the 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 <u>peak</u> demands on the system. Thus, production plant investment is usually classified as demand related. **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) that the utility must install to satisfy its obligation-to-serve requirement.

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

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

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

A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to construct a system's electrical pathways that comply with local or national safety and reliability codes, and to attach customers to that system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

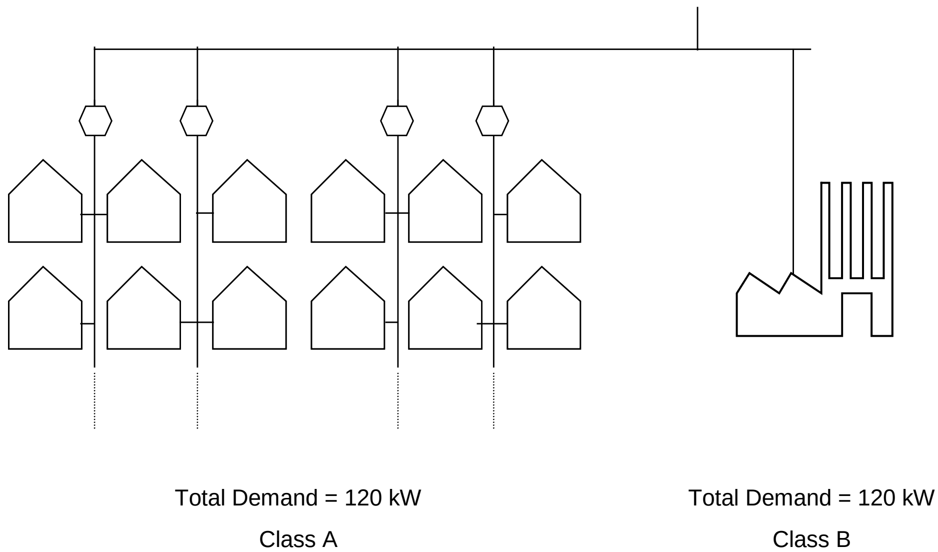
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10 kW load, having a total demand of 120 kW. This is the same total demand as is imposed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

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

To the extent that the distribution system components must be sized to accommodate additional load beyond the capacity of the system required by local or national safety and reliability codes, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2

Classification of Distribution Investment



Demand vs. Energy Costs

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

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

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

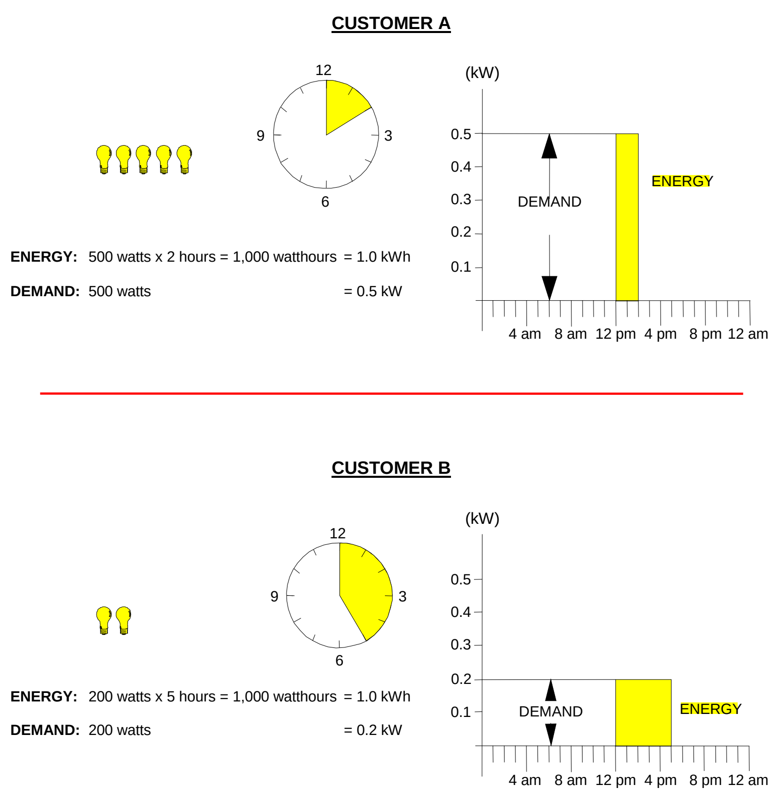
Although both customers had precisely the same kWh energy usage, Customer A’s kW demand was 2.5 times Customer B’s. Therefore, the utility must install 2.5 times as much generating capacity, lines and substations for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

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 across time. 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



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 the customer's 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 and a more efficient use of capacity. 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. Factors are developed to allocate the demand, energy and customer-related 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 energy-related 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.

For demand-related costs, we construct an allocation factor by looking at the important class demands for generation, transmission, and the various voltage levels in the distribution system, recognizing which customers are served at each voltage level (i.e. transmission voltage, primary voltage and secondary voltage).

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 customer classes 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.

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

A Yes, the following Table 1 shows the cost-based revenue requirement for each customer class. Note that the cost, per unit, to serve the Large GS/Small Primary and Large Primary customers is significantly less than the cost to serve the other customers. In fact, similar relationships hold true on any electric utility system.

TABLE 1
Revenue Requirement for Major Classes
Average and Excess Method
(Dollars in Millions)

Rate Class	Cost-Based Revenue	Energy Sales (MWh)	Cost per kWh
	(1)	(2)	(3)
Residential	$ 1,809.6	13,316,127	13.59 ¢
Small GS	373.0	3,238,553	11.52
Large GS/Small Primary	874.1	10,892,656	8.02
Large Primary	218.0	3,678,892	5.93
Total	$ 3,274.7	31,126,227	10.52 ¢

Sources:
(1) Direct Testimony of Nicholas Bowden, Table 6
(2) Schedule NSB-D1

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

The Large Primary customers have a higher load factor and take service at a higher voltage than other classes. 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.

Since these customers take service at a higher voltage level, this means that they do not cause the utility to incur the costs associated with lower voltage distribution. Losses incurred in providing service also are lower.

Utility System Load Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

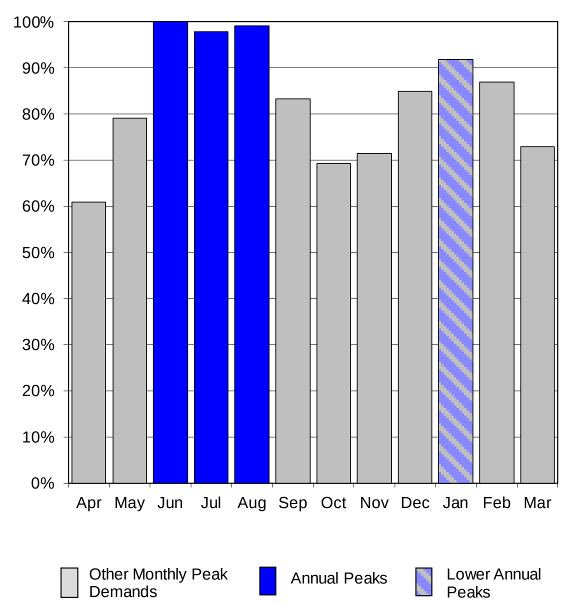
A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed, or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for AMO Missouri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

Figure 4

AMEREN MISSOURI

Case No. ER-2024-0319

Analysis of Ameren's (Missouri) Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended March 2024



This shows the monthly system peak demands for the test year used in the study. The highlighted bars show the months in which the highest peaks occurred.

This analysis shows that summer peaks dominate the AMO system. (This same information is presented in tabular form on Schedule MEB-COS-2.) The system peak occurred in June, with a just slightly lower peak demand in August. The July peak was 97.9% of the annual peak. The fourth highest peak occurred in January. The 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 cause 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 AMO SYSTEM?

A As noted, the AMO 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 most 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 ALLOCATION METHODS ARE MOST FREQUENTLY USED?

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.

Q WHAT IS THE A&E METHOD?

A Unlike the coincident peak method which relies strictly on a class's relative contribution to one or more utility peaks, the A&E method is one of a family of methods that 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.

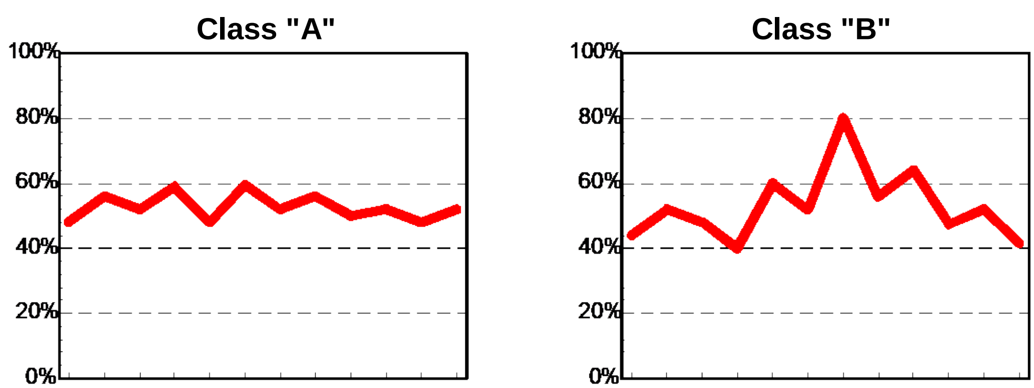
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability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



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

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 maximum demands of its customers. There also may be higher costs as a result of the greater variability in 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 METHOD DO YOU RECOMMEND FOR GENERATION AND TRANSMISSION?

A First, in order to reflect cost-causation the allocation method must give predominant weight to loads occurring during the peak months. Loads during these months (the peak loads) are the primary driver that has caused, and continues to cause, the utility to maintain and/or 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 months, or a version of an A&E allocation that uses class non-coincident peak loads occurring

[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.

during the peak months, would be most appropriate to reflect these characteristics. The results of both methods should be similar as long as only peak period loads are used. Like Ameren Missouri, 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.

Ms. York provides more detail on the allocations.

IV. 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.

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 (Ameren Missouri 2020 IRP, MO PSC Case. No. EO-2021-0021, Chapter 8). The costs expended pursuant to the Missouri Energy Efficiency Investment Act ("MEEIA") are likely to exceed $1 billion over the next ten 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 PURELY A COST-BASED ALLOCATION?

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

Q HAVE YOU REVIEWED AMO'S COST OF SERVICE RESULTS AND THE EXTENT TO WHICH EACH CUSTOMER CLASS REQUIRES A CHANGE IN RATES IN ORDER TO REACH AMO'S REQUESTED REVENUE REQUIREMENT?

A Yes, this is summarized in my Table 2 which is from Table 6 on page 26 of the Direct Testimony of AMO's witness Nick Bowden.

Table 2 – Cost-Based Rate Changes by Customer Class ($Millions)

Customer Class	Equal Rate of Return Revenue Requirement	Current Revenue Requirement	Change Required in Dollars	Change Required in Percentage
1M	$1,809.6	$1,458.5	$351.1	24.1%
2M	$373.0	$330.5	$42.5	12.8%
3M & 4M	$874.1	835.8	38.3	4.6%
11M	$218.0	$219.8	-$1.8	-0.8%
5M	$53.7	$39.2	$14.5	37.0%
6M	$4.6	$3.0	$1.6	56.9%
Total	$3,333.0	$2,886.86	$446.2	15.46%

Q WHAT DOES THIS TABLE SHOW?

A It shows that AMO's rates are significantly different from the allocated cost of service for each rate schedule. If all rates were currently covering their cost of service, nothing more and nothing less, the changes required shown in the final column would all be equal to 15.46%. However, they are not. Setting aside the lighting classes (5M and 6M) the required changes in revenues to reach cost of service at AMO's claimed revenue requirement is from a 24.1% rate increase for the residential class (1M) to a 0.8% DECREASE (Schedule 11M). While it is customary to find that all of the major customer classes differ from costs to some extent, the extent of the differences and the range of the differences here for AMO are exceptionally large.

Q DOES AMO RECOGNIZE THE EXISTENCE OF THESE LARGE DISPARITIES?

A Yes, AMO acknowledges them.

Q ARE THE ADJUSTMENTS THAT AMO PROPOSE ADEQUATE TO MAKE SIGNIFICANT MOVEMENT TOWARD COST OF SERVICE?

A No. While it is gratifying to see that AMO has finally recognized that it has a major imbalance problem in its rates, and while we appreciate AMO making some movement, the movement is insufficient to make a major difference in the relationship between rates and costs for the major customer classes.

Q PLEASE ELABORATE.

A AMO's spread of the revenue requirement increase is shown in my Table 3 which is from Table 8 on page 31 of Mr. Bowden's Direct Testimony.

Table 3 – AMO's Revenue Requirement Adjustments

Customer Class	Normalized Retail Revenues	Requested Revenue Requirement	Requested Revenue Adjustment	Percentage Increase
1M	1,459,656,650	1,689,782,220	230,125,070	15.77%
2M	330,496,306	381,686,865	51,190,559	15.49%
3M	588,810,561	680,101,832	91,291,271	15.50%
4M	244,460,840	280,981,595	36,520,754	14.94%
11M	214,054,267	244,488,305	30,434,038	14.22%
5M	39,182,322	45,260,353	6,078,030	15.51%
6M	2,949,574	3,406,241	456,667	15.48%
MSD	85,992	99,276	13,284	15.45%
Total	2,879,696,512	3,325,806,685	446,110,173	15.49%

Q WHAT DOES THIS ANALYSIS SHOW?

A As to the major customer classes, very little movement is proposed. For the residential class, which requires an increase that is 8.64 percentage points above the average (24.1% - 15.46%) to reach cost of service, AMO's proposal has the residential class exceeding the system average increase by only 0.28 percentage points (15.77% -

15.49%). At this glacial pace, it would take 30 rate cases to bring the residential class up to cost of service.

Q WHAT IS THE SITUATION WITH RESPECT TO THE LARGE PRIMARY CLASS RATE 11M?

A As shown on Mr. Bowden's Table 8 and in my Table 3 AMO proposes to give Rate 11M a 14.22% increase which is only 1.27 percentage points (15.49% - 14.22%) below the average.

As shown on Mr. Bowden's Table 6, and my Table 2, Rate 11M would require a decrease of 0.8 percentage points to achieve cost of service at AMO's proposed revenue requirement. That is 16.29 percentage points (15.49% to 0.80%) below system average. At this rate of convergence, it would take more than 12 rate cases to bring Rate 11M down to cost of service.

Q DO YOU HAVE ANY SPECIFIC RECOMMENDATIONS?

A Yes. After reviewing the analysis presented by my colleague, Ms. York, I recommend that the increases be allocated in order to move each class one-third of the way toward its cost of service.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

<u>Qualifications 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 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, finance, mathematics, computer science and business.

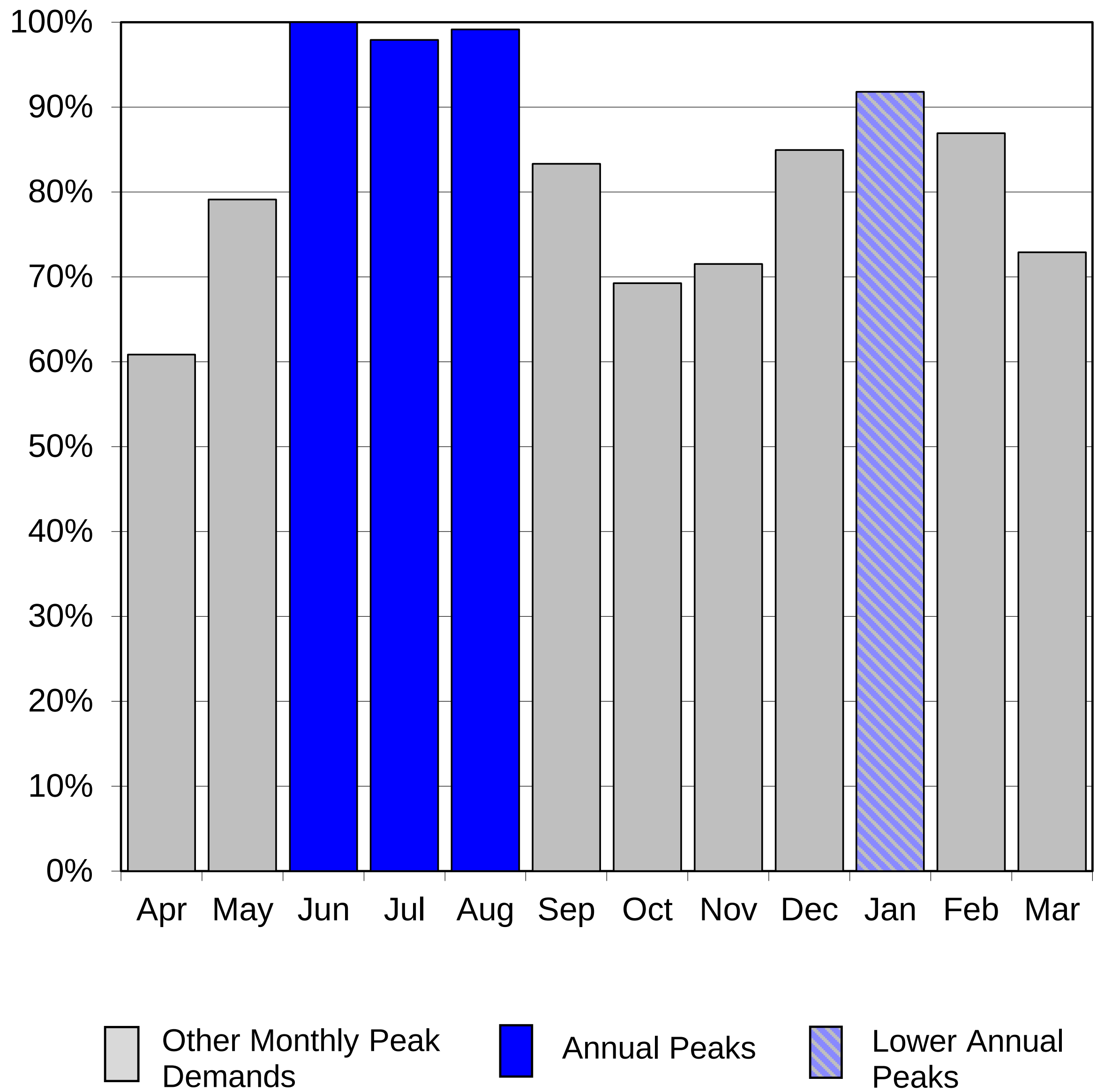
Brubaker & Associates, Inc. and its predecessor firm have participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has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

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.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

AMEREN MISSOURI
Case No. ER-2024-0319

Analysis of Ameren's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) For the Test Year Ended March 2024



Schedule MEB-COS-1

AMEREN MISSOURI
Case No. ER-2024-0319

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 2024

Line	Description	Total Company MW (1)	Percent (2)
1	April	3,873	60.8%
2	May	5,035	79.1%
3	June	6,365	100.0%
4	July	6,231	97.9%
5	August	6,310	99.1%
6	September	5,304	83.3%
7	October	4,407	69.2%
8	November	4,553	71.5%
9	December	5,407	84.9%
10	January	5,842	91.8%
11	February	5,533	86.9%
12	March	4,639	72.9%

Source: Ameren Missouri COS, System_CP Worksheet