Exhibit No.:	
Issue:	Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Industrials
Case No.:	ER-2011-0004
Date Testimony Prepared:	March 16, 2011

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	**)**	**File No. ER-2011-0004** Tariff No. YE-2011-0154

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Enbridge Energy, LP
Explorer Pipeline Company
Praxair, Inc.

March 16, 2011

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9358

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

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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 Enbridge Energy, LP, Explorer Pipeline Company and Praxair, Inc. in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and schedules which were prepared in written form for introduction into evidence in the Missouri Public Service Commission's Case No. ER-2011-0004.

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 14th day of March, 2011.

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

Tammy S Klossner

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

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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 testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Enbridge Energy, LP, Explorer Pipeline Company and Praxair, Inc. (collectively "Industrials"). These companies purchase substantial amounts of electricity from The Empire District Electric Company ("Empire") and the outcome of this proceeding will have an impact on their cost of electricity.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of a class cost of service study for Empire, to explain how the study should be used, to recommend an appropriate allocation of any rate increase, and to make rate design recommendations.

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 Empire. 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.

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. Empire exhibits significant summer and winter 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 Empire. These are the coincident peak methodology and the average and excess ("A&E") methodology.

4. 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.

5. The results of my class cost of service study are summarized on Schedule MEB-COS-4. Schedule MEB-COS-5 shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates.

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

7. Adjustments to the individual elements of the LP rate should be much more moderate than proposed by Empire. Empire's proposal would cause increases to some customers to approach 50%, which is far too large of an increase to be imposed in this case.

8. For both the LP rate and the GP rate, the final rate design should limit the increase to any particular rate element to not more than 1.5 times the average percentage increase to the rate schedule.

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 GOOD OR SERVICE?

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 and 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 2,000 MW of electricity, the utility must have at least 2,000 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 <u>service</u> of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

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

Q DO ALL CUSTOMERS RECEIVE THE SAME QUALITY OF SERVICE?

A No. While most customers receive what is known as “firm” service, many utilities, including Empire, also offer the option of “interruptible” service. On the Empire system, Praxair takes approximately 95% of its requirements on an interruptible basis, and only the remaining 5% on a firm basis. Praxair has been an interruptible customer of Empire for many years, and Empire and Praxair have recently renegotiated Praxair's interruptible contract.

Q PLEASE EXPLAIN IN MORE DETAIL THE NATURE OF INTERRUPTIBLE POWER AND HOW IT BENEFITS THE UTILITY SYSTEM AND THE OTHER CUSTOMERS.

A Interruptible power is power that is provided to customers on the basis that its availability can be withdrawn for the benefit of service to firm customers, if the power is required to provide reliable service to firm customers. In other words, interruptible power is sold to the interruptible customers when it is not needed to supply firm load customers. The conditions under which the interruptible power may be withdrawn from the interruptible customer are defined in the agreements under which the utility sells power on an interruptible basis.

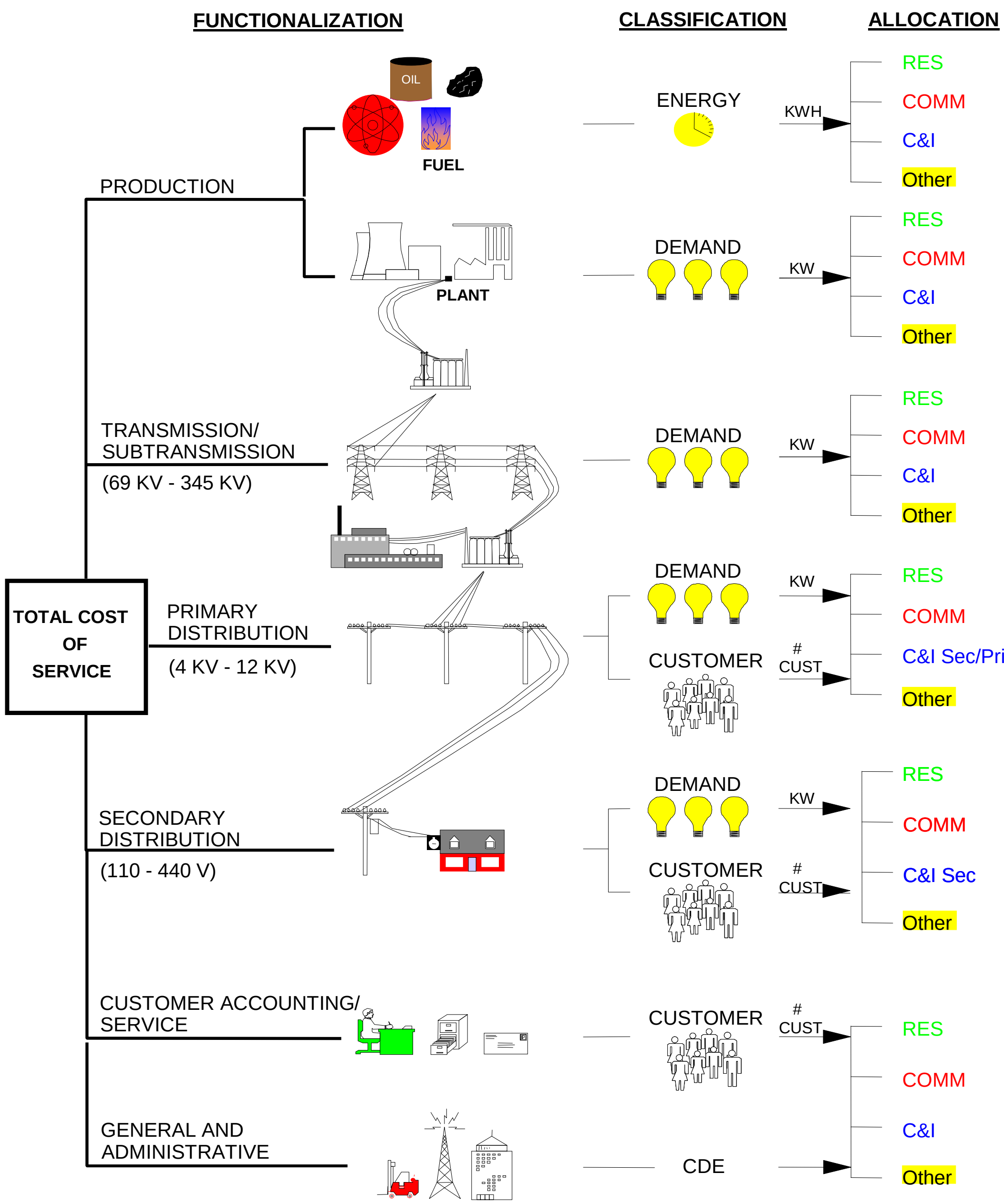
From a planning perspective, a utility does not need to plan generation resources to serve interruptible load. Rather, the planning process basically focuses on the needs of firm customers. It is the peak loads of the customers which drive the amount of generating resources required to provide firm service to firm customers. (Empire is summer peaking, but also has a very high winter load as well.)

Having arranged for that amount of generation resources (installed generation capacity and/or firm purchased power) necessary to provide firm service, a utility is able to sell power on an interruptible basis to customers willing to accept less than firm service. The power is sold to the interruptible customers when it is not needed to supply the needs of the firm customers. This obviously allows the utility to operate with a smaller amount of generation capacity than would be the case if all load were served on a firm basis.

I will explain in more detail later in this testimony how Praxair's interruptible load characteristics should be considered in this case.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT A 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 1,000 MW – it must install and/or contract for enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance ("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., 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.

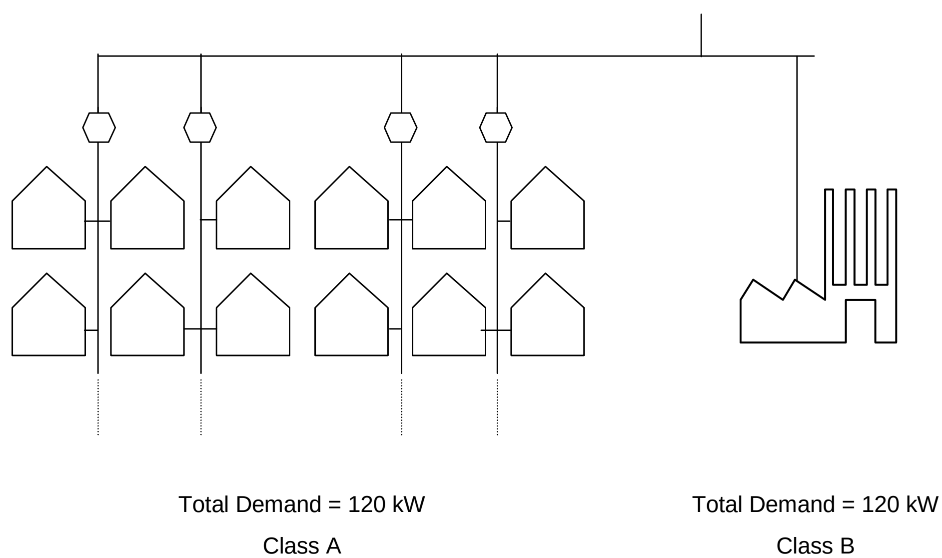
Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

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>



Demand vs. Energy Costs

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

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

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

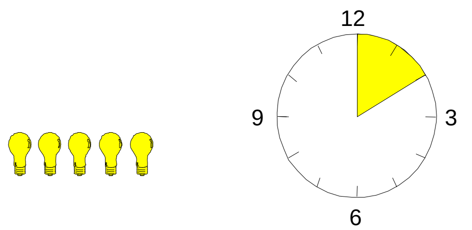
Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

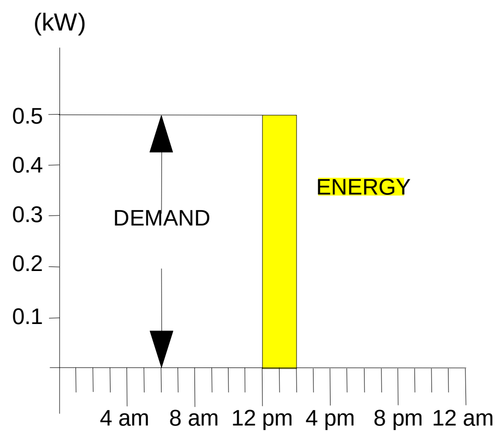
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

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

Figure 3
DEMAND VS. ENERGY

CUSTOMER A

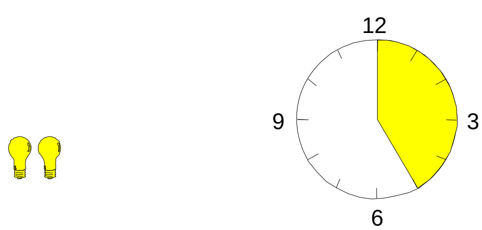


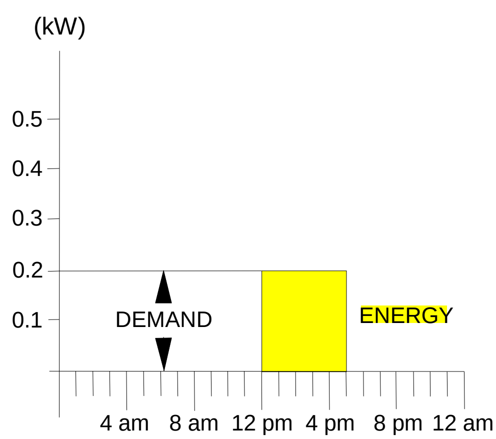


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

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. For demand-related costs, we construct an allocation factor by looking at the important class demands.

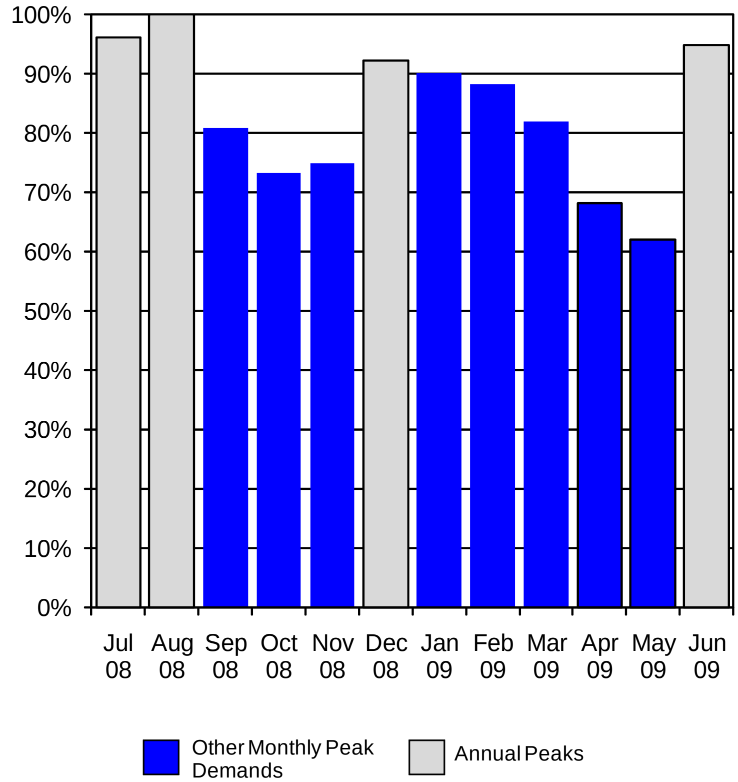
Utility System Characteristics

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 Empire's Missouri jurisdiction are shown on Schedule MEB-COS-1. For convenience, it is also shown here as Figure 4.

Figure 4
EMPIRE DISTRICT ELECTRIC COMPANY

**Analysis of Empire District's (Missouri) Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended June 2009**



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 both summer and winter peaks dominate the Empire 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 many other months. The July peak was close, at 96% of the annual peak. The peaks in June and December were 5% and 8%, respectively, lower than the annual peak.

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 EMPIRE SYSTEM?

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

Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?

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

The coincident peak method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation.

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]

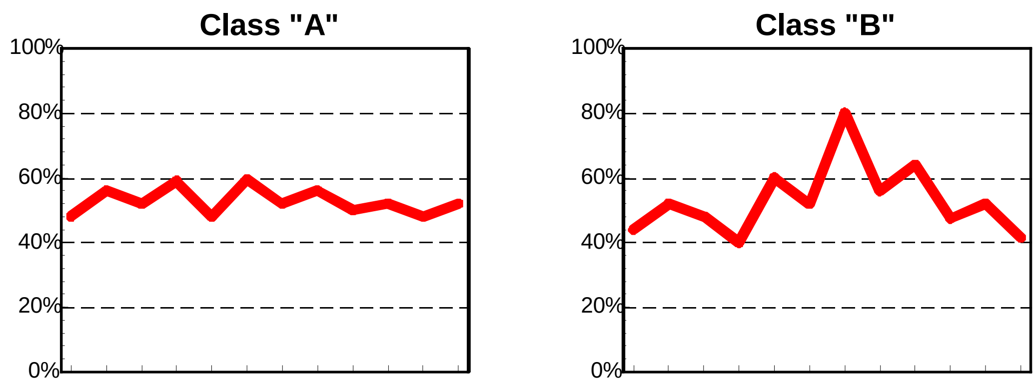
[1] NARUC Electric Utility Cost Allocation Manual, 1992, page 81.

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

Load Patterns



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 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

[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.

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 peak months. Loads during these months 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 months, or a version of an A&E cost of service study that uses class non-coincident peak loads occurring during the peak months, would be most appropriate to reflect these characteristics. The results should be similar as long as only peak period 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.

Although I believe that an A&E study using the four highest peak months (as has been adopted in the case of Ameren Missouri) would be appropriate for Empire, it is true that Empire's monthly load pattern is somewhat flatter than Ameren Missouri's. For purposes of this case, and to be conservative, I will utilize the loads from each of the 12 months for purposes of my primary class cost of service study.[3] Schedule

[3]Empire uses loads from each of the 12 months. In this case, it has used a coincident peak form of A&E; whereas, in prior cases, it has used the non-coincident peak version of A&E.

MEB-COS-3 shows the derivation of the A&E demand allocation factor utilizing the 12 monthly non-coincident peaks for each class.

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 12 non-coincident peaks for each class and 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 class non-coincident peak demand shown on line 2 minus the class 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 annual 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 "components" 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, which reflects results at present rates.

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

A Schedule MEB-COS-4 is a summary of the key elements and the results of the class cost of service study. The top section of the schedule shows the revenues, expenses and operating income based on an A&E-12NCP cost of service study.

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

Q HOW HAVE YOU TREATED PRAXAIR IN THIS STUDY?

A For purposes of this study, I have ignored the fact that Praxair is an interruptible customer. As a result, Praxair has been allocated full generation and transmission costs without regard to the interruptible nature of its load. In calculating the rate of return, however, the revenues used for Praxair are before the subtraction of the credit which Praxair receives for its interruptibility. This approach for interruptible customers is based on the concept that the service should first be priced as firm, with the interruptible credit separately determined, and not derived from the cost of service study results. (As discussed later, I have prepared an alternate study that explicitly recognizes Praxair's interruptibility in order to test the cost basis for the rate.)

Q DID EMPIRE SUBMIT A CLASS COST OF SERVICE STUDY?

A Yes. Empire submitted a class cost of service study. In testimony, Empire's witness Dr. Overcast indicated that he had used the A&E method for allocating generation and transmission costs. A close look at the Company's study, however, reveals that he in fact did not use the A&E methodology. Rather, he used an average and peak methodology which double counts the average demand in the development of the allocation factor. The result is to substantially over-allocate costs to high load factor customers. I will address this issue in more detail in my rebuttal testimony.

Q HAVE YOU USED EMPIRE'S STUDY?

A I have used the study framework as a basis for preparing my cost of service study. As explained below, I have developed cost of service studies using different allocations for generation and transmission fixed costs.

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

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

Q HAVE YOU PREPARED ANY COST OF SERVICE STUDIES BESIDES THE A&E-12NCP STUDY PRESENTED IN SCHEDULE MEB-COS-4?

A Yes. I have prepared an A&E study using 4 NCPs. In addition, I have prepared a cost of service study utilizing the 12 monthly non-coincident peaks but explicitly recognizing the interruptible nature of Praxair's demand. During the months of April through September Praxair's load is interruptible down to 300 kilowatts, and during the months of October through March, down to 480 kilowatts. To be conservative, I have set Praxair's demands at 500 kW for purposes of this cost of service study and for Praxair's revenues have subtracted the interruptible credit that it receives.

The derivation of the generation capacity allocation factors and the results of each cost of service study are presented in the appendices to my schedules.

Q PLEASE REFER TO THE APPENDICES TO YOUR SCHEDULES AND EXPLAIN THE ADDITIONAL COST OF SERVICE STUDIES PRESENTED THERE.

A MEB-COS-Appendix 1 is a study based on the A&E method, but using 4 NCPs. Page 1 is the summary of the results, and is in the same format as Schedule MEB-COS-4. Page 2 shows the increases and decreases on a revenue neutral basis required to move each class to cost of service, and is in the same format as Schedule MEB-COS-5. Page 3 is the development of the A&E allocation factor, and is comparable to Schedule MEB-COS-3.

Q HOW DO THE RESULTS OF THE A&E-4NCP STUDY COMPARE TO THE RESULTS OF THE A&E-12NCP STUDY?

A A comparison of the rates of return and the increases and decreases required to move each class to cost of service reveals that the results of both studies are very consistent. In both cases the Residential class requires an increase of about 10%, while all other major customer classes would require a decrease in revenues.

Q PLEASE EXPLAIN THE ALTERNATE COST OF SERVICE STUDY SHOWN IN SCHEDULE MEB-COS-APPENDIX 2.

A This schedule is an A&E study that uses 12 NCPs, but allocates generation fixed costs to Praxair only on the basis of its firm load. The revenues used to measure the profitability of Praxair in this study are after subtracting the interruptible credit that Praxair receives for its interruptibility.

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

A The results are significantly different from the results of the other studies only for Praxair. Considering the true interruptible nature of Praxair's load when allocating generation fixed costs, the rate of return on Praxair is quite high because the interruptible credit received is substantially smaller than the embedded cost of the generation capacity that is allocated to Praxair. This analysis clearly confirms that the amount of the interruptible credit which Praxair receives is substantially less than would be justified on a pure cost of service basis.

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.

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 Schedule MEB-COS-4, movement of all classes to cost of service will require an increase to the Residential class and a decrease to almost 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 $19 million, or 10%, in order to move to cost of service. All other classes would require a corresponding decrease. For the major classes, the decreases range from about 2% to 15%.

Q HOW DOES EMPIRE PROPOSE TO ADJUST REVENUES?

A Empire proposes a non-uniform allocation of its requested increase. Because this non-uniform allocation is based on Empire's faulty class cost of service study, it is not an appropriate basis for a class revenue distribution.

Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF EMPIRE'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 Empire 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 a cost of service adjustment that moves classes roughly 25% of the way toward cost of service. Column 4 shows the adjustment that moves classes roughly 50% of the way toward cost of service. This range 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 revenue-neutral increase of 2.7% to 5.3% 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 25% to 50% of the way toward cost of service, which limits the Residential class revenue-neutral increase to 2.7% to 5.3% (as compared to the 10% 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.

Specific Rate Design

Q ARE YOU OFFERING A PROPOSAL FOR HOW TO ADJUST THE COMPONENTS WITHIN RATES GP AND LP TO REFLECT ANY INCREASE TO THESE RATE SCHEDULES?

A Yes. As Empire has noted, in both schedules the energy charges are high in relation to variable costs, and the demand charges are low in relation to fixed costs. Empire makes radical adjustments to the charges in the current tariffs, particularly in Rate LP, where it proposes to increase demand charge revenues by about 88%, and facilities charge revenues by 218%. At the same time, it proposes about a 25% reduction in energy charges. These charges should be considered in light of Empire's proposed overall almost 15% increase in Rate LP.

Q WHAT IS YOUR RECOMMENDED RATE DESIGN APPROACH FOR RATE LP?

A For Rate LP, my recommendation is that it receive essentially the overall system average percentage increase. In that context, I would propose to increase the demand charge and facilities charge components of the LP tariff by not more than 150% of the overall average increase assigned to the LP class. This will permit a movement in the right direction without creating the dramatic impacts on customers that Empire's proposed rate design would produce.

Q **WHAT DO YOU MEAN BY DRAMATIC IMPACTS?**

A As an example, two of the accounts of the industrial intervenors that are served on Rate LP would experience nearly a 25% overall increase, while another one would experience almost a 50% increase because of the dramatic changes that Empire has incorporated in its proposed LP tariff. These increases are far too large and much more moderation should be employed in moving the rates closer to cost of service.

Q **DO YOU HAVE ANY RECOMMENDATIONS FOR RATE GP?**

A Empire's proposal for Rate GP is much more modest. It adjusts the energy and demand charges in approximately the same proportions, but proposes to more than double the facilities charges. My recommendation would be that the facilities charges not be increased more than 150% of the average increase assigned to the GP rate as a result of this case.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

Appendix A

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

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

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

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

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

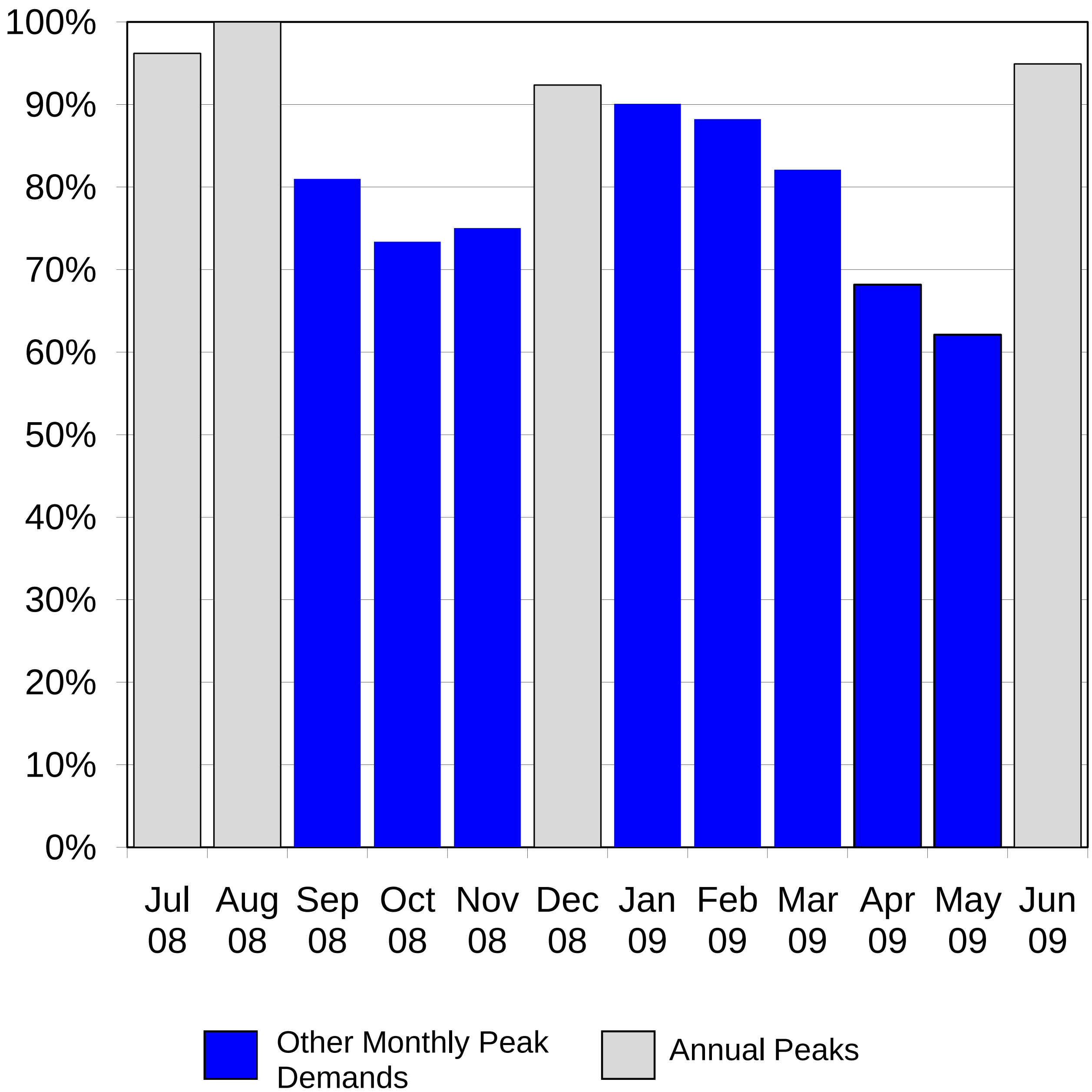
Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been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

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

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

EMPIRE DISTRICT ELECTRIC COMPANY

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



EMPIRE DISTRICT ELECTRIC COMPANY

Analysis of Empire District's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended June 2009

Line	Description	Missouri Retail MW (1)	Percent (2)
1	July 2008	943	96.2
2	August	980	100.0
3	September	794	81.0
4	October	719	73.4
5	November	735	75.0
6	December	905	92.4
7	January 2009	883	90.1
8	February	865	88.3
9	March	805	82.1
10	April	668	68.2
11	May	609	62.1
12	June	931	94.9

Source: From workpapers, file name "Datasheet", tab name "MOGen".

EMPIRE DISTRICT ELECTRIC COMPANY

Development of
Average and Excess Demand Allocator
Based on 12 Non-Coincident Peaks
For the Test Year Ended June 2009

Line	Description	Missouri Retail	Residential Rate RG	Commercial Service Rate CB	Commercial Service-Heating Rate SH	General Power Rate GP	Praxair Rate SC-P	Total Electric Building Rate TEB	Feed Mill Rate PFM	Large Power Rate LP	Misc. Service Rate MS	Street Lights Rate SPL	Private Lights Rate PL	Special Lights Rate LS
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Missouri System Peak - kW	980,129	493,238	91,159	22,442	182,077	92	70,608	116	120,328	68	-	-	-
2	Avg of 12 Highest Monthly NCP Values - kW	916,538	446,613	78,462	21,165	154,636	8,635	80,414	204	115,987	68	4,677	4,585	1,092
3	Energy Sales with Losses - MWh	3,462,347	1,714,543	317,310	98,866	862,757	65,656	403,215	474	648,677	676	16,601	15,862	849
4	Average Demand - kW	473,229	195,724	36,223	11,286	98,488	7,495	46,029	54	74,050	77	1,895	1,811	97
5	Average Demand - Percent	1.000000	0.413593	0.076543	0.023849	0.208120	0.015838	0.097266	0.000114	0.156478	0.000163	0.004005	0.003826	0.000205
6	Class Excess Demand - kW	443,309	250,889	42,239	9,879	56,148	1,140	34,385	150	41,937	(9)	2,782	2,774	995
7	Class Excess Demand - Percent	1.000000	0.565946	0.095282	0.022285	0.126656	0.002572	0.077564	0.000338	0.094600	(0.000021)	0.006275	0.006258	0.002245
	Allocator:													
8	Annual Load Factor * Average Demand	0.482823	0.199692	0.036957	0.011515	0.100485	0.007647	0.046962	0.000055	0.075551	0.000079	0.001934	0.001847	0.000099
9	(1-LF) * Excess Demand	0.517177	0.292694	0.049278	0.011525	0.065504	0.001330	0.040114	0.000175	0.048925	(0.000011)	0.003245	0.003236	0.001161
10	Average and Excess Demand Allocator	1.000000	0.492386	0.086235	0.023040	0.165989	0.008977	0.087077	0.000230	0.124476	0.000068	0.005179	0.005084	0.001260

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

System Annual Load Factor	48.28%
1 - Load Factor	51.72%

Source: Datasheet.xls

Schedule MEB-COS-3

EMPIRE DISTRICT ELECTRIC COMPANY

Cost of Service Based on
Average and Excess Demand Allocator,
12 Non-Coincident Peaks
For the Test Year Ended June 2009
($000)'s

Line	Description	Missouri Retail	Residential Rate RG	Commercial Service Rate CB	Commercial Service-Heating Rate SH	General Power Rate GP	Praxair Rate SC-P	Total Electric Building Rate TEB	Feed Mill Rate PFM	Large Power Rate LP	Misc. Service Rate MS	Street Lights Rate SPL	Private Lights Rate PL	Special Lights Rate LS
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Revenue from Sales	395,791	181,660	37,570	9,901	75,690	3,632	35,320	75	45,564	62	1,768	4,417	133
2	Other Revenues	8,823	3,332	603	159	1,414	64	673	1	1,706	1	819	46	6
3	Total Revenues	404,615	184,992	38,173	10,059	77,104	3,697	35,992	76	47,270	62	2,588	4,462	139
4	O&M Expense	239,559	114,599	20,981	5,661	41,913	2,637	19,953	34	30,999	36	1,238	1,361	147
5	Depreciation Expense	54,122	29,849	5,359	1,263	7,539	282	3,736	10	5,224	4	355	432	69
6	Other Taxes	15,637	8,581	1,596	373	2,150	86	1,075	3	1,507	1	110	136	19
7	Income Tax	23,276	4,963	2,597	745	7,942	193	3,381	9	2,387	7	246	859	(53)
8	Total Expenses	332,594	157,992	30,533	8,042	59,544	3,198	28,145	55	40,117	49	1,949	2,787	182
9	Operating Income	72,020	27,000	7,640	2,017	17,560	498	7,847	21	7,153	14	638	1,675	-43
10	Interest on Customer Deposits	(321)	(255)	(47)	(8)	(8)	0	(3)	(0)	0	0	0	0	(0)
11	Net Operating Income	71,700	26,745	7,593	2,009	17,552	498	7,844	21	7,153	14	638	1,675	-43
12	Plant in Service	1,713,153	940,700	171,620	40,597	237,887	9,301	119,627	316	164,204	103	12,011	14,669	2,117
13	Depreciation Reserve	(510,269)	(289,879)	(52,018)	(11,927)	(67,558)	(2,102)	(32,838)	(89)	(45,340)	(31)	(3,462)	(4,382)	(642)
14	Other Rate Base Items	(134,976)	(75,477)	(14,796)	(3,570)	(17,273)	(552)	(9,449)	(31)	(11,135)	(5)	(1,104)	(1,400)	(184)
15	Total Rate Base	1,067,908	575,344	104,806	25,100	153,056	6,647	77,340	196	107,730	67	7,444	8,887	1,291
16	Rate of Return	6.71%	4.65%	7.25%	8.00%	11.47%	7.50%	10.14%	10.47%	6.64%	20.54%	8.57%	18.85%	-3.34%
17	Relative Rate of Return	1.00	0.69	1.08	1.19	1.71	1.12	1.51	1.56	0.99	3.06	1.28	2.81	(0.50)

Note: Based on 12NCP A&E and 48% Load Factor.

Schedule MEB-COS-4

EMPIRE DISTRICT ELECTRIC COMPANY

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

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Average Current ROR* (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential - Rate RG	$ 181,660	$ 575,344	$ 26,745	4.65%	69	$ 38,629	$ 11,884	$ 19,287	10.62%
2	Commercial Service - Rate CB	37,570	104,806	7,593	7.25%	108	7,037	(557)	(904)	-2.41%
3	Commercial Service Heating - Rate SH	9,901	25,100	2,009	8.00%	119	1,685	(324)	(525)	-5.30%
4	General Power - Rate GP	75,690	153,056	17,552	11.47%	171	10,276	(7,276)	(11,809)	-15.60%
5	Praxair - Rate SC-P	3,632	6,647	498	7.50%	112	446	(52)	(85)	-2.33%
6	Total Electric Building - Rate TEB	35,320	77,340	7,844	10.14%	151	5,193	(2,651)	(4,303)	-12.18%
7	Feed Mill - Rate PFM	75	196	21	10.47%	156	13	(7)	(12)	-15.99%
8	Large Power - Rate LP	45,564	107,730	7,153	6.64%	99	7,233	80	130	0.28%
9	Misc. Service - Rate MS	62	67	14	20.54%	306	5	(9)	(15)	-24.38%
10	Street Lights - Rate SPL	1,768	7,444	638	8.57%	128	500	(138)	(224)	-12.69%
11	Private Lights - Rate PL	4,417	8,887	1,675	18.85%	281	597	(1,079)	(1,750)	-39.63%
12	Special Lights- Rate LS	133	1,291	(43)	-3.34%	-50	87	130	211	158.78%
13	Total	$ 395,791	$ 1,067,908	$ 71,700	6.71%	100	$ 71,700	$ (0)	$ (0)	0.00%

Source: Schedule MEB-COS-4
* Column 2 x Column 4, Line 13 (6.71%)

EMPIRE DISTRICT ELECTRIC COMPANY

Recommended Cost of Service Adjustments
Using Modified ECOS at Present Rates
($ in Thousands)

Line	Rate Class	Current Revenues	Move 25% Toward Cost Of Service	Percentage Change	Move 50% Toward Cost Of Service	Percentage Change
		(1)	(2)	(3)	(4)	(5)
1	Residential - Rate RG	$ 181,660	$ 4,822	2.65%	$ 9,644	5.31%
2	Commercial Service - Rate CB	37,570	(226)	-0.60%	(452)	-1.20%
3	Commercial Service Heating - Rate SH	9,901	(131)	-1.33%	(263)	-2.65%
4	General Power - Rate GP	75,690	(2,952)	-3.90%	(5,905)	-7.80%
5	Praxair - Rate SC-P	3,632	(21)	-0.58%	(42)	-1.16%
6	Total Electric Building - Rate TEB	35,320	(1,076)	-3.05%	(2,151)	-6.09%
7	Feed Mill - Rate PFM	75	(3)	-4.00%	(6)	-7.99%
8	Large Power - Rate LP	45,564	32	0.07%	65	0.14%
9	Misc. Service - Rate MS	62	(4)	-6.10%	(8)	-12.19%
10	Street Lights - Rate SPL	1,768	(56)	-3.17%	(112)	-6.34%
11	Private Lights - Rate PL	4,417	(438)	-9.91%	(875)	-19.82%
12	Special Lights- Rate LS	133	53	39.70%	105	79.39%
13	Total	$ 395,791	$ -	0.00%	$ -	0.00%

EMPIRE DISTRICT ELECTRIC COMPANY

Cost of Service Based on
Average and Excess Demand Allocator,
4 Non-Coincident Peaks
For the Test Year Ended June 2009
($000)'s

Line	Description	Missouri Retail	Residential Rate RG	Commercial Service Rate CB	Commercial Service-Heating Rate SH	General Power Rate GP	Praxair Rate SC-P	Total Electric Building Rate TEB	Feed Mill Rate PFM	Large Power Rate LP	Misc. Service Rate MS	Street Lights Rate SPL	Private Lights Rate PL	Special Lights Rate LS
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Revenue from Sales	395,791	181,660	37,570	9,901	75,690	3,632	35,320	75	45,564	62	1,768	4,417	133
2	Other Revenues	8,823	3,293	608	163	1,441	64	671	1	1,710	1	817	46	9
3	Total Revenues	404,615	184,953	38,178	10,063	77,131	3,696	35,991	76	47,274	62	2,586	4,463	142
4	O&M Expense	239,559	114,182	21,036	5,703	42,205	2,632	19,936	33	31,039	37	1,217	1,364	176
5	Depreciation Expense	54,122	29,537	5,400	1,295	7,758	278	3,723	10	5,254	4	339	435	90
6	Other Taxes	15,637	8,494	1,607	381	2,211	85	1,072	3	1,516	1	105	137	25
7	Income Tax	23,276	5,341	2,547	707	7,677	198	3,397	9	2,350	7	266	855	(79)
8	Total Expenses	332,594	157,554	30,590	8,086	59,851	3,193	28,127	55	40,159	49	1,927	2,791	211
9	Operating Income	72,020	27,399	7,588	1,977	17,280	503	7,863	21	7,115	14	659	1,672	-70
10	Interest on Customer Deposits	(321)	(255)	(47)	(8)	(8)	0	(3)	(0)	0	0	0	0	(0)
11	Net Operating Income	71,700	27,144	7,541	1,969	17,273	503	7,860	21	7,115	14	659	1,672	-70
12	Plant in Service	1,713,153	930,434	172,964	41,630	245,081	9,177	119,201	313	165,192	105	11,475	14,764	2,816
13	Depreciation Reserve	(510,269)	(287,767)	(52,295)	(12,139)	(69,039)	(2,076)	(32,750)	(89)	(45,543)	(32)	(3,352)	(4,402)	(785)
14	Other Rate Base Items	(134,976)	(74,473)	(14,928)	(3,671)	(17,977)	(540)	(9,407)	(31)	(11,231)	(5)	(1,052)	(1,409)	(252)
15	Total Rate Base	1,067,908	568,195	105,742	25,819	158,066	6,561	77,044	193	108,417	69	7,071	8,953	1,778
16	Rate of Return	6.71%	4.78%	7.13%	7.62%	10.93%	7.67%	10.20%	10.69%	6.56%	19.94%	9.32%	18.67%	-3.95%
17	Relative Rate of Return	1.00	0.71	1.06	1.14	1.63	1.14	1.52	1.59	0.98	2.97	1.39	2.78	(0.59)

Note: Based on 4NCP A&E and 48% Load Factor.

EMPIRE DISTRICT ELECTRIC COMPANY

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

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Average Current ROR* (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential - Rate RG	$ 181,660	$ 568,195	$ 27,144	4.78%	71	$ 38,149	$ 11,005	$ 17,860	9.83%
2	Commercial Service - Rate CB	37,570	105,742	7,541	7.13%	106	7,100	(442)	(717)	-1.91%
3	Commercial Service Heating - Rate SH	9,901	25,819	1,969	7.62%	114	1,734	(235)	(382)	-3.86%
4	General Power - Rate GP	75,690	158,066	17,273	10.93%	163	10,613	(6,660)	(10,809)	-14.28%
5	Praxair - Rate SC-P	3,632	6,561	503	7.67%	114	441	(63)	(102)	-2.80%
6	Total Electric Building - Rate TEB	35,320	77,044	7,860	10.20%	152	5,173	(2,688)	(4,362)	-12.35%
7	Feed Mill - Rate PFM	75	193	21	10.69%	159	13	(8)	(12)	-16.67%
8	Large Power - Rate LP	45,564	108,417	7,115	6.56%	98	7,279	164	267	0.59%
9	Misc. Service - Rate MS	62	69	14	19.94%	297	5	(9)	(15)	-23.87%
10	Street Lights - Rate SPL	1,768	7,071	659	9.32%	139	475	(184)	(299)	-16.90%
11	Private Lights - Rate PL	4,417	8,953	1,672	18.67%	278	601	(1,070)	(1,737)	-39.33%
12	Special Lights- Rate LS	133	1,778	(70)	-3.95%	-59	119	190	308	232.03%
13	Total	$ 395,791	$ 1,067,908	$ 71,700	6.71%	100	$ 71,700	$ (0)	$ (0)	0.00%

Source: Schedule MEB-COS-4
* Column 2 x Column 4, Line 13 (6.71%)

EMPIRE DISTRICT ELECTRIC COMPANY

Calculation of 4NCP Average and Excess Demand Allocator

Line	Rate Classes	Rate	4NCP Class Demands	Energy kWh @ Gen	Average Demand	Excess Demand	Percents: Average Demand	Percents: Excess Demand	Allocator	Used in COS	Delta	Used for COSS	
							48.28%	51.72%					
1	Residential	RG	513,377	1,714,543,361	195,724	317,653	0.413593	0.543761	0.480912	0.459236	0.021677	508,520	0.480912
2	Comm Service	CB	93,581	317,310,039	36,223	57,358	0.076544	0.098186	0.087737	0.077938	0.009799	92,774	0.087737
3	Comm S Htg	SH	25,608	98,865,505	11,286	14,322	0.023849	0.024517	0.024194	0.023873	0.000321	25,583	0.024194
4	General Power	GP	181,560	862,757,122	98,488	83,072	0.208119	0.142203	0.174029	0.188949	(0.014920)	184,019	0.174029
5	Praxair	SC-P	8,841	65,655,786	7,495	1,346	0.015838	0.002304	0.008839	0.009167	(0.000329)	9,346	0.008839
6	Tot El Building	TEB	90,803	403,215,447	46,029	44,774	0.097266	0.076644	0.086601	0.095088	(0.008487)	91,572	0.086601
7	Feed Mill	PFM	247	474,474	54	193	0.000114	0.000330	0.000226	0.000106	0.000120	239	0.000226
8	Large Power	LP	130,560	648,676,817	74,050	56,510	0.156478	0.096734	0.125580	0.140862	(0.015282)	132,789	0.125580
9	Misc Service	MS	68	675,570	77	(9)	0.000163	(0.000015)	0.000071	0.000130	(0.000059)	75	0.000071
10	Special Lts	SPL	4,885	16,601,310	1,895	2,990	0.004004	0.005118	0.004580	0.002318	0.002263	4,843	0.004580
11	Private Lts	PL	5,586	15,862,380	1,811	3,775	0.003827	0.006462	0.005190	0.002215	0.002975	5,488	0.005190
12	Sports Lts	LS	2,291	848,926	97	2,194	0.000205	0.003756	0.002041	0.000119	0.001923	2,159	0.002041
13	Total MO		1,057,407	4,145,486,737	473,229	584,178			1.000000	1.000000	(0.000000)	1,057,407	1.000000

Note: The Load Factor is based on the CP-T Demand of 980,129 kW.

EMPIRE DISTRICT ELECTRIC COMPANY

Cost of Service Based on
Average and Excess Demand Allocator,
12 Non-Coincident Peaks
For the Test Year Ended June 2009
($000)'s

Line	Description	Missouri Retail	Residential Rate RG	Commercial Service Rate CB	Commercial Service-Heating Rate SH	General Power Rate GP	Praxair Rate SC-P	Total Electric Building Rate TEB	Feed Mill Rate PFM	Large Power Rate LP	Misc. Service Rate MS	Street Lights Rate SPL	Private Lights Rate PL	Special Lights Rate LS
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Revenue from Sales	395,791	181,817	37,603	9,909	75,756	3,293	35,350	75	45,603	62	1,770	4,421	133
2	Other Revenues	8,823	3,348	606	159	1,418	36	675	1	1,709	1	819	46	6
3	Total Revenues	404,615	185,165	38,208	10,069	77,173	3,328	36,025	76	47,312	62	2,589	4,466	139
4	O&M Expense	239,559	114,773	21,011	5,668	41,952	2,329	19,977	34	31,028	36	1,240	1,362	148
5	Depreciation Expense	54,122	29,980	5,381	1,268	7,569	52	3,754	10	5,246	4	357	434	69
6	Other Taxes	15,637	8,617	1,602	374	2,158	22	1,080	3	1,513	1	110	136	19
7	Income Tax	23,276	4,865	2,583	742	7,932	342	3,371	9	2,375	7	245	859	(54)
8	Total Expenses	332,594	158,236	30,576	8,053	59,611	2,744	28,182	56	40,163	49	1,952	2,791	182
9	Operating Income	72,020	26,930	7,632	2,016	17,563	584	7,843	20	7,150	14	637	1,676	-43
10	Interest on Customer Deposits	(321)	(255)	(47)	(8)	(8)	0	(3)	(0)	0	0	0	0	(0)
11	Net Operating Income	71,700	26,675	7,585	2,008	17,555	584	7,840	20	7,150	14	637	1,676	-44
12	Plant in Service	1,713,153	944,999	172,344	40,766	238,849	1,725	120,216	319	164,923	103	12,059	14,717	2,134
13	Depreciation Reserve	(510,269)	(290,764)	(52,167)	(11,961)	(67,756)	(543)	(32,959)	(90)	(45,488)	(31)	(3,472)	(4,392)	(645)
14	Other Rate Base Items	(134,976)	(75,898)	(14,867)	(3,587)	(17,367)	190	(9,506)	(32)	(11,205)	(5)	(1,109)	(1,405)	(186)
15	Total Rate Base	1,067,908	578,337	105,310	25,218	153,726	1,372	77,750	198	108,230	67	7,478	8,920	1,303
16	Rate of Return	6.71%	4.61%	7.20%	7.96%	11.42%	42.55%	10.08%	10.35%	6.61%	20.63%	8.52%	18.79%	-3.35%
17	Relative Rate of Return	1.00	0.69	1.07	1.19	1.70	6.34	1.50	1.54	0.98	3.07	1.27	2.80	(0.50)

Note: Based on 12NCP A&E, 48% Load Factor, Set Praxair's demand to 500 kW and energy to 4,380,000 kWh (100% load factor on 500 kW), and subtracted $3.76 per kW for the Interruptible Credit .

EMPIRE DISTRICT ELECTRIC COMPANY

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

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Average Current ROR* (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential - Rate RG	$ 181,817	$ 578,337	$ 26,675	4.61%	69	$ 38,830	$ 12,155	$ 19,727	10.85%
2	Commercial Service - Rate CB	37,603	105,310	7,585	7.20%	107	7,071	(515)	(836)	-2.22%
3	Commercial Service Heating - Rate SH	9,909	25,218	2,008	7.96%	119	1,693	(314)	(510)	-5.15%
4	General Power - Rate GP	75,756	153,726	17,555	11.42%	170	10,321	(7,234)	(11,741)	-15.50%
5	Praxair - Rate SC-P	3,293	1,372	584	42.55%	634	92	(492)	(798)	-24.24%
6	Total Electric Building - Rate TEB	35,350	77,750	7,840	10.08%	150	5,220	(2,620)	(4,252)	-12.03%
7	Feed Mill - Rate PFM	75	198	20	10.35%	154	13	(7)	(12)	-15.58%
8	Large Power - Rate LP	45,603	108,230	7,150	6.61%	98	7,267	117	190	0.42%
9	Misc. Service - Rate MS	62	67	14	20.63%	307	4	(9)	(15)	-24.48%
10	Street Lights - Rate SPL	1,770	7,478	637	8.52%	127	502	(135)	(219)	-12.39%
11	Private Lights - Rate PL	4,421	8,920	1,676	18.79%	280	599	(1,077)	(1,748)	-39.54%
12	Special Lights- Rate LS	133	1,303	(44)	-3.35%	-50	87	131	213	160.34%
13	Total	$ 395,791	$ 1,067,908	$ 71,700	6.71%	100	$ 71,700	$ (0)	$ (0)	0.00%

Source: Schedule MEB-COS-4
* Column 2 x Column 4, Line 13 (6.71%)

EMPIRE DISTRICT ELECTRIC COMPANY

Calculation of 12NCP Average and Excess Demand Allocator
For Praxair, used 500 kW for all months.

Line	Rate Classes	Rate	12NCP Class Demands	Energy kWh @ Gen	Average Demand	Excess Demand	Percents Average Demand	Percents Excess Demand	Allocator	Used in COS	Delta	Used for COSS	
							47.57%	52.43%					
1	Residential	RG	446,613	1,714,543,361	195,724	250,889	0.419798	0.567405	0.497190	0.459236	0.037955	451,649	0.497190
2	Comm Service	CB	78,462	317,310,039	36,223	42,239	0.077693	0.095527	0.087043	0.077938	0.009105	79,070	0.087043
3	Comm S Htg	SH	21,165	98,865,505	11,286	9,879	0.024207	0.022342	0.023229	0.023873	(0.000644)	21,101	0.023229
4	General Power	GP	154,636	862,757,122	98,488	56,148	0.211242	0.126983	0.167064	0.188949	(0.021885)	151,761	0.167064
5	Praxair	SC-P	500	4,380,000	500	-	0.001072	-	0.000510	0.009167	(0.008657)	463	0.000510
6	Tot El Building	TEB	80,414	403,215,447	46,029	34,385	0.098725	0.077764	0.087735	0.095088	(0.007353)	79,699	0.087735
7	Feed Mill	PFM	204	474,474	54	150	0.000116	0.000339	0.000233	0.000106	0.000127	212	0.000233
8	Large Power	LP	115,987	648,676,817	74,050	41,937	0.158826	0.094844	0.125279	0.140862	(0.015582)	113,804	0.125279
9	Misc Service	MS	68	675,570	77	(9)	0.000165	(0.000020)	0.000068	0.000130	(0.000062)	62	0.000068
10	Street Lts	SPL	4,677	16,601,310	1,895	2,782	0.004064	0.006292	0.005232	0.002318	0.002914	4,753	0.005232
11	Private Lts	PL	4,585	15,862,380	1,811	2,774	0.003884	0.006274	0.005137	0.002215	0.002922	4,667	0.005137
12	Spec Lts	LS	1,092	848,926	97	995	0.000208	0.002250	0.001279	0.000119	0.001160	1,162	0.001279
13	Total MO		908,403	4,084,210,951	466,234	442,169			1.000000	1.000000	(0.000000)	908,403	1.000000

Note: The Load Factor is based on the CP-T Demand of 980,129 kW.
Used 4,380,000 kWh for Praxair (100% load factor on 500 kW).