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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power &
Light Company's Request for Authority
to Implement a General Rate Increase
for Electric Service

Case No. ER-2018-0145

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Missouri Industrial Energy Consumers

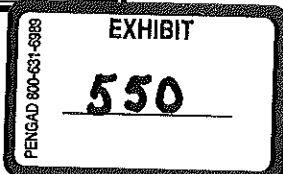
July 6, 2018



BRUBAKER & ASSOCIATES, INC.

Project 10551

MIEC Exhibit No. 550
Date 10/31/18 Reporter JB
File No. ER-2018-0145



BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

_____))
In the Matter of Kansas City Power &))
Light Company's Request for Authority) Case No. ER-2018-0145
to Implement a General Rate Increase))
for Electric Service))
_____)

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

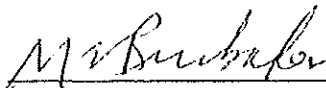
Affidavit of Maurice Brubaker

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

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

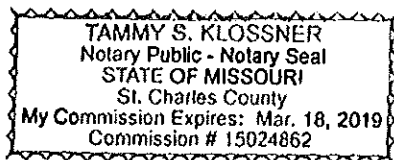
2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2018-0145.

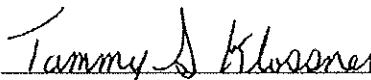
3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.



Maurice Brubaker

Subscribed and sworn to before me this 5th day of July, 2018.





Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Kansas City Power & Light Company’s Request for Authority to Implement a General Rate Increase for Electric Service))))))	Case No. ER-2018-0145
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**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

**In the Matter of Kansas City Power &
Light Company's Request for Authority
to Implement a General Rate Increase
for Electric Service**

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)
) **Case No. ER-2018-0145**
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)

Direct Testimony of Maurice Brubaker

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

4 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

5 A That information is contained in Appendix A to this testimony.

6 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

7 A This testimony is presented on behalf of the Missouri Industrial Energy Consumers
8 ("MIEC"), a non-profit company that represents the interests of industrial customers in
9 Missouri utility matters. These companies purchase substantial amounts of electricity
10 from Kansas City Power & Light Company ("KCPL") and the outcome of this proceeding
11 will have an impact on their cost of electricity.

12 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

13 A The purpose of my testimony is to present the results of KCPL's class cost of service
14 study, to explain how the study should be used, to recommend an appropriate
15 allocation of any rate increase, and to make rate design recommendations.

**Maurice Brubaker
Page 1**

1 Q HOW IS YOUR TESTIMONY ORGANIZED?

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

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

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

15 **Summary**

16 Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

17 A My testimony and recommendations may be summarized as follows:

- 18 1. Class cost of service is the starting point and the most important guideline for
19 establishing the level of rates charged to customers.
- 20 2. KCPL exhibits significant summer peak demands as compared to demands in
21 other months. (See Schedule MEB-COS-1)
- 22 3. There are two generally accepted methods for allocating generation and
23 transmission fixed costs that would apply to KCPL. These are the coincident peak
24 methodology and the average and excess ("A&E") methodology.
- 25 4. KCPL has presented an A&E – 4 Coincident Peak ("A&E-4CP") class cost of
26 service study.
- 27 5. KCPL's study is reasonable and I will rely on it.

Maurice Brubaker
Page 2

- 1 6. The results of KCPL's class cost of service study are presented on Schedule MEB-
2 COS-3 and expanded on Schedule MEB-COS-4, which shows the adjustments
3 required to move each class to its cost of service on a revenue neutral basis at
4 present rates. They range from an increase of 17.5% for the Residential class to
5 a decrease of 16.3% for the Small General Service class.
- 6 7. The rates for all classes of customers are so far from cost of service that equity
7 demands a significant movement toward cost of service be made. With KCPL
8 opting for certain provisions included in SB 564 (PISA) that includes a rate increase
9 moratorium, it is important that a significant movement be made now, since the
10 next opportunity will be at least three years from when rates from this case will go
11 into effect.
- 12 8. In addition to the fact that KCPL's industrial rates are far above cost of service, the
13 lack of competitiveness of KCPL's industrial rates compels the recognition of the
14 large departures from cost and movement of those rates closer to cost in order to
15 improve KCPL's competitive position. As shown on Schedule MEB-COS-2 (and
16 discussed more fully later in this testimony) KCPL's Missouri Industrial rates are
17 the sixth highest out of 41 Midwestern electric utilities.

18

COST OF SERVICE PROCEDURES

Overview

20 **Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.**

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

1 **Electricity Fundamentals**

2 **Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?**

3 **A** No. Electricity is different from most other goods or services purchased by consumers.

4 For example:

- 5 ▪ It cannot be stored; it must be delivered as produced;
- 6 ▪ It must be delivered to the customer's home or place of business;
- 7 ▪ The delivery occurs instantaneously when and in the amount needed by the
8 customer; and
- 9 ▪ Both the total quantity used (energy or kWh) by a customer and the rate of use
10 (demand or kW) are important.

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

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

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

1 Generating units, transmission lines and substations and distribution lines and
2 substations are rated according to the maximum demand that can safely be imposed
3 on them. (They are not rated according to average annual demand; that is, the amount
4 of energy consumed during the year divided by 8,760 hours.) On a hot summer
5 afternoon when customers demand 2,000 MW of electricity, the utility must have at
6 least 2,000 MW of generation, plus additional capacity to provide adequate reserves,
7 so that when a consumer flips the switch, the lights turn on, the machines operate and
8 air conditioning systems cool our homes, schools, offices, and factories.

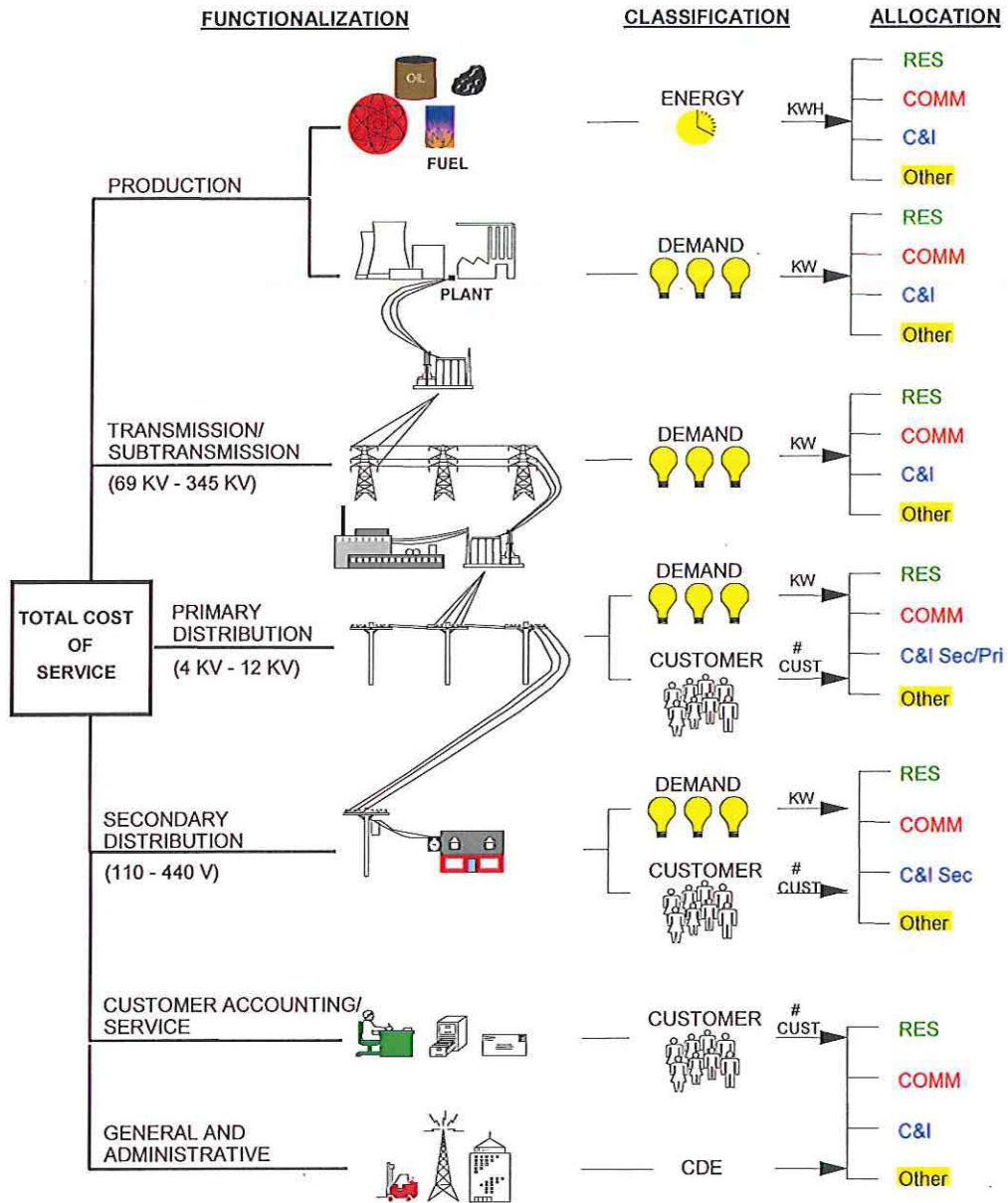
9 Satisfying customers' demand for electricity over time – providing **energy** – is
10 the third dimension of utility service. It is also the dimension with which many people
11 are most familiar, because people often think of electricity simply in terms of kWhs. To
12 see one reason why this isn't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

14 The tomatoes we buy at the supermarket for about \$1.50 a pound might
15 originally come from Florida where they are bought for about 30¢ a pound. In addition
16 to the cost of buying them at the point of production, there is the cost of bringing them
17 to the state of Missouri and distributing them in bulk to local wholesalers. The cost of
18 transportation, insurance, handling and warehousing must be added to the original 30¢
19 a pound. Then they are distributed to neighborhood stores, which adds more handling
20 costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can
21 then purchase as many or few tomatoes as they desire at their convenience. In
22 addition, there are losses from spoilage and damage in handling. These "line losses"
23 represent an additional cost which must be recovered in the final price. What we are
24 really paying for at the store is not only the vegetable itself, but the service of having it
25 available in convenient amounts and locations. If we took the time and trouble (and

1 expense) to go down to the wholesale produce distributor, the price would be less. If
2 we could arrange to buy them in bulk in Florida, they would be even cheaper.

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

Figure 1
PRODUCTION AND DELIVERY OF ELECTRICITY



1 **A CLOSER LOOK AT THE COST OF SERVICE STUDY**

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

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

11 **Functionalization**

12 **Q PLEASE EXPLAIN FUNCTIONALIZATION.**

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

17 Referring to Figure 1, at the top level there is generation, sometimes called
18 production. The next level is the extra high voltage transmission and subtransmission
19 system (69,000 volts to 345,000 volts). Then the voltage is stepped down to primary
20 voltage levels of distribution –4,160 to 12,000 volts. Finally, the voltage is stepped
21 down by pole transformers at the "secondary" level to 110-440 volts used to serve
22 homes, barbershops, light manufacturing and the like. Additional investment and
23 expenses are required to serve customers at secondary voltages, compared to the cost
24 of serving customers at higher voltage.

1 Each additional transformation, thus, requires additional investment, additional
2 expenses and results in some additional electrical losses. To say that "a kilowatthour
3 is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but
4 when you buy a kWh at home you're not only buying the energy itself but also the
5 service of having it delivered right to your doorstep in convenient form. Those who buy
6 at the bulk or wholesale level – like some of the Large Power Service customers – pay
7 less because some of the expenses to the utility are avoided. (Actually, the expenses
8 are borne by the customer who must invest in transformers and other equipment, or
9 pay separately for some services.)

10 Classification

11 Q WHAT IS CLASSIFICATION?

12 A Once the costs have been functionalized, the next step is to identify the primary
13 causative factor (or factors). This step is referred to as **classification**. Costs are
14 classified as demand-related, energy-related or customer-related.

15 Looking at the production function, the amount of production plant capacity
16 required is primarily determined by the peak rate of usage during the year. If the utility
17 anticipates a peak demand of 2,000 MW – it must install and/or contract for enough
18 generating capacity to meet that anticipated demand (plus some reserve to
19 compensate for variations in load and capacity that is temporarily unavailable).

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

1 maintenance ("O&M") expenses, taxes and insurance) **are fixed**; that is, **they do not**
2 **vary with the amount of kWhs generated and sold.** These fixed costs are
3 determined by the amount of capacity (i.e., kilowatts) that the utility must install to
4 satisfy its obligation-to-serve requirement.

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

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

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

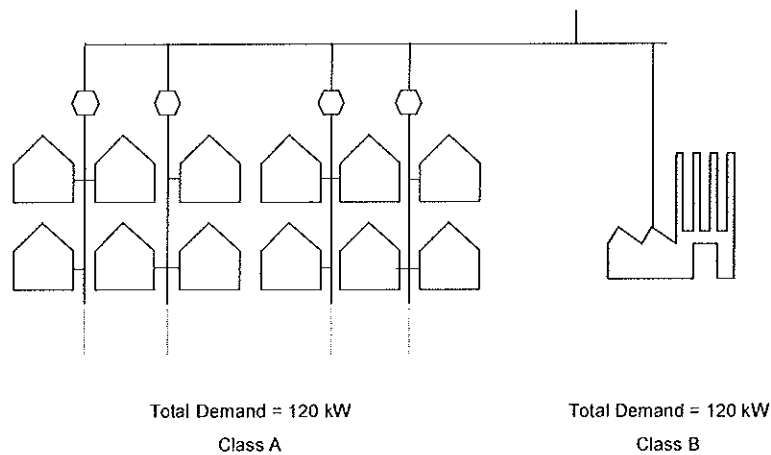
20 A certain portion of the cost of the distribution system – poles, wires and
21 transformers – is required simply to attach customers to the system, regardless of their
22 demand or energy requirements. This minimum or "skeleton" distribution system may
23 also be considered a customer-related cost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

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

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

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

Figure 2
Classification of Distribution Investment



1 **Demand vs. Energy Costs**

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

4 **A** The difference between demand-related and energy-related costs explains the fallacy
5 of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3 compares
6 the electrical requirements of two customers, A and B, each using 100-watt light bulbs.
7 Customer A turns on all five of his/her 100-watt light bulbs for two hours.
8 Customer B, by contrast, turns on two light bulbs for five hours. Both customers use
9 the same amount of energy – 1,000 watthours or 1 kWh. However, Customer A utilized
10 electric power at a higher rate, 500 watts per hour or 0.5 kW, than Customer B who
11 demanded only 200 watts per hour or 0.2 kW.

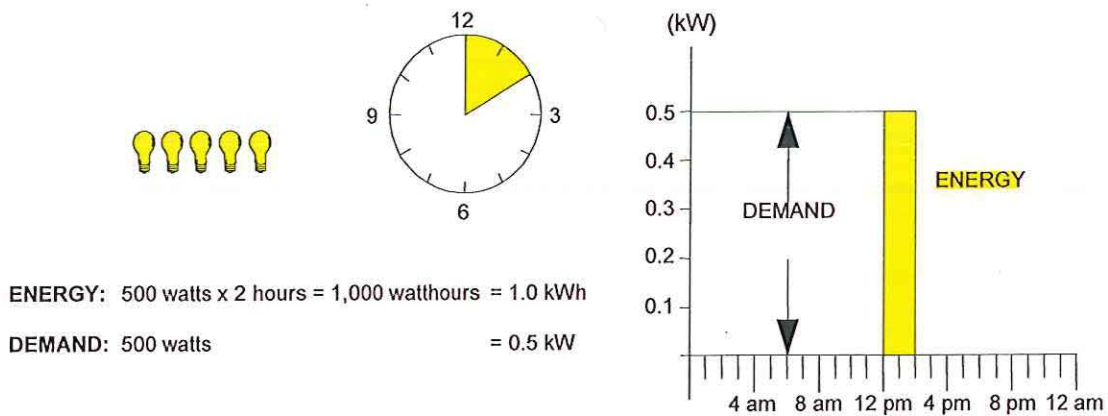
12 Although both customers had precisely the same kWh energy usage, Customer
13 A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5
14 times as much generating capacity for Customer A as for Customer B. The cost of
15 serving Customer A, therefore, is much higher.

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

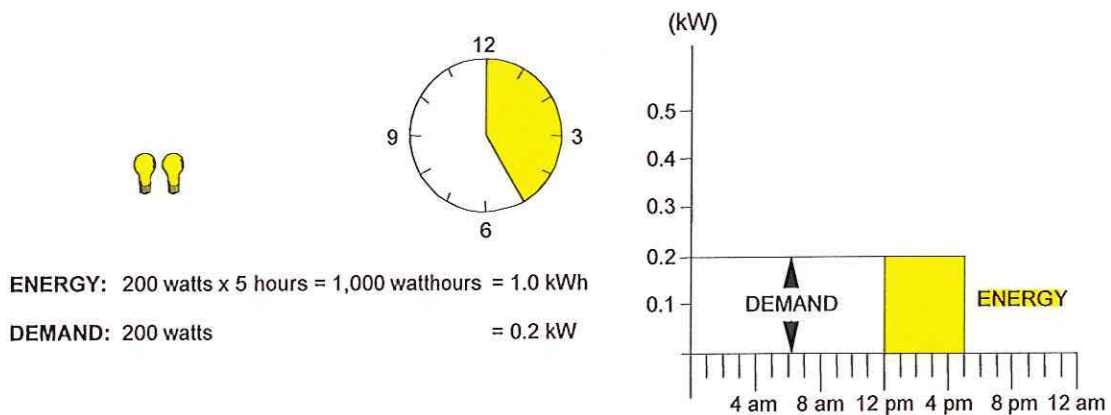
17 **A** Yes. Load factor is an expression of how uniformly a customer uses energy. In our
18 example of the light bulbs, the load factor of Customer B would be higher than the load
19 factor of Customer A because the use of electricity was spread over a longer period of
20 time, and the number of kWhs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

Figure 3 DEMAND VS. ENERGY

CUSTOMER A



CUSTOMER B



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

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

14 **Allocation**

15 **Q WHAT IS ALLOCATION?**

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

20 For example, we have already determined that the amount of fuel expense on
21 the system is a function of the energy required by customers. In order to allocate this
22 expense among classes, we must determine how much each class contributes to the
23 total kWh consumption and we must recognize the line losses associated with
24 transporting and distributing the kWh. These contributions, expressed in percentage

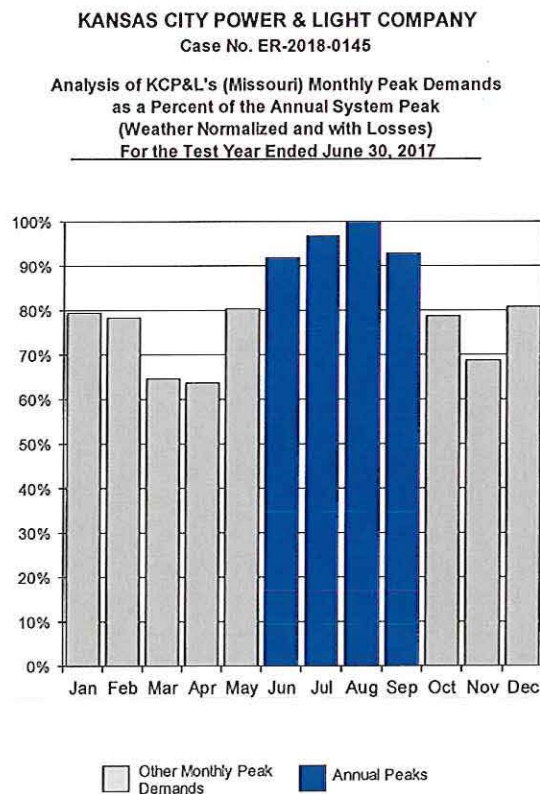
1 terms, are then multiplied by the expense to determine how much expense should be
2 attributed to each class. For demand-related costs, we construct an allocation factor
3 by looking at the important class demands.

4 **Utility System Characteristics**

5 Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

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

Figure 4



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

3 This analysis shows that summer peaks dominate the KCPL system. (This
4 same information is presented in tabular form on Schedule MEB-COS-2.) This clearly
5 shows that the system peak occurred in August, and was substantially higher than the
6 monthly peaks occurring in most other months. The peaks in June, July and September
7 were only 8.0%, 3.2%, and 7.2%, respectively, lower than the annual peak, while peaks
8 in other months were substantially lower.

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

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

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

17 **A** As discussed previously, production and transmission plant must be sized to meet the
18 maximum demand imposed on these facilities. Thus, an appropriate allocation method
19 should accurately reflect the characteristics of the loads served by the utility. For
20 example, if a utility has a high summer peak relative to the demands in other seasons,
21 then production and transmission capacity costs should be allocated relative to each
22 customer class's contribution to the summer peak demands. If a utility has predominant
23 peaks in both the summer and winter periods, then an appropriate allocation method

1 would be based on the demands imposed during both the summer and winter peak
2 periods. For a utility with a very high load factor and/or a non-seasonal load pattern,
3 then demands in all months may be important.

4 **Q WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE KCPL**
5 **SYSTEM?**

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

11 **Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?**

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

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

17 **Q WHAT IS THE A&E METHOD?**

18 A The A&E method is one of a family of methods that incorporates a consideration of
19 both the maximum rate of use (demand) and the duration of use (energy). As the name
20 implies, A&E makes a conceptual split of the system into an "average" component and
21 an "excess" component. The "average" demand is simply the total kWh usage divided
22 by the total number of hours in the year. This is the amount of capacity that would be

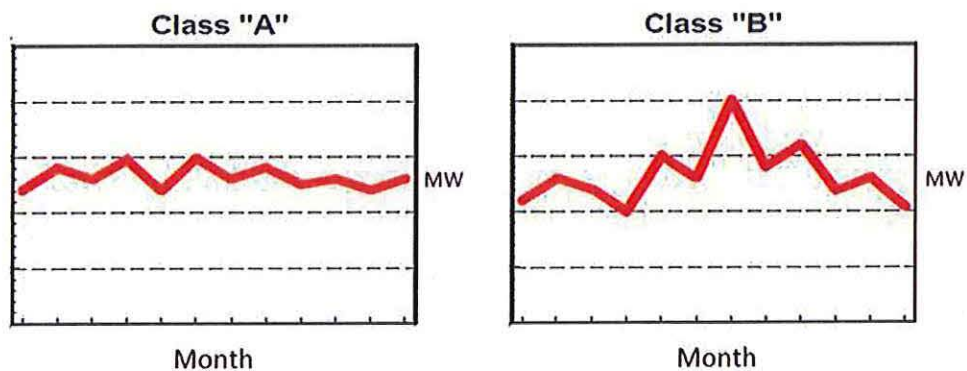
1 required to produce the energy if it were taken at the same demand rate each hour.
2 The system "excess" demand is the difference between the system peak demand and
3 the system average demand.

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

9 Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

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

Figure 5
Load Patterns



11 Both classes use the same total amount of energy and, therefore, have the same
12 average demand. Class B, though, has a much greater maximum demand² than Class
13 A. The greater maximum demand imposes greater costs on the utility system. This is
14 because the utility must provide sufficient capacity to meet the projected maximum

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

²During 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.

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

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

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

12 **A** First, in order to reflect cost-causation the methodology must give predominant weight
13 to loads occurring during the summer months. Loads during these months (the peak
14 loads) are the primary driver that has and continues to cause the utility to expand its
15 generation and transmission capacity, and therefore should be given predominant
16 weight in the allocation of capacity costs.

17 Either a coincident peak study, using the demands during the summer (peak)
18 months, or a version of an A&E cost of service study that uses class demands occurring
19 during the summer, would be most appropriate to reflect these characteristics. The
20 results should be similar as long as only summer period peak loads are used. I
21 recommend the A&E method.

22 **Q DO YOU AGREE WITH THE A&E-4CP STUDY PRESENTED BY KCPL?**

23 **A** Yes. Given KCPL's load characteristics, I find this study to be reasonable.

1 Q HAVE YOU HAD OCCASION TO STUDY THE COMPETITIVENESS OF KCPL'S
2 INDUSTRIAL RATES?

3 A Yes. Schedule MEB-COS-2 presents a summary ranking of the rates in 38 Midwestern
4 electric utility company service territories. KCPL's Missouri rates have the dubious
5 distinction of being sixth highest out of these 41 utilities in terms of their industrial rates.
6 This unhappy circumstance is largely the result of two factors. First is failure to adopt
7 a mainstream cost of service study to measure appropriate rate levels, and the second
8 is not moving rates to cost of service, even on the basis of the cost of service studies
9 that were presented in rate cases. I will discuss this in more detail later.

10 **Making the Cost of Service Study – Summary**

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

13 A As previously discussed, the cost of service procedure involves three steps:
14 1. Functionalization – Identify the different functional "levels" of the system;
15 2. Classification – Determine, for each functional type, the primary cause or causes
16 (customer, demand or energy) of that cost being incurred; and
17 3. Allocation – Calculate the class proportional responsibilities for each type of cost
18 and spread the cost among classes.

19 Q WHERE ARE THE COST OF SERVICE RESULTS PRESENTED?

20 A The results are presented in Schedule MEB-COS-3, which reflects results at present
21 rates.

1 Q REFERRING TO SCHEDULE MEB-COS-3, PLEASE EXPLAIN THE
2 ORGANIZATION AND WHAT IS SHOWN.

3 A Schedule MEB-COS-3 is a summary of the key elements and the results of KCPL's
4 class cost of service study. The top section of the schedule shows the revenues,
5 expenses and operating income based on an A&E-4CP cost of service study.

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

8 Adjustment of Class Revenues

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

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

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

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

21 Electric rates also play a role in economic development, both with respect to job
22 creation and job retention. This is particularly true in the case of industries where
23 electricity is one of the largest components of the cost of production.

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

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

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

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

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

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

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

18 A Yes. The success of DSM (both energy efficiency and demand response programs)
19 depends, to a large extent, on customer receptivity. There are many actions that can
20 be taken by consumers to reduce their electricity requirements. A major element in a
21 customer’s decision-making process is the amount of reduction that can be achieved
22 in the electric bill as a result of DSM activities. If the bill received by a customer is

1 subsidized by other customers; that is, the bill is determined using rates that are below
2 cost, that customer will have less reason to engage in DSM activities than when the bill
3 reflects the actual cost of the electric service provided.

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

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

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

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

23 From a rate design perspective, overpricing the energy portion of the rate and
24 underpricing the fixed components of the rate (such as customer and demand charges)

1 will result in a disproportionate share of revenues being collected from large customers
2 and high load factor customers. To the extent that these customers may have lower
3 cost alternatives than do the smaller or the low load factor customers, the same
4 problems noted above are created.

5 REVENUE ALLOCATION

6 **Q PLEASE REFER AGAIN TO SCHEDULE MEB-COS-3 AND SUMMARIZE THE**
7 **RESULTS OF KCPL'S CLASS COST OF SERVICE STUDY.**

8 **A** As indicated on line 400 of Schedule MEB-COS-3, the Residential class has a rate of
9 return far below the system average, which means it is not covering its cost of service.
10 On the other hand, all other customers are being charged far more than their cost of
11 service.

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

14 **A** This is shown on Schedule MEB-COS-4. The first five columns summarize the results
15 of the cost of service study at present rates, and are taken from Schedule MEB-COS-
16 3. The remaining columns of Schedule MEB-COS-4 determine the amount of increase
17 or decrease, on a revenue neutral basis, required to move each customer class to the
18 average rate of return at current revenue levels. That is, it shows the amount of
19 increase or decrease required to have every class yield the same rate of return, before
20 considering any overall increase in revenues. Note that the Residential class would
21 require an increase of about \$59 million, or 17.5%, in order to move to cost of service.
22 All other classes would require a corresponding decrease. The decreases range f rom

1 about 7.8% for the Medium General Service class to 16.3% for the Small General
2 Service class.

3 **Q HOW DOES KCPL PROPOSE TO ADJUST REVENUES?**

4 A KCPL proposes only a very modest recognition of the larger disparities in the
5 revenue/cost relationships of the classes.

6 **Q WOULD KCPL'S ALLOCATION MOVE CLASS RATES CLOSER TO COST OF
7 SERVICE?**

8 A Not appreciably. KCPL's allocation would essentially maintain the status quo in which
9 the Residential class is far below cost of service, and other classes are above cost of
10 service.

11 **Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF
12 KCPL'S REVENUE REQUIREMENT?**

13 A Yes. I will focus on adjustments to be made on a revenue neutral basis at present
14 rates. After having made my recommended revenue neutral adjustments at present
15 rates, any overall change in revenues allowed to KCPL (whether an increase or a
16 decrease) can then be applied on an equal percentage across-the-board basis to these
17 adjusted class revenues.

18 **Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.**

19 A My proposal is shown on Schedule MEB-COS-5, pages 1 and 2. Column 1 shows
20 class revenues at current rates. Column 2 shows the proposed cost of service
21 adjustment. This adjustment on page 1 moves classes roughly 50% of the way toward

1 cost of service, and the adjustment on page 2 moves 25% of the way toward cost of
2 service. A movement in this range would not be unreasonable. The smaller the overall
3 increase granted to KCPL, (or the larger the decrease) the larger the movement toward
4 cost of service can be without causing undue rate shock.

5 While some will want to talk about the impact on the Residential class of this
6 increase, it is also important not to lose sight of the fact that by not moving all the way
7 to cost of service, the other customer classes are continuing to support the Residential
8 class by bearing more of the burden of the revenue responsibility than they should. My
9 recommendation of moving 25% to 50% of the way toward cost of service, which limits
10 the Residential class revenue-neutral increase to between 4.4% and 8.8% (as
11 contrasted to the 17.5% increase required to move all the way to cost of service) is
12 relatively moderate, and must be considered in light of the fact that other classes are
13 being asked to continue to provide part of the revenue responsibility that rightly should
14 be shouldered by the Residential class. With KCPL opting for certain provisions
15 included in SB 564 (PISA) that includes a rate increase moratorium, it is important that
16 a significant movement be made now, since the next opportunity will be at least three
17 years from when rates from this case will go into effect.

18 **Q IN ADDITION TO THE FACTORS THAT YOU HAVE NOTED PREVIOUSLY, ARE**
19 **THERE OTHER REASONS WHY MOVING KCPL'S INDUSTRIAL RATES CLOSER**
20 **TO COST OF SERVICE IS IMPORTANT?**

21 **A** Yes. As I mentioned earlier in this testimony, KCPL has the dubious distinction of
22 having the sixth highest industrial rate out of 41 Midwestern utility service territories.
23 This is not a good place to be. Industrial customers are the most price sensitive, and
24 the level of industrial power rates plays an important role in facility siting decisions and

1 in operating decisions when multi-facility corporations have demands for their product
2 that do not fully load all of their existing facilities. Production (and employment) will
3 generally favor those locations that have the lowest cost, and the cost of utilities is
4 always considered, and frequently is a major factor.

5 The competitiveness of KCPL rates was a factor cited by KCPL witness Lutz (at
6 page 6 of his direct testimony), and KCPL witness Sullivan (at pages 25-26 of his direct
7 testimony) in KCPL's decision to adopt a main-stream cost of service methodology.

8 Mr. Sullivan's testimony is particularly enlightening with respect to the
9 importance of competition and the level of industrial rates. In discussing why it matters
10 which methodology for cost of service is used by other utilities (he uses Ameren and
11 Westar as examples), Mr. Sullivan states the following at pages 25 and 26 of his direct
12 testimony:

13 "The primary reason it matters deals with competition and specifically
14 competition for industrial customers. As discussed earlier in my
15 testimony, KCP&L's industrial customers generally have a very high
16 load factor, much higher than the system average and much higher than
17 the other customer classes. As will be discussed in the next section of
18 my testimony, of the three methodologies predominantly recommended
19 in Missouri and Kansas, the A&E methodology is the only method that
20 gives a significant recognition to the relative load factors of the customer
21 classes. Further, when a system is not operating at a very high load
22 factor, the A&E methodology best assigns the higher cost of unused
23 capacity.

24 If the CCOS study is used as a principle tool in assigning the utility
25 revenue requirement to customer classes and thus rate design,
26 industrial cost responsibility and thus industrial rates for utilities using
27 the A&E methodology will be lower than using either of the other two
28 methodologies, all other things being equal. Thus, if the rates for the
29 two major utilities with which KCP&L competes are using the A&E
30 methodology and KCP&L is not, KCP&L will be at a competitive
31 disadvantage in attracting and retaining industrial load.

32 **Q. Why is it important to attract and retain industrial load?**

33 A. There are numerous reasons why this is important. First, industrial
34 customers have higher load factors that increase the overall
35 efficiency of the electric system, particularly generation and

1 transmission facilities. The loads are stable throughout the day,
2 allowing the utility to invest in lower cost base load generating
3 facilities. Second, industrial customers usually provide a large
4 amount of direct and indirect jobs. The direct jobs are associated
5 with the industrial facility itself. The indirect jobs include the
6 supporting companies that provide materials to the facility and the
7 residential and commercial development supported by the
8 employees of the industrial company.”

9 Q HAVE YOU COMPARED THE ESCALATION IN KCPL'S RATES WITH THE
10 ESCALATION IN THE RATES OF OTHER UTILITIES IN THE MIDWEST?

11 A Yes. For the Industrial customers rates I have made that comparison. From 2005 to
12 2017, KCPL's industrial rates have increased by 91% as contrasted to an overall
13 increase of approximately 34% for the overall group.

14 **ANALYSIS OF LARGE CUSTOMER RATE STRUCTURE**

15 Q WHAT IS THE STRUCTURE OF THE TARIFFS APPLICABLE TO KCPL'S
16 LARGEST CUSTOMERS?

17 A The LGS and LPS tariffs consist of a series of charges differentiated by voltage level.
18 There are separate charges for service at secondary voltage, service at primary
19 voltage, service at substation voltage, and service at transmission voltage. The rates
20 charged at the higher voltage levels are lower than the rates charged at the lower
21 voltage levels in order to recognize differences in cost of service.

22 At each voltage level, the rate consists of customer charges, facilities charges,
23 charges for reactive power, demand charges and energy charges. Demand charges
24 and energy charges also are seasonally differentiated, with summer charges being
25 applied during the four consecutive months beginning May 16 and ending
26 September 15.

1 **Q WHAT IS THE STRUCTURE OF THE DEMAND CHARGES?**

2 A In addition to being seasonally differentiated, the demand charges at each voltage level
3 consist of multiple block charges.

4 **Q WHAT IS THE STRUCTURE OF THE ENERGY CHARGES?**

5 A The energy charges are structured as three "hours use" blocks. The three blocks
6 consist of the first 180 hours use of the billing demand, the next 180 hours use of the
7 billing demand and the tail block is for consumption in excess of 360 hours use of the
8 billing demand.

9 These are what are known as hours use, or load factor based charges. The
10 rates decrease as the hours use increases to recognize the spreading of fixed costs
11 over more kilowatthours as the number of hours use, or load factor, increases. This
12 structure also recognizes that energy consumed in the high load factor block likely will
13 be off-peak or at times when energy costs are lower than during on-peak periods.

14 **Q PLEASE EXPLAIN HOW THE HOURS USE FUNCTION WORKS.**

15 A The number of kWh to be billed in each hours use block is determined by the
16 customer's billing demand and the amount of kWh purchased.

17 A customer operating basically a one-day shift (eight hours a day for five days
18 a week) would have usage in the range of 180 kWh per kW of billing demand.³ A
19 customer operating two shifts likely would utilize approximately twice that much energy,
20 and therefore use an additional 180 or so kWh per kW of demand, thereby filling up
21 both the first and second blocks.

³8 hours/day x 5 days per week x 4.33 weeks per month = 173 hours

1 Thus, it is reasonable to consider the first block as being primarily the daytime
2 on-peak hours, the second block for early morning, evening and/or weekend hours,
3 and the third block for additional use in weekend and nighttime hours. Given these
4 considerations, it is appropriate that the energy charges for the initial hours use blocks
5 be higher than for the third hours use block in order to collect more fixed costs during
6 the on-peak and shoulder periods.

7 **Q CAN YOU ILLUSTRATE WITH AN EXAMPLE OF HOW THE RATE WORKS?**

8 A Yes. Assume that a customer has a 1,000 kW billing demand, and uses 500,000 kWh
9 in a month. This customer would be using 500 kWh per kW,⁴ or 500 kWh for each kW
10 of demand. To apply the rate, the 1,000 kW of demand would be multiplied by 180
11 kWh per kW, which is the size of the first block, and would result in 180,000 kWh being
12 priced out at the first block. The customer would also fully utilize the second block, so
13 180,000 kWh would go in it as well and be priced at the second block rate. The
14 remaining 140,000 kWh⁵ would be billed in the third, or high load factor, block.

15 **Q WHAT IS THE LEVEL OF THE ENERGY CHARGES FOR THE HIGH LOAD FACTOR**
16 **(OVER 360 HOURS USE) BLOCK UNDER CURRENT TARIFFS?**

17 A The charges vary slightly by voltage level and by season, but range from approximately
18 2.5¢/kWh to 2.7¢/kWh in LPS and from 3.6¢/kWh to 4.4¢/kWh for LGS.

⁴500,000 ÷ 1,000 kW = 500 kWh/kW

⁵500,000 - 180,000 - 180,000 = 140,000 kWh

1 Q DO YOU AGREE WITH THE LEVEL OF THE OFF-PEAK ENERGY CHARGES IN
2 THE CURRENT TARIFFS?

3 A No, I do not. I believe the high load factor block energy charges collect more fixed
4 costs than is appropriate.

5 Q PLEASE EXPLAIN.

6 A I have analyzed KCPL's current rate case filing and its claims for costs. KCPL's
7 calculated average variable costs (Schedule MEM-2 to the direct testimony of Marisol
8 Miller) are between 2.1 and 2.2¢/kWh, depending on voltage level. The energy charges
9 in the high load factor block of KCPL's current LGS and LPS tariffs are considerably
10 higher, as previously noted. Since KCPL proposes an essentially equal percentage
11 increase to collect its requested revenue increase, these relationships would be
12 perpetuated. Since the primary driver for this case is increased fixed costs, this equal
13 percentage on the total rate is particularly inappropriate.

14 Q WHAT DO YOU CONCLUDE FROM THIS REVIEW?

15 A Based on the level of the average variable costs and also the avoided energy costs, it
16 is clear that the off-peak energy charges are collecting more costs than appropriate.

17 Q WHAT SHOULD BE THE LEVEL OF THE OFF-PEAK ENERGY CHARGE?

18 A Recognizing that most of the fixed costs should be collected from use during the
19 on-peak period and that consumption in the high load factor block occurs mostly during
20 evening and weekend periods when KCPL's energy costs would be lower than they
21 are during the on-peak periods, it is reasonable that the high load factor energy block
22 be at a level approximating the utility's average variable costs.

1 This structure would collect more costs through demand charges and provide
2 better price signals to customers. It would also be a more equitable rate because it will
3 charge high load factor and low load factor customers more appropriately. This
4 structure also would improve the stability of KCPL's earnings. Because customer
5 demands are generally more stable than their energy purchases, this rate design would
6 make KCPL's revenue collection and earnings less volatile.

7 **Q HOW DO YOU PROPOSE TO ADJUST THE LGS AND LPS RATES IN THIS CASE?**

8 **A**The appropriate method depends on whether the rate schedule revenue is increasing
9 or decreasing.

10 If Rate Schedule Revenue is Increasing

11 In the interest of gradualism, my proposal is to maintain the energy charges for
12 the high load factor (over 360 hours use per month, or over a 50% load factor) block at
13 their current levels, increase the middle blocks (hours use from 181 to 360) by three
14 quarters of the average percentage increase for the rate, and to collect the balance of
15 the revenue requirement for the rate by applying a uniform percentage increase to the
16 remaining charges of the rate. This includes the customer charge, the reactive demand
17 charge, the facilities charges, the demand charges and the initial block energy charges.

18 If Rate Schedule Revenue is Decreasing

19 If rate schedule revenue is decreasing, I would decrease the high load factor
20 block of each voltage level by a uniform amount per kilowatthour equal to the total
21 revenue decrease for the rate schedule divided by the total number of kilowatthours
22 sold under the rate schedule.

1 Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

2 A Yes, it does.

Qualifications of Maurice Brubaker

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

4 **Q PLEASE STATE YOUR OCCUPATION.**

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

7 **Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

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

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

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

18 In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis,
19 Missouri. Since that time I have been engaged in the preparation of numerous studies
20 relating to electric, gas, and water utilities. These studies have included analyses of
21 the cost to serve various types of customers, the design of rates for utility services, cost

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1 forecasts, cogeneration rates and determinations of rate base and operating income. I
2 have also addressed utility resource planning principles and plans, reviewed capacity
3 additions to determine whether or not they were used and useful, addressed demand-
4 side management issues independently and as part of least cost planning, and have
5 reviewed utility determinations of the need for capacity additions and/or purchased
6 power to determine the consistency of such plans with least cost planning principles. I
7 have also testified about the prudence of the actions undertaken by utilities to meet the
8 needs of their customers in the wholesale power markets and have recommended
9 disallowances of costs where such actions were deemed imprudent.

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

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

23 Brubaker & Associates, Inc. and its predecessor firm has participated in over
24 700 major utility rate and other cases and statewide generic investigations before utility
25 regulatory commissions in 40 states, involving electric, gas, water, and steam rates and

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1 other issues. Cases in which the firm has been involved have included more than 80
2 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

3 While the firm has always assisted its clients in negotiating contracts for utility
4 services in the regulated environment, increasingly there are opportunities for certain
5 customers to acquire power on a competitive basis from a supplier other than its
6 traditional electric utility. The firm assists clients in identifying and evaluating purchased
7 power options, conducts RFPs and negotiates with suppliers for the acquisition and
8 delivery of supplies. We have prepared option studies and/or conducted RFPs for
9 competitive acquisition of power supply for industrial and other end-use customers
10 throughout the United States and in Canada, involving total needs in excess of 3,000
11 megawatts. The firm is also an associate member of the Electric Reliability Council of
12 Texas.

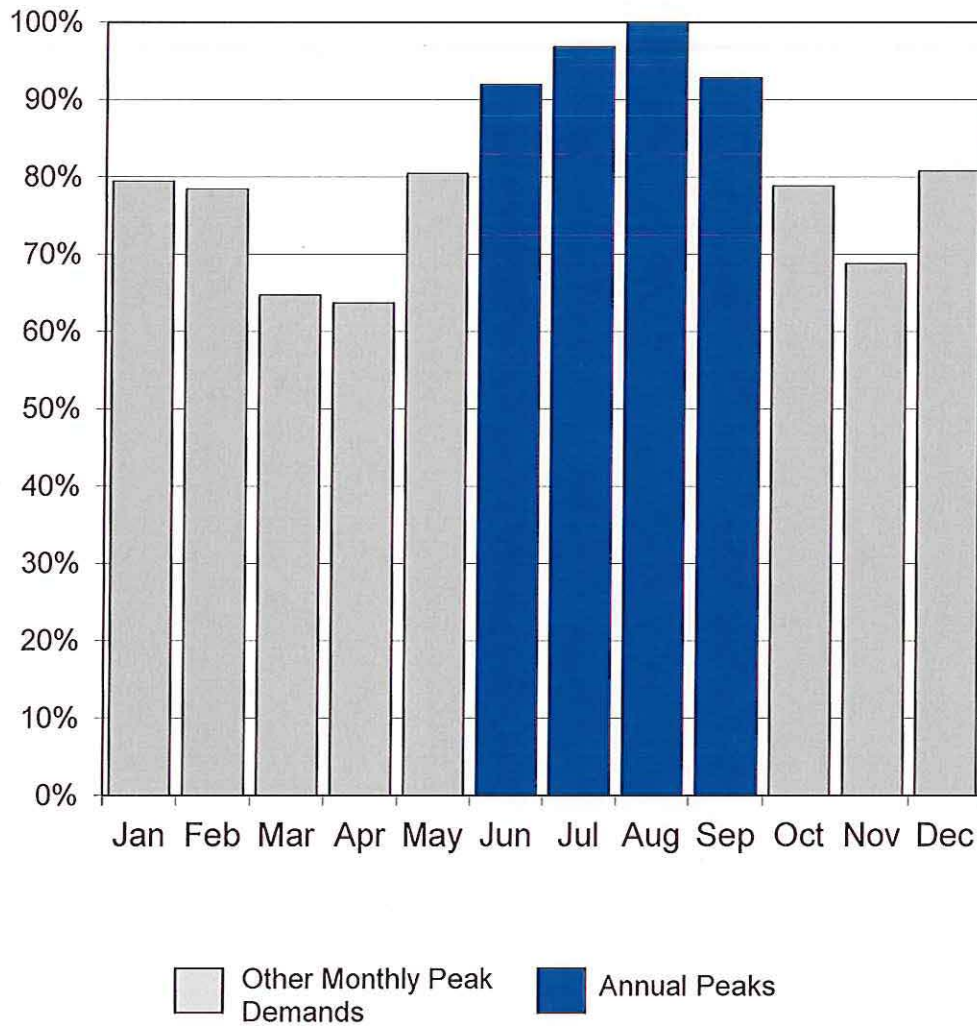
13 In addition to our main office in St. Louis, the firm has branch offices in Phoenix,
14 Arizona and Corpus Christi, Texas.

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KANSAS CITY POWER & LIGHT COMPANY

Case No. ER-2018-0145

Analysis of KCP&L's (Missouri) Monthly Peak Demands as a Percent of the Annual System Peak (Weather Normalized and with Losses) For the Test Year Ended June 30, 2017



KANSAS CITY POWER & LIGHT COMPANY

Case No. ER-2018-0145

**Analysis of KCP&L's Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended June 30, 2017**

<u>Line</u>	<u>Description</u>	<u>Total Company MW (1)</u>	<u>Percent (2)</u>
1	January	1,426	79.5%
2	February	1,408	78.4%
3	March	1,162	64.8%
4	April	1,144	63.7%
5	May	1,444	80.5%
6	June	1,651	92.0%
7	July	1,738	96.8%
8	August	1,795	100.0%
9	September	1,666	92.8%
10	October	1,415	78.8%
11	November	1,235	68.8%
12	December	1,451	80.8%

Source: WN KCPL Allocators MO Rev 11-30-17
Avg & Excess 4CP.xls

Kansas City Power & Light Company

Vertically Integrated Midwest Utilities Industrial Power Cost (50 MW/68% LF) - 2017

Line	Utility	State	¢/kWh	Ranking
1	Madison Gas & Electric Company	Wisconsin	9.52	1
2	Entergy New Orleans, Inc.	Louisiana	9.09	2
3	We Energies (formerly Wisconsin Electric)	Wisconsin	8.90	3
4	Kansas City Power & Light Company	Kansas	8.62	4
5	Montana-Dakota Utilities Company	North Dakota	8.49	5
6	Kansas City Power & Light Company	Missouri	8.49	6
7	Northwestern Wisconsin Electric Company	Wisconsin	8.43	7
8	Northern States Power Company	Minnesota	8.38	8
9	Northern States Power Company	South Dakota	7.95	9
10	Otter Tail Power Company	Minnesota	7.93	10
11	Empire District Electric Company	Missouri	7.89	11
12	Northern States Power Company	North Dakota	7.78	12
13	Minnesota Power Company	Minnesota	7.78	13
14	CLECO Power LLC	Louisiana	7.75	14
15	Northern States Power Company	Wisconsin	7.48	15
16	WP&L	Wisconsin	7.36	16
17	Westar Energy-KGE	Kansas	7.25	17
18	Westar Energy-KPL	Kansas	7.25	18
19	Montana-Dakota Utilities Company	South Dakota	7.12	19
20	Otter Tail Power Company	North Dakota	6.89	20
21	Northwestern Energy	South Dakota	6.88	21
22	Wisconsin Public Service Corporation	Wisconsin	6.83	22
23	Empire District Electric Company	Arkansas	6.81	23
24	Interstate Power & Light	Iowa	6.57	24
25	Entergy Louisiana, Inc.	Louisiana	6.50	25
26	Superior Water, Light & Power Company	Wisconsin	6.50	26
27	Kansas City Power & Light - GMO	Missouri	6.46	27
28	Ameren Missouri	Missouri	6.22	28
29	Otter Tail Power Company	South Dakota	6.21	29
30	Empire District Electric Company	Kansas	6.09	30
31	Empire District Electric Company	Oklahoma	6.06	31
32	Black Hills Power, Inc. d/b/a Black Hills Energy	South Dakota	5.86	32
33	Entergy Arkansas, Inc.	Arkansas	5.85	33
34	Southwestern Electric Power Company	Louisiana	5.63	34
35	OG&E Electric Services	Arkansas	5.60	35
36	Entergy Louisiana, LLC (formerly Entergy Gulf States, Inc.)	Louisiana	5.40	36
37	Southwestern Electric Power Company	Arkansas	5.34	37
38	MidAmerican Energy	Iowa	4.79	38
39	Public Service Company of Oklahoma	Oklahoma	4.20	39
40	OG&E Electric Services	Oklahoma	3.76	40
41	MidAmerican Energy	South Dakota	3.32	41

Source: EEI Typical Bills and Average Rates Report

Notes:

- MidAmerican Energy Iowa Rates are calculated as the average of East, North, and South System
- Weighting = 4 months 2017 summer rate and 8 months 2017 winter rate

KANSAS CITY POWER & LIGHT COMPANY
2018 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 6/30/2017

LINE NO.	DESCRIPTION	MISSOURI RETAIL (1)	RESIDENTIAL (2)	SMALL GEN. SERVICE (3)	MEDIUM GEN. SERVICE (4)	LARGE GEN. SERVICE (5)	LARGE PWR SERVICE (6)	TOTAL LIGHTING (7)
0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE							
0020								
0030	OPERATING REVENUE							
0040	RETAIL SALES REVENUE	870,989,124	338,121,886	58,411,963	132,367,581	190,095,339	141,652,131	10,340,224
0050	OTHER OPERATING REVENUE	303,325,239	96,404,901	15,441,996	44,453,630	74,691,529	69,249,304	3,083,880
0060	TOTAL OPERATING REVENUE	1,174,314,363	434,526,788	73,853,958	176,821,211	264,786,867	210,901,434	13,424,104
0070								
0080	OPERATING EXPENSES							
0090	FUEL	165,926,224	53,379,845	8,427,153	24,263,314	40,466,894	37,752,327	1,636,690
0100	PURCHASED POWER	275,438,518	86,595,215	13,984,639	40,381,734	68,203,206	63,480,981	2,792,743
0110	OTHER OPERATION & MAINTENANCE EXPENSES	299,498,569	151,126,121	17,726,941	38,122,858	51,030,623	38,817,951	2,674,075
0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	124,617,389	58,845,381	7,039,001	18,339,078	22,857,562	15,750,500	1,785,868
0130	AMORTIZATION EXPENSES	25,525,373	11,735,311	1,415,867	3,769,815	4,919,125	3,449,120	236,135
0140	TAXES OTHER THAN INCOME TAXES	64,993,344	30,469,547	3,659,239	9,383,915	12,240,444	8,636,539	603,660
0150	CURRENT INCOME TAXES	32,259,407	433,393	4,223,778	7,468,230	11,808,403	7,424,730	900,872
0160	DEFERRED INCOME TAXES	2,449,517	1,171,561	139,528	356,526	449,810	306,508	25,584
0170	TOTAL ELECTRIC OPERATING EXPENSES	990,708,340	393,756,374	56,616,147	142,085,470	211,976,066	175,618,657	10,655,627
0180								
0190	NET ELECTRIC OPERATING INCOME	183,606,023	40,770,414	17,237,812	34,735,741	52,810,801	35,282,777	2,768,477
0200								
0210	RATE BASE							
0220	TOTAL ELECTRIC PLANT	5,564,493,533	2,598,855,070	312,391,787	810,336,219	1,053,547,398	737,945,909	51,417,151
0230	LESS: ACCUM. PROV. FOR DEPREC	2,245,853,467	1,051,302,484	126,564,795	322,839,125	423,128,344	299,040,798	22,977,921
0240	NET PLANT	3,318,640,066	1,547,552,585	185,826,992	487,497,094	630,419,053	438,905,111	28,439,230
0250	PLUS:							
0260	CASH WORKING CAPITAL	(58,635,031)	(26,382,537)	(3,519,964)	(8,644,775)	(11,461,442)	(8,038,208)	(588,105)
0270	MATERIALS & SUPPLIES	64,704,386	28,893,393	3,525,254	9,582,207	12,899,784	9,288,758	514,990
0280	PREPAYMENTS	7,053,628	3,099,469	381,218	1,034,481	1,433,819	1,058,373	46,269
0290	FUEL INVENTORY	67,502,104	21,528,343	3,424,765	9,866,004	16,523,204	15,486,117	673,671
0300	REGULATORY ASSETS	55,949,144	22,729,460	2,991,270	8,438,596	12,247,177	9,138,459	404,182
0310	LESS:							
0320	CUSTOMER ADVANCES FOR CONSTRUCTION	1,668,576	948,764	106,123	240,886	230,100	109,499	33,204
0330	CUSTOMER DEPOSITS	4,337,669	2,306,087	1,638,070	335,782	54,077	3,654	0
0340	DEFERRED INCOME TAXES	789,779,808	368,860,750	44,338,397	115,012,657	149,532,110	104,738,154	7,297,740
0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	31,794,080	9,995,752	1,614,258	4,661,295	7,872,748	7,327,658	322,368
0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	0	0	0	0	0	0	0
0370	INCOME ELIGIBLE WEATHERIZATION	861,057	861,057	0	0	0	0	0
0380	TOTAL RATE BASE	2,626,773,107	1,214,448,303	144,932,687	387,522,988.3	504,372,559	353,659,645	21,836,925
0390								
0400	RATE OF RETURN	6.99%	3.36%	11.89%	8.96%	10.47%	9.98%	12.68%
0410	RELATIVE RATE OF RETURN	1.00	0.48	1.70	1.28	1.50	1.43	1.81

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2018-0145

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to
Cost of Service 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 @ Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	\$ 338,122	\$ 1,214,448	\$ 40,770	3.357%	48	\$ 84,887	\$ 44,117	\$ 59,178	17.5%
2	Small General Service	58,412	144,933	17,238	11.894%	170	10,130	(7,107)	(9,534)	-16.3%
3	Medium General Service	132,368	387,523	34,736	8.964%	128	27,087	(7,649)	(10,260)	-7.8%
4	Large General Service	190,095	504,373	52,811	10.471%	150	35,255	(17,556)	(23,550)	-12.4%
5	Large Power Service	141,652	353,660	35,283	9.976%	143	24,720	(10,563)	(14,169)	-10.0%
6	Total Lighting	<u>10,340</u>	<u>21,837</u>	<u>2,768</u>	12.678%	181	<u>1,526</u>	<u>(1,242)</u>	<u>(1,666)</u>	-16.1%
7	Total	\$ 870,989	\$ 2,626,773	\$ 183,606	6.990%	100	\$ 183,606	\$ (0)	\$ (0)	0.0%

Source: Schedule MEB-COS-3

KANSAS CITY POWER & LIGHT COMPANY

Case No. ER-2018-0145

**Cost of Service Adjustments for
50% Movement Toward
Cost of Service at Present Rates
(\$ in Millions)**

<u>Line</u>	<u>Rate Class</u>	<u>Current Revenues (1)</u>	<u>Move 50% Toward Cost Of Service⁽¹⁾ (2)</u>	<u>Adjusted Current Revenue (3)</u>	<u>Revenue-neutral Percent Increase in Current Revenue (4)</u>
1	Residential	\$ 338.1	\$ 29.6	\$ 367.7	8.8 %
2	Small General Service	58.4	(4.8)	53.6	(8.2)%
3	Medium General Service	132.4	(5.1)	127.2	(3.9)%
4	Large General Service	190.1	(11.8)	178.3	(6.2)%
5	Large Power Service	141.7	(7.1)	134.6	(5.0)%
6	Total Lighting	<u>10.3</u>	<u>(0.8)</u>	<u>9.5</u>	(8.1)%
7	Total	\$ 871.0	\$ -	\$ 871.0	(0.0)%

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-4, times 50%.

KANSAS CITY POWER & LIGHT COMPANY

Case No. ER-2018-0145

**Cost of Service Adjustments for
25% Movement Toward
Cost of Service at Present Rates
(\$ in Millions)**

<u>Line</u>	<u>Rate Class</u>	<u>Current Revenues (1)</u>	<u>Move 25% Toward Cost Of Service⁽¹⁾ (2)</u>	<u>Adjusted Current Revenue (3)</u>	<u>Revenue-neutral Percent Increase in Current Revenue (4)</u>
1	Residential	\$ 338.1	\$ 14.8	\$ 352.9	4.4 %
2	Small General Service	58.4	(2.4)	56.0	(4.1)%
3	Medium General Service	132.4	(2.6)	129.8	(1.9)%
4	Large General Service	190.1	(5.9)	184.2	(3.1)%
5	Large Power Service	141.7	(3.5)	138.1	(2.5)%
6	Total Lighting	<u>10.3</u>	<u>(0.4)</u>	<u>9.9</u>	(4.0)%
7	Total	\$ 871.0	\$ -	\$ 871.0	(0.0)%

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-4, times 25%.