

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

**AN ADJUSTMENT OF THE ELECTRIC  
RATES, TERMS AND CONDITIONS  
OF KENTUCKY UTILITIES COMPANY**

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**CASE NO: 2003-00434**

**DIRECT TESTIMONY OF  
WILLIAM STEVEN SEELYE**

**PRINCIPAL & SENIOR CONSULTANT  
THE PRIME GROUP, LLC**

**December 29, 2003**

**Filed: December 29, 2003**

1 **Q. Please state your name and business address.**

2 A. My name is William Steven Seelye and my business address is The Prime Group, LLC,  
3 6435 West Highway 146, Crestwood, Kentucky, 40014.

4 **Q. By whom are you employed?**

5 A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in  
6 Crestwood, Kentucky, providing consulting and educational services in the areas of  
7 utility marketing, regulatory analysis, cost of service, rate design and fuel and power  
8 procurement.

9 **Q. What is the purpose of your testimony in this proceeding?**

10 A. The purpose of my testimony is to sponsor fully allocated class cost of service studies  
11 based on Kentucky Utilities Company's ("Kentucky Utilities" or "KU's") embedded  
12 cost of providing service for the 12 months ended September 30, 2003, to sponsor certain  
13 pro-forma revenue and expense adjustments, to describe the proposed allocation of the  
14 revenue increase, to sponsor KU's proposed rates for electric service, and to discuss the  
15 revenue impact of modifying certain miscellaneous charges.

16 **Q. Please summarize your testimony.**

17 A. We prepared a fully allocated, embedded cost of service study using cost of service  
18 methodologies that have been accepted by the Commission in previous rate cases. The  
19 purpose of this study is to determine the contribution that each customer class is making  
20 towards KU's overall rate of return. Rates of return are computed for each rate class.  
21 KU's cost of service study shows a significant variation in the class rates of return.

22 KU was guided by the embedded cost of service study in allocating the proposed

1 revenue increase to the classes of service. However, to fully reflect the results of the  
2 cost of service study would have required the residential class to receive a rate increase  
3 of 25.3%. Therefore, in allocating the proposed electric increase KU moderated the  
4 increase allocated to residential and lighting customers. These increases were limited to  
5 approximately 1 percentage point above the overall percentage increase. Accordingly,  
6 KU is proposing an increase of 9.56% to the residential class as compared to 8.54% to  
7 ultimate consumers. The residential increase is thus slightly more than 1 percentage  
8 point above the overall increase. For other classes, we allocated the increase to facilitate  
9 the transition to cost of service as much as practicable.

10 In designing rates, we developed unit charges that more closely correspond to the  
11 unit costs indicated by the cost of service study. For residential rates, KU is proposing an  
12 increase in the customer charge that will reflect 63.3% of the customer-related costs  
13 shown in the cost of service study. Although we are not proposing to recover all of the  
14 customer-related costs through the customer charge, KU's proposed residential customer  
15 charge will represent a significant movement in the direction of reflecting cost of service.

16 KU is also proposing to eliminate the declining-block rate structure for residential  
17 customers. This rate structure cannot be strongly supported by cost of service results. In  
18 examining this issue we analyzed the relationship between customer load factor and  
19 customer usage and found that the relationship does not support a blocked rate structure.  
20 Specifically, three statistical analyses were performed: (i) a statistical analysis of the  
21 relationship between monthly non-coincident peak load factor and monthly kWh energy  
22 usage; (ii) a statistical analysis of the relationship between monthly coincident peak load

1 factor and customer usage during the summer months, (iii) a statistical analysis of the  
2 relationship between coincident peak load factor and monthly kWh energy usage during  
3 the winter months. The purpose of these regression analyses was to correlate energy  
4 usage to key drivers in the cost of service study, namely summer coincident demand,  
5 winter coincident demand, and maximum customer demands. These analyses indicate  
6 that there is only moderate support for a declining-block rate structure, and as a result,  
7 KU is proposing a flat energy charge, which is easier for customers to understand.

8 KU is proposing to transition the customer charge for commercial and industrial  
9 customers toward the customer-related costs indicated in the cost of service study.  
10 Additionally, we are proposing to move the demand and energy charges toward cost of  
11 service. This generally translated into decreasing the energy charge and increasing the  
12 demand charge for demand/energy rates. KU is also proposing to increase the per kW  
13 credit provided to curtailable/interruptible customers based on the results of an analysis  
14 of current avoided capacity costs of a combustion turbine.

15 We are implementing a redundant capacity charge for customers with backup  
16 distribution feeds. As they rely more heavily on technology, commercial and industrial  
17 customers are installing backup distribution feeds with automatic switchgear to guard  
18 against electric service interruptions. KU's proposed redundant capacity rate will allow  
19 the utility to provide this service without adversely impacting other customers that do not  
20 require the same level of reliability.

21 As much as possible, we are also trying to simplify KU's rate schedules and tariff  
22 language. KU is consolidating several rate schedules, including, for example, the

1 residential service (Rate RS) is being consolidated with full electric residential service  
2 (Rate FERS), and the high load-factor rate (Rate HLF) is being consolidated with  
3 combined lighting and power service (Rate LP). Furthermore, we are making changes  
4 to harmonize the service schedules offered by KU and LG&E so that operating practices  
5 and policies are more consistent between the two companies. The companies have  
6 consolidated many of the operating departments that use the tariffs and explain the rate  
7 schedules to customers. Harmonizing the tariffs is important if the utilities are to achieve  
8 the cost savings contemplated by their merger.

9 **Q. Are you supporting certain information required by Commission regulations 807**  
10 **KAR 5:001, Section 10(6)(a)-(v)?**

11 A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:  
12

- |    |                                       |                  |        |
|----|---------------------------------------|------------------|--------|
| 13 | • New Rates Effect – Overall Revenues | Section 10(6)(d) | Tab 23 |
| 14 | • Average Customer Class Bill Impact  | Section 10(6)(e) | Tab 24 |
| 15 | • Analysis of Customer Bills          | Section 10(6)(g) | Tab 26 |
| 16 | • Cost of Service Study               | Section 10(6)(u) | Tab 40 |
| 17 | • Period-End Customer Additions       | Section 10(7)(e) | Tab 46 |

18  
19 **Q. How is your testimony organized?**

20 A. My testimony is divided into the following sections: (I) Qualifications, (II) the  
21 Jurisdictional Separation Study, (III) Cost of Service, (IV) Pro-forma Adjustments, (V)  
22 Revenue Allocation and Rates, and (VI) Miscellaneous Service Charges.  
23

1 **I. QUALIFICATIONS**

2 **Q. Please describe your educational background and prior work experience.**

3 A. I received a Bachelor of Science degree in Mathematics from the University of Louisville  
4 in 1979. I have also completed 54 hours of graduate level course work in Industrial  
5 Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville  
6 Gas and Electric Company (“LG&E”). From May 1979 until December, 1990, I held  
7 various positions within the Rate Department of LG&E. In December 1990, I became  
8 Manager of Rates and Regulatory Analysis. In May 1994, I was given additional  
9 responsibilities in the marketing area and was promoted to Manager of Market  
10 Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with  
11 two other former employees of LG&E.

12 Since leaving LG&E, I have provided consulting services to numerous investor-  
13 owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate  
14 and regulatory filings, cost of service and wholesale and retail rate designs. Specifically,  
15 I have prepared and filed Order No. 888 and Order No. 889 compliance filings at the  
16 Federal Energy Regulatory Commission (“FERC”) for a number of electric utilities as  
17 well as Order No. 888 and Order No. 889 waiver requests for other utilities. I have  
18 prepared market power analyses in support of market-based rate filings at FERC for  
19 utilities and their marketing affiliates, as well as assisting other utilities with their  
20 market-based rate filings. I have assisted utilities with developing strategic marketing  
21 plans and implementing these plans. I have provided utility clients with assistance  
22 regarding regulatory policy and strategy; state and federal regulatory filing development;

1 cost of service development and support; the development of innovative rates to achieve  
2 strategic objectives; the unbundling of rates and the development of menus of rate  
3 alternatives for use with customers; performance-based rate development; and energy  
4 marketing and brokering capability development. I have provided training to account  
5 executives in sales and customer negotiation, as well as providing training in ratemaking  
6 and utility finance regarding basic utility marketing. I have provided marketing, market  
7 research and marketing support services for utility clients and have assisted them in  
8 assessing their marketing capabilities and processes.

9 **Q. Have you ever testified before any state or federal regulatory commissions?**

10 A. Yes, on a number of occasions. In Kentucky, I testified in Administrative Case No. 244  
11 regarding rates for cogenerators and small power producers, Case No. 8924 regarding  
12 marginal cost of service and in numerous 6-month and 2-year fuel adjustment clause  
13 proceedings. I testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg  
14 City's Utilities Commission ("Prestonsburg") rates. I testified in Case No. 99-046 on  
15 behalf of Delta Natural Gas Company, Inc. ("Delta") concerning its rate stabilization plan  
16 and in Case No. 99-176 concerning cost of service, rate design and expense adjustments  
17 in connection with Delta's rate case. In Case No. 2000-080, I testified on behalf of  
18 Louisville Gas and Electric Company concerning cost of service, rate design, and pro-  
19 forma adjustments to revenues and expenses. In Florida, I testified in Docket No. 981827  
20 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric  
21 Cooperative Inc.'s wholesale rates and cost of service. I also testified in Alabama in  
22 Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and

1 pro-forma revenue adjustments. In Illinois, I testified in Docket No. 01-0637 on behalf  
2 of Central Illinois Light Company (“CILCO”) concerning the modification of interim  
3 supply service and the implementation of black start service in connection with providing  
4 unbundled electric service. In Colorado, I testified in Consolidated Docket Nos. 01F-  
5 530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory  
6 dispute case. I submitted rebuttal testimony in Case No. 2000-548 on behalf of  
7 Louisville Gas and Electric Company regarding the company’s prepaid metering  
8 program. I submitted testimony on behalf of Louisville Gas and Electric Company in  
9 Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-  
10 00429 regarding the calculation of merger savings. I testified before the FERC in  
11 Docket No. EL02-25-000 et al. concerning Public Service of Colorado’s fuel cost  
12 adjustment. I testified before the Public Utilities Commission of Nevada on behalf of  
13 Nevada Power Company in Case No. 03-10001 regarding cash working capital. Most  
14 recently, I testified before the Public Utilities Commission of Nevada on behalf of Sierra  
15 Pacific Power Company in Case No. 03-12002 regarding cash working capital.

1 **III. Jurisdictional Separation Study**

2 **Q. Was a jurisdictional separation study performed to allocate costs between the**  
3 **Kentucky retail jurisdiction and other jurisdictions not regulated by the**  
4 **Commission?**

5 A. Yes. I supervised and participated in the preparation of a jurisdictional separation study  
6 based on KU's accounting costs per books for the 12 months ended September 30, 2003.

7

8 **Q. Please explain how the study was performed.**

9 A. We used the same methodology as in prior jurisdictional separation studies, including the  
10 one accepted by the Commission in KU's last general rate case. Continuity in the  
11 methodology used to perform the jurisdictional separation study is extremely important  
12 because the study is used to allocate costs among four different jurisdictions – Kentucky  
13 retail, Virginia retail, Tennessee retail, and FERC wholesale. A methodology consistent  
14 with the cost allocation principles followed by the FERC was used in the study. If  
15 different methodologies were to be used from one study to another or from one  
16 jurisdiction to another, the utility could be denied the opportunity to recover prudently  
17 incurred costs or perhaps even allowed to over collect its costs.

18 **Q. What were the principal allocators used in the study?**

19 A. Two key allocators were used in the study: (1) a demand allocator based on the Average 12  
20 CP method which uses the 12 monthly system peak demands during the 12 months ended  
21 September 30, 2003, to allocate production and transmission fixed costs; (2) and an energy  
22 allocator based on the energy used within each jurisdiction. This methodology is consistent

1 with the methodologies utilized at the FERC. Distribution costs are specifically assigned  
2 among jurisdictions in the study.

3 **Q. Do the results of the jurisdictional separation study become the starting point for**  
4 **the embedded cost of service study that you performed?**

5 A. Yes. The results of the jurisdictional separation study are entered in the functional  
6 assignment section of the cost of service study described below. The revenue requirement  
7 exhibits and pro-forma adjustment schedules sponsored by S. Bradford Rives and Valerie L.  
8 Scott also utilize results from the jurisdictional separation study.

9 **Q. Is there an exhibit summarizing the results of the jurisdictional separation study?**

10 A. The results of the study are summarized in Schedule 1.38 to Rives Exhibit 1 and a copy of  
11 the full output of the jurisdictional separation study itself is included as Seelye Exhibit 1.

12  
13 **III. COST OF SERVICE**

14 **Q. Did you prepare a cost of service study for Kentucky Utilities based on financial and**  
15 **operating results for the 12 months ended September 30, 2003?**

16 A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost  
17 of service study for electric operations based on jurisdictionally allocated costs from the  
18 jurisdictional separation study. The cost of service study corresponds to the pro-forma  
19 financial exhibits included in the testimony of Mr. Rives. The objective in performing  
20 the electric cost of service study is to determine the rate of return on rate base that KU is  
21 earning from each customer class, which provides an indication as to whether KU's  
22 electric service rates reflect the cost of providing service to each customer class.

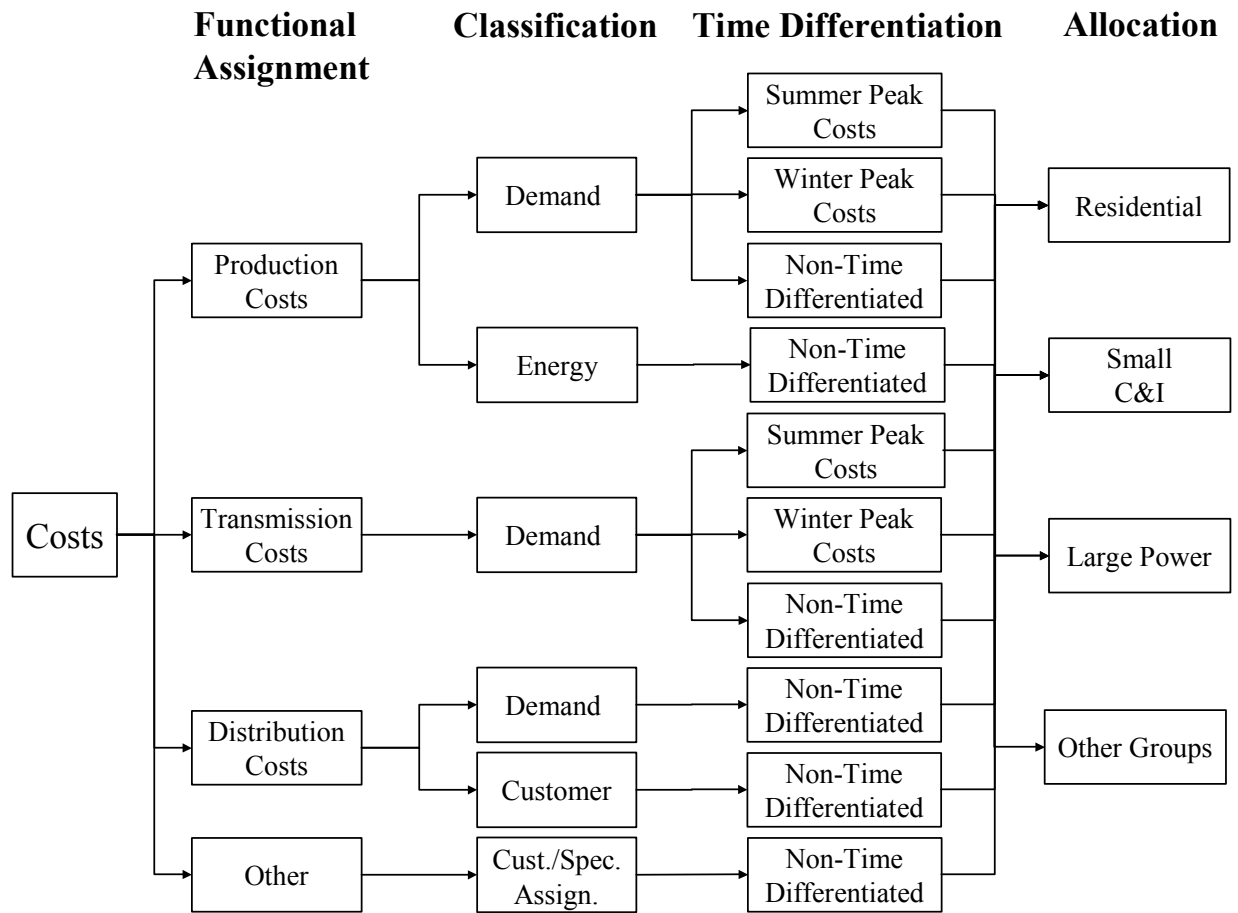
1 **Q. Did you develop the model used to perform LG&E’s cost of service studies?**

2 A. Yes. I developed the spreadsheet model used to perform the cost of service study being  
3 submitted in this proceeding.

4 **Q. What procedure was used in performing the cost of service study?**

5 A. The three traditional steps of an embedded cost of service study – functional assignment,  
6 classification, and allocation – were augmented to include a fourth step, assigning costs  
7 to costing periods. The cost of service study was therefore prepared using the following  
8 procedure: (1) costs were functionally assigned (*functionalized*) to the major functional  
9 groups; (2) costs were then *classified* as commodity-related, demand-related, or  
10 customer-related; (3) costs were assigned to the costing periods; and then (4) costs were  
11 allocated to KU’s rate classes. These steps are depicted in the following diagram (Figure  
12 1).

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**Figure 1**

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

1 **Q. Did you use the same methodology in KU’s cost of service study as was used in**  
2 **LG&E’s cost of service study filed concurrently in Case No. 2003-00433?**

3 A. Yes.

4 **Q. How were costs time differentiated in the study?**

5 A. A modified Base-Intermediate-Peak (“BIP”) methodology was used to assign production  
6 and transmission costs to the costing period.<sup>1</sup> Using this methodology, production and  
7 transmission demand-related costs were assigned to three categories of capacity – base,  
8 intermediate, and peak. Base costs were determined by dividing the minimum system  
9 demand by the maximum (summer) demand. Intermediate costs were calculated by  
10 dividing the winter peak demand by the summer peak demand and subtracting the base  
11 component. Peak costs included all costs not assigned to base and intermediate  
12 components.

13 Costs that were assigned as base, intermediate, and peak were then either assigned  
14 to the summer and winter peak periods or assigned as non-time-differentiated.

15 Intermediate costs were pro-rated to the winter and summer peak periods in the same  
16 ratio as the number of hours contained in each costing period to the total. Peak costs are  
17 assigned to the summer peak period.

18 **Q. How were the summer and winter peak periods determined?**

19 A. The summer peak period corresponds to the four-month period from June through  
20 September. The winter peak period corresponds to the eight non-summer months of

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1 In Case No. 90-158, LG&E’s last electric base rate case and the most recent rate case filed by either LG&E or KU, the Commission found LG&E’s cost of service study, which utilized the modified BIP methodology, to be “acceptable and suitable for use as a starting point for electric rate design.” (Order in Case No. 90-158, dated December 21, 1990, page 58.)

1 October through May. The load curves included in Seelye Exhibit 2 showing the  
2 monthly peak days in the summer and winter months support the selection of the hours in  
3 the summer and winter peak periods. The hours between the hour ending 11 and the hour  
4 ending 21 of June through September were selected as the summer peak period. The  
5 hours between the hour ending 9 and the hour ending 22 of October through May were  
6 selected as the winter peak period. The load curve is flatter during the winter, thus  
7 necessitating a larger number of hours to be included in the peak period during the winter  
8 months.

9 We have shortened the peak periods from earlier cost of service studies, for a  
10 number of reasons. First, we believe that the costing periods are more reflective of the  
11 hours during which the company could realize a peak. Second, shortening the time  
12 periods in the company's time-of-day rates may provide customers with a greater  
13 opportunity to shift load to the off-peak period.

14 **Q. In determining the costing periods and applying the modified BIP methodology,**  
15 **what demands were used?**

16 A Demands for the combined LG&E and KU systems were used to determine the costing  
17 periods and in determining the percentages of production and transmission fixed cost  
18 assigned to the costing periods. Since the two systems are planned jointly it was  
19 important to develop costing periods and assign costs to the costing periods based on the  
20 combined loads for LG&E and KU. Developing the costing periods and allocation  
21 factors in the cost of service study do not result in any shifting in booked expenses of one  
22 utility to the other. LG&E's cost of service study relied on LG&E's accounting costs,

1 and KU's cost of service study relied on KU's accounting costs. The modified BIP  
2 methodology simply affects how costs are assigned to the costing periods within the  
3 LG&E and KU cost of service studies.

4 **Q. What percentages were assigned to the costing periods?**

5 A Seelye Exhibit 3 shows the application of the modified BIP methodology. Using this  
6 methodology 26.45% of KU's production and transmission fixed costs were assigned to  
7 the summer peak period, 39.97% to the winter peak period, and 33.58% as non-time-  
8 differentiated.

9 **Q. How were costs classified as energy related, demand related or customer related?**

10 A. Classification provides a method of arranging costs so that the service characteristics that  
11 give rise to the costs can serve as a basis for allocation. Costs classified as *energy related*  
12 tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power  
13 expenses are examples of costs typically classified as energy costs. Costs classified as  
14 *demand related* tend to vary with the capacity needs of customers, such as the amount of  
15 generation, transmission or distribution equipment necessary to meet a customer's needs.  
16 Production plant and the cost of transmission lines are examples of costs typically  
17 classified as demand costs. Costs classified as *customer related* include costs incurred to  
18 serve customers regardless of the quantity of electric energy purchased or the peak  
19 requirements of the customers and include the cost of the minimum system necessary to  
20 provide a customer with access to the electric grid. As will be discussed later in my  
21 testimony, costs related to Distribution Primary Lines, Distribution Secondary Lines and  
22 Distribution Line Transformers were classified as demand-related and customer-related

1 using the zero-intercept methodology. Distribution Services, Distribution Meters,  
2 Distribution Street and Customer Lighting, Customer Accounts Expense, Customer  
3 Service and Information and Sales Expense were classified as customer-related.

4 **Q. Have you prepared an exhibit showing the results of the functional assignment,  
5 time-differentiation and classification steps of the electric cost of service study?**

6 A. Yes. Seelye Exhibit 4 shows the results of the first three steps of the electric cost of  
7 service study, functional assignment, time differentiation and classification.

8 **Q. Please describe the allocation factors used in the electric cost of service study.**

9 A. The following allocation factors were used in the KU electric cost of service study:

- 10
- 11 • **E01** – The energy cost component of purchased power  
12 costs was allocated on the basis of the kWh sales to each  
13 class of customers during the test year.
  - 14 • **PPWDA and PPSDA** – The winter demand and summer  
15 demand cost components of production and transmission  
16 fixed costs were allocated on the basis of each class's  
17 contribution to the coincident peak demand during the  
18 winter and summer peak hour of the test year.
  - 19 • **NCPP** – The demand cost component is allocated on the  
20 basis of the maximum class demands for primary and  
21 secondary voltage customer.
  - 22 • **SICD** – The demand cost component is allocated on the

- 1 basis of the sum of individual customer demands for  
2 secondary voltage customers.
- 3 • **C02** – The customer cost component of customer services  
4 is allocated on the basis of the average number of  
5 customers for the test year.
  - 6 • **C03** – Meter costs were specifically assigned by relating  
7 the costs associated with various types of meters to the  
8 class of customers for whom these meters were installed.
  - 9 • **YECust04** – Costs associated with lighting systems were  
10 specifically assigned to the lighting class of customers.
  - 11 • **YECust05 and YECust06** – Meter reading, billing costs  
12 and customer service expenses were allocated on the basis  
13 of a customer weighting factor based on discussions with  
14 LG&E’s meter reading, billing and customer service  
15 departments.
  - 16 • **Cust05** – The customer cost component is allocated on the  
17 basis of the average number of customers for the test year.
  - 18 • **YECust07** – The customer cost component is allocated on  
19 the basis of the year-end number of customers using line  
20 transformers and secondary voltage conductor.
  - 21 • **YECust08** – The customer cost component is allocated on  
22 the basis of the year-end number of customers using

1 primary voltage conductor.

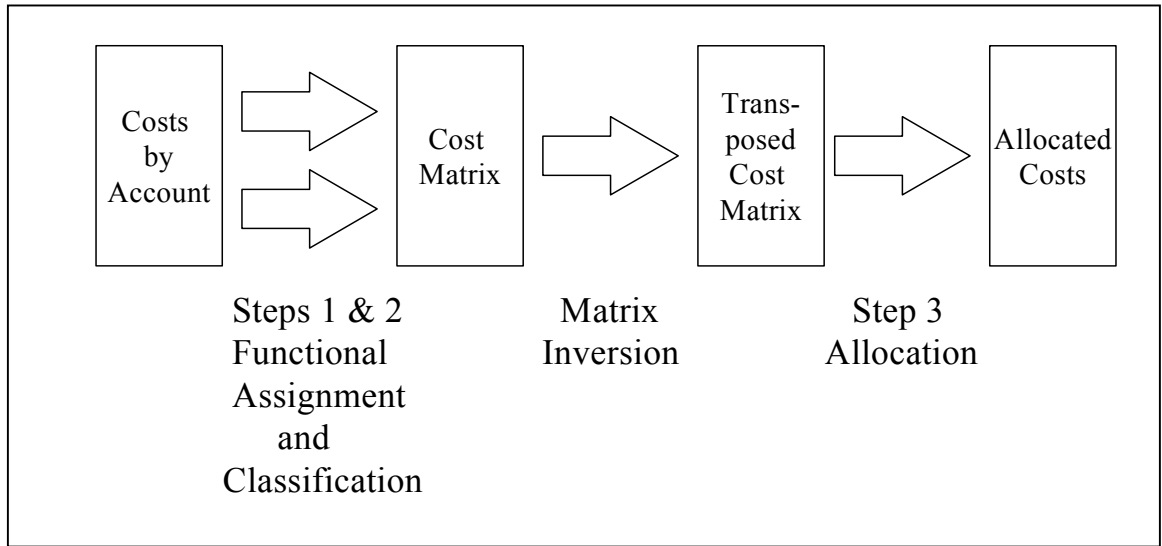
2 **Q. In your cost of service model, once costs are functionally assigned and classified,**  
3 **how are these costs allocated to the customer classes?**

4 A. In the cost of service model used in this study, KU's accounting costs are functionally  
5 assigned and classified using what are referred to in the model as "functional vectors".  
6 These vectors are multiplied (using *scalar multiplication*) by the various accounts in  
7 order to simultaneously assign costs to the functional groups and classify costs.  
8 Therefore, in the portion of the model included in Seelye Exhibit 4, KU's accounting  
9 costs are functionally assigned and classified using the explicitly determined functional  
10 vectors of the analysis and using internally generated functional vectors. The explicitly  
11 determined functional vectors, which are primarily used to direct where costs are  
12 functionally assigned and classified, are shown on pages 49 through 52. Internally  
13 generated functional vectors are utilized throughout the study to functionally assign costs  
14 on the basis of similar costs or on the basis of internal cost drivers. The internally  
15 generated functional vectors are also shown on pages 49 through 52 of Seelye Exhibit 4.  
16 An example of this process is the use of total operation and maintenance expenses less  
17 purchased power ("OMLPP") to allocate cash working capital included in rate base.  
18 Because cash working capital is determined on the basis of 12.5% of operation and  
19 maintenance expenses, exclusive of purchased power expenses, it is appropriate to  
20 functionally assign and classify these costs on the same basis. (See Seelye Exhibit 4,  
21 pages 9 through 12 for the functional assignment of cash working capital on the basis of  
22 OMLPP shown on pages 49 through 52.) The functional vector used to allocate a

1 specific cost is identified by the column in the model labeled “Vector” and refers to a  
2 vector identified elsewhere in the analysis by the column labeled “Name”.

3           Once costs for all of the major accounts are functionally assigned and classified,  
4 the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base,  
5 Operation and Maintenance Expenses) is then transposed and allocated to the customer  
6 classes using “allocation vectors” or “allocation factors”. This process is illustrated in  
7 Figure 2 below.

8



**Figure 2**

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 5. The costs shown in the column labeled “Total System” in Seelye Exhibit 5 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 4. The column labeled “Ref” in Seelye Exhibit 5 provides a reference to the results included in Seelye Exhibit 4.

**Q. What methodologies are commonly used to classify distribution plant?**

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the “minimum system” methodology and the “zero-intercept” methodology. In the minimum system approach, “minimum” standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of these minimum size plant. The

1 minimum system determined in this manner is then classified as customer-related and  
2 allocated on the basis of the number of customers in each rate class. All costs in excess  
3 of the minimum system are classified as demand-related. The theory supporting this  
4 approach maintains that in order for a utility to serve even the smallest customer, it would  
5 have to install a minimum size system. Therefore, the costs associated with the minimum  
6 system are related to the number of customers that are served, instead of the demand  
7 imposed by the customers on the system.

8 In preparing this study, the “zero-intercept” methodology was used to determine  
9 the customer components of overhead conductor, underground conductor, and line  
10 transformers. Because the zero intercept methodology is less subjective than the  
11 minimum system approach, the zero-intercept methodology is strongly preferred over the  
12 minimum system methodology when the necessary data is available. With the zero  
13 intercept methodology, we are not forced to choose a minimum size conductor or line  
14 transformer to determine the customer component. In the zero-intercept methodology, a  
15 zero-size conductor or line transformer is the absolute minimum system.

16 **Q. What is the theory behind the zero-intercept methodology?**

17 A. The theory behind the zero intercept methodology is that there is a linear relationship  
18 between the unit cost (\$/ft or \$/transformer) of conductor or line transformers and the  
19 load flow capability of the plant, which is proportionate to the cross-sectional area of the  
20 conductor or the kVA rating of the transformer. After establishing a linear relation,  
21 which is given by the equation:

$$y = a + bx$$

where:

**y** is the unit cost of the conductor or transformer,

**x** is the size of the conductor (MCM) or transformer (kVA), and

**a, b** are the coefficients representing the

intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of conductor or transformers that is invariant to the size (and load carrying capability) of the plant.

Like most electric utilities, the number of feet of conductor on KU's system is not uniformly distributed over all sizes of wire. For example, KU has over 13.4 million feet of #4 ACRS overhead conductor, but only 120 feet of #8 CU Duplex overhead conductor. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis both types of conductor would have the same impact on the analysis, even though there is hundreds of thousands times more #4 ACRS conductor than #8 CU Duplex conductor.

1           Using a weighted regression analysis, the cost and size of each type of  
2 conductor or transformer is, in effect, weighted by the number of feet of installed  
3 conductor or the number of transformers. In a weighted regression analysis, the  
4 following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

5  
6 is minimized, where  $w$  is the weighting factor for each size of conductor or  
7 transformer, and  $y$  is the observed value and  $\hat{y}$  is the predicted value of the  
8 dependent variable.

9 **Q. Has the Commission accepted the use of the zero-intercept methodology?**

10 A. Yes. The Commission found the cost of service studies (both electric and gas) submitted  
11 in LG&E's last two base rate cases (Case No. 2000-080 and Case No. 90-158) to be  
12 reasonable, thus providing a means of measuring class rates of return and suitable for use  
13 as a guide in developing appropriate revenue allocations and rate design. The  
14 Commission also found the embedded cost of service study submitted by Union Light  
15 Heat and Power in its recent gas base rate case (Case No. 2001-00092), which utilized a  
16 zero-intercept methodology, to be reasonable.

17 **Q. Have you prepared exhibits showing the results of the zero-intercept analysis?**

18 A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and  
19 line transformers are included in Seelye Exhibits 6, 7, and 8.

1 **Q. Please summarize the results of the electric cost of service study.**

2 A. The following table (Table 1) summarizes the rates of return for each customer class  
3 before and after reflecting the rate adjustments proposed by KU. The Actual Adjusted  
4 Rate of Return was calculated by dividing the adjusted net operating income by the  
5 adjusted net cost rate base for each customer class. The adjusted net operating income  
6 and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The  
7 Proposed Rate of Return was calculated by dividing the net operating income adjusted  
8 for the proposed rate increase by the adjusted net cost rate base.

9

| <b>TABLE 1</b>                        |                                       |                                |
|---------------------------------------|---------------------------------------|--------------------------------|
| <b>Electric Class Rates of Return</b> |                                       |                                |
| <b>Customer Class</b>                 | <b>Actual Adjusted Rate of Return</b> | <b>Proposed Rate of Return</b> |
| <b>Residential</b>                    | 0.44%                                 | 2.41%                          |
| <b>General Service Rate</b>           | 5.66%                                 | 7.83%                          |
| <b>Large Power (LP &amp; HLF)</b>     | 8.06%                                 | 10.91%                         |
| <b>Large Power TOD</b>                | 7.08%                                 | 9.96%                          |
| <b>Coal Mining Power</b>              | 11.19%                                | 14.30%                         |
| <b>Coal Mining TOD</b>                | 8.77%                                 | 11.65%                         |
| <b>Special Contracts</b>              | 9.35%                                 | 8.96%                          |
| <b>Lighting</b>                       | 2.84%                                 | 4.12%                          |
| <b>Total System</b>                   | 3.93%                                 | 6.17%                          |

10

11 **VI. ELECTRIC PRO-FORMA ADJUSTMENTS**

12 **Q. Was an adjustment made to eliminate unbilled revenues for electric operations?**

13 A. Yes. Consistent with prior rate cases, the effect of unbilled revenues was removed from test-  
14 year operating revenues. For KU's electric operations, \$675,000 in unbilled revenue were  
15 added to test-year operating results. An adjustment to remove the effect of unbilled revenues

1 was accepted by the Commission in LG&E's last two base rate cases, Case No. 2000-080  
2 and Case No. 90-158. This adjustment is included in Schedule 1.00 of Rives Exhibit 1.

3 **Q. Has an adjustment been made to eliminate the mismatch in fuel cost recovery?**

4 A. Yes. Consistent with past Commission practice, the mismatch between fuel costs and fuel  
5 cost recovery through KU's fuel adjustment clause ("FAC") has been eliminated. These  
6 over- or under-recoveries were taken directly from KU's monthly FAC filings. This  
7 adjustment is included in Schedule 1.01 of Rives Exhibit 1.

8 **Q. Has an adjustment been made to reflect the roll-in of the FAC and Environmental  
9 Cost Recovery ("ECR") for a full year?**

10 A. Yes. Test-year revenues have been adjusted to reflect the rolled-in level of base rates and  
11 FAC and ECR billings for a full year. Seelye Exhibit 9 shows the impact on base rate  
12 revenues of the FAC and ECR roll-ins for a full year. Seelye Exhibit 10 shows the impact on  
13 FAC billings of reflecting the new base fuel cost (Fb/Sb) for a full year. The adjustment to  
14 reflect the FAC roll-in is included in Schedules 1.02 Rives Exhibit 1. The adjustment to  
15 reflect the ECR roll-in is included in Schedule 1.04 of Rives Exhibit 1.

16 **Q. Was an adjustment made to eliminate environmental cost recovery ("ECR")  
17 revenues and expenses?**

18 A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses  
19 associated with full-recovery cost trackers, an adjustment was made to eliminate  
20 \$25,039,979 of ECR revenues and \$248,468 in ECR costs. The ECR surcharge provides for  
21 full recovery of environmental costs that qualify for the surcharge and contains a mechanism  
22 to true up actual ECR revenues to allowed ECR revenues under the surcharge. The

1 adjustment to revenues of \$25,039,979 includes all ECR billings during the test year  
2 (including ECR recoveries for the 1994 Plan and for the post-1994 Plan). The adjustment to  
3 expenses of \$248,468 includes operating expenses recovered under the ECR during the test  
4 year for compliance costs that will continue to be recovered through the surcharge (i.e.,  
5 operating expenses relating to the post-1994 Plan). Because KU is proposing to eliminate  
6 the 1994 Plan from its monthly Environmental Surcharge filings on a going-forward  
7 basis, only the operating expenses associated with the post-1994 Plan are eliminated in  
8 this adjustment. However, all ECR revenues collected in the test year are eliminated  
9 because failure to do so would overstate KU's adjusted operating revenues by that  
10 portion of ECR revenues not eliminated. KU proposes to recover the revenue  
11 requirements on any remaining rate base in the 1994 Plan through base rates, and  
12 proposes to recover revenue requirements of remaining rate base in the post-1994 Plan  
13 through the monthly Environmental Surcharge filings. KU's capitalization includes an  
14 adjustment to eliminate the ECR rate base for the post-1994 Plan and does not include an  
15 adjustment for the ECR rate base for the 1994 Plan (see Rives Exhibit 2). This  
16 adjustment is included in Schedule 1.03 of Rives Exhibit 1.

17 **Q. Please explain the off-system sales revenue adjustment for the ECR calculation**  
18 **shown in Schedule 1.05 of Rives Exhibit 1.**

19 A. In the determination of the ECR surcharge, a portion of KU's environmental compliance  
20 costs recovered through the surcharge are allocated to off-system sales. However, by  
21 including off-system revenues in test-year operating results, off-system revenues are credited  
22 to jurisdictional customers. This results in an overstatement of margins from off-system

1 sales and a mismatch of the revenues and expenses relating to the off-system sales portion of  
2 the allocated environmental surcharge monthly revenue requirement. Therefore, consistent  
3 with the methodology prescribed in the Commission's Order on rehearing in Case No. 98-  
4 474 dated June 1, 2000, an adjustment of \$776,418 was made to reduce revenues to reflect  
5 the environmental surcharge calculations recognized in the determination of off-system  
6 sales.

7 **Q. Was an adjustment made to eliminate demand-side management revenues and**  
8 **expenses from test-year operating results?**

9 A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses  
10 associated with full-recovery cost trackers, an adjustment was made to eliminate \$2,942,935  
11 of revenue recovered through the Demand-Side Management Cost Recovery Mechanism  
12 ("DSMRM") and the corresponding \$2,946,471 of demand-side management expenses  
13 recorded during the test year. The DSMRM includes a balance adjustment that  
14 automatically adjusts unit charges under the mechanism to account for differences between  
15 revenues collected and demand-side management program costs incurred during the  
16 applicable period. This adjustment is included in Schedule 1.09 of Rives Exhibit 1.

17 **Q. Was an adjustment made to annualize for year-end customers for the electric**  
18 **business?**

19 A. Yes. The numbers of customers served at the end of the test period for the rate classes  
20 were higher than the average numbers of customers for the 12-month test period. The  
21 differences between the number of customers served at year-end and the average number  
22 for each rate class during the test period was multiplied by the average annual kWh usage

1 per customer. The average usage for each rate class was then multiplied by the average  
2 revenue per kWh (including customer charges, energy charges, demand charges and  
3 minimum bills), resulting in an upward adjustment to electric operating revenue of  
4 \$251,167.

5 The additional operating expenses associated with serving the higher number of  
6 customers and volumes were calculated by applying an operating ratio to the revenue  
7 adjustment. Consistent with the Commission's practice, the operating ratio of 60.28  
8 percent was determined by dividing operation and maintenance expenses, exclusive of  
9 wages and salaries, pensions and benefits, and regulatory commission expenses, by base  
10 rate revenues calculated at the currently effective rates. When applied to the year-end  
11 revenue adjustment, the application of the operating ratio resulted in an upward  
12 adjustment to expenses of \$151,410.

13 The detailed calculations of the electric year-end adjustment to revenues and  
14 expenses are contained in Seelye Exhibit 11. This adjustment is included in Schedule  
15 1.10 of Rives Exhibit 1.

16 **Q. Please explain the adjustment to reflect customers switching to other rates during**  
17 **the test year.**

18 A. Seelye Exhibit 12 includes an adjustment to reflect the change in revenue due to a  
19 customer switching from a special contract rate to KU's proposed Non-Conforming Load  
20 Service Rate NCLS (with interruptible service) resulting in a decrease in revenue of  
21 \$1,898,980. The transfer of the special contract customer is currently being considered in

1 Case No. 2003-396, which has not been set for hearing. This adjustment is included in  
2 Schedule 1.28 of Rives Exhibit 1.

3  
4 **V. ALLOCATION OF ELECTRIC REVENUE INCREASE AND RATE DESIGN**

5 **Q. Have you prepared an exhibit reconstructing KU's test-year billing units for the**  
6 **electric business?**

7 A. Yes. The reconstruction of KU's electric billing determinants is shown on Exhibit 13. As  
8 shown in the column labeled "Calculated Divided by Actual" of Seelye Exhibit 13, page 1,  
9 the net base rate revenues calculated on pages 2 through 32 of that exhibit were within a  
10 factor of 0.998557 of KU's actual net revenues, thus, confirming the accuracy of the test  
11 period billing determinants.

12 **Q. After considering all of the required adjustments, what is the proposed increase in**  
13 **revenues and how is the increase allocated among the individual customer classes?**

14 A. In this filing, KU is proposing to increase its annual electric revenues by \$58,252,463  
15 (reflecting a revenue deficiency of \$58,254,344 shown on Exhibit 7 of Mr. Rives'  
16 testimony). Seelye Exhibit 14 shows that the proposed increase would result in an increase  
17 of 8.54% percent in jurisdictional revenues from sales to ultimate consumers. KU is also  
18 proposing to increase certain miscellaneous charges and to decrease lease charges, resulting  
19 in a net increase in miscellaneous revenues.

20 The proposed rates apportion the revenue increase among the customer classes as  
21 follows:

|   |
|---|
| <b>Table 2</b><br><b>Proposed Electric Increase</b> |
|---|

| <b>Customer Class</b>                        | <b>Proposed Increase</b> | <b>Percentage</b> |
|--|--------------------------|-------------------|
| <b>Residential</b>                           | \$24,185,323             | 9.56%             |
| <b>General Service</b>                       | \$ 5,792,730             | 8.74%             |
| <b>Combined Lighting &amp; Power Service</b> | \$18,885,564             | 8.32%             |
| <b>Commercial/Industrial TOD</b>             | \$ 6,725,688             | 7.99%             |
| <b>Coal Mining Power Service</b>             | \$ 725,107               | 8.49%             |
| <b>Large Mine Power TOD</b>                  | \$ 513,353               | 8.49%             |
| <b>Special Contracts</b>                     | (\$ 202,024)             | (1.39%)           |
| <b>Lighting</b>                              | \$ 1,179,334             | 8.80%             |
| <b>Total Ultimate Consumers</b>              | \$57,805,074             | 8.54%             |

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As shown on Seelye Exhibit 15, the effects on individual class revenues were determined by applying both the current and proposed prices to the adjusted billing determinants for each customer class.

**Q. How was the proposed allocation among the rate classes determined?**

A. We were guided by the cost of service study in allocating the proposed increase among the rate classes, but did not follow the cost of service study precisely. If KU had tried to equalize the rates for return by rate classes, the residential rate would have received an increase of 25.30%, as shown in Seelye Exhibit 16. KU thus limited the increase that Rate RS could receive to approximately one percentage point above the overall percentage increase to ultimate consumers, as discussed in Mr. Beer’s testimony. Consequently, KU is proposing an increase of 9.56% to the residential class and 8.54% to ultimate consumers. The Company provided me with strong guidance that the residential increase should be no more than approximately 9.6%. KU wanted to transition towards a better balance between class rates of return, while at the same time recognizing other ratemaking objectives, such as

1 customer acceptance, gradualism and the need to maintain price stability by avoiding overly  
2 disruptive changes.

3 **Q. How were the increases allocated to the other rate classes?**

4 A. The class rates of return fell within a pattern of four groups. One group contained rate  
5 classes that were reasonably close to the overall rate of return. Another group contained  
6 classes significantly below the overall rate of return. Yet, another group contained classes  
7 above the overall rate of return, and, finally, one rate class (All Electric Schools and one  
8 special contract) were significantly above the overall rate of return. Therefore, we developed  
9 three increase tiers for allocating the KU electric increase. The first tier, applicable to  
10 customer classes with rates of return below the overall rate of return, such as the residential  
11 class, was set at *approximately* 9.6%. This approximate increase was applied to the  
12 residential class and lighting customer classes. The second tier was determined by applying  
13 the overall approximate increase to certain classes, such as some of the lighting rates and  
14 mining rates. With the exception of mining rates, this increase was applied to customer  
15 classes whose return was reasonably close to the overall return. Our objective with  
16 increasing mining rates at the overall percentage increase was to begin moving in the  
17 direction of transitioning these customers to the otherwise applicable standard rate schedule  
18 (either LP or LCI). The third tier was developed on the basis of the percentage required to  
19 produce the required increase requested by KU. This increase tier was approximately 8.3%.  
20 KU is not proposing an increase to either All Electric Schools Rate AES or National  
21 American Stainless. Given the high rates of return, an increase for these two classes cannot  
22 be justified.

1 **Q. If you used only three tiers, why do some of the increases to the rate classes appear**  
2 **to vary from these percentages?**

3 A. There are several reasons. First, the three-tier approach described previously was a general  
4 rule that was not strictly followed. Rate design for this number of rate schedules is too  
5 complex to use a simple “one size fits all” rule of thumb. Second, and more significantly,  
6 there were other rate design objectives that we followed. For example, because we also tried  
7 to more accurately reflect the demand/energy cost relationship in the company’s  
8 demand/energy rates, some customers will be impacted more than others. It is virtually  
9 impossible to transition toward cost of service without producing these sorts of effects.  
10 Third, some of the apparent increases are due to the fact that KU is proposing a significant  
11 increase in the Curtailable Service Rider (“CSR”) credit. Customers taking interruptible  
12 service will see a lower overall increase. Changes to Curtailable Service will be discussed  
13 later in my testimony.

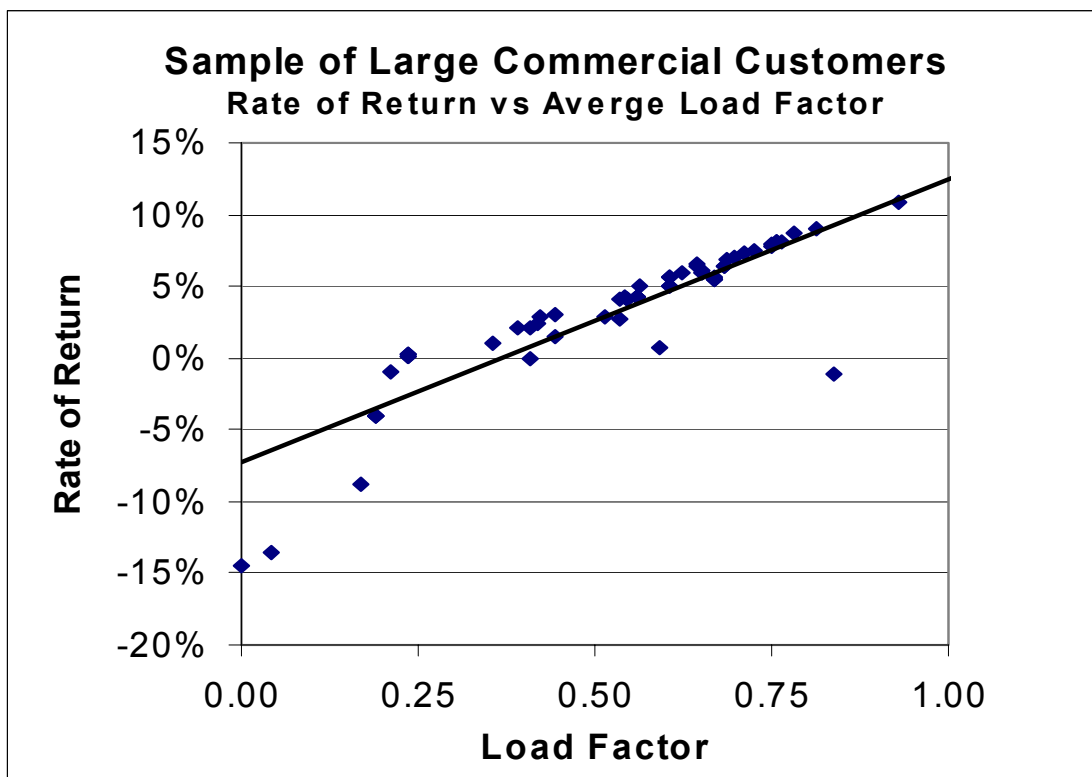
14 **Q. What guidelines were followed in designing the electric rates?**

15 A. Unit charges were developed that would transition toward the unit costs indicated in the  
16 electric cost of service study. For KU’s two-part rates consisting of a customer charge and  
17 energy charge, such as Residential Rate RS and General Service Rate GS, the customer  
18 charges were increased to cover more of the customer-related costs identified in the cost of  
19 service study, and energy charges were set at a level that more properly reflected energy- and  
20 demand-related costs. Similarly, for KU’s three-part rates consisting of a customer charge,  
21 demand charge and energy charge, such as the Lighting & Power and Large Commercial &  
22 Industrial rates, unit charges were selected that more closely followed the unit costs

1 determined in the cost of service study, which in most cases translated into increasing the  
2 customer and demand charges but lowering the energy charge.

3 **Q. Why is it important to develop energy and demand charges for commercial and**  
4 **industrial rates that reflect unit costs identified in the cost of service study?**

5 A. Just as there are different rates of return from one class of service to another, there are  
6 different rates for return from one customer to another within any given customer class. If  
7 the unit charges in a utility's rate schedule do not reflect cost of service, then the differences  
8 in intra-class rates of return (as opposed to inter-class rates of return) can be significant. The  
9 following graph of a typical group of large commercial customers illustrates this point.



10 In this graph, individual rates of return (or "individual customer profitability") are graphed  
11 against load factor. The upward slope in the graph illustrates that with a demand-energy rate  
12

1 that does not properly reflect the cost of providing service, the individual rates of return for  
2 customers with high load factors are significantly greater than customers with low load  
3 factors within the same class. High load-factor customers are thus being penalized instead of  
4 rewarded for having a more constant usage pattern. This situation can be alleviated, or at  
5 least mitigated, by designing rates that do not recover too much of a utility's fixed costs  
6 through the energy charge. A properly designed rate will flatten the linear trend line shown  
7 in the graph, thus eliminating intra-class subsidies. Ignoring the results of a cost of service  
8 study can cause individual rates of return within a class to get further and further out of line,  
9 creating even greater intra-class subsidies.

10 **Q. Has KU made any general changes to the electric tariffs or other changes not**  
11 **specifically discussed in your testimony?**

12 A. Yes. KU's electric rate schedules have been updated to include a listing of all applicable  
13 adjustment clauses. There are a number of changes that have been proposed to simplify or  
14 clarify the language in the electric tariff or to re-organize the structure of the tariff which are  
15 not detailed in my testimony. Other changes are discussed in L. "Butch" Cockerill's  
16 testimony.

17 **Q. Please describe the current rate structure for Rate RS.**

18 A. Rate RS is a two-part rate consisting of a customer charge and an energy charge. The  
19 energy charge is structured as a declining-block rate. KU is proposing to eliminate the  
20 declining-block structure.

1 **Q. What is a declining-block rate structure?**

2 A. A declining-block rate, or “declining step” rate as it is sometimes called, is a rate where the  
3 charges *decrease* at specified increments of usage. For example, in the case of KU’s current  
4 Residential Rate RS, the price for the first 100 kWh of customer usage is currently \$0.05017  
5 per kWh, the price for the next 300 kWh of customer usage is \$0.04572 per kWh, and all  
6 usage over 400 kWh the energy charge is \$0.04172 per kWh of customer usage. With a  
7 declining-block rate structure, a customer using a large amount of electric energy would  
8 receive a lower average price than a customer using a small amount of electric energy. In  
9 other words the rate goes down with increased usage. A declining-block rate is still a pricing  
10 structure that is commonly used within the industry.

11 **Q. How can a declining-block rate structure be supported based on the cost of**  
12 **providing service?**

13 A. Within a rate class, if the non-customer-related cost per kilowatt-hour for serving a smaller  
14 customer is higher than the cost per kilowatt-hour of serving a larger customer, then a  
15 declining-block rate can be supported.

16 **Q. Based on the cost drivers identified in the cost of service study, is there any basis for**  
17 **a declining block rate structure?**

18 A. A standard justification for a declining-block rate structure is to provide for recovery of  
19 customer-related costs through the initial block of the rate. If customer-related costs are  
20 recovered through the energy charge rather than through a customer-charge, then the cost per  
21 kilowatt-hour would certainly decrease in proportion with customer usage. However, if all  
22 customer-related costs are recovered through the customer charge, then there is less of a

1 justification for a declining-block structure. However, a declining block rate structure could  
2 be justified if it can be shown that demand-related costs, which would still be recovered  
3 through the energy charge in a two-part rate, go down as customer usage levels go up.  
4 Likewise, an inverted block rate structure (which consists of a pricing pattern that increases  
5 as usage goes up) could be justified if it can be shown that demand-related costs go up as  
6 customer usage levels go up. This would be equivalent to showing that customer load factor  
7 is either positively or negatively correlated with customer usage.

8 **Q. What do you mean by customer load factor?**

9 A. Customer load factor is the relationship between a customer's kWh usage and maximum  
10 demand, and can be calculated by dividing a customer's kWh usage by the customer's  
11 maximum demand multiplied by the number of hours over which the kWh usage was  
12 measured. Load factor can be determined by measuring the customer's maximum monthly  
13 demand or by measuring the customer's kW demand at the time of the utility system peak.

14 A blocked rate structure can be supported if there is a positive or negative correlation  
15 between a customer's load factor and kWh usage. If load factors within a customer class  
16 increase with greater usage, then a declining-block rate structure can be supported. However  
17 if load factors within a customer class decrease in relation to greater usage, then an inverted  
18 block rate structure can be supported.

19 **Q. Have you performed an analysis of this relationship?**

20 A. Yes. A statistical analysis was performed on KU's load research data to determine whether  
21 there is a relationship between load factor and kWh energy for residential customers. The  
22 data that was used was monthly load research data that contained observations for individual

1 customer energy usage, non-coincident peak demand and coincident peak demand.  
2 Coincident peak demands and non-coincident peak demands are key drivers in the electric  
3 cost of service study. Specifically, three statistical analyses were performed. First, the  
4 monthly non-coincident peak load factor for all customers in the sample for all months of the  
5 year was regressed on customers' monthly kWh energy usage. Second, the coincident peak  
6 load factor for all customers in the sample for the summer months of June, July, August, and  
7 September was regressed on customers' monthly kWh energy usage for those same months.  
8 Third, the coincident peak load factor for all customers in the sample for the non-summer  
9 months of January through May and October through December was regressed on  
10 customers' monthly kWh energy usage for those same months. The purpose of these  
11 regression analyses was to correlate energy usage to key drivers in the cost of service study,  
12 namely summer coincident demand, winter coincident demand, and maximum customer  
13 demands.

14 **Q. What did these analyses indicate?**

15 A. The linear regression analysis indicated a statistically significant relationship between  
16 monthly *non-coincident peak load factor* and monthly *energy usage* for KU residential  
17 customers based on observations for all months during the year. The regression coefficient  
18 for kWh energy usage is positive which indicates that kWh energy usage has a relationship  
19 with non-coincident peak load factor, with a t-value of 36.746 which indicates statistical  
20 significance at the 99% confidence level. In other words, the analysis indicated that non-  
21 coincident peak load factor increases with customer usage. However, the R-Square is only  
22 0.38, which indicates that only 38% of the variation in the non-coincident peak load can be

1 explained kWh usage. The results of this statistical analysis are contained in Seelye Exhibit  
2 17. These results suggest that there is a moderate basis for a declining-block rate structure  
3 year around based on non-coincident peak load factors.

4 The linear regression analysis did not indicate a statistically significant relationship  
5 between monthly *coincident peak load factor* and monthly *energy usage* for KU residential  
6 customers based on observations for the *summer months*. The t-value for kWh energy usage  
7 is -1.895, which is not statistically significant at the 95% level. This lack of relationship can  
8 be visually verified in the graph contained in Seelye Exhibit 18. The R-Square statistic of  
9 0.005 shows that summer kWh energy usage for KU residential customers explains only  
10 about 0.5% of the variation in summer coincident peak load factor. Stated differently, about  
11 99.5% of the variation in summer coincident peak load factor for KU residential customer is  
12 unexplained by this model. The results of this statistical analysis are contained in Seelye  
13 Exhibit 18. These results suggest that there is no basis for either a declining-block or an  
14 inverted-block rate structure during the summer months based on coincident peak load  
15 factors. This is extremely important given that summer peak period costs are allocated on  
16 the basis of coincident peaks during the summer months.

17 The linear regression analysis indicated a statistically significant relationship  
18 between monthly *coincident peak load factor* and monthly *energy usage* for the KU  
19 residential customers based on observations for the *winter months*. The regression  
20 coefficient for kWh energy usage is negative which indicates that kWh usage has an inverse  
21 relationship with winter coincident peak load factor, with a t-value of -5.522 which indicates  
22 statistical significance at the 99% confidence level. However, the R-Square statistic of 0.021

1 shows that only about 2.1% of the variation in winter coincident peak load factor can be  
2 explained by kWh usage. The results of this statistical analysis are contained in Seelye  
3 Exhibit 19. These results suggest that *there is no basis for either a declining-block or an*  
4 *inverted-block rate structure during the winter months* based on coincident peak load  
5 factors.

6 **Q. Do you believe that a declining-block rate or inverted-block rate can be strongly**  
7 **supported based on these analyses?**

8 A. No. The only support indicated by any of these analyses is for a year around declining-block  
9 rate as shown in the analysis of the non-coincident peak load factor. However, the R-Square  
10 supporting this conclusion is not strong. Furthermore, this analysis only relates to  
11 distribution demand-related costs. Even if, in spite of the relatively poor R-Square, a year  
12 around declining-block rate were developed based on distribution costs, the step in the rate  
13 would be very small because distribution demand-related costs are a relatively small portion  
14 of KU's total demand-related costs.

15 **Q. But doesn't the fact that production and transmission demand-related costs are higher**  
16 **in the summer than in the winter support an inverted block rate in the summer months**  
17 **and a declining-block rate in the winter months?**

18 A. No. It is important not to confuse seasonal differences in costs with differences that would  
19 translate into an inverted- or declining-block structure. The higher costs in the summer  
20 months only support a seasonally differentiated rate, not an inverted block rate. A seasonally  
21 differentiated rate fully addresses the seasonal nature of the costs, while blocked rates should  
22 address any cost changes resulting from load factor differences across usage levels within

1 each costing period. As indicated by the load factor analyses described above, there are no  
2 material load-factor differences across usage levels within each costing period that would  
3 justify a blocked rate structure.

4 **Q. Are you proposing to eliminate the block rate structure for residential service?**

5 A. Yes. A flat energy charge is more reflective of the cost of providing service and is easier for  
6 customers to understand. Furthermore, with a higher customer charge there is less need to  
7 retain the declining-block rate structure.

8 **Q. What rate design is being proposed for residential service?**

9 A. We are proposing a two-part rate consisting of a customer charge and a flat energy charge.  
10 We are proposing to eliminate the declining block rate structure. We are proposing a  
11 customer charge of \$9.00 per month and a flat energy charge of \$0.04145/kWh.

12 **Q. Why is KU not proposing a seasonal rate structure?**

13 A. Although a seasonal rate structure could be supported based on the results of the cost of  
14 service study, the implementation of a seasonal rate would require major modifications to  
15 KU's billing system. The company did not feel that the benefits justified the additional  
16 billing costs and customer education effort required to implement seasonal rates.

17 **Q. What is the relationship between the proposed customer charge and the customer-  
18 related costs identified in the cost of service study?**

19 A. As shown in Seelye Exhibit 20, the cost of service study indicates that customer-related costs  
20 for Rate RS are \$14.21 per month. A \$9.00 per month customer charge would represent a  
21 significant movement in the direction of reflecting KU's customer-related costs in rates.

1 Even so, a \$9.00 customer charge represents only 63.3% of total customer-related costs  
2 (\$9.00 ÷ \$14.21 = 63.3 %).<sup>2</sup>

3 **Q. Is KU proposing to eliminate Full Electric Residential Service Rate FERS?**

4 A. Yes. Because the cost structures and unit charges of Rate RS and Rate FERS are so similar,  
5 we determined that there is no valid justification for maintaining two separate rates.  
6 Consequently, KU is proposing to eliminate Rate FERS and move the customers served  
7 under Rate FERS to Rate RS.

8 **Q. Are any other changes being proposed to the residential rate schedule?**

9 A. Yes. KU is proposing to limit future service under Rate RS to single phase service.  
10 Customers already receiving three phase service under this rate schedule as of its effective  
11 date will continue to be served under Rate RS. In addition, the availability of service  
12 description has been simplified, a reference to the terms and conditions for service has been  
13 added, and the minimum demand charge has been deleted.

14 **Q. Is KU proposing to change the Volunteer Fire Department Rate (“VFD”) for  
15 electric service?**

16 A. Yes. Rate VFD currently contains the same charges as Rate FERS. Because FERS is being  
17 eliminated and the customers moved to Rate RS, Rate VFD will be modified to match the  
18 rates being proposed for Rate RS. Consequently, we are proposing a customer charge of  
19 \$9.00 per month and an energy charge of \$0.04145/kWh.

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<sup>2</sup> The increase in the customer charge would be similar to the increase toward cost of service with respect to the residential gas customer charge in LG&E’s last gas rate case, Case No. 2000-080. In that proceeding, the customer charge was increased to \$7.00, with the cost of service study then indicating that customer-related costs were \$11.48. Thus, in the last gas base rate case the Commission approved a customer charge that reflected 61.0% of total customer-related costs ( $\$7.00 \div \$11.48 = 61.0\%$ ).

1 **Q. Is KU proposing to retain the Combined Off-Peak Water Heating rider?**

2 A. No. Rate CWH is an old promotional water-heating rate that is no longer justified. The  
3 number of customers served under this rate schedule has been declining steadily for a  
4 number of years. We are proposing to consolidate this schedule with Rates RS and GS, as  
5 applicable. Customers currently served under this rate schedule would take service under  
6 either Rate RS or Rate GS. The electric cost of service study indicates an extremely low rate  
7 of return for this customer class.

8 **Q. Is KU proposing any changes to the rate structure of General Service Rate GS?**

9 A. Yes. We are proposing to eliminate the declining block rate structure and increase the  
10 customer charge. The proposed customer charge is \$20.00 per meter per month and the  
11 proposed energy charge is \$0.04697/kWh

12 **Q. Are any other changes being proposed to the Rate GS service schedule?**

13 A. Yes. The availability of future service under this rate schedule has been limited to secondary  
14 service at maximum loads no greater than 200 kW per month. Customers already receiving  
15 primary service, or service with loads greater than 200 kW, under this rate schedule as of its  
16 effective date will continue to be served under this schedule.

17 **Q. Why has KU proposed that future service under Rate GS be limited to secondary  
18 service at load no greater than 200 kW?**

19 A. KU proposes to limit service under this schedule to secondary service because customers  
20 should be served on a rate schedule that provides the appropriate price signals through  
21 demand and energy charges. Ideally, all customers should be served under a three-part rate  
22 consisting of a customer charge, demand charge and energy charge. A three-part rate more

1 properly reflects the principal cost drivers of utilities – namely number of customers served,  
2 maximum demand, and the amount of energy used. However, the higher cost of installing  
3 metering equipment to measure demands has been a prohibiting factor to implementing  
4 three-part rates on a wider scale.

5 **Q. Is KU proposing to eliminate Electric Space Heating Rider Rate 33?**

6 A. Yes. This is an old promotional rate that is no longer justified. There are relatively few  
7 customers served under this rate and we are proposing to merge Rate 33 with Rate GS. Any  
8 existing customers are served under Rate GS for their non-space heating usage and we are  
9 proposing that their space heating usage will also be billed on Rate GS.

10 **Q. What changes is KU proposing to Large Power Rate LP?**

11 A. We are proposing to implement a customer charge and eliminate the declining block  
12 structure of the energy charge. Additionally, we are proposing to recover more fixed costs  
13 through the demand charge rather than continue to recover a portion of demand-related fixed  
14 costs through the energy charge. We have also eliminated redundant or unnecessary  
15 language and limited single-phase service to a minimum average of 200 kW. All service  
16 under this rate schedule remains limited to a maximum average of 5000 kW.

17 **Q. Is KU proposing to merge any of its other rate schedules with its Rate LP?**

18 A. Yes. We are proposing to eliminate High Load Factor Rate HLF and Water Pumping Rate  
19 M and merge them into Rate LP. None of these schedules are used to serve many customers.  
20 KU wants to simplify its rates, eliminate some of its specialized schedules, and combine  
21 rates that serve customers of similar size.

1 **Q. Please explain the proposed changes to the Large Industrial/Commercial Time of**  
2 **Day Rate LCI-TOD?**

3 A. KU is proposing to implement a customer charge and to recover more fixed costs through  
4 the demand charge rather than through the energy charge. We have deleted the limiting  
5 reference to large commercial/industrial customers, eliminated redundant or unnecessary  
6 language and have added language regarding the determination of maximum load under the  
7 schedule.

8 **Q. Is KU proposing to change the peak periods set forth in Rates LCI-TOD and Large**  
9 **Mine Power Time-of-Day Rate LMP-TOD?**

10 A. Yes. The hours during the peak period of KU's time-of-day rates are the same in the winter  
11 as they are during the summer. Consistent with the costing periods identified in the cost of  
12 service study, we are proposing different hours for the summer billing months of June  
13 through September than for the winter billing months of October through May. The peak  
14 period will be reduced by 3 hours during the summer months. The shorter peak period  
15 during the summer billing months should provide large commercial and industrial customers  
16 with slightly greater opportunity to shift load to off-peak periods. The following table  
17 summarizes the changes to the peak periods:  
18

1

| <b>Table 3<br/>Changes to Peak Periods<br/>Rates LCI-TOD and LMP</b>   |   |
|--|---|
| <b>Current Peak Periods</b>  | <b>Proposed Peak Period</b>   |
| <b>Peak Period (Both Winter and Summer)</b><br>Weekdays, 8 A.M. to 10 P.M., Eastern Standard Time (EST), year round. | <b>Summer Peak Period</b><br>Weekdays, from 10 A.M. to 9 P.M. Eastern Standard Time (EST) during the 4 monthly billing periods of June through September. |
|  | <b>Winter Peak Period</b><br>Weekdays, from 8 A.M. to 10 P.M Eastern Standard Time (EST) during the 8 monthly billing periods of October through May.     |

2

3 **Q. What changes are being proposed to the Curtailable Service Rider?**

4 A. KU is proposing several major changes to this rider. First, the credit would be increased to  
5 \$4.19 for customers served at primary voltages and to \$4.09 for customers served at  
6 transmission voltages. Second, the hours of interruption would be increased to 500 hours of  
7 interruption per year, thus eliminating the rate differentials for different hours of curtailment.  
8 Because the credit will be determined on the basis of the full capacity cost of a combustion  
9 turbine generating unit, it is important that customers receiving the credit be subject to  
10 interruption for a number of hours representative of the amount of time that combustion  
11 turbines could be expected to operate according to the company’s resource planning models.  
12 Third, KU is proposing to charge \$16/kW for non-compliance during a requested  
13 interruption. This charge will apply to each failure to interrupt. Fourth, certain provisions of

1 the CSR schedule have been modified to harmonize the rate schedule with LG&E's CSR  
2 schedule.

3 **Q. What is basis of the proposed CSR credit?**

4 A. The credit will be based on the avoided capacity cost of a combustion turbine generator. The  
5 avoided cost was determined by applying a levelized annual carrying charge to the installed  
6 cost per kW of a combustion turbine. Levelized fixed operation and maintenance expenses  
7 were also included in the avoided cost calculation. Additionally, the avoided cost was  
8 increased to reflect KU's planning reserve margin. The credits were loss adjusted to  
9 calculate a credit for transmission and primary voltage customers. The avoided cost  
10 calculation is included in Seelye Exhibit 21. The utility depends on being able to call upon  
11 the interruptible load during periods of capacity constraint. If the customer fails to curtail its  
12 load, then there can be serious consequences. Furthermore, if the customer does not  
13 interrupt, no avoided costs are realized for KU and its customers.

14 **Q. What is the basis of the proposed charge for failure to curtail?**

15 A. The \$16/kW non-compliance charge was based on approximately 4 months of the credit.  
16 The foundation for the charge is that each failure to comply with a request to curtail the  
17 customer's load should result in the customer paying back 4 months of the credit, which is  
18 not an unreasonable charge given that in its resource planning scenarios the company does  
19 not plan to serve load that can be curtailed.

20 **Q. What changes are being proposed to KU's lighting rates?**

21 A. The lighting rates are being increased by approximately 8.8%. In addition, we have  
22 eliminated redundant or unnecessary language, eliminated reference to five lights which are

1 no longer used by customers, and restricted certain mercury vapor lights. KU is also  
2 proposing to merge the Decorative Street Lighting Rate DEC. St. Lt. into Street Lighting  
3 Service Rate St. Lt. so that we have only one rate schedule applicable to street lighting. It  
4 should be noted that this does not reflect a withdrawal of service. The charges are simply  
5 being shown on Rate St. Lt. KU has also eliminated redundant or unnecessary language  
6 contained in Private Outdoor Lighting Rate P.O.Lt. Additionally, KU is proposing to  
7 eliminate Customer Outdoor Lighting Rate C.O.Lt. and move the customers to Rate P.O.Lt  
8 so that all outdoor lighting will be served by a single rate schedule. The lights being  
9 eliminated are inefficient and used by very few customers.

10 **Q. Is KU proposing to add a Rider for Intermittent and Fluctuating Loads (“IFL”)?**

11 A. Yes. We are proposing that the IFL rider be added to address concerns about loads having a  
12 detrimental effect on the system, thus potentially adversely affecting other KU customers or  
13 KU’s facilities.

14 **Q. Is KU proposing to implement an Excess Facilities rider?**

15 A. Yes. KU is implementing an Excess Facilities rider to standardize its practices and offerings  
16 across LG&E and Kentucky Utilities. Kentucky Utilities has a widely-used facilities lease  
17 arrangement that is similar in purpose to LG&E’s Excess Facilities rider. If a customer on  
18 Kentucky Utilities’ system requires non-standard facilities (such as a second back-up feed or  
19 automatic switchgear) or wanted to lease transformers from the utility to take service at a  
20 lower voltage, Kentucky Utilities’ longstanding practice was to lease the facilities to the  
21 customer at an annual lease rate of 28% of the cost of the facilities. The lease payment was  
22 intended to cover the carrying costs on the investment, depreciation, and operation and

1 maintenance expenses. The payment would continue for as long as the customer required  
2 the facilities. The way that the 28% was determined, the lease payment in effect provided  
3 for the eventual replacement of the facilities through the application of a straight carrying  
4 charge methodology (as opposed to a levelized carrying charge methodology). Kentucky  
5 Utilities has been offering lease arrangements since at least the early 1980s and has  
6 numerous such arrangements with customers.

7 **Q. Are there any problems KU's facilities lease arrangement?**

8 A. No. We are simply updating the charges in the lease arrangements to reflect current costs  
9 and incorporating KU's facilities lease arrangements under an Excess Facilities rider.

10 **Q. How is KU proposing to structure the Excess Facilities rider?**

11 A. We are proposing to separate the rate into two components: (i) a carrying charge component  
12 and (ii) an operating expenses component. For KU the carrying charge component for  
13 distribution facilities would be 0.94% per month as applied to the original cost of the  
14 facilities, and the operating expenses component would be 0.56%. The carrying charge  
15 component would cover the utility's cost of capital, grossed up for income taxes related to  
16 the investment. The operating expenses component would cover the operation and  
17 maintenance expenses, property taxes, and the cost of replacing the facilities. A customer  
18 can choose either to pay for the facilities up front through a contribution in aid of  
19 construction or pay the carrying charge set forth in the rate. If a customer chooses to make a  
20 contribution in aid of construction for the facilities then only the operating expenses  
21 component of the rate (0.56%) would apply. If a customer does not want to pay for the  
22 facilities up front, then both the carrying charge component and the operating expenses

1 component would apply. In either case, the utility would be responsible for replacing the  
2 facilities should the facilities fail.

3 **Q. Have you prepared an exhibit showing the calculation of the charges set forth in the**  
4 **proposed Excess Facilities rider?**

5 A. Yes. The cost support for the charges is included in Seelye Exhibit 22. As can be seen from  
6 this exhibit, the carrying charge component of the rate corresponds to the weighted cost of  
7 capital proposed by KU in this proceeding, grossed up for income taxes. The operating  
8 expenses component includes operating expenses, maintenance expenses, insurance, taxes  
9 other than income taxes, and depreciation expenses. The depreciation expenses are intended  
10 to cover the replacement over time of the facilities.

11 **Q. Have you prepared an exhibit showing the revenue impact of replacing the special**  
12 **lease arrangements with the Excess Facilities rider?**

13 A. Yes, this impact is shown in Seelye Exhibit 23.

14 **Q. Please describe the Redundant Capacity rider proposed by KU.**

15 A. The purpose of the Redundant Capacity rider is to allow customers that have one or more  
16 redundant feeds to reserve back-up capacity on the distribution system. As customers come  
17 to rely on greater use of electric technology, there is more and more customer interest in  
18 having a redundant feed along with automatic relay equipment capable of switching from a  
19 principal circuit to a backup circuit in the event that electric service from the primary feed is  
20 lost. With the greater use of technology, some customers are finding it increasingly difficult  
21 to tolerate electrical outages for even short periods of time. A customer who wants a second  
22 feed must pay the cost of the customer-specific facilities required to provide the feed,

1 including the second distribution line, automatic relay equipment, or other customer-specific  
2 facilities that may be required. Customers can pay for the customer-specific facilities by  
3 either making a contribution in aid of construction or by taking service under the Excess  
4 Facilities rider. If the customer wants to have full backup capacity on the second feed, there  
5 are additional costs incurred by KU of ensuring that there is sufficient network distribution  
6 capacity to provide full backup in the event that a relay occurs on the automatic switchgear.  
7 In order to ensure that there is sufficient backup capacity for the redundant feed the utility  
8 must plan the distribution facility as if there were two customers placing demands on the  
9 system. For this reason, KU is proposing to implement a demand charge to cover the  
10 distribution demand-related cost of providing backup service for new customers with  
11 redundant feeds. The demand charge would be applied to the customer's monthly billing  
12 demand determined under the standard rate schedule under which the customer receives  
13 electric service.

14 **Q. What are the proposed Redundant Capacity charges?**

15 A. The proposed demand charge for primary voltage customers is \$0.63 per kW per month of  
16 billing demand and the proposed demand charge for secondary voltage customers is \$0.80  
17 per kW per month of billing demand.

18 **Q. How was the demand charge for the proposed Redundant Capacity rider**  
19 **determined?**

20 A. The demand charge was determined by computing the distribution demand-related revenue  
21 requirements from the electric cost of service study for primary and secondary voltage  
22 service under KU's large power rates and dividing this amount by the billing demands for

1 this class of customers. KU is proposing different demand charges for customers served at  
2 primary and secondary voltages. The cost support for the proposed demand charges is  
3 included in Seelye Exhibit 24.  
4

5 **VI. MISCELLANEOUS SERVICE CHARGES**

6 **Q. Is KU proposing to change any of its miscellaneous non-recurring charges?**

7 A. Yes. KU is proposing to change or add a number of miscellaneous non-recurring charges.  
8 First, KU is proposing to increase the disconnect/reconnect charge to \$31.00. Second, KU is  
9 proposing to increase the returned check fee from \$5.00 to \$9.00. Third, KU is proposing to  
10 increase the meter test charge from \$14.00 to \$31.40. These three changes will be addressed  
11 in Mr. Cockerill's testimony.

12 **Q. Have you prepared an exhibit showing the revenue impact of the proposed changes**  
13 **to the miscellaneous charges?**

14 A. Yes. Seelye Exhibit 25 shows the impact on miscellaneous revenue of the proposed  
15 changes. Page 1 shows the revenue impact of modifying the disconnect/reconnect charge.  
16 This change results in an increase of \$962,913 in annual revenue. Page 2 shows that the  
17 revenue impact of increasing the returned check charge is \$39,441. Page 3 shows the  
18 revenue impact of modifying the meter-test charge. This change results in an increase of  
19 \$1,409 in annual revenue. It should be pointed out that increasing these charges could  
20 result in a reduction in the utilization of these charges, thus producing slightly lower revenue  
21 than the proposed pro-forma amount requested in this proceeding. Nevertheless, economic  
22 efficiencies can be achieved by sending the correct price signal through the implementation

1 of charges that properly reflect the cost of providing the service. This is what we have tried  
2 to do with all of the rate modifications discussed in my testimony.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

4 A. Yes, it does.