COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC	**)**	
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	**CASE NO.**
ELECTRIC AND GAS RATES	**)**	**2014-00372**

SUPPLEMENTAL RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
WALLACE MCMULLEN AND SIERRA CLUB'S AMENDED INITIAL DATA REQUESTS
DATED JANUARY 8, 2015

FILED: JANUARY 28, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of January 2015.

(SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of January 2015.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Supplemental Response to Sierra Club's Initial Data Requests
Dated January 8, 2015

Question No. 5

Responding Witness: Robert M. Conroy / Dr. Martin J. Blake / Counsel

Q-5. Reference Martin Blake, p. 19, II. 9-18.

b) Please provide copies of all e-mail communications, internal memoranda, reports, or other documentation of Dr. Blake's and the Company's consideration of the amount to increase the basic service charge and of the decision to increase the basic service charge to $18.00 per month.

A-5. **ORIGINAL RESPONSE**

b) The Company objected to this question on January 19, 2015, because it requires the Company to reveal the contents of communications with counsel and the mental impressions of counsel, which information is protected from disclosure by the attorney-client privilege and the work product doctrine. Without waiver of these objections, see the attached documents that have been identified within the time permitted for this response. Counsel for the Company is continuing to undertake a reasonable and diligent search for other such documents and will reasonably supplement this response through a rolling production of documents.

SUPPLEMENTAL RESPONSE

b) The Company incorporates by reference the objections stated above. Without waiver of these objections, see the additional attached documents that have been identified.

The Company is also filing contemporaneously herewith a privilege log describing the responsive documents the Company is not producing on the ground of attorney-client or work product privilege.

From: Jeff Wernert(jwernert@theprimegroupllc.com)
To: Conroy, Robert
CC: marty.blake.prime@gmail.com
BCC:
Subject: Re[4]: Updated KU Exhibits for Blake Testimony
Sent: 11/14/2014 04:04:01 PM -0500 (EST)
Attachments: Exhibit MJB-8 - Functional Assignment.pdf; Exhibit MJB-9 - Allocation.pdf; Exhibit MJB-10 - Residential Customer Charge.pdf; Exhibit MJB-15 - Gas Functional Assignment.pdf; Exhibit MJB-16 - Gas Allocation.pdf;

Attached are updated LG&E Exhibits 8, 9, 10, 15, and 16.

Jeff Wernert
The Prime Group LLC
(502) 409-4059

------ Original Message ------
From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
To: "'Jeff Wernert'" <jwernert@theprimegroupllc.com>
Cc: "marty.blake.prime@gmail.com" <marty.blake.prime@gmail.com>
Sent: 11/14/2014 3:46:21 PM
Subject: RE: Re[2]: Updated KU Exhibits for Blake Testimony

> Thanks. Looks like for LG&E, MJB-8, 9, 10, 15, and 16 will need to be changed as well. I know that Marty is making edits to MJB-9.
>
> **Robert M. Conroy**
> *Director, Rates*
> *LG&E and KU Services Company*
> (502) 627-3324 (phone)
> (502) 627-3213 (fax)
> (502) 741-4322 (mobile)
> robert.conroy@lge-ku.com
>
> ---
>
> **From:** Jeff Wernert [mailto:jwernert@theprimegroupllc.com]
> **Sent:** Friday, November 14, 2014 3:41 PM
> **To:** Conroy, Robert
> **Cc:** marty.blake.prime@gmail.com
> **Subject:** Re[2]: Updated KU Exhibits for Blake Testimony
>
> Attached is an updated MJB-8 for KU.
>
> Jeff Wernert
> The Prime Group LLC
> (502) 409-4059
>
> ------ Original Message ------
> From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
> To: "'Jeff Wernert'" <jwernert@theprimegroupllc.com>
> Sent: 11/14/2014 3:28:13 PM
> Subject: RE: Updated KU Exhibits for Blake Testimony
>
>> Jeff,
>> The KU Exhibit MJB-8 needs to have the exhibit reference moved to the footer right side.
>> Thanks
>>
>> **Robert M. Conroy**
>> *Director, Rates*
>> *LG&E and KU Services Company*
>> (502) 627-3324 (phone)
>> (502) 627-3213 (fax)
>> (502) 741-4322 (mobile)
>> robert.conroy@lge-ku.com
>>
>> ---
>>
>> **From:** Jeff Wernert [mailto:jwernert@theprimegroupllc.com]
>> **Sent:** Friday, November 14, 2014 10:37 AM
>> **To:** marty.blake.prime@gmail.com
>> **Cc:** lfeltner@theprimegroupllc.com; Conroy, Robert; Foxworthy, Carol; Schroeder, Andrea
>> **Subject:** Updated KU Exhibits for Blake Testimony

Marty,

Attached are updated KU Exhibits to account for the formatting changes Robert requested yesterday and the updated TOU exhibit reflecting the seasonal differences in the Peak window for the Residential TOU Pilot. Please let me know if any additional changes need to be made per your review this morning.

Thanks,

Jeff Wernert
The Prime Group LLC
6001 Claymont Village Drive
Suite 8
Crestwood, KY 40014
(502) 409-4059
jwernert@theprimegroupllc.com

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Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2016

Rate RS

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 575,369,351	$ 19,485,352	$ 104,977,165	$ 158,055,735	$ 284,576,291	$ 2,152,032	$ 1,144,615,927
(2)	Rate Base Adjustments	-	-	-	-	-	-	$ -
(3)	Rate Base as Adjusted	$ 575,369,351	$ 19,485,352	$ 104,977,165	$ 158,055,735	$ 284,576,291	$ 2,152,032	$ 1,144,615,927
(4)	Rate of Return	4.52%	4.52%	4.52%	4.52%	4.52%	4.52%	
(5)	Return	$ 25,984,269	$ 879,978	$ 4,740,876	$ 7,137,959	$ 12,851,757	$ 97,188	$ 51,692,027
(6)	Interest Expenses	$ 14,078,955	$ 476,795	$ 2,568,730	$ 3,867,532	$ 6,963,417	$ 52,659	$ 28,008,089
(7)	Net Income	$ 11,905,314	$ 403,183	$ 2,172,146	$ 3,270,426	$ 5,888,340	$ 44,529	$ 23,683,938
(8)	Income Taxes	$ 8,417,187	$ 285,055	$ 1,535,731	$ 2,312,227	$ 4,163,120	$ 31,482	$ 16,744,802
(9)	Operation and Maintenance Expenses	$ 50,008,582	$ 169,971,473	$ 9,409,771	$ 13,946,889	$ 32,567,103	$ 16,569,169	$ 292,472,988
(10)	Depreciation Expenses	$ 31,181,777	$ -	$ 4,343,426	$ 8,899,436	$ 15,983,791	$ -	$ 60,408,430
(11)	Other Taxes	$ 7,537,480	$ -	$ 1,336,382	$ 2,079,498	$ 3,734,874	$ -	$ 14,688,234
(12)	Other Depreciation Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(13)	Curtailable Service Credit	$ 1,716,993	$ -	$ -	$ -	$ -	$ -	$ 1,716,993
(14)	Expense Adjustments - Prod. Demand	$ 35,568	$ -	$ -	$ -	$ -	$ -	$ 35,568
(15)	Expense Adjustments - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(18)	Expense Adjustments - Other	$ 446,245	$ 15,112	$ 81,418	$ 122,585	$ 220,712	$ 1,669	$ 887,741
(19)	Expense Adjustments - Total	$ 481,813	$ 15,112	$ 81,418	$ 122,585	$ 220,712	$ 1,669	$ 923,309
(20)	Total Cost of Service	$ 125,328,100	$ 171,151,619	$ 21,447,605	$ 34,498,594	$ 69,521,356	$ 16,699,509	$ 438,646,783
(21)	Less: Misc Revenue - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(22)	Less: Misc Revenue - Other	$ (39,766,360)	$ (157,799)	$ (850,139)	$ (1,279,986)	$ (2,304,590)	$ (17,428)	$ (44,376,302)
(23)	Less: Misc Revenue - Total	$ (39,766,360)	$ (157,799)	$ (850,139)	$ (1,279,986)	$ (2,304,590)	$ (17,428)	$ (44,376,302)
(24)	Net Cost of Service	$ 85,561,740	$ 170,993,820	$ 20,597,466	$ 33,218,608	$ 67,216,766	$ 16,682,081	$ 394,270,481
(25)	Billing Units	4,267,045,465	4,267,045,465	4,267,045,465	4,267,045,465	4,338,229	4,338,229	
(26)	Unit Costs	$ 0.02005	$ 0.04007	$ 0.00483	$ 0.00778	$ 15.49	$ 3.85	$ 19.34

Customer Charge	19.34
Energy Charge	0.072737

From: Foxworthy, Carol(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WALLACEC)
To: Sturgeon, Allyson; Conroy, Robert; Staton, Ed; Lovekamp, Rick; 'Riggs, Kendrick R.'; 'Ingram III, Lindsey'; 'duncan.crosby@skofirm.com'; McGee, Dawn; Schroeder, Andrea; 'Marty Blake'; 'Jeff Wernert (jwernert@theprimegroupllc.com)'; 'Larry Feltner (lfeltner@theprimegroupllc.com)'
CC:
BCC:
Subject: RE: Blake KU Testimony
Sent: 11/11/2014 08:30:41 AM -0500 (EST)
Attachments: Dr Blake Testimony KU 2014-00371 Foxworthy edits.docx;

Attached are my edits to Marty's KU testimony. I also have questions/comments about Exhibit MJB-11, peaking hours for time of day residential rates. Specifically, the exhibit says that 87.5% of peaks will be captured by the proposed on-peak window. The only way I could duplicate that result is by including all shoulder peaks in the peaks to be captured; however, the shoulder peaks occurring from 1 pm through 5 pm, or 34 peaks, will not be captured because the shoulder months are included in the winter peaks. Is the correct percent of peaks captured through the proposed on-peak period more like 68% (i.e., 48 winter peaks, 14 shoulder peaks, and 58 summer peaks)?

Carol Foxworthy
LG&E-KU
State Regulation and Rates
502-627-2527
502-627-3213 (fax)

From: Sturgeon, Allyson
Sent: Friday, November 07, 2014 12:57 PM
To: Conroy, Robert; Staton, Ed; Lovekamp, Rick; Riggs, Kendrick R.; Ingram III, Lindsey; duncan.crosby@skofirm.com; Foxworthy, Carol; McGee, Dawn; Schroeder, Andrea
Subject: FW: Blake KU Testimony

ATTORNEY-CLIENT COMMUNICATION

CONFIDENTIAL AND PRIVILEGED

FYI

From: Marty Blake [mailto:marty.blake.prime@gmail.com]
Sent: Friday, November 07, 2014 12:55 PM
To: Sturgeon, Allyson
Subject: Blake KU Testimony

The first draft of my testimony and associated exhibits are attached. I look forward to your comments.
Marty Blake
The Prime Group LLC
502-425-7882

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	**CASE NO. 2014-00371**
ADJUSTMENT OF ITS ELECTRIC	)	
BASE RATES	)	

TESTIMONY OF
DR. MARTIN BLAKE
PRINCIPAL
THE PRIME GROUP, LLC

Filed: November 26, 2014

Table of Contents

Exhibits

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. By whom and in what capacity are you employed?

A. I am a Member and Principal of The Prime Group, LLC. The Prime Group provides consulting services in the areas of strategic planning, cost of service, rate design, regulatory support, and training for energy industry clients. A core part of our business is working with utilities to perform cost of service analyses and providing assistance in developing reasonable cost-based rates.

Q. Please describe your professional experience and educational background.

A. I hold a Ph.D. in Agricultural Economics and a Master of Arts degree in Economics from the University of Missouri, Columbia. I served as Commissioner on the New Mexico Public Service Commission from January 1986 through November 1989. I then worked as the Director of Rates, Regulatory and Strategic Planning for Louisville Gas and Electric from December 1989 through June 1996. I have taught at the NARUC Institute at Michigan State University for many years; and I have been an independent consultant with the Prime Group since 1996. A detailed description of my professional experience and educational background is provided in Exhibit MJB-1.

Q. In what cases have you previously testified?

A. I have testified in numerous proceedings before both state and federal regulatory bodies. Exhibit MJB-2 is a summary of the testimony I have presented in other regulatory proceedings.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Kentucky Utilities Company ("KU" or "Company").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (i) describe and support KU's electric cost of service study; (ii) describe the proposed allocation of the revenue increase to KU's electric rate classes; (iii) describe the electric rate designs, new rates, and percentage increase by rate class; and (iv) support certain filing requirements from 807 KAR 5:001.

Q. What are the fully forecasted test period and base period on which the rate case application and the electric cost of service study that you developed are based?

A. The fully forecasted test period on which the filing is based is the twelve months ended June 30, 2016. Consistent with KRS 278.192, the cost of service study and the adjustments in rates are supported by a fully forecasted test period. Because the effective date of KU's proposed rates is January 1, 2015, the first twelve consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning July 1, 2015 and ending on June 30, 2016. The base period for the filing is the 12 months ending February 28, 2015. The base period consists of six months of actual historical data for the period March 1, 2014 through August 31, 2014 and six months of estimated data for the period September 1, 2014 through February 28, 2015. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, consisting of not less than six months of actual historical data and not more than six months of estimated data. Because KU's proposed base period, which begins March 1, 2014, includes not less than six months of actual historical data (March 1, 2014 through August 31, 2014), includes no more than six months of estimated data (September 1, 2014 through February 28, 2015), and begins less than nine months prior to the filing date in this proceeding, the proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Please summarize your testimony.

A. The Company's fully allocated, embedded cost of service study for its electric operations were prepared using cost of service methodologies that have been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to fairly allocate the cost of providing safe, reliable service to the various customer classes that KU serves, to determine the contribution that each customer class is making towards KU's overall rate of return and to provide the data necessary to develop rate components that more accurately reflect cost causation. In the cost of service study, rates of return are calculated for each rate class. Because of the magnitude of the increase, KU is proposing to increase each electric rate class by the same percentage. Reduction of the differences in rates of return among classes would lead to double digit increases for some classes, which KU wanted to avoid. The Company is proposing unit charges that more accurately reflect cost causation for its electric rates.

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

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

- Cost of Service Studies Section 10(6)(u) Tab XX

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction and Qualifications, (II) Electric Cost of Service Study, and (III) Electric Rate Design and the Allocation of the Increase.

Q. Did you use the same methodology in KU's electric cost of service study that was used in LG&E's electric cost of service study filed concurrently in Case No. 2014-00372?

A. Yes.

II. ELECTRIC COST OF SERVICE STUDY

Q. Did The Prime Group prepare a cost of service study for KU's electric operations based on forecasted financial and operating results for the 12 months ended June 30, 2016?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study for KU'S electric operations based on a forecasted test year ended June 30, 2016. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Blake. The objective in performing the electric cost of service study is to allocate KU's revenue requirement as fairly as possible to all of the classes of customers that KU serves, to determine the rate of return on rate base that KU is earning from each customer class, and to provide the data necessary to develop rate components that more accurately reflect cost causation.

Q. What model was used to perform the cost of service study?

A. The cost of service study was performed using a proprietary EXCEL spreadsheet model that was developed by The Prime Group and that has been utilized in previous filings by KU to support requests for adjustments in its rates.

Q. Have you prepared an exhibit showing the results of the jurisdictional separation of KU's costs into Kentucky and Virginia components?

A. Yes. Exhibit MJB-3 shows the results of the study separating KU's costs into Kentucky and Virginia components.

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

A. Regardless of whether a historic test year or a forecasted test year is used to develop a cost of service study, the methodology for developing a cost of service study is basically the same. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods which time differentiates the costs. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then (4) costs were allocated to the various rate classes that KU serves. These steps are depicted in the following diagram (Figure 1).

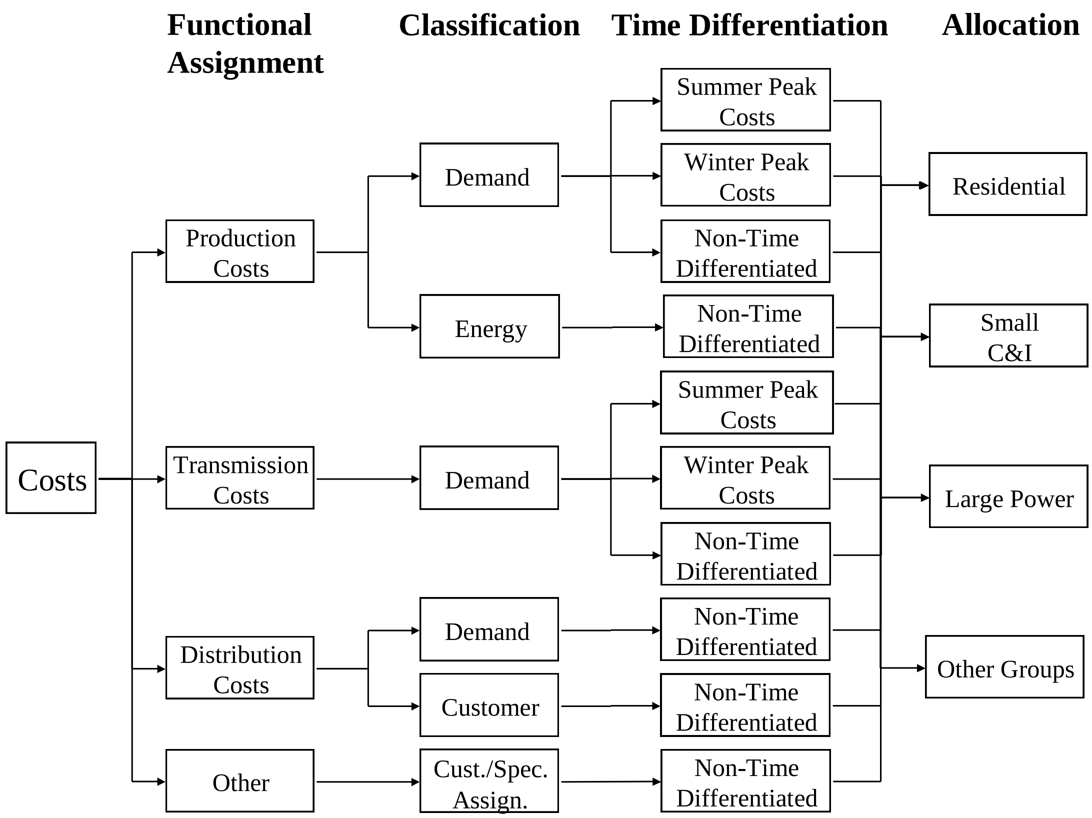

Figure 1

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.

Q. How were costs time differentiated in the study?

A. A modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to the relevant costing periods.[1] Using this methodology, production and transmission demand-related costs were assigned to three categories of capacity – base, intermediate, and peak. The percentages of production and transmission fixed cost that were assigned to the base period were determined by dividing the minimum system demand by the maximum demand. The percentages of production and transmission fixed cost that were assigned to the intermediate period were calculated by dividing the summer peak demand by the winter peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer or winter peak periods or assigned as non-time-differentiated. Base costs were assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. In applying the modified BIP methodology, what demands were used?

A Demands for the combined KU and LG&E systems were used to determine the costing periods and in determining the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly, developing costing periods and assigning costs to the costing periods based on the combined loads for KU and LG&E accurately reflects cost causation.

[1] In Case No. 90-158, 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, at 58.)

Developing the costing periods and allocation factors in the cost of service study based on the combined loads for KU and LG&E does not result in any shifting of booked expenses from one utility to the other. KU's cost of service study relied on KU's accounting costs, and LG&E's cost of service study relied on LG&E's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the KU and LG&E cost of service studies.

Q. What percentages were assigned to the costing periods?

A Exhibit MJB-4 shows the application of the modified BIP methodology. Using this methodology 34.10% of KU's production and transmission fixed costs were assigned to the winter peak period, 30.91% to the summer peak period, and 34.99% as base period costs that are non-time-differentiated.

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

A. Classification involves utilizing the appropriate cost driver for each functionally assigned cost which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. For costs classified as *energy-related*, the appropriate cost driver is the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand-related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. The costs of production plant and transmission lines are examples of costs typically classified as demand-related costs. Costs classified as *customer-related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum set of distribution equipment necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, a portion of the costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related because these costs do not vary with customers' capacity or energy usage.

Q. What methodologies are commonly used to classify distribution plant between customer-related and demand-related components?

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

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is preferred over the minimum system methodology when the necessary data is available. Additionally, KU has utilized the zero-intercept methodology in determining customer-related costs in prior rate case filings before this Commission. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer-related component of distribution costs. In the zero-intercept methodology, the estimated cost of a zero-size conductor or line transformer is the absolute minimum system for determining customer-related costs.

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

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost of conductor ($/ft) or line transformers ($/kVa of transformer size) and the load flow capability of the plant measured as the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, 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 feet of conductor and the number of transformers on KU's system is not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted linear regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted linear regression analysis all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

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

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

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

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

A. Yes. The Commission found LG&E's cost of service study (both electric and natural gas) submitted in Case No. 2000-080 and Case No. 90-158 to be reasonable, thus providing a means of measuring class rates of return that are suitable for use as a guide in developing appropriate revenue allocations and rate design. The cost of service studies in both of these proceedings utilized a zero-intercept methodology to calculate the splits between demand-related and customer-related distribution costs. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable.

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

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Exhibits MJB-5, MJB-6 and MJB-7, respectively.

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

A. Yes. Exhibit MJB-8 shows the results of the first three steps of the electric cost of service study; namely functional assignment, classification, and time differentiation. In the cost of service model used in this study, the calculations for functionally assigning, classifying and time differentiating KU's accounting costs are made using what are referred to in the model as “functional vectors”. These vectors are multiplied (using *scalar multiplication*) by the dollar amount in the various accounts in order to simultaneously functionally assign, classify and time differentiate KU’s accounting costs. These calculations occur in the portion of the cost of service model included in Exhibit MJB-8. In Exhibit MJB-8, KU’s accounting costs are functionally assigned, classified and time differentiated using explicitly determined functional vectors and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned, classified, and time differentiated, are shown on pages 61 through 65 of Exhibit MJB-8. Internally generated functional vectors are utilized throughout the study to functionally assign, classify and time differentiate costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 61 through 65 of Exhibit MJB-8. An example of this process is the use of total operation and maintenance expenses less purchased power (“OMLPP”) to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign, classify and time differentiate these costs on the same basis. (See Exhibit MJB-8, pages 11 through 15, row 112 for the functional assignment, classification and time differentiation of cash working capital on the basis of OMLPP which is shown on pages 31 through 35, row 325.) The functional vector used to allocate a specific cost is identified in the column of the model labeled “Vector” and refers to a vector identified elsewhere in the analysis by the column labeled “Name”.

Q. Please describe the how the functionally assigned, classified and time differentiated costs were allocated to the various classes of customers that KU serves.

A. Exhibit MJB-9 shows the allocation of the functionally assigned, classified and time differentiated costs to the various classes of customers that KU serves. For a forecasted test year, the average number of customers is used for allocating customer-related costs rather than the year end number of customers that is used for a historic test year. The following allocation factors were used in the electric cost of service study to allocate the functionally assigned, classified and time differentiated costs:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production and transmission fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.

- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **Cust04** – Customer-related costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05 and Cust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor calculated using the average number of customers for the test year based on discussions with KU's meter reading, billing and customer service departments.
- **Cust07** – Customer-related costs are allocated on the basis of the average number of customers using line transformers and secondary voltage conductor.
- **Cust08** – Customer-related costs are allocated on the basis of the average number of customers using primary voltage conductor.

Q. In your cost of service model, once costs are functionally assigned, classified and time differentiated, what calculations are used to allocate these costs to the various customer classes that KU serves?

A. Once costs for all of the major accounts are functionally assigned, classified, and time differentiated, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". A transpose of a matrix is formed by turning all the rows of a given matrix into columns and vice-versa. This process results in the columns of functionally assigned, classified and time differentiated costs becoming rows in the transposed matrix which then can be allocated to the various classes of customers that KU serves. This process is illustrated in Figure 2 below.

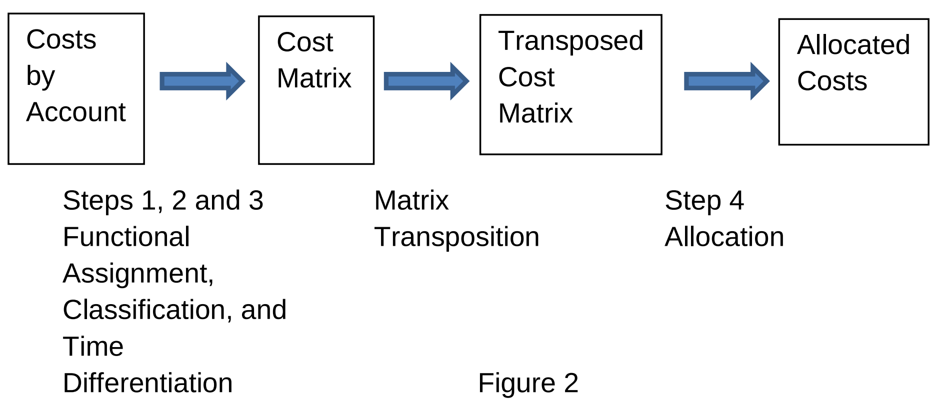

Figure 2

The results of the class allocation step of the cost of service study are included in Exhibit MJB-9. The costs shown in the column labeled "Total System" in Exhibit MJB-9 were carried forward from the functionally assigned, classified and time differentiated costs shown in Exhibit MJB-8. The column labeled "Ref" in Exhibit MJB-9 provides a reference to the results included in Exhibit MJB-8.

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

A. Table 1 below summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by KU. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Blake's and Mr. Conroy's testimonies. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

Table 1 - Electric Class Rates of Return		
Rate Class	**Actual Adjusted Rates of Return**	**Proposed Rates of Return**
Residential Rate RS	2.77%	4.84%
General Service Single Phase	9.01%	12.14%
All Electric Schools Single Phase	4.43%	7.14%
Power Service Secondary Rate PS	11.29%	15.04%
Power Service Primary Rate PS	8.24%	11.46%
Time of Day Secondary Rate TODS	5.42%	8.69%
Time of Day Primary Rate TODP	3.34%	6.40%
Retail Transmission Service Rate RTS	3.41%	6.52%
Fluctuating Load Service Rate FLS	1.53%	4.61%
Lighting	2.75%	4.13%
Total	4.55%	7.18%

Determination of the actual adjusted and proposed rates of return are detailed in Exhibit MJB-9, pages 29 and 30 and pages 33 and 34, respectively.

III. ELECTRIC RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

Q. Have you prepared exhibits showing KU's base year and test year billing determinants for the electric business and showing the impact of applying the new rates to base year and test year billing determinants?

A. Yes. The KU's base year electric billing determinants are shown provided in Schedule M-1.3, and KU's test year (forecast) electric billing determinants are shown provided in Schedule M-2.3. Schedule M-2.3 shows the result of applying the proposed rates to the test year billing determinants by class of customers. A summary of the revenue increases that result from applying KU's proposed rates to the test year billing determinants is provided on pages 1 and 2 of Schedule M-2.3.

Q. What revenue increase is KU proposing for electric operations?

A. KU is proposing an increase in electric test-year revenues of $153,442,682, which is calculated by applying the proposed rates to test-year billing determinants as shown on page 1 of Schedule M-2.3. It should be pointed out that this amount is slightly less than the revenue requirement increase of $153,442,682 shown on page 2 of Schedule M-2.3.

Q. Please summarize how KU proposes to allocate the electric revenue increase to the classes of service?

A. The increase for all rate classes served by KU was calculated by applying the same 9.57 percent increase to all of the rate classes that KU serves. With an increase of this magnitude, attempting to reduce the differences in rates of return among classes would result in large double digit increases for some classes which KU wanted to avoid. With the second lowest rate of return as shown in the cost of service summary in Exhibit MJB-14, the increase to the residential class would have been particularly large if differences in rates of return among customer classes were reduced in this proceeding, which is a result that the Company wanted to avoid.

B. RESIDENTIAL ELECTRIC RATE INCREASE

Q. Is KU proposing to bring the rate components in residential electric rates more in line with the unit costs shown in the cost of service study?

A. Yes. KU is proposing to increase the monthly residential basic service charge from $10.75 to $18.00 to bring it more in line with the customer-related costs identified in the cost of service study. Even considering this increase, the basic service charge will be less than the amount that would recover all of the customer-related distribution costs identified in the cost of service. The cost of service study indicates that the customer-related, non-volumetric fixed distribution cost for the residential class is $21.47 per customer per month. KU is proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service, but is not proposing to go all of the way to the full amount indicated by the cost of service study. The derivation of the cost based residential basic service cost from data in the electric cost of service study is provided in Exhibit MJB-10.

Q. Does the current monthly basic service charge of $10.75 adequately recover customer-related costs from residential customers?

A. No. The current basic service charge of $10.75 per customer per month does not even recover all of the customer-related operating expenses, let alone any of the margins (return) that would normally be assigned as customer-related cost. These customer-related costs are non-volumetric fixed distribution costs that are not related to a customer's energy or capacity usage. Based on calculations from the cost of service study shown in Exhibit MJB-10, customer-related costs are $21.47 per customer per month; therefore, the current service charge of $10.75 under-recovers customer-related fixed distribution costs by $10.72 per customer per month. When this under-recovery of $10.72 per customer per month is multiplied by the 5,164,249 customer months for KU's residential rate class during the test year, the result is $55,360,749 in non-volumetric customer-related fixed operating expenses and margins that are being "variablized" and recovered through a kWh energy charge rather than being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is about 0.89 cents per kWh of fixed operating expenses and margins collected through the energy charge (calculated as $55,360,749 / 6,197,488,349 kWh = $0.089 per kWh). Thus, compared to rates that reflect straight cost causation, the basic service charge is $10.72 per customer per month too low and the energy charge is 0.89 cents per kWh too high. The recovery of non-volumetric fixed operating expenses and margins through the energy charge results in intra-class subsidies, results in customer energy bills being more variable than necessary and does not provide the proper environment for energy efficiency and conservation.

Q. **What are intra-class subsidies and how can intra-class subsidies be avoided?**

A. When one rate class subsidizes another rate class it is referred to as "inter-class subsidies", but when customers within a particular rate class subsidize other customers served under the same rate schedule it is referred to as "intra-class subsidies." The rate-making principle that should be followed to avoid intra-class subsidies is that, as much as possible, fixed costs should be recovered through fixed charges (such as the basic service charge and demand charge) and variable costs should be recovered through variable charges (such as the energy charge). If fixed costs are recovered through variable charges, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of fixed costs and margins, while customers using less energy than the average customer in the class are paying less than their fair share of fixed costs and margins. These fixed costs and margins should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is *not* the correct cost driver for the customer-related, non-volumetric fixed costs that should be collected through a fixed monthly charge. The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. In order to eliminate this source of intra-class subsidies, KU wants to pursue a rate design that moves more in the direction of recovering fixed costs through fixed charges and variable costs through variable charges.

Q. What would be the impact of the proposed increase in the basic service charge on the average customer?

A. Given a specified increase for the class, the average residential customer would see the same increase whether all of the increase is recovered through the basic service charge or through an increase of both the basic service charge and energy charge. Ultimately, the proposed rate for any given class of customers is based on averages and any rate design that was revenue neutral (i.e., generates the same amount of revenue) would have no impact whatsoever on a customer with a usage equal to the class average. The impact on customer energy bills would be greatest at the extremes of very low energy usage and very high energy usage. The change would result in higher energy bills for low-usage customers, as the subsidy that they had been receiving was removed, and lower energy bills for high-usage customers as the subsidies that they had been paying were eliminated.

Q. Typically, who are the low-usage customers who would be paying higher energy bills once the subsidies were removed?

A. For utilities such as KU, operating in an both rural and urban service territories, low usage customers tend to be loads like vacation homes, hunting cabins, fishing cabins, boat docks, garages, workshops, outbuildings, and unusual service connections. All of these loads typically consume very few kilowatt hours during the course of a year and the usage is sporadic. However, the utility still incurs fixed costs in installing the minimum system requirements necessary to serve these loads. A rate design with a low basic service charge and with a significant portion of fixed operating expenses and margins recovered through the energy charge would result in revenue that was insufficient to support the investment necessary to serve the types of low usage loads described above. Such a rate design would result in these customers being subsidized by the other customers who have above-average usage. A rate design with a low basic service charge and with a significant portion of the utility's fixed operating expenses and margins recovered through the energy charge sends an improper economic signal to customers. It sends a signal that it is relatively inexpensive to provide the minimum set of equipment necessary to provide service to customers, and this is definitely not the case.

Q. Would recovering a portion of the increase through the basic service charge rather than through the energy charge send the wrong signals for energy conservation?

A. No. In the 1970s and early 1980s, conservation advocates would often argue in favor of higher energy charges and lower service charges as a way to encourage conservation. Utilities in some of the more progressive jurisdictions have recognized the problem that variabilizing fixed costs causes with regard to energy efficiency and conservation. Many energy efficiency and conservation advocates have realized that a more constructive approach is to try and align the interests of the customers and the utility in a way that encourages the utility to promote conservation rather than being financially penalized by it. In fact, KU and LG&E are currently doing more in the area of demand-side management, energy efficiency, and energy conservation than any of the other utilities in Kentucky.

The problem with recovering non-volumetric distribution fixed costs through the energy charge is that whenever customers take measures to conserve energy or use energy more efficiently they reduce the amount of fixed costs recovered by the utility. In this situation, even though its revenues have been reduced by efforts of its customers to conserve energy or use energy more efficiently, none of the utility's non-volumetric distribution fixed costs have been avoided. What happens in this situation is that the utility's earnings are reduced as a result of customers using less energy, which makes it difficult for the utility to aggressively pursue energy efficiency and conservation programs that might benefit its customers. This is likely to be a bigger problem as customers, states and the federal government put more emphasis on conservation and energy efficiency. To align the interests of customers and the utility, regulators in some jurisdictions have moved toward decoupling for electric utilities. Decoupling prevents the utility from being financially harmed by energy efficiency and conservation, and helps to create an environment where the utility can work with customers to encourage greater energy efficiency. Appropriately recovering non-volumetric distribution fixed costs through the basic service charge removes disincentives for utilities to promote conservation and energy efficiency and is a form of decoupling that is actually supported by cost of service and a rate design that more accurately reflects cost causation.

Q. Would recovering more of non-volumetric distribution fixed cost through the basic service charge rather than through the energy charge have the effect of stabilizing customers' monthly bills?

A. Yes. Increasing the basic service charge will reduce the spikes that customers see in their bills during high usage months and cause customer bills to be less variable throughout the course of a year.

C. OPTIONAL RESIDENTIAL TIME-OF-DAY RATES

Q. Explain why the Company is proposing to eliminate the Low Emission Vehicle Service rate and to replace it with residential time-of-day rate options.

A. The Low Emission Vehicle Service (LEV) rate is currently available as an option to customers served under KU's residential rate schedule to encourage the charging of low emission vehicles in off-peak periods. The LEV rate is basically a time-of-day rate for a single application. Rather than limit the financial benefit that residential customers can derive from shifting load to off-peak periods to only low emission vehicle load, KU proposes to eliminate the LEV rate and replace it with residential time-of-day rate options that provide a financial incentive to shift any residential load to off-peak. Time-of-day rates provide financial incentives to encourage customers to move usage to off-peak periods that are less costly to serve. KU and LG&E have had very positive experiences with time-of-day rates for large commercial and industrial customers. Time-of-day rates more accurately reflect the actual cost of providing service to customers. Production and transmission plant costs are designed to meet the maximum load requirements placed on the systems. Because loads vary significantly throughout the course of a day, the likelihood of maximum loads occurring during certain hours greatly exceeds the likelihood of maximum system loads occurring during other hours of the day. It is therefore reasonable from a cost of service perspective to recover the majority of the Company's fixed production and transmission costs through the application of charges that would only be applicable during on-peak periods. Time-of-day rates also send a better price signal to customers encouraging them to reduce their loads during hours of the day for which the Company would have to install new production and transmission facilities to meet load increases on the system. Time-of-day rates represent a standard ratemaking tool to encourage the efficient utilization of KU's generation and transmission resources on the part of customers. The introduction of time-of-day rates for residential customers that the Company is proposing in this proceeding will provide customers with the opportunity to reduce their energy bills by moving usage from on-peak to off-peak periods. The derivation of the Residential time-of-day rate options that KU is proposing is shown in Exhibit MJB-11.

Q. Describe the time-of-use rate options that the Company is proposing for residential customers.

A. There are two time-of-day rate options that the Company is offering to residential customers, an all-energy rate option with a time differentiated energy charge and a demand rate option with a time differentiated demand charge. Customers can opt to take service under either one of these options or to remain on the standard residential service rate, but the decision to take either of the options is voluntary. The total number to customers who can sign up for the all-energy rate option and the demand rate option is limited to 500 customers because of metering and billing issues in implementing this rate. The time-of-day periods for the winter months of October through April are:

<u>All-Energy Rate Option</u>

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM – 11 AM
Weekends	All Hours	

<u>Demand Rate Option</u>

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM – 11 AM
Weekends	All Hours	

The time-of-day periods for the summer months of May through September are:

<u>All-Energy Rate Option</u>

	Off-Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM - 5 PM
Weekends	All Hours	

Demand Rate Option

	Off Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM – 5 PM
Weekends	All Hours	

The months included in the winter and summer periods are consistent with the months included in the winter and summer periods in the commercial and industrial time-of-day rates that KU offers. The time-of-day rates that apply to the on-peak and off-peak periods are:

All-Energy Rate Option

Basic Service Charge:	$18.00 per month
Plus an Energy Charge:	
Off Peak Hours:	$0.051 per kWh
On Peak Hours:	$0.25874 per kWh

Demand Rate Option

Basic Service Charge:	$18.00 per month
Plus an Energy Charge:	$ 0.04008 per kWh
Plus a Demand Charge:	
Off Peak Hours:	$ 3.25 per kW
On Peak Hours:	$11.56 per kW

The on-peak demand charge will apply to the customer's maximum integrated hourly demand during the on-peak period for each month. Derivation of the on-peak and off-peak periods and calculation of the on-peak and off-peak time-of-day rates are provided in Exhibit MJB-11.

D. STANDBY CHARGES

Q. What changes does KU propose to make to its Supplemental/Stand-by Rider, Rider SS?

A. Historically, KU's services have been provided under firm-service rates. With the advent of customer-owned generation, this situation is gradually changing. Rider SS specifies that KU is obligated only to provide firm service and is not required to provide supplemental or standby service unless that service is contracted for under Rider SS. This provision is supported by "EXCLUSIVE SERVICE ON INSTALLATION CONNECTED" on Rate Sheet No. 97.2. This provision does not in any way restrict or impinge upon a customer's right to receive firm service under the applicable rate schedule while also taking service under the Company's Net Metering Service Rider, Rider NMS.

Q. What are the proposed Supplemental/Standby Service charges?

A. The proposed demand charges per contract demand (kW or kVA) for customers taking service at secondary voltages is $12.84 per kW per month, for customers taking service at primary voltages is $11.63 per kW and for customers taking service at transmission voltage is $10.58 per kW per month based on information contained in the cost-of-service study. For customers served at transmission voltage, the Supplemental/Standby Service demand charge includes fixed production and transmission costs. For customers served at primary voltages, the Supplemental/Standby Service demand charge includes fixed production, transmission and primary distribution costs. For customers served at secondary voltages, the Supplemental/Standby Service demand charge includes fixed production, transmission, primary and secondary distribution costs. The fixed costs are calculated based on cost information from the cost of service study for the following cost categories: (i) Production and Transmission, (ii) Primary Distribution, and (iii) Secondary Distribution. The additive nature of the Supplemental/Standby Service demand charges is illustrated in the table below:

	Charge
Standby Charge at Transmission Votage	**$ 10.58**
Plus: additional primary standby costs	$ 1.05
Charge for Primary Standby Service	**$ 11.63**
Plus: additional secondary standby costs	$ 1.21
Charge for Primary Standby Service	**$ 12.84**

Production and Transmission Costs represent annual fixed cost revenue requirements. The unit charge is calculated by multiplying the KU coincident peak demand by twelve months and dividing this product into the production and transmission fixed cost determined based on the rate of return proposed in this proceeding. Because customers on KU's system are served at different voltages, distribution fixed costs must be based on a fixed charge calculation for customers served exclusively under a primary-voltage rate or a secondary-voltage rate. Primary Distribution Costs were determined based on the fixed cost revenue requirements for the Power Service - Primary and Time of Day Primary customer classes on a combined basis, and Secondary Distribution Costs were determined based on the fixed cost revenue requirements for the Power Service - Secondary and Time of Day

Secondary customer classes on a combined basis. The cost support for the proposed demand charges is included in Exhibit MJB-12.

E. REDUNDANT CAPACITY CHARGES

Q. What changes does KU propose to make to its Redundant Capacity Rider, Rider RC?

A. The rider as originally provided considered a load being served on one delivery feed where access to an alternate feed allowed the transfer of that load to a second feed. There have been requests for a configuration allowing the load to be served on a split bus so that, in effect, half the load is served on each of two feeds and each of the half loads can be switched to put the total load on either circuit in order to provide enhanced reliability for the customer.

Q. What are the proposed Redundant Capacity charges?

A. The proposed demand charge for Redundant Capacity for primary voltage customers is $1.11 per kW or kVA per month of billing demand and the proposed demand charge for secondary voltage customers is $1.12 per kW per month of billing demand.

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

A. The demand charge was determined by computing the distribution demand-related revenue requirements from the electric cost of service study for primary and secondary voltage service under KU's standard demand/energy rates (Rates PS, TODS, and TODP) and dividing this amount by the billing demands for these classes of customers. There are different demand charges for customers served at primary and secondary voltages. The cost support for the proposed demand charges is included in Exhibit MJB-13.

F. OTHER CHARGES

Q. Other than the changes mentioned previously, is the Company proposing any other significant structural changes to its rates?

A. No. However, in general, the Company is proposing to modify individual rate components to move them more in the direction of straight cost based rates that more accurately reflect the unit costs from the cost of service study. A cost based rate is one that calculates and bills rate components using the same cost drivers used to allocate each classification of costs in the cost of service study. For example, the Company is proposing to increase the basic service charge for Residential Service Rate RS from $10.75 to $18.00 per month to more accurately reflect the actual cost of providing service. As demonstrated in Exhibit MJB-10 this charge is calculated by dividing customer-related, non-volumetric fixed costs for the residential class by the number of customer-months for the residential class during the test year which results in a flat monthly charge per customer served.

Q. Please summarize the results of your cost of service and rate design testimony in this proceeding.

A. Exhibit MJB-14 provides a summary of the unadjusted cost of service results, the adjusted cost of service results and the results of applying the proposed rate increases to the various classes of customers that KU serves.

Q. Does this conclude your testimony?

A. Yes, it does.

From: Foxworthy, Carol(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WALLACEC)
To: Sturgeon, Allyson; Conroy, Robert; Staton, Ed; Lovekamp, Rick; 'Riggs, Kendrick R.'; 'Ingram III, Lindsey'; 'duncan.crosby@skofirm.com'; McGee, Dawn; Schroeder, Andrea; 'Marty Blake'; 'Jeff Wernert (jwernert@theprimegroupllc.com)'; 'Larry Feltner (lfeltner@theprimegroupllc.com)'
CC:
BCC:
Subject: RE: Blake KU Testimony
Sent: 11/11/2014 08:30:41 AM -0500 (EST)
Attachments: Dr Blake Testimony KU 2014-00371 Foxworthy edits.docx;

Attached are my edits to Marty's KU testimony. I also have questions/comments about Exhibit MJB-11, peaking hours for time of day residential rates. Specifically, the exhibit says that 87.5% of peaks will be captured by the proposed on-peak window. The only way I could duplicate that result is by including all shoulder peaks in the peaks to be captured; however, the shoulder peaks occurring from 1 pm through 5 pm, or 34 peaks, will not be captured because the shoulder months are included in the winter peaks. Is the correct percent of peaks captured through the proposed on-peak period more like 68% (i.e., 48 winter peaks, 14 shoulder peaks, and 58 summer peaks)?

Carol Foxworthy
LG&E-KU
State Regulation and Rates
502-627-2527
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From: Sturgeon, Allyson
Sent: Friday, November 07, 2014 12:57 PM
To: Conroy, Robert; Staton, Ed; Lovekamp, Rick; Riggs, Kendrick R.; Ingram III, Lindsey; duncan.crosby@skofirm.com; Foxworthy, Carol; McGee, Dawn; Schroeder, Andrea
Subject: FW: Blake KU Testimony

ATTORNEY-CLIENT COMMUNICATION
CONFIDENTIAL AND PRIVILEGED
FYI

From: Marty Blake [mailto:marty.blake.prime@gmail.com]
Sent: Friday, November 07, 2014 12:55 PM
To: Sturgeon, Allyson
Subject: Blake KU Testimony

The first draft of my testimony and associated exhibits are attached. I look forward to your comments.

Marty Blake
The Prime Group LLC
502-425-7882

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	**CASE NO. 2014-00371**
ADJUSTMENT OF ITS ELECTRIC	)	
BASE RATES	)	

TESTIMONY OF
DR. MARTIN BLAKE
PRINCIPAL
THE PRIME GROUP, LLC

Filed: November 26, 2014

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. By whom and in what capacity are you employed?

A. I am a Member and Principal of The Prime Group, LLC. The Prime Group provides consulting services in the areas of strategic planning, cost of service, rate design, regulatory support, and training for energy industry clients. A core part of our business is working with utilities to perform cost of service analyses and providing assistance in developing reasonable cost-based rates.

Q. Please describe your professional experience and educational background.

A. I hold a Ph.D. in Agricultural Economics and a Master of Arts degree in Economics from the University of Missouri, Columbia. I served as Commissioner on the New Mexico Public Service Commission from January 1986 through November 1989. I then worked as the Director of Rates, Regulatory and Strategic Planning for Louisville Gas and Electric from December 1989 through June 1996. I have taught at the NARUC Institute at Michigan State University for many years; and I have been an independent consultant with the Prime Group since 1996. A detailed description of my professional experience and educational background is provided in Exhibit MJB-1.

Q. In what cases have you previously testified?

A. I have testified in numerous proceedings before both state and federal regulatory bodies. Exhibit MJB-2 is a summary of the testimony I have presented in other regulatory proceedings.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Kentucky Utilities Company ("KU" or "Company").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (i) describe and support KU's electric cost of service study; (ii) describe the proposed allocation of the revenue increase to KU's electric rate classes; (iii) describe the electric rate designs, new rates, and percentage increase by rate class; and (iv) support certain filing requirements from 807 KAR 5:001.

Q. What are the fully forecasted test period and base period on which the rate case application and the electric cost of service study that you developed are based?

A. The fully forecasted test period on which the filing is based is the twelve months ended June 30, 2016. Consistent with KRS 278.192, the cost of service study and the adjustments in rates are supported by a fully forecasted test period. Because the effective date of KU's proposed rates is January 1, 2015, the first twelve consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning July 1, 2015 and ending on June 30, 2016. The base period for the filing is the 12 months ending February 28, 2015. The base period consists of six months of actual historical data for the period March 1, 2014 through August 31, 2014 and six months of estimated data for the period September 1, 2014 through February 28, 2015. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, consisting of not less than six months of actual historical data and not more than six months of estimated data. Because KU's proposed base period, which begins March 1, 2014, includes not less than six months of actual historical data (March 1, 2014 through August 31, 2014), includes no more than six months of estimated data (September 1, 2014 through February 28, 2015), and begins less than nine months prior to the filing date in this proceeding, the proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Please summarize your testimony.

A. The Company's fully allocated, embedded cost of service study for its electric operations were prepared using cost of service methodologies that have been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to fairly allocate the cost of providing safe, reliable service to the various customer classes that KU serves, to determine the contribution that each customer class is making towards KU's overall rate of return and to provide the data necessary to develop rate components that more accurately reflect cost causation. In the cost of service study, rates of return are calculated for each rate class. Because of the magnitude of the increase, KU is proposing to increase each electric rate class by the same percentage. Reduction of the differences in rates of return among classes would lead to double digit increases for some classes, which KU wanted to avoid. The Company is proposing unit charges that more accurately reflect cost causation for its electric rates.

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

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

- Cost of Service Studies Section 10(6)(u) Tab XX

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction and Qualifications, (II) Electric Cost of Service Study, and (III) Electric Rate Design and the Allocation of the Increase.

Q. Did you use the same methodology in KU's electric cost of service study that was used in LG&E's electric cost of service study filed concurrently in Case No. 2014-00372?

A. Yes.

II. ELECTRIC COST OF SERVICE STUDY

Q. Did The Prime Group prepare a cost of service study for KU's electric operations based on forecasted financial and operating results for the 12 months ended June 30, 2016?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study for KU'S electric operations based on a forecasted test year ended June 30, 2016. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Blake. The objective in performing the electric cost of service study is to allocate KU's revenue requirement as fairly as possible to all of the classes of customers that KU serves, to determine the rate of return on rate base that KU is earning from each customer class, and to provide the data necessary to develop rate components that more accurately reflect cost causation.

Q. What model was used to perform the cost of service study?

A. The cost of service study was performed using a proprietary EXCEL spreadsheet model that was developed by The Prime Group and that has been utilized in previous filings by KU to support requests for adjustments in its rates.

Q. Have you prepared an exhibit showing the results of the jurisdictional separation of KU's costs into Kentucky and Virginia components?

A. Yes. Exhibit MJB-3 shows the results of the study separating KU's costs into Kentucky and Virginia components.

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

A. Regardless of whether a historic test year or a forecasted test year is used to develop a cost of service study, the methodology for developing a cost of service study is basically the same. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods which time differentiates the costs. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then (4) costs were allocated to the various rate classes that KU serves. These steps are depicted in the following diagram (Figure 1).

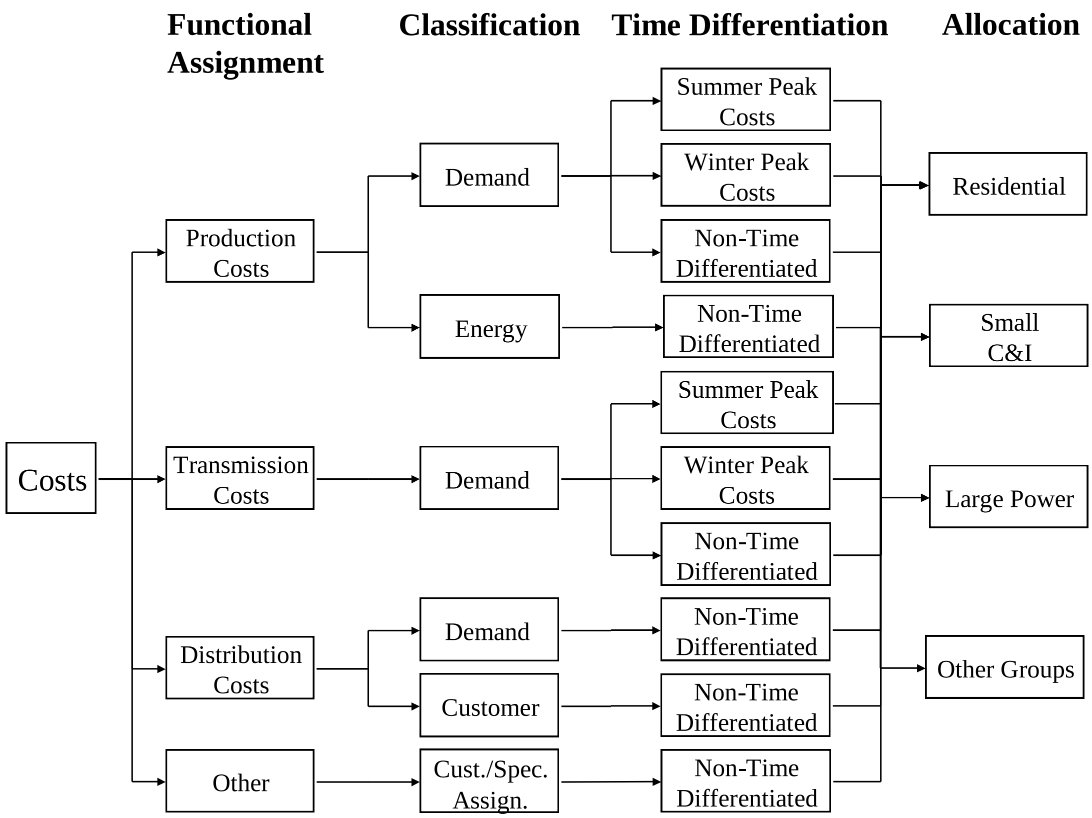

Figure 1

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.

Q. How were costs time differentiated in the study?

A. A modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to the relevant costing periods.[1] Using this methodology, production and transmission demand-related costs were assigned to three categories of capacity – base, intermediate, and peak. The percentages of production and transmission fixed cost that were assigned to the base period were determined by dividing the minimum system demand by the maximum demand. The percentages of production and transmission fixed cost that were assigned to the intermediate period were calculated by dividing the summer peak demand by the winter peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer or winter peak periods or assigned as non-time-differentiated. Base costs were assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. In applying the modified BIP methodology, what demands were used?

A Demands for the combined KU and LG&E systems were used to determine the costing periods and in determining the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly, developing costing periods and assigning costs to the costing periods based on the combined loads for KU and LG&E accurately reflects cost causation.

[1] In Case No. 90-158, 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, at 58.)

Developing the costing periods and allocation factors in the cost of service study based on the combined loads for KU and LG&E does not result in any shifting of booked expenses from one utility to the other. KU's cost of service study relied on KU's accounting costs, and LG&E's cost of service study relied on LG&E's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the KU and LG&E cost of service studies.

Q. What percentages were assigned to the costing periods?

A Exhibit MJB-4 shows the application of the modified BIP methodology. Using this methodology 34.10% of KU's production and transmission fixed costs were assigned to the winter peak period, 30.91% to the summer peak period, and 34.99% as base period costs that are non-time-differentiated.

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

A. Classification involves utilizing the appropriate cost driver for each functionally assigned cost which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. For costs classified as *energy-related*, the appropriate cost driver is the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand-related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. The costs of production plant and transmission lines are examples of costs typically classified as demand-related costs. Costs classified as *customer-related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum set of distribution equipment necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, a portion of the costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related because these costs do not vary with customers' capacity or energy usage.

Q. What methodologies are commonly used to classify distribution plant between customer-related and demand-related components?

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

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is preferred over the minimum system methodology when the necessary data is available. Additionally, KU has utilized the zero-intercept methodology in determining customer-related costs in prior rate case filings before this Commission. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer-related component of distribution costs. In the zero-intercept methodology, the estimated cost of a zero-size conductor or line transformer is the absolute minimum system for determining customer-related costs.

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

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost of conductor ($/ft) or line transformers ($/kVa of transformer size) and the load flow capability of the plant measured as the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, 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 feet of conductor and the number of transformers on KU's system is not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted linear regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted linear regression analysis all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

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

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

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

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

A. Yes. The Commission found LG&E's cost of service study (both electric and natural gas) submitted in Case No. 2000-080 and Case No. 90-158 to be reasonable, thus providing a means of measuring class rates of return that are suitable for use as a guide in developing appropriate revenue allocations and rate design. The cost of service studies in both of these proceedings utilized a zero-intercept methodology to calculate the splits between demand-related and customer-related distribution costs. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable.

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

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Exhibits MJB-5, MJB-6 and MJB-7, respectively.

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

A. Yes. Exhibit MJB-8 shows the results of the first three steps of the electric cost of service study; namely functional assignment, classification, and time differentiation. In the cost of service model used in this study, the calculations for functionally assigning, classifying and time differentiating KU's accounting costs are made using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the dollar amount in the various accounts in order to simultaneously functionally assign, classify and time differentiate KU's accounting costs. These calculations occur in the portion of the cost of service model included in Exhibit MJB-8. In Exhibit MJB-8, KU's accounting costs are functionally assigned, classified and time differentiated using explicitly determined functional vectors and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned, classified, and time differentiated, are shown on pages 61 through 65 of Exhibit MJB-8. Internally generated functional vectors are utilized throughout the study to functionally assign, classify and time differentiate costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 61 through 65 of Exhibit MJB-8. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign, classify and time differentiate these costs on the same basis. (See Exhibit MJB-8, pages 11 through 15, row 112 for the functional assignment, classification and time differentiation of cash working capital on the basis of OMLPP which is shown on pages 31 through 35, row 325.) The functional vector used to allocate a specific cost is identified in the column of the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Q. Please describe the how the functionally assigned, classified and time differentiated costs were allocated to the various classes of customers that KU serves.

A. Exhibit MJB-9 shows the allocation of the functionally assigned, classified and time differentiated costs to the various classes of customers that KU serves. For a forecasted test year, the average number of customers is used for allocating customer-related costs rather than the year end number of customers that is used for a historic test year. The following allocation factors were used in the electric cost of service study to allocate the functionally assigned, classified and time differentiated costs:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production and transmission fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.

- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **Cust04** – Customer-related costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05 and Cust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor calculated using the average number of customers for the test year based on discussions with KU's meter reading, billing and customer service departments.
- **Cust07** – Customer-related costs are allocated on the basis of the average number of customers using line transformers and secondary voltage conductor.
- **Cust08** – Customer-related costs are allocated on the basis of the average number of customers using primary voltage conductor.

Q. In your cost of service model, once costs are functionally assigned, classified and time differentiated, what calculations are used to allocate these costs to the various customer classes that KU serves?

A. Once costs for all of the major accounts are functionally assigned, classified, and time differentiated, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". A transpose of a matrix is formed by turning all the rows of a given matrix into columns and vice-versa. This process results in the columns of functionally assigned, classified and time differentiated costs becoming rows in the transposed matrix which then can be allocated to the various classes of customers that KU serves. This process is illustrated in Figure 2 below.

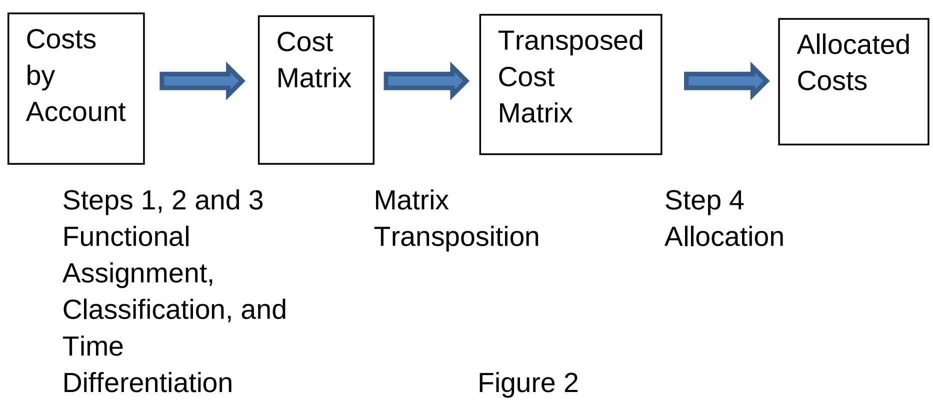

Figure 2

The results of the class allocation step of the cost of service study are included in Exhibit MJB-9. The costs shown in the column labeled "Total System" in Exhibit MJB-9 were carried forward from the functionally assigned, classified and time differentiated costs shown in Exhibit MJB-8. The column labeled "Ref" in Exhibit MJB-9 provides a reference to the results included in Exhibit MJB-8.

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

A. Table 1 below summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by KU. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Blake's and Mr. Conroy's testimonies. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

Table 1 - Electric Class Rates of Return

Rate Class	Actual Adjusted Rates of Return	Proposed Rates of Return
Residential Rate RS	2.77%	4.84%
General Service Single Phase	9.01%	12.14%
All Electric Schools Single Phase	4.43%	7.14%
Power Service Secondary Rate PS	11.29%	15.04%
Power Service Primary Rate PS	8.24%	11.46%
Time of Day Secondary Rate TODS	5.42%	8.69%
Time of Day Primary Rate TODP	3.34%	6.40%
Retail Transmission Service Rate RTS	3.41%	6.52%
Fluctuating Load Service Rate FLS	1.53%	4.61%
Lighting	2.75%	4.13%
Total	4.55%	7.18%

Determination of the actual adjusted and proposed rates of return are detailed in Exhibit MJB-9, pages 29 and 30 and pages 33 and 34, respectively.

III. ELECTRIC RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

Q. Have you prepared exhibits showing KU's base year and test year billing determinants for the electric business and showing the impact of applying the new rates to base year and test year billing determinants?

A. Yes. The KU's base year electric billing determinants are shown provided in Schedule M-1.3, and KU's test year (forecast) electric billing determinants are shown provided in Schedule M-2.3. Schedule M-2.3 shows the result of applying the proposed rates to the test year billing determinants by class of customers. A summary of the revenue increases that result from applying KU's proposed rates to the test year billing determinants is provided on pages 1 and 2 of Schedule M-2.3.

Q. What revenue increase is KU proposing for electric operations?

A. KU is proposing an increase in electric test-year revenues of $153,442,682, which is calculated by applying the proposed rates to test-year billing determinants as shown on page 1 of Schedule M-2.3. It should be pointed out that this amount is slightly less than the revenue requirement increase of $153,442,682 shown on page 2 of Schedule M-2.3.

Q. Please summarize how KU proposes to allocate the electric revenue increase to the classes of service?

A. The increase for all rate classes served by KU was calculated by applying the same 9.57 percent increase to all of the rate classes that KU serves. With an increase of this magnitude, attempting to reduce the differences in rates of return among classes would result in large double digit increases for some classes which KU wanted to avoid. With the second lowest rate of return as shown in the cost of service summary in Exhibit MJB-14, the increase to the residential class would have been particularly large if differences in rates of return among customer classes were reduced in this proceeding, which is a result that the Company wanted to avoid.

B. RESIDENTIAL ELECTRIC RATE INCREASE

Q. Is KU proposing to bring the rate components in residential electric rates more in line with the unit costs shown in the cost of service study?

A. Yes. KU is proposing to increase the monthly residential basic service charge from $10.75 to $18.00 to bring it more in line with the customer-related costs identified in the cost of service study. Even considering this increase, the basic service charge will be less than the amount that would recover all of the customer-related distribution costs identified in the cost of service. The cost of service study indicates that the customer-related, non-volumetric fixed distribution cost for the residential class is $21.47 per customer per month. KU is proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service, but is not proposing to go all of the way to the full amount indicated by the cost of service study. The derivation of the cost based residential basic service cost from data in the electric cost of service study is provided in Exhibit MJB-10.

Q. Does the current monthly basic service charge of $10.75 adequately recover customer-related costs from residential customers?

A. No. The current basic service charge of $10.75 per customer per month does not even recover all of the customer-related operating expenses, let alone any of the margins (return) that would normally be assigned as customer-related cost. These customer-related costs are non-volumetric fixed distribution costs that are not related to a customer's energy or capacity usage. Based on calculations from the cost of service study shown in Exhibit MJB-10, customer-related costs are $21.47 per customer per month; therefore, the current service charge of $10.75 under-recovers customer-related fixed distribution costs by $10.72 per customer per month. When this under-recovery of $10.72 per customer per month is multiplied by the 5,164,249 customer months for KU's residential rate class during the test year, the result is $55,360,749 in non-volumetric customer-related fixed operating expenses and margins that are being "variablized" and recovered through a kWh energy charge rather than being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is about 0.89 cents per kWh of fixed operating expenses and margins collected through the energy charge (calculated as $55,360,749 / 6,197,488,349 kWh = $0.089 per kWh). Thus, compared to rates that reflect straight cost causation, the basic service charge is $10.72 per customer per month too low and the energy charge is 0.89 cents per kWh too high. The recovery of non-volumetric fixed operating expenses and margins through the energy charge results in intra-class subsidies, results in customer energy bills being more variable than necessary and does not provide the proper environment for energy efficiency and conservation.

Q. What are intra-class subsidies and how can intra-class subsidies be avoided?

A. When one rate class subsidizes another rate class it is referred to as "inter-class subsidies", but when customers within a particular rate class subsidize other customers served under the same rate schedule it is referred to as "intra-class subsidies." The rate-making principle that should be followed to avoid intra-class subsidies is that, as much as possible, fixed costs should be recovered through fixed charges (such as the basic service charge and demand charge) and variable costs should be recovered through variable charges (such as the energy charge). If fixed costs are recovered through variable charges, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of fixed costs and margins, while customers using less energy than the average customer in the class are paying less than their fair share of fixed costs and margins. These fixed costs and margins should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is *not* the correct cost driver for the customer-related, non-volumetric fixed costs that should be collected through a fixed monthly charge. The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. In order to eliminate this source of intra-class subsidies, KU wants to pursue a rate design that moves more in the direction of recovering fixed costs through fixed charges and variable costs through variable charges.

Q. **What would be the impact of the proposed increase in the basic service charge on the average customer?**

A. Given a specified increase for the class, the average residential customer would see the same increase whether all of the increase is recovered through the basic service charge or through an increase of both the basic service charge and energy charge. Ultimately, the proposed rate for any given class of customers is based on averages and any rate design that was revenue neutral (i.e., generates the same amount of revenue) would have no impact whatsoever on a customer with a usage equal to the class average. The impact on customer energy bills would be greatest at the extremes of very low energy usage and very high energy usage. The change would result in higher energy bills for low-usage customers, as the subsidy that they had been receiving was removed, and lower energy bills for high-usage customers as the subsidies that they had been paying were eliminated.

Q. Typically, who are the low-usage customers who would be paying higher energy bills once the subsidies were removed?

A. For utilities such as KU, operating in an both rural and urban service territories, low usage customers tend to be loads like vacation homes, hunting cabins, fishing cabins, boat docks, garages, workshops, outbuildings, and unusual service connections. All of these loads typically consume very few kilowatt hours during the course of a year and the usage is sporadic. However, the utility still incurs fixed costs in installing the minimum system requirements necessary to serve these loads. A rate design with a low basic service charge and with a significant portion of fixed operating expenses and margins recovered through the energy charge would result in revenue that was insufficient to support the investment necessary to serve the types of low usage loads described above. Such a rate design would result in these customers being subsidized by the other customers who have above-average usage. A rate design with a low basic service charge and with a significant portion of the utility’s fixed operating expenses and margins recovered through the energy charge sends an improper economic signal to customers. It sends a signal that it is relatively inexpensive to provide the minimum set of equipment necessary to provide service to customers, and this is definitely not the case.

Q. Would recovering a portion of the increase through the basic service charge rather than through the energy charge send the wrong signals for energy conservation?

A. No. In the 1970s and early 1980s, conservation advocates would often argue in favor of higher energy charges and lower service charges as a way to encourage conservation. Utilities in some of the more progressive jurisdictions have recognized the problem that variabilizing fixed costs causes with regard to energy efficiency and conservation. Many energy efficiency and conservation advocates have realized that a more constructive approach is to try and align the interests of the customers and the utility in a way that encourages the utility to promote conservation rather than being financially penalized by it. In fact, KU and LG&E are currently doing more in the area of demand-side management, energy efficiency, and energy conservation than any of the other utilities in Kentucky.

The problem with recovering non-volumetric distribution fixed costs through the energy charge is that whenever customers take measures to conserve energy or use energy more efficiently they reduce the amount of fixed costs recovered by the utility. In this situation, even though its revenues have been reduced by efforts of its customers to conserve energy or use energy more efficiently, none of the utility's non-volumetric distribution fixed costs have been avoided. What happens in this situation is that the utility's earnings are reduced as a result of customers using less energy, which makes it difficult for the utility to aggressively pursue energy efficiency and conservation programs that might benefit its customers. This is likely to be a bigger problem as customers, states and the federal government put more emphasis on conservation and energy efficiency. To align the interests of customers and the utility, regulators in some jurisdictions have moved toward decoupling for electric utilities. Decoupling prevents the utility from being financially harmed by energy efficiency and conservation, and helps to create an environment where the utility can work with customers to encourage greater energy efficiency. Appropriately recovering non-volumetric distribution fixed costs through the basic service charge removes disincentives for utilities to promote conservation and energy efficiency and is a form of decoupling that is actually supported by cost of service and a rate design that more accurately reflects cost causation.

Q. Would recovering more of non-volumetric distribution fixed cost through the basic service charge rather than through the energy charge have the effect of stabilizing customers' monthly bills?

A. Yes. Increasing the basic service charge will reduce the spikes that customers see in their bills during high usage months and cause customer bills to be less variable throughout the course of a year.

C. OPTIONAL RESIDENTIAL TIME-OF-DAY RATES

Q. Explain why the Company is proposing to eliminate the Low Emission Vehicle Service rate and to replace it with residential time-of-day rate options.

A. The Low Emission Vehicle Service (LEV) rate is currently available as an option to customers served under KU's residential rate schedule to encourage the charging of low emission vehicles in off-peak periods. The LEV rate is basically a time-of-day rate for a single application. Rather than limit the financial benefit that residential customers can derive from shifting load to off-peak periods to only low emission vehicle load, KU proposes to eliminate the LEV rate and replace it with residential time-of-day rate options that provide a financial incentive to shift any residential load to off-peak. Time-of-day rates provide financial incentives to encourage customers to move usage to off-peak periods that are less costly to serve. KU and LG&E have had very positive experiences with time-of-day rates for large commercial and industrial customers. Time-of-day rates more accurately reflect the actual cost of providing service to customers. Production and transmission plant costs are designed to meet the maximum load requirements placed on the systems. Because loads vary significantly throughout the course of a day, the likelihood of maximum loads occurring during certain hours greatly exceeds the likelihood of maximum system loads occurring during other hours of the day. It is therefore reasonable from a cost of service perspective to recover the majority of the Company's fixed production and transmission costs through the application of charges that would only be applicable during on-peak periods. Time-of-day rates also send a better price signal to customers encouraging them to reduce their loads during hours of the day for which the Company would have to install new production and transmission facilities to meet load increases on the system. Time-of-day rates represent a standard ratemaking tool to encourage the efficient utilization of KU's generation and transmission resources on the part of customers. The introduction of time-of-day rates for residential customers that the Company is proposing in this proceeding will provide customers with the opportunity to reduce their energy bills by moving usage from on-peak to off-peak periods. The derivation of the Residential time-of-day rate options that KU is proposing is shown in Exhibit MJB-11.

Q. Describe the time-of-use rate options that the Company is proposing for residential customers.

A. There are two time-of-day rate options that the Company is offering to residential customers, an all-energy rate option with a time differentiated energy charge and a demand rate option with a time differentiated demand charge. Customers can opt to take service under either one of these options or to remain on the standard residential service rate, but the decision to take either of the options is voluntary. The total number to customers who can sign up for the all-energy rate option and the demand rate option is limited to 500 customers because of metering and billing issues in implementing this rate. The time-of-day periods for the winter months of October through April are:

<u>All-Energy Rate Option</u>

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM – 11 AM
Weekends	All Hours	

<u>Demand Rate Option</u>

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM – 11 AM
Weekends	All Hours	

The time-of-day periods for the summer months of May through September are:

<u>All-Energy Rate Option</u>

	Off-Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM - 5 PM
Weekends	All Hours	

Demand Rate Option

	Off Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM – 5 PM
Weekends	All Hours	

The months included in the winter and summer periods are consistent with the months included in the winter and summer periods in the commercial and industrial time-of-day rates that KU offers. The time-of-day rates that apply to the on-peak and off-peak periods are:

All-Energy Rate Option

Basic Service Charge: $18.00 per month

Plus an Energy Charge:
Off Peak Hours: $0.051 per kWh
On Peak Hours: $0.25874 per kWh

Demand Rate Option

Basic Service Charge: $18.00 per month

Plus an Energy Charge: $ 0.04008 per kWh

Plus a Demand Charge:
Off Peak Hours: $ 3.25 per kW
On Peak Hours: $11.56 per kW

The on-peak demand charge will apply to the customer's maximum integrated hourly demand during the on-peak period for each month. Derivation of the on-peak and off-peak periods and calculation of the on-peak and off-peak time-of-day rates are provided in Exhibit MJB-11.

D. STANDBY CHARGES

Q. What changes does KU propose to make to its Supplemental/Stand-by Rider, Rider SS?

A. Historically, KU's services have been provided under firm-service rates. With the advent of customer-owned generation, this situation is gradually changing. Rider SS specifies that KU is obligated only to provide firm service and is not required to provide supplemental or standby service unless that service is contracted for under Rider SS. This provision is supported by "EXCLUSIVE SERVICE ON INSTALLATION CONNECTED" on Rate Sheet No. 97.2. This provision does not in any way restrict or impinge upon a customer's right to receive firm service under the applicable rate schedule while also taking service under the Company's Net Metering Service Rider, Rider NMS.

Q. What are the proposed Supplemental/Standby Service charges?

A. The proposed demand charges per contract demand (kW or kVA) for customers taking service at secondary voltages is $12.84 per kW per month, for customers taking service at primary voltages is $11.63 per kW and for customers taking service at transmission voltage is $10.58 per kW per month based on information contained in the cost-of-service study. For customers served at transmission voltage, the Supplemental/Standby Service demand charge includes fixed production and transmission costs. For customers served at primary voltages, the Supplemental/Standby Service demand charge includes fixed production, transmission and primary distribution costs. For customers served at secondary voltages, the Supplemental/Standby Service demand charge includes fixed production, transmission, primary and secondary distribution costs. The fixed costs are calculated based on cost information from the cost of service study for the following cost categories: (i) Production and Transmission, (ii) Primary Distribution, and (iii) Secondary Distribution. The additive nature of the Supplemental/Standby Service demand charges is illustrated in the table below:

	Charge	
Standby Charge at Transmission Votage	**$**	**10.58**
Plus: additional primary standby costs	$	1.05
Charge for Primary Standby Service	**$**	**11.63**
Plus: additional secondary standby costs	$	1.21
Charge for Primary Standby Service	**$**	**12.84**

Production and Transmission Costs represent annual fixed cost revenue requirements. The unit charge is calculated by multiplying the KU coincident peak demand by twelve months and dividing this product into the production and transmission fixed cost determined based on the rate of return proposed in this proceeding. Because customers on KU's system are served at different voltages, distribution fixed costs must be based on a fixed charge calculation for customers served exclusively under a primary-voltage rate or a secondary-voltage rate. Primary Distribution Costs were determined based on the fixed cost revenue requirements for the Power Service - Primary and Time of Day Primary customer classes on a combined basis, and Secondary Distribution Costs were determined based on the fixed cost revenue requirements for the Power Service - Secondary and Time of Day

Secondary customer classes on a combined basis. The cost support for the proposed demand charges is included in Exhibit MJB-12.

E. REDUNDANT CAPACITY CHARGES

Q. What changes does KU propose to make to its Redundant Capacity Rider, Rider RC?

A. The rider as originally provided considered a load being served on one delivery feed where access to an alternate feed allowed the transfer of that load to a second feed. There have been requests for a configuration allowing the load to be served on a split bus so that, in effect, half the load is served on each of two feeds and each of the half loads can be switched to put the total load on either circuit in order to provide enhanced reliability for the customer.

Q. What are the proposed Redundant Capacity charges?

A. The proposed demand charge for Redundant Capacity for primary voltage customers is $1.11 per kW or kVA per month of billing demand and the proposed demand charge for secondary voltage customers is $1.12 per kW per month of billing demand.

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

A. The demand charge was determined by computing the distribution demand-related revenue requirements from the electric cost of service study for primary and secondary voltage service under KU's standard demand/energy rates (Rates PS, TODS, and TODP) and dividing this amount by the billing demands for these classes of customers. There are different demand charges for customers served at primary and secondary voltages. The cost support for the proposed demand charges is included in Exhibit MJB-13.

F. OTHER CHARGES

Q. Other than the changes mentioned previously, is the Company proposing any other significant structural changes to its rates?

A. No. However, in general, the Company is proposing to modify individual rate components to move them more in the direction of straight cost based rates that more accurately reflect the unit costs from the cost of service study. A cost based rate is one that calculates and bills rate components using the same cost drivers used to allocate each classification of costs in the cost of service study. For example, the Company is proposing to increase the basic service charge for Residential Service Rate RS from $10.75 to $18.00 per month to more accurately reflect the actual cost of providing service. As demonstrated in Exhibit MJB-10 this charge is calculated by dividing customer-related, non-volumetric fixed costs for the residential class by the number of customer-months for the residential class during the test year which results in a flat monthly charge per customer served.

Q. Please summarize the results of your cost of service and rate design testimony in this proceeding.

A. Exhibit MJB-14 provides a summary of the unadjusted cost of service results, the adjusted cost of service results and the results of applying the proposed rate increases to the various classes of customers that KU serves.

Q. Does this conclude your testimony?

A. Yes, it does.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Supplemental Response to Sierra Club's Initial Data Requests
Dated January 8, 2015

Question No. 20

Responding Witness: Robert M. Conroy / Counsel

Q-20. Reference Robert Conroy, pp. 26-29.

a) Please provide all documents and communications relating to the success of Rate LEV in shifting consumption away from peak hours, and any other evaluation of customer behavior under the tariff.

A-20. **ORIGINAL RESPONSE**

a) The Company objected to this question on January 19, 2015, because it requires the Company to reveal the contents of communications with counsel and the mental impressions of counsel, which information is protected from disclosure by the attorney-client privilege and the work product doctrine. Without waiver of these objections, see the attached documents that have been identified within the time permitted for this response. Counsel for the Company is continuing to undertake a reasonable and diligent search for other such documents and will reasonably supplement this response through a rolling production of documents.

SUPPLEMENTAL RESPONSE

a) The Company incorporates by reference the objections stated above. Without waiver of these objections, see the additional attached documents that have been identified.

The Company is also filing contemporaneously herewith a privilege log describing the responsive documents the Company is not producing on the ground of attorney-client or work product privilege.

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C. LG&E and KU

LG&E and KU both offer a pilot TOU rate to residential customers who have low-emission vehicles, Rate LEV. The rate's purpose is to allow customers who own plug-in electric or hybrid vehicles, or who use electric-powered home-filling stations for their natural-gas vehicles, to charge or fuel their vehicles at an off-peak rate that is less than the standard residential rate. Rate LEV has three TOU rates, the time-periods for which are different in the summer than for the rest of the year. LG&E and KU formulated the rates to be revenue-neutral compared to the standard residential rate. As of the end of November 2013, LG&E has 13 customers on Rate LEV and KU has 5 customers on the rate.

Administrative Case No. 2012-00428
Report of the Joint Parties: Dynamic Pricing

Prior to offering Rate LEV, LG&E conducted a three-year variable-CPP pilot program, which it called its Responsive Pricing Pilot. The pilot offered three-tiered TOU rates with a variable-CPP component to a geographically targeted sample of residential and small commercial customers. Low- and medium-pricing periods had rates lower than the standard rate and made up approximately 87% of the hours in a year. CPP events could occur during hours of high generation system demand for up to eighty hours per year, implemented at LG&E's discretion. Customers received at least 30 minutes' notice prior to CPP events, which had a rate of approximately five times that of the standard flat rate. Responsive-pricing participants received four devices to help them control their energy usage and respond to CPP events: smart meters, programmable communicating thermostats, in-home energy-usage displays, and load-control switches.

The pilot's results showed that customers consistently decreased their energy usage slightly in high-pricing and CPP periods; however, they used more energy overall throughout the summer periods compared to non-Responsive Pricing customers. Average demand reductions during CPP events varied from 0.2 kW to over 1.0 kW per participant during high-temperature periods, but those customers' demand rebounded after CPP periods ended, with a maximum average load increase of 0.8 kW. Even with participating customers' increased usage during summer months, they had an average bill decrease of 1.4% for those months.

LG&E's Responsive Pricing Pilot ended in 2010, and LG&E has removed the Responsive Pricing pilot rates from its tariff.

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a PPL company

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211 Sower Boulevard
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January 31, 2014

RE: *Low Emission Vehicle Service ("LEV") Report*
Case No. 2009-00548

Dear Mr. DeRouen:

Pursuant to the Kentucky Public Service Commission's Final Order in Case No. 2009-00548, which approved the rates and charges for service that included Standard Rate Low Emission Vehicle Service ("LEV"), Kentucky Utilities Company hereby file this report in compliance with Section 4 under AVAILABILITY OF SERVICE, Original Sheet No. 79.

Should you have any questions regarding the enclosed, please do not hesitate to contact me

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

Louisville Gas and Electric Company and Kentucky Utilities Company
Standard Rate Low Emission Vehicle Service ("LEV") Report
Submitted to Kentucky Public Service Commission
January 31, 2014

Pursuant to the Kentucky Public Service Commission's Final Orders in Case No. 2009-00548 and in Case No. 2009-00549, which approved the rates and charges for service that included Standard Rate Low Emission Vehicle Service ("LEV"), Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies") hereby file this report in compliance with Section 4 under AVAILABILITY OF SERVICE, Original Sheet No. 79.

The LEV rate was designed as a three year pilot program which may be restricted to a maximum of one hundred customers otherwise served under Rate Schedule RS (residential) (or GS where the GS service is used in conjunction with RS service to serve a detached garage and energy usage is no more than 300 kWh per month) to assess customer response to off peak power pricing differentials for low emission vehicles. This three-year pilot program is currently limited to customers who demonstrate that the power delivered to premises is consumed, in part, for the powering of low emission vehicles licensed for operation on public streets or highways. Such vehicles include: 1) battery electric vehicles or plug-in hybrid electric vehicles recharged through a charging outlet at customer's premises; and 2) natural gas vehicles refueled through an electric-powered refueling appliance at customer's premises. LEV pilot program participation is voluntary and features three energy (kWh) pricing periods (off peak, intermediate, and peak) as opposed to a standard residential customer's flat rate. The purpose of this rate structure is to provide an economic incentive for customers to consume more of their energy off peak which is recognized as having a greater availability of supply. The rate structure changes depending on the time of year and is detailed below.

May through September		
Time	**Weekdays**	**Weekends**
Midnight to 10 a.m.	Off Peak	Off Peak
10 a.m. to 1 p.m.	Intermediate	Off Peak
1 p.m. to 7 p.m.	Peak	Off Peak
7 p.m. to 10 p.m.	Intermediate	Off Peak
10 p.m. to Midnight	Off Peak	Off Peak
October through April		
Time	**Weekdays**	**Weekends**
Midnight to 6 a.m.	Off Peak	Off Peak
6 a.m. to 12 p.m.	Peak	Off Peak
12 p.m. to 10 p.m.	Intermediate	Off Peak
10 p.m. to Midnight	Off Peak	Off Peak

During the pilot period, the Companies had a total of only nine customers participating in the program (six LG&E and three KU customers). At the end of 2013, the number of customers participating had increased to 18 (13 LG&E and five KU customers). The Companies compared customers' energy usage by price tier and then utilized the data to compare a standard rate bill and LEV rate bill for the length of customers' participation on the program. As detailed in the chart below, the Companies found that seven of the nine customers who were on the LEV pilot program during the initial three year period realized a decrease in their total monthly bill as compared to what they would have been charged under the standard rate.

.Name	LEV Rate Effective Date	Number of Bills	LEV Rate Total ($)	Rate RS Total ($)	Difference Total ($)	Average Difference per Bill ($)
Customer 1	17-Jun-11	27	4,940.30	4,988.64	(48.33)	(1.79)
Customer 2	11-Jan-12	20	1,720.18	1,829.05	(108.87)	(5.44)
Customer 3	9-Jul-12	15	1,276.94	1,535.18	(258.24)	(17.22)
Customer 4	6-Aug-12	13	995.75	1,032.87	(37.11)	(2.85)
Customer 5	21-Jan-13	7	890.69	849.26	41.43	5.92
Customer 6	18-Feb-13	7	$340.23	$394.75	(54.52)	(7.79)
Customer 7	8-Jun-13	3	$264.05	$291.31	(27.26)	(9.09)
Customer 8	19-Jun-13	3	$512.52	$549.03	(36.51)	(12.17)
Customer 9	24-Jul-13	3	$571.58	$566.44	5.14	1.71

Additionally, the Companies compared LEV pilot participants' 12-month historical usage (i.e., usage prior to beginning of pilot) and LEV pilot usage. This data is detailed in the following table. Costs are total customer electric billed costs.

LEV Rate Participant Usage and Costs		Monthly Energy Usage (kWh)			Monthly Bill Total ($)		
		Min	Max	Avg	Min	Max	Avg
Customer 1	12 Months Prior to Pilot	1,187	3,838	2,097	98.39	289.06	166.70
	27 Months on the Pilot	698	4,014	2,148	62.23	335.66	182.97
Customer 2	12 Months Prior to Pilot	500	1,608	941	46.61	134.36	84.13
	20 Months on the Pilot	425	1,510	987	35.54	117.56	86.01
Customer 3	12 Months Prior to Pilot	676	2,070	1,150	58.03	160.69	93.15
	15 Months on the Pilot	297	2,055	1,205	20.74	143.22	85.13
Customer 4	12 Months Prior to Pilot	514	1,067	786	47.41	85.96	66.26
	13 Months on the Pilot	569	1,450	904	49.06	114.98	76.60
Customer 5	12 Months Prior to Pilot	782	2,070	1,167	61.54	160.69	97.96
	7 Months on the Pilot	768	2,024	1,287	69.00	234.83	127.24
Customer 6	12 Months Prior to Pilot	742	1,305	1,065	$63.97	$110.01	$88.81
	7 Months on the Pilot	486	709	568	$44.76	$52.40	$48.60
Customer 7	12 Months Prior to Pilot	374	1,415	748	$39.70	$122.96	$70.75
	3 Months on the Pilot	479	1,341	986	$43.02	$119.06	$88.02
Customer 8	12 Months Prior to Pilot	1,349	3,188	2,297	$115.78	$278.71	$200.09
	3 Months on the Pilot	1,867	2,004	1,943	$166.62	$174.66	$170.84
Customer 9	12 Months Prior to Pilot	1,957	7,578	3,871	$166.31	$647.19	$332.66
	3 Months on the Pilot	1,263	2,946	2,071	$123.97	$276.37	$190.53

The Companies also found that on average all LEV pilot participants used most of their energy during the off peak pricing period. However, not all LEV pilot participants used energy equally during intermediate and peak pricing periods. This trend is depicted in the chart below.

LEV Rate Participant Average Monthly Usage by Price Tier (kWh)			
Customer 1	Off Peak	1,223	56.95%
	Intermediate	497	23.16%
	Peak	427	19.90%
Customer 2	Off Peak	604	61.13%
	Intermediate	249	25.21%
	Peak	135	13.67%
Customer 3	Off Peak	930	77.13%
	Intermediate	229	19.04%
	Peak	46	3.83%
Customer 4	Off Peak	550	60.83%
	Intermediate	217	23.97%
	Peak	137	15.20%
Customer 5	Off Peak	623	48.42%
	Intermediate	342	26.54%
	Peak	322	25.03%
Customer 6	Off Peak	441	77.53%
	Intermediate	98	17.22%
	Peak	30	5.25%
Customer 7	Off Peak	684	69.31%
	Intermediate	195	19.77%
	Peak	108	10.92%
Customer 8	Off Peak	1,282	66.01%
	Intermediate	383	19.70%
	Peak	278	14.29%
Customer 9	Off Peak	1,183	57.14%
	Intermediate	431	20.80%
	Peak	457	22.07%

The results do indicate some promise for shifting consumption patterns. Nonetheless, the Companies recognize that the number of program participants is too small to deduce any concrete suggestions related to a larger group of customers.

Moreover, the impact of the LEV pilot participants on the Companies' electric system has been minimal thus far. Typically, LEV charging loads are low at Level 1 charging (i.e., charging the vehicle from a standard 120V household outlet) and present no infrastructure concerns. Level 2 charging (i.e. charging the vehicle through a 240V charging station installed on premise) loads can reach up to 19.2 kW; however, most residential Level 2 installations operate at a lower power (i.e., no more than 7.5 kW). Nonetheless, the Companies recognize that such installations need to be carefully reviewed. Only one of the LEV pilot program participants installed a Level 2 charger with a load capacity of approximately 10 kW. The Companies reviewed the electric distribution service equipment at the customer's location and upgraded infrastructure to avoid the potential for problems.

The program allows the Companies to evaluate existing electric distribution infrastructure on an individual basis, to ensure LEV charging loads are adequately served. However, the pilot does not track those customers who are LEV owners but are not interested in the LEV rate. With increased penetration and no accurate method for tracking LEVs and their charging service locations, the Companies recognize that there is some uncertainty with predicting their actual impact on the Companies' electric system load and capacity. Affected infrastructure would include (in order) services, secondary and transformers and potentially primary conductor should infiltration of LEVs escalate.

Even though the program was established to target residential customers with low emission vehicles, it enabled the Companies the opportunity to introduce a product offering to residential customers which assists in raising awareness of a time-of-use pricing rate structure and potentially shifting energy and demand to off peak periods in general. The Companies recommend continuance of the LEV rate schedule as originally approved. Furthermore, the Companies propose that any desired or necessary changes to this tariff be handled through normal course of a general base rate case.

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January 31, 2014

RE: *Low Emission Vehicle Service ("LEV") Report*
Case No. 2009-00549

Dear Mr. DeRouen:

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Should you have any questions regarding the enclosed, please do not hesitate to contact me

Sincerely,

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Customer 7	12 Months Prior to Pilot	374	1,415	748	$39.70	$122.96	$70.75
	3 Months on the Pilot	479	1,341	986	$43.02	$119.06	$88.02
Customer 8	12 Months Prior to Pilot	1,349	3,188	2,297	$115.78	$278.71	$200.09
	3 Months on the Pilot	1,867	2,004	1,943	$166.62	$174.66	$170.84
Customer 9	12 Months Prior to Pilot	1,957	7,578	3,871	$166.31	$647.19	$332.66
	3 Months on the Pilot	1,263	2,946	2,071	$123.97	$276.37	$190.53

The Companies also found that on average all LEV pilot participants used most of their energy during the off peak pricing period. However, not all LEV pilot participants used energy equally during intermediate and peak pricing periods. This trend is depicted in the chart below.

LEV Rate Participant Average Monthly Usage by Price Tier (kWh)			
Customer 1	Off Peak	1,223	56.95%
	Intermediate	497	23.16%
	Peak	427	19.90%
Customer 2	Off Peak	604	61.13%
	Intermediate	249	25.21%
	Peak	135	13.67%
Customer 3	Off Peak	930	77.13%
	Intermediate	229	19.04%
	Peak	46	3.83%
Customer 4	Off Peak	550	60.83%
	Intermediate	217	23.97%
	Peak	137	15.20%
Customer 5	Off Peak	623	48.42%
	Intermediate	342	26.54%
	Peak	322	25.03%
Customer 6	Off Peak	441	77.53%
	Intermediate	98	17.22%
	Peak	30	5.25%
Customer 7	Off Peak	684	69.31%
	Intermediate	195	19.77%
	Peak	108	10.92%
Customer 8	Off Peak	1,282	66.01%
	Intermediate	383	19.70%
	Peak	278	14.29%
Customer 9	Off Peak	1,183	57.14%
	Intermediate	431	20.80%
	Peak	457	22.07%

The results do indicate some promise for shifting consumption patterns. Nonetheless, the Companies recognize that the number of program participants is too small to deduce any concrete suggestions related to a larger group of customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

Supplemental Response to Sierra Club's Initial Data Requests
Dated January 8, 2015

Question No. 23

Responding Witness: David S. Sinclair / Robert M. Conroy / Counsel

Q-23. Reference Testimony of David Sinclair, pp. 26-27.

c) Please provide copies of all e-mail communications, internal memoranda, reports, or other documentation of the Company's consideration of changes to the provisions of the CSR tariffs and of the decision to adopt the proposed changes.

A-23. **ORIGINAL RESPONSE**

c) The Company objected to this question on January 19, 2015, because it requires the Company to reveal the contents of communications with counsel and the mental impressions of counsel, which information is protected from disclosure by the attorney-client privilege and the work product doctrine. Without waiver of these objections, see the attached documents that have been identified within the time permitted for this response. Counsel for the Company is continuing to undertake a reasonable and diligent search for other such documents and will reasonably supplement this response through a rolling production of documents.

SUPPLEMENTAL RESPONSE

c) The Company incorporates by reference the objections stated above. Without waiver of these objections, see the additional attached documents that have been identified.

The Company is also filing contemporaneously herewith a privilege log describing the responsive documents the Company is not producing on the ground of attorney-client or work product privilege.

From: Oelker, Linn(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E009358)
To: Freibert, Charlie
CC: Brunner, Bob; Martin, Charlie
BCC:
Subject: CSR10andCSR30 Pages from KU Tariff PSC No. 16 - Eff 6-30-14.docx
Sent: 07/14/2014 01:01:35 PM -0400 (EDT)
Attachments: CSR10andCSR30 Pages from KU Tariff PSC No. 16 - Eff 6-30-14.docx;

Moreover, the impact of the LEV pilot participants on the Companies' electric system has been minimal thus far. Typically, LEV charging loads are low at Level 1 charging (i.e., charging the vehicle from a standard 120V household outlet) and present no infrastructure concerns. Level 2 charging (i.e. charging the vehicle through a 240V charging station installed on premise) loads can reach up to 19.2 kW; however, most residential Level 2 installations operate at a lower power (i.e., no more than 7.5 kW). Nonetheless, the Companies recognize that such installations need to be carefully reviewed. Only one of the LEV pilot program participants installed a Level 2 charger with a load capacity of approximately 10 kW. The Companies reviewed the electric distribution service equipment at the customer's location and upgraded infrastructure to avoid the potential for problems.

The program allows the Companies to evaluate existing electric distribution infrastructure on an individual basis, to ensure LEV charging loads are adequately served. However, the pilot does not track those customers who are LEV owners but are not interested in the LEV rate. With increased penetration and no accurate method for tracking LEVs and their charging service locations, the Companies recognize that there is some uncertainty with predicting their actual impact on the Companies' electric system load and capacity. Affected infrastructure would include (in order) services, secondary and transformers and potentially primary conductor should infiltration of LEVs escalate.

Even though the program was established to target residential customers with low emission vehicles, it enabled the Companies the opportunity to introduce a product offering to residential customers which assists in raising awareness of a time-of-use pricing rate structure and potentially shifting energy and demand to off peak periods in general. The Companies recommend continuance of the LEV rate schedule as originally approved. Furthermore, the Companies propose that any desired or necessary changes to this tariff be handled through normal course of a general base rate case.

From: Freibert, Charlie(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=TRADERS/CN=FREIBERTC)
To: Oelker, Linn
CC: Freibert, Charlie; Brunner, Bob; Martin, Charlie
BCC:
Subject: DRAFT edits of CSR10. CSR10andCSR30 Pages from KU Tariff PSC No 16 - Eff 6-30-14.docx
Sent: 07/14/2014 01:35:20 PM -0400 (EDT)
Attachments: CSR10andCSR30 Pages from KU Tariff PSC No 16 - Eff 6-30-14.docx;

From: Marty Blake(marty.blake.prime@gmail.com)
To: Riggs, Kendrick R.; Conroy, Robert
CC: Larry (work) Feltner
BCC:
Subject: CSR Insert
Sent: 07/18/2014 09:52:01 AM -0400 (EDT)
Attachments: CSR testimony insert.docx;

Attached is testimony regarding CSR based on what we discussed earlier this week. Any comments or suggested changes? I am also working on the weather normalization portion of the testimony and will send you that portion after I have it prepared. As we address rate case issues, I plan to write testimony addressing those issues while the discussion is still fresh in my mind.

Marty Blake
The Prime Group LLC
502-425-7882

CURTAILABLE SERVICE RIDER

Q. Please summarize the proposed changes to the Company's curtailable service riders.

A. The Company currently has two curtailable service riders – CSR10 and CSR30. CSR10 provides for a ten minute notice provision with up to 100 hours of curtailment with no buy-through provision and 275 hours of curtailment with a buy-through provision. CSR30 provides for a thirty minute notice provision with up to 100 hours of curtailment with no buy-through provision and 250 hours of curtailment with a buy-through provision. Because of the longer required notice provision in CSR30, the curtailable credits provided under CSR30 are lower than the credits provided under CRS10. The two curtailable service riders were the result of negotiated settlements in prior rate cases.

In this proceeding, LG&E is proposing to: 1) leave the curtailable credits the same in CSR10 and CSR30; 2) change the contract options in both CSR10 and CSR 30 so that they match the assumptions used to calculate these credits; and 3) change the criteria for qualifying for the CSR rates from not less than 1,000 kW individually to not less than 5,000 kVa individually to make the criteria consistent with the billing units in the applicable tariffs and to reduce the potential administrative burden.

Q. Identify and explain the contract options that need to be changed in order to match the assumptions used to calculate the credits with the contract options specified in the CSR tariffs.

A. Currently, CSR10 and CSR30 contain the following language regarding Contract Option:

> For the purposes of this rider, a system reliability event is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing

> (“ARS”) at some point during the event. Company may also request at its sole discretion up to 250 hours of curtailment per year with a buy-through option, whereby Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kilowatt hours of curtailable requirements.

This Contract Option language needs to be changed to:

> For the purposes of this rider, a system reliability event is any condition or occurrence that impairs KU and LG&E’s ability to maintain service to contractually committed system load. Company may also request up to 250 hours of curtailment per year with a buy-through option to reduce the average hourly production cost to its native load customers. The Customer may, at its option, choose either to curtail service in accordance with this Rider or to continue to purchase its curtailable requirements by paying the Automatic Buy-Through Price, as set forth below, for all kVa of curtailable requirements.

The second and third criteria were eliminated from the current tariff language in order to match the tariff language with the assumptions used to calculate the CSR credits. The current language restricts the Company to curtailing only after it has pursued all options, including buying high priced emergency power. By eliminating the second and third criteria the Company can curtail before it purchases high priced emergency power. The key issue here is where does curtailment under the CSR tariffs fall in the dispatch stack, before any available emergency power is purchased or after emergency power is purchased. Because the curtailable credits are priced based on the avoided cost of a new natural gas fired combustion turbine, these curtailments must perform the same functions as a new combustion turbine in the dispatch stack. A new combustion turbine would be loaded before any attempt to purchase high priced emergency power, not after purchasing emergency power. The CSR10 and CSR30 tariffs need to provide native load customers who are paying the curtailable credits the same protection against emergency energy purchases that a combustion turbine would provide. To provide this protection, it is necessary to load curtailable load in the dispatch stack before emergency power purchases are made, not after emergency power purchases are made as criteria 2 and 3 in the current Contract Option language require. Because of the high prices that occur when generation resources are tight and utilities are near or at their peaks, buying emergency power before curtailing load would typically amount to purchasing power at prices over $1,000 per MWh (the emergency power price) and selling it at $26 per MWh (the energy price in the applicable rates). This substantial difference between the price of emergency power and the retail rate significantly erodes the value of curtailable load to the Company if curtailable power is loaded only after any available emergency power is purchased and would require a significant reduction in the curtailable credits.

Additional language was added regarding the 250 hours of curtailment per year with a buy-through option that would allow the Company to use curtailment to reduce the average hourly production cost to its native load customers. Buy-through power would be indexed to the cost of natural gas, which is the primary fuel used in LG&E's combustion turbine units. This would benefit the native load customer who are paying the curtailable credit by reducing average hourly production cost when the opportunity to do this using curtailments with buy through is available. The 250 hours of curtailment with buy through would not be used to curtail customers and sell the freed up power into the wholesale power market. It would only be used to reduce LG&E's average hourly production cost when this would be a benefit to native load customers.

With these changes, the Company is proposing to refine the provisions of the proposed CSR riders so that they correspond more closely to the operational characteristics the Company would actually enjoy if it were to install combustion turbine capacity. In other words, the Company wants the provisions of CSR to mirror as much as possible the benefits that the customers who pay the curtailable credits would receive if the Company installed a combustion turbine.

Q. Are there any other changes being proposed to CSR?

A. Yes. The criteria for qualifying for the CSR rates would be changed from not less than 1,000 kW individually to not less than 5,000 kVa individually. The change to measuring the qualification criteria in kVa makes the criteria consistent with the billing units in the tariffs to which the CSR rider would apply. Raising the qualification criteria to 5,000 would reduce the potential administrative burden of signing up and calling for curtailments from relatively small loads. Raising the qualification criteria to 5,000 kVa would not affect any LG&E customers currently taking service under the CSR riders.

From: Marty Blake(marty.blake.prime@gmail.com)
To: Riggs, Kendrick R.; Conroy, Robert
CC: Larry (work) Feltner
BCC:
Subject: Revised CSR testimony
Sent: 07/18/2014 10:21:49 AM -0400 (EDT)
Attachments: CSR testimony insert.docx;

I revised the CSR testimony to include examples of PJM and MISO prices when generation resources are tight to help illustrate the point that customers would be subject to substantial financial risk if curtailable load is loaded only after any available power is purchased.

CURTAILABLE SERVICE RIDER

Q. Please summarize the proposed changes to the Company's curtailable service riders.

A. The Company currently has two curtailable service riders – CSR10 and CSR30. CSR10 provides for a ten minute notice provision with up to 100 hours of curtailment with no buy-through provision and 275 hours of curtailment with a buy-through provision. CSR30 provides for a thirty minute notice provision with up to 100 hours of curtailment with no buy-through provision and 250 hours of curtailment with a buy-through provision. Because of the longer required notice provision in CSR30, the curtailable credits provided under CSR30 are lower than the credits provided under CRS10. The two curtailable service riders were the result of negotiated settlements in prior rate cases.

In this proceeding, LG&E is proposing to: 1) leave the curtailable credits the same in CSR10 and CSR30; 2) change the contract options in both CSR10 and CSR 30 so that they match the assumptions used to calculate these credits; and 3) change the criteria for qualifying for the CSR rates from not less than 1,000 kW individually to not less than 5,000 kVa individually to make the criteria consistent with the billing units in the applicable tariffs and to reduce the potential administrative burden.

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The second and third criteria were eliminated from the current tariff language in order to match the tariff language with the assumptions used to calculate the CSR credits. The current language restricts the Company to curtailing only after it has pursued all options, including buying high priced emergency power. By eliminating the second and third criteria the Company can curtail before it purchases high priced emergency power. The key issue here is where does curtailment under the CSR tariffs fall in the dispatch stack, before any available emergency power is purchased or after emergency power is purchased. Because the curtailable credits are priced based on the avoided cost of a new natural gas fired combustion turbine, these curtailments must perform the same functions as a new combustion turbine in the dispatch stack. A new combustion turbine would be loaded before any attempt to purchase high priced emergency power, not after purchasing emergency power. The CSR10 and CSR30 tariffs need to provide native load customers who are paying the curtailable credits the same protection against emergency energy purchases that a combustion turbine would provide. To provide this protection, it is necessary to load curtailable load in the dispatch stack before emergency power purchases are made, not after emergency power purchases are made as criteria 2 and 3 in the current Contract Option language require. For example, on January 7, 2014, the day that PJM and the Midcontinent ISO experienced peaks, real time power prices reached a high of $1,841 per MWh in PJM and $1,966 per MWh in MISO. Because of the high prices that occur when generation resources are tight and utilities are near or at their peaks, buying emergency power before curtailing load would typically amount to purchasing power at prices well over $1,000 per MWh (real time energy prices when resources are tight) and selling it at $26 per MWh (the energy price in the applicable rates). If curtailable load is curtailed only after any available power is purchased regardless of price, the native load customers who pay the curtailable credits would bear these costs and would be subject to substantial risk, which is unfair because they are not receiving the benefits for which they are paying. The substantial difference between the price of emergency power when generation resources are tight and the retail rate significantly erodes the value of curtailable load to the Company if curtailable power is loaded only after any available power is purchased and would require a significant reduction in the curtailable credits paid to customers taking service under the CSR rider.

Additional language was added regarding the 250 hours of curtailment per year with a buy-through option that would allow the Company to use curtailment to reduce the average hourly production cost to its native load customers. Buy-through power would be indexed to the cost of natural gas, which is the primary fuel used in LG&E's combustion turbine units. This would benefit the native load customer who are paying the curtailable credit by reducing average hourly production cost when the opportunity to do this using curtailments with buy through is available. The 250 hours of curtailment with buy through would not be used to curtail customers and sell the freed up power into the wholesale power market. It would only be used to reduce LG&E's average hourly production cost when this would be a benefit to native load customers.

With these changes, the Company is proposing to refine the provisions of the proposed CSR riders so that they correspond more closely to the operational characteristics the Company would actually enjoy if it were to install combustion turbine capacity. In other words, the Company wants the provisions of CSR to mirror as much as possible the benefits that the customers who pay the curtailable credits would receive if the Company installed a combustion turbine.

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A. Yes. The criteria for qualifying for the CSR rates would be changed from not less than 1,000 kW individually to not less than 5,000 kVa individually. The change to measuring the qualification criteria in kVa makes the criteria consistent with the billing units in the tariffs to which the CSR rider would apply. Raising the qualification criteria to 5,000 would reduce the potential administrative burden of signing up and calling for curtailments from relatively small loads. Raising the qualification criteria to 5,000 kVa would not affect any LG&E customers currently taking service under the CSR riders.

From: Keels, Lisa(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E009671)
To: Kallam, Karen
CC: Huff, David
BCC:
Subject: FW: Proposed Tariff Changes
Sent: 04/14/2014 09:05:06 AM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DE....docx;

My question/concern is included as a comment in the document.

Lisa

Please consider the environment before printing this e-mail

From: Kallam, Karen
Sent: Monday, April 07, 2014 4:12 PM
To: Hornung, Mike; Keels, Lisa; Myers, Jeff
Cc: Huff, David
Subject: FW: Proposed Tariff Changes

David asks that you take a look at the attached document. Do you have any concerns or additions? Please let him know.

Thanks,

Karen Kallam

Customer Energy Efficiency

LG&E and KU Energy Services

(502) 627-3730

From: Kallam, Karen On Behalf Of Huff, David
Sent: Monday, April 07, 2014 4:11 PM
To: Woodworth, Steve; Malloy, John; Bruner, Cheryl
Cc: Huff, David
Subject: RE: Proposed Tariff Changes

All: David's comments on Steve's document…

<<Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14.docx>>

Karen Kallam

Customer Energy Efficiency

LG&E and KU Energy Services

(502) 627-3730

From: Woodworth, Steve
Sent: Friday, April 04, 2014 10:25 AM
To: Malloy, John; Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

Attached is the final list of proposed tariff changes. Please let me know your thoughts by Wednesday, 4/9, so I can consolidate and send to

Robert. Thanks

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx >>

From: Malloy, John
Sent: Thursday, April 03, 2014 2:18 PM
To: Woodworth, Steve
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

Steve,

Do we have a final list that we are moving forward?

thanks

John P. Malloy
LGE - KU Energy LLC
VP Energy Delivery - Retail
220 West Main Street
Louisville, KY 40202
T 1.502.627.4836
F 1.502.217.2162
M 1.502.445.6776
john.malloy@LGE-KU.com

<< OLE Object: Picture (Device Independent Bitmap) >>

From: Woodworth, Steve
Sent: Tuesday, March 04, 2014 9:50 AM
To: Malloy, John
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx >>

Yes

From: Malloy, John
Sent: Tuesday, March 04, 2014 9:21 AM
To: Woodworth, Steve
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

Access denied!

Should we meet as a team and discuss the "WHY's"?

From: Woodworth, Steve
Sent: Tuesday, March 04, 2014 9:02 AM
To: Malloy, John
Cc: Bruner, Cheryl; Huff, David
Subject: Proposed Tariff Changes

John,

Please take a look at the potential items we want to address in the upcoming rate case. I would like to send this to Robert Conroy for his review after your feedback.

Thanks,

-Steve

http://home/projects/pprc/Shared%20Documents/Customer%20Service%20Rate%20Case%20Pre-Planning%20Team%20-%20Proposed%20Tariff%20Revisions.docx

[redacted]
Redacted as Unresponsive
[redacted]

Item	LOB	Tariff Description and Sheet No.	Proposed Revision	Volume / Customer Impact	Sponsor
Redacted as Unresponsive [redacted]					
4	E	LG&E / KU- CSR10 & CSR30 = Sheet # 50 and #51 - Curtailable Service Rider	Under the CSR rider, a customer is provided a monthly credit for allowing LGE/KU to curtail their load. In some months the credit a customer receives does not allow LGE/KU to recover the cost to serve. Discount does not reflect the intrinsic value and should be adjusted and more closely align <u>with "call option" valuation.</u>	KU CSR10 – 3 KU CSR30 – 2 LGE CSR10 – 1 LGE CSR30 - 1	Conroy

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

[redacted]
Redacted as Unresponsive
[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Huff, David; Malloy, John; Bruner, Cheryl
CC:
BCC:
Subject: RE: Proposed Tariff Changes
Sent: 04/08/2014 12:26:46 PM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DE....docx;

Thanks David for your comments. I have responded to your points and will maintain with the document when sent to R&R.

-Steve

<<Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14 - SEW-04-08-14 Response.docx>>

From: Kallam, Karen On Behalf Of Huff, David
Sent: Monday, April 07, 2014 4:11 PM
To: Woodworth, Steve; Malloy, John; Bruner, Cheryl
Cc: Huff, David
Subject: RE: Proposed Tariff Changes

All: David's comments on Steve's document…

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14.docx >>

Karen Kallam

Customer Energy Efficiency

LG&E and KU Energy Services

(502) 627-3730

From: Woodworth, Steve
Sent: Friday, April 04, 2014 10:25 AM
To: Malloy, John; Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

Attached is the final list of proposed tariff changes. Please let me know your thoughts by Wednesday, 4/9, so I can consolidate and send to Robert. Thanks

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Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

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John P. Malloy
LGE - KU Energy LLC
VP Energy Delivery - Retail

220 West Main Street
Louisville, KY 40202
T 1.502.627.4836
F 1.502.217.2162
M 1.502.445.6776
john.malloy@LGE-KU.com

<< OLE Object: Picture (Device Independent Bitmap) >>

From: Woodworth, Steve
Sent: Tuesday, March 04, 2014 9:50 AM
To: Malloy, John
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx >>

Yes

From: Malloy, John
Sent: Tuesday, March 04, 2014 9:21 AM
To: Woodworth, Steve
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

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http://home/projects/pprc/Shared%20Documents/Customer%20Service%20Rate%20Case%20Pre-Planning%20Team%20-%20Proposed%20Tariff%20Revisions.docx

[redacted]

Redacted as Unresponsive

[redacted]

Item	LOB	Tariff Description and Sheet No.	Proposed Revision	Volume / Customer Impact	Sponsor
Redacted as Unresponsive [redacted]					
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[redacted]
Redacted as Unresponsive
[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

From: Kallam, Karen(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E006057)
To: Hornung, Mike; Keels, Lisa; Myers, Jeff
CC: Huff, David
BCC:
Subject: FW: Proposed Tariff Changes
Sent: 04/07/2014 04:12:28 PM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DE....docx;

David asks that you take a look at the attached document. Do you have any concerns or additions? Please let him know.

Thanks,

Karen Kallam

Customer Energy Efficiency

LG&E and KU Energy Services

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Subject: RE: Proposed Tariff Changes

All: David's comments on Steve's document…

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Steve,

Do we have a final list that we are moving forward?

thanks

John P. Malloy
LGE - KU Energy LLC
VP Energy Delivery - Retail
220 West Main Street
Louisville, KY 40202
T 1.502.627.4836
F 1.502.217.2162
M 1.502.445.6776
john.malloy@LGE-KU.com

<< OLE Object: Picture (Device Independent Bitmap) >>

From: Woodworth, Steve
Sent: Tuesday, March 04, 2014 9:50 AM
To: Malloy, John
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx >>

Yes

From: Malloy, John
Sent: Tuesday, March 04, 2014 9:21 AM
To: Woodworth, Steve
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

Access denied!

Should we meet as a team and discuss the "WHY's"?

From: Woodworth, Steve
Sent: Tuesday, March 04, 2014 9:02 AM
To: Malloy, John
Cc: Bruner, Cheryl; Huff, David
Subject: Proposed Tariff Changes

John,

Please take a look at the potential items we want to address in the upcoming rate case.   I would like to send this to Robert Conroy for his review after your feedback.

Thanks,

-Steve

http://home/projects/pprc/Shared%20Documents/Customer%20Service%20Rate%20Case%20Pre-Planning%20Team%20-%20Proposed%20Tariff%20Revisions.docx

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Item	LOB	Tariff Description and Sheet No.	Proposed Revision	Volume / Customer Impact	Sponsor
[redacted] Redacted as Unresponsive					
4	E	LG&E / KU- CSR10 & CSR30 = Sheet # 50 and #51 - Curtailable Service Rider	Under the CSR rider, a customer is provided a monthly credit for allowing LGE/KU to curtail their load. In some months the credit a customer receives does not allow LGE/KU to recover the cost to serve. Discount does not reflect the intrinsic value and should be adjusted and more closely align with “call option” valuation.	KU CSR10 – 3 KU CSR30 – 2 LGE CSR10 – 1 LGE CSR30 - 1	Conroy

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From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: McGonnell, Robert
CC:
BCC:
Subject: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14 - SEW-04-08-14 Response.docx
Sent: 04/10/2014 10:56:03 AM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DE....docx;

<<Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14 - SEW-04-08-14 Response.docx>>

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From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Huff, David; Malloy, John; Bruner, Cheryl
CC:
BCC: Woodworth, Steve
Subject: RE: Proposed Tariff Changes
Sent: 04/08/2014 12:26:46 PM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DE....docx;

Thanks David for your comments. I have responded to your points and will maintain with the document when sent to R&R.

-Steve

<<Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14 - SEW-04-08-14 Response.docx>>

From: Kallam, Karen On Behalf Of Huff, David
Sent: Monday, April 07, 2014 4:11 PM
To: Woodworth, Steve; Malloy, John; Bruner, Cheryl
Cc: Huff, David
Subject: RE: Proposed Tariff Changes

All: David's comments on Steve's document…

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DEH-04-07-14.docx >>

Karen Kallam

Customer Energy Efficiency

LG&E and KU Energy Services

(502) 627-3730

From: Woodworth, Steve
Sent: Friday, April 04, 2014 10:25 AM
To: Malloy, John; Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

Attached is the final list of proposed tariff changes. Please let me know your thoughts by Wednesday, 4/9, so I can consolidate and send to Robert. Thanks

<< File: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx >>

From: Malloy, John
Sent: Thursday, April 03, 2014 2:18 PM
To: Woodworth, Steve
Cc: Bruner, Cheryl; Huff, David
Subject: RE: Proposed Tariff Changes

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John P. Malloy
LGE - KU Energy LLC
VP Energy Delivery - Retail

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Louisville, KY 40202
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Subject: RE: Proposed Tariff Changes

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Cc: Bruner, Cheryl; Huff, David
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Item	LOB	Tariff Description and Sheet No.	Proposed Revision	Volume / Customer Impact	Sponsor
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From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Reinert, Marty; Bush, Howard
CC:
BCC: Woodworth, Steve
Subject: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx
Sent: 05/28/2014 10:59:51 AM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx;

<<Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions.docx>>

Gentlemen,

Attached is a consolidated proposed list of changes from Customer Service as well as the list Marty sent me a couple of weeks ago.

-Steve

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Item	LOB	Tariff Description and Sheet No.	Proposed Revision	Volume / Customer Impact	Sponsor
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