COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
SIERRA CLUB'S INITIAL DATA REQUESTS
DATED JANUARY 8, 2015

FILED: JANUARY 23, 2015

VERIFICATION

STATE OF TEXAS	)	
	)	**SS:**
COUNTY OF TRAVIS	)	

The undersigned, **William E. Avera**, being duly sworn, deposes and says he is President of FINCAP, Inc., 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.

William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17 day of January 2015.

_______________(SEAL)
Notary Public

My Commission Expires:

Robert Middelton Avera
NOTARY PUBLIC STATE OF TEXAS
Notary Public, State of Texas
Expires: 06-17-2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer 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.

Kent W Blake

Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd 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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Dr. Martin J. Blake**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, 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.

Martin J Blake
Dr. Martin J. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th 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

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

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th 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

VERIFICATION

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

The undersigned, **David E. Huff**, being duly sworn, deposes and says that he is Director – Customer Energy Efficiency Smart Grid Strategy for Louisville Gas and Electric Company and Kentucky Utilities 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 E. Huff

David E. Huff

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th 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

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is Vice President of FINCAP, Inc., 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.

____
Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17 day of Jan 2015.

______________________________(SEAL)
Notary Public

My Commission Expires:

____

NOTARY PUBLIC, STATE OF TEXAS
Robert Middelton Avera
Notary Public,
State of Texas
Expires:06-17-2018

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 19th 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

VERIFICATION

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

The undersigned, **Victor A. Staffieri**, being duly sworn, deposes and says that he is Chief Executive Officer of 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.

Victor A. Staffieri

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of January 2015.

(SEAL)
Notary Public

My Commission Expires:

03/29/2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Edwin R. Staton**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, 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.

Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of January 2015.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul Gregory Thomas**, being duly sworn, deposes and says that he is Vice President, Electric Distribution, 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.

Paul Gregory Thomas

Paul Gregory Thomas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 26th 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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Chief Operating Officer 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.

Paul W. Thompson

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th 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

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 1

Responding Witness: Victor A. Staffieri / Paul W. Thompson / David S. Sinclair

Q-1. Reference Testimony of Victor A. Staffieri, p. 8, ll.11-13.

a) What operations and maintenance costs will KU be able to avoid due to the flat sales growth the Company is experiencing?

b) What generation, transmission, or distribution projects has the Company been able to cancel or defer due to flat sales growth?

A-1. a) The Company does not track or quantify a change in the amount of its variable operations and maintenance costs resulting from any specific level of sales growth. The Company does, however, constantly examine, and adjust if necessary, its operations and maintenance levels so that reliable service is provided to customers in the most efficient manner possible. Those adjustments are reflected in the operation and maintenance expenses projected for the forecasted test period in this case. Please also see the numerous examples provided throughout Mr. Thompson's Direct Testimony of programs and practices the Company utilizes to ensure efficiency at any level of sales.

b) The Company does not track specific generation, transmission, or distribution projects that are implemented, cancelled, or deferred due to any particular level of demand. Instead, the Company constantly examines, and adjusts if necessary, those projects so that reliable service is provided to customers in the most efficient manner possible. That examination process is described in great detail in the Company's most recent Integrated Resource Plan (see Case No. 2014-00141) and is also addressed, in part, in Mr. Sinclair's Direct Testimony in this case. For example, after much consideration and study, the Company recently withdrew its request for a Certificate of Public Convenience and Necessity for the construction of Green River Unit 5 in Muhlenberg County after nine of KU's municipal customers gave notice of their decision to terminate their contracts with KU.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 2

Responding Witness: Kent W. Blake

Q-2. Reference Staffieri, p. 9, ll.11-20.

a) How much of KU's requested $153 million increase in revenue requirement is attributable to the requested increase in return on equity to 10.5%?

A-2. Please see the Company's responses to AG 1-168, AG 1-169, and AG 1-170 which show the effect of changes to return on equity on the requested revenue requirement.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 3

Responding Witness: Dr. Martin J. Blake

Q-3. Reference Testimony of Dr. Martin Blake, pp. 3-4.

a) Please provide working electronic spreadsheet versions, with all cell formulas and file linkages intact, of Schedules M-2.1, M-2.2, and M-2.3.

b) Please provide working electronic versions, with all cell formulas and file linkages intact, of all linked spreadsheet files.

A-3. a-b See the response to PSC 2-60. The attachment provided in response to PSC 2-60 lists all files submitted in response to the request for exhibits, schedules, and workpapers from Dr. Blake, Mr. Conroy, and Mr. Blake. The spreadsheets for Schedules M-2.1 through 2.3 are included in this list.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 4

Responding Witness: Paul Gregory "Greg" Thomas / Dr. Martin J. Blake

Q-4. Reference Martin Blake, p. 15, ll. 1-3.

a) Please confirm that demand-related secondary conductor costs were allocated using the SICD allocator.

b) Please provide the rationale for allocating demand-related secondary conductor costs on the basis of the sum of individual customer demands rather than on the basis of maximum class demand.

c) Does the Company employ guidelines for sizing of primary and secondary conductors? If so, please provide copies of such guidelines.

d) Please confirm that demand-related line transformer costs were allocated using the SICD allocator.

e) Please provide the rationale for allocating demand-related line transformer costs on the basis of the sum of individual customer demands rather than on the basis of maximum class demand.

f) Does the Company employ guidelines for sizing of line transformers? If so, please provide copies of such guidelines.

g) Has the Company studied the impact of load diversity on loadings on distribution equipment? If so, please provide copies of all such studies.

A-4. a) Demand related secondary conductor was allocated to each class using the SICD allocator

b) Secondary conductor and line transformers are sized to meet a more localized demand, whereas primary conductor and substations are sized to meet a more diversified demand. Since primary conductor and substations are sized to meet the loads of many customers with varying demands, volatility of individual customer usage is reduced by serving the customers as a group, i.e., the low usage of some customers offset the high usage of others. Therefore, secondary conductor and line transformers are allocated to each class using the sum of the individual customer maximum demands, which is a localized demand. It more closely matches the demand that is driving the size of the conductor, or transformer, that was installed than would a class maximum demand that is more reflective of diversity. This very concept is discussed in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual. On page 97 of that manual it states the following: "**The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands.**"

Furthermore, KU has followed this allocation methodology consistently and it has been accepted by the Commission.

c) Capacity ratings for KU's primary circuits vary significantly from small rural lines to large circuits serving high density urban areas. There is no set capacity rating for these circuits and therefore no formal standard governing such. Primary and secondary conductors are selected from standard available sizes and are individually sized for their expected application based on factors such as load (normal and emergency), load factor, ability to limit voltage drop and flicker to acceptable limits, strength requirements and expected load growth.

d) The demand portion of line transformers was also allocated using the SICD allocator.

e) See the explanation in the response to part b).

f) A guideline used for sizing residential line transformers based on diversified load is provided. See attached. Transformers for commercial and industrial applications are chosen from standard available sizes and are individually sized for their application based on factors including expected peak loading, load factor, ability to limit voltage drop and flicker to acceptable limits and expected load growth.

g) Yes, for residential load only. See the attached studies.

1.3 Distribution Circuit Guidelines

1.3.1 Circuit Loading Guidelines

<u>12.47 kV and 13.8 kV Circuits</u>

In general, 12.47 kV and 13.8 kV circuits are designed to have normal and contingency condition loading guidelines as given below.

<u>Circuit Ratings</u>

Normal	440 amps
Contingency	600 amps

The circuit capacity-limiting factor, in most instances, is the size of the underground exit cable from the substation. The overhead conductor size at the lateral pole can also limit a circuit's normal and contingency operating capacity.

Typically, new distribution circuits use 1000 kcmil, aluminum, single conductor, or 750 kcmil, copper, single conductor, underground exit cables. Either 795 AA open wire or 795 AA spacer cable is used for the overhead distribution leaving the lateral pole. Occasionally, 336 AA open wire or 336 AA spacer cable may be used. The wire size used is dependent on load and voltage drop conditions. Underground exit cable sizes and overhead wire sizes leaving the substation should be checked to determine the normal operating and contingency capacity rating of a circuit.

The normal circuit capacity ratings give operating personnel the ability to transfer loads under contingency conditions without creating low voltage problems and circuit overloads. A contingency condition is defined as the loss of a distribution circuit or a substation transformer. If circuits are loaded to their maximum capacity (i.e. 600 amps), inability to switch loads under contingency conditions can cause customers to be without power for long periods.

<u>4.16 kV Circuits</u>

The 4.16 kV distribution circuits are some of the oldest on the system. There is no set capacity rating for these circuits. Each circuit's capacity rating will vary according to the size of the underground exit cable or overhead wire leaving the substation lateral pole. The most common underground exit cable used on 4.16 kV circuits is 350 kcmil, three conductor, paper-lead-rubber (PLR). Over the years, many of these cables have been replaced with 500 kcmil, single conductor, cross-link polyethelyne (XLP) insulation. Substation cut-sheets are

used to determine the exact type of underground exit cable. The overhead wire size leaving the substation lateral pole must be checked to ensure it is not limiting the circuit's capacity.

Attachment to Response to Sierra Club-1 Question No. 4(f)
Page 1 of 5
Thomas

Residential Load and Diversity

Prepared By: Rudy Dewitt Michael T. Leake Richard Jones
Status: Draft Pending Review

BACKGROUND

Residential development represents a substantial portion of most electric utility companies, and as such, requires a need to accurately estimate non-coincident and coincident peak demands. Accurate estimates help to determine electric systems' capacity requirements as well as provide design technicians and engineering a realistic design standard to maximize the use of materials and equipment. This is important for any electric utility to stay competitive and generally keep the "cost to serve" down. In an effort to develop residential demand and diversity equations suitable for the LG&E/KU/ODP operating region, a fairly comprehensive study was initiated and a set of standard equations developed for use.

For the sake of simplicity, only two general classes of service were considered, *RS* for residential service homes with non-electric heating, and *FERS* for full electric residential service. The Demand (D) equations can be used to estimate the realistic demand of a residence by its size and character of service. Because short term or instantaneous demands have little impact on system requirements, the calculated Demand is the peak one-hour demand value for a home of a given size and character of use.

The Diversified Demand Factor (DDF) equations can be used to estimate with a high degree of confidence the diversified load of multiple homes from a common load point, for example off a common secondary, off a common transformer, multiple customers on an overhead tap or half loop of a URD feed, etc. Or it can even be used to estimate load for the whole subdivision. The Diversified Demand Factor is applied to the sum of the individual peak demands to allow for the fact that all customer off a common source will not experience their peak demands at the same time. The LG&E/KU/ODP standard equations for Demand and the Diversified Demand Factor are:

FERS	***RS***
D= 6.5 watts/ft^2 + 6000 watts	D= 3.4 watts/ft^2 + 6000 watts
$DDF = .55 + \frac{.25}{N} + \frac{.20}{\sqrt{N}}$	$DDF = .52 + \frac{.38}{N} + \frac{.10}{\sqrt{N}}$
Where *N* is the number of homes and the square footage is the average conditioned living space of the homes	

These equations were derived from an extensive review of technical literature on residential demand and diversity and data derived from past PURPA studies. These equations were then refined and validated through an extensive study of real load data from load research meters on the LG&E system. For details on the most recent load study, visit the Electric Codes and Standards Home Page or contact the Electric Codes and Standards group. Also a spreadsheet for calculating residential loading, checking voltage drop and sizing transformers can be found on the home page.

RESIDENTIAL CUSTOMER CLASSIFICATIONS

Residential customers were classified into two basic groups: Full electric residential service (FERS) and residential service (RS). The FERS class would generally be a winter peaking load since some form of electric heating is used and the RS class would generally be a summer peaking load since most of these would have air conditioning. Each of these groups will have subclasses, but unfortunately these were not considered. A brief table of the subclasses is as follows:

FERS AND RS SUB-CLASSES

MAJOR CLASS	***SUB-CLASSES***	
	Heat Source	***Major Appliances***
FERS Winter Peaking	1. Heat Pump + Auxiliary Heating 2. Electric Furnace 3. Baseboard 4. Ceiling Cable 5. Electric Boiler (Steam Heating)	1. Oven 2. Range 3. Clothes Dryer 4. Water Heater

Attachment to Response to Sierra Club-1 Question No. 4(f)
Page 2 of 5
Thomas

RS Summer Peaking	1. Natural Gas Furnace 2. Wood or Other Fossil fuel 3. Heat Pump + natural gas or Other Fossil Fuel 4. Natural Gas or Other Fossil Fuel Boiler (Steam Ht.) 5. Portable (Room Heaters) of Any Kind	1. Air Conditioning Room or Central 2. Any Combination of Any Number of The FERS Major Appliances

From this brief table of Sub-classes, there are at least 5 *FERS* subclasses and as many as 25 RS subclasses.

SOURCE DOCUMENTS AND RESOURCES

Many source documents were used in aiding this study and analysis. Primary documents included:

1. Westinghouse Electric Utility Engineering reference book – Distribution Systems, volume 3, Chapter 2.
2. Ebasco/Electrical World Electric Distribution Systems Engineering Manual, Volume 2.
3. KU/ODP and LG&E Residential Load Survey (PURPA) data.
4. Air Conditioning Contractors of America (ACCA) manual J, load calculations for residential Winter and Summer air conditioning.
5. Other utility companies' engineering standards or surveys.

The Westinghouse and EBASCO documents generally provide basic demand and diversity estimating equations. Although not explicitly stated in either document, there appeared to be two (2) load components for peak demand and two (2) diversity equations. The load components are variable and fixed, and diversity equations reflect these load components.

LOAD COMPONENTS

The variable load component is compromised predominantly of comfort heating and cooling, lighting and some other discretionary small loads. The comfort heating and air conditioning load is not only living area dependent, but also ambient and indoor comfort temperature dependent. This gives a wide range for maximum (15 minute) demands but this range narrows for hourly integrated demands.

As an example, an 1800 ft^2 FERS residence would typically have a 3 ton heat pump and 15 kW auxiliary (resistance) heating. For a mild winter day the heating demand would be about 3 kW, both 15 minute and hourly integrated, but on a cold day the 15 minute peak demand could approach 18 kW while the hourly integrated demand is only about 12 kW.

Lighting loads are reasonably proportional to living area as well as other discretionary devices such as TV sets, home computers, radios and clocks. The combination of the HVAC, lighting and discretionary loads can all be approximated as the variable load component expressed as watts per square foot of living area. A brief table of variable loads and their non-coincident demands is shown below:

VARIABLE LOAD COMPONENT WATTS/FT²		
Heating	***Air Conditioning***	***Lighting & Misc.***
HP Only: 1.67 HP+ AH: 1.67 to 10.00 Other Electric: 5.00 to 10.00	HP or Central: 1.25 to 1.67	2.5 to 3.0

This brief table yields variable non-coincident demands of:
Winter 4.17 to 13.0 Watts/ft^2
Summer 3.75 to 4.67 Watts/ft^2

The fixed load component is comprised of many individual major and small appliance loads. A brief table of these, as well as their individual non-coincident demands is shown below.

FIXED LOAD COMPONENT			
Major Appliance	***Watts Demand***	***Small Appliance***	***Watts Demand***
Oven (2)	5000	* Refrigerator	300
Range (4)	8000	Microwave	700
Water Heater (2)	5000	Portable fans	200
Clothes Dryer	5000	* Coffee Maker	1200
Clothes Motor	300	Toaster	1200
		Freezer	500
		Dish Washer	1200
		Hair Dryer	1500
		Portable Heater	1500
		* Washing Machine	300
Undiversified Totals (2) = 2 Elements (4) = 4 Elements	23300	* Most Common For Both FERS and RS Classes	8600

This table yields a ***fixed*** load component of 25100 to 31900 watts for FERS class and 1800 to 31900 watts for RS class. The contribution to ***peak*** demands for either class is just as varied.

The combined variable and fixed load components yield non-coincident demand equations as follows:

Variable (w/ft2)	***Fixed (watts)***
Dw = 4.17 to 13	25100 to 31900
Ds = 3.75 to 4.67	1800 to 31900

These are actually total connected loads, and for an 1800 ft^2 residence, the total connected loads would be:

FERS Winter	***RS Summer***
32.606 to 55.3 kW	8.55 to 40.306 kW

Final estimated demand equations can be written in the forms:

Dw = (Vw) (LA) + Fw

Ds = (Vs) (LA) + Fs

Dw = Coincident winter demand of both variable and fixed
Vw = Variable winter demand coefficient in watts per square foot
LA = Living area of residence in square feet
Fw = Fixed winter demand component in watts
Ds = Coincident summer demand of both variable and fixed loads in watts
Vs = Variable summer demand coefficient in watts per square foot
LA = Living area of residence in square feet
Fs = Fixed summer demand component in watts

The determination of these components and their contributions to total residence coincident demand can reasonably be done if enough sample points (residences) can be obtained under peak loading conditions of individual residences. Additionally, coincident factors can be determined for a group of similar size residences to aid in determining diversity equations. LG&E and KU/ODP Residential Load Research programs (PURPA) were used to the extent possible to determine estimated demand and diversity equations.

DIVERSITY EQUATIONS

With a group of similar electrical loads with similar peak demands, the total coincident demand is almost always much less than the sum of the individual peak demands, this is especially true for residential loads. Since there are two load components, variable and fixed, there are two generic diversity equations as follows:

1. Variable Loads

A. Winter $DDF_{WV} = .7 + \frac{.3}{\sqrt{N}}$

B. Summer $DDF_{SV} = .8 + \frac{.2}{\sqrt{N}}$

2. Fixed Loads $DDF_F = F + \frac{1-F}{N}$

where:
DDF_{WV} = Diversified demand factor winter variable
DDF_{SV} = Diversified demand factor summer variable
N = Number of equal loads
DDF_F = Diversified demand factor fixed load
F = Coefficient usually in the range of .25 to .35

To get a single diversity equation for winter and a single diversity equation for summer some manipulations are required.

Let: $\overline{D}w = \overline{V}w + \overline{F}w$ and $\overline{V}w + \overline{F}w = 1.00$

$\overline{D}s = \overline{V}s + \overline{F}s$ and $\overline{V}s + \overline{F}s = 1.00$

then: $DDFw = \overline{F}w\left(F + \frac{1-F}{N}\right) + \overline{V}w\left(.7 + \frac{.3}{\sqrt{N}}\right)$

$DDFs = \overline{F}s\left(F + \frac{1-F}{N}\right) + \overline{V}s\left(.8 + \frac{.2}{\sqrt{N}}\right)$

Both of these equations are in the form of:

$DDF = A + \frac{B}{N} + \frac{C}{\sqrt{N}}$

and A + B + C = 1.00.

While it is theoretically possible to determine the A, B, and C coefficients for any size residence and either class (FERS or RS), it has been determined that the weighted average from the KU/ODP PURPA data would be most practical. The study from the LG&E data did indeed favorably match the KU/ODP weighted average coefficients.

The original estimated demand equations for the LG&E/KU/ODP companies were based upon the Westinghouse, EBASCO and several different utility companies' practices as follows:

For FERS Winter	***For RS Summer***
D = 5.4 watts/ft^2 + 6000 watts	D = 2.0 watts/ft^2 + 5300 watts

Linear regression from the LG&E PURPA data provides the following equations:

For FERS Winter	***For RS Summer***
D = 4.7 watts/ft^2 + 5790 watts	D = 3.94 watts/ft^2 + 2440 watts

Modifying the values from the linear regression to provide a 95% confidence level for actual load data, the demand equations selected to be somewhat conservative are:

For FERS Winter	***For RS Summer***
D = 6.5 watts/ft^2 + 6000 watts	D = 3.4 watts/ft^2 + 6000 watts

The original estimated diversity equations for the LG&E/KU/ODP companies were based upon the Westinghouse, EBASCO and several different utility companies' practices as follows:

FERS Winter

$$DDF = .55 + \frac{.25}{N} + \frac{.20}{\sqrt{N}}$$

RS Summer

$$DDF = .52 + \frac{.38}{N} + \frac{.10}{\sqrt{N}}$$

The LG&E PURPA data was used to develop the FERS and RS demand equations and to verify the diversity equations. The KU/ODP PURPA data was used for weighted average diversity equations. (Since no really accurate residence size was in the KU/ODP PURPA data, demand equations were not readily obtainable.)

The final equations for demands and diversities are:

FERS

D= 6.5 watts/ft^2 + 6000 watts

$$DDF = .55 + \frac{.25}{N} + \frac{.20}{\sqrt{N}}$$

RS

D= 3.4 watts/ft^2 + 6000 watts

$$DDF = .52 + \frac{.38}{N} + \frac{.10}{\sqrt{N}}$$

As more PURPA studies are done, there may be some refinements on estimated demands, but the diversity equations will probably remain the same.

LG&E and KU
Residential Demand and Diversity Study

Prepared by: Brent Sundheimer
Engineering Intern, Electric Policies & Standards
6/15/04

Residential Diversity and Demand Study

Purpose of the Study:

The primary goal of this study was to validate and/or refine equations developed by Rudy Dewitt, Contractor - Electric Policies and Standards group, for estimating residential peak loads and diversity factors. By utilizing load survey meters, the energy usage every 15 minutes for each monitored house is recorded, as opposed to the normal meters which only show an accumulated total energy usage. This data can then be used to determine an understanding of energy use patterns within the home, determine peak loading and how peak loads from multiple homes aggregate on common equipment such as common secondary, transformers and primary systems.

The purpose of this study was to help to create and optimize engineering design tools and information relating to residential peak loads and diversity. This information can then be used to estimate capacity requirements, optimize designs and to more efficiently size primary and secondary wire/cables and transformers. Because new business is by far the single largest capital budget item within Distribution Operation's annual budget, and new residential business is a significant portion of that item, optimizing design of new residential infrastructure has a significant potential to positively impact annual costs.

Definitions:

FERS - (Full Electric Residential Service) A classification for customers without gas (propane or natural) heating.
RS - (Residential Service) A classification for customers with gas heating.
15 Minute Demand - The averaged demand, in KW, over a 15 minute period.
Peak 15 Minute Demand - The maximum averaged 15 minute peak demand, in KW, over an entire year.
Rolling Peak Demand - The maximum 15 minute peak demand, in KW, averaged over four consecutive 15 minute periods during a year.
Fixed Demand Component - The component of the peak demand equation that is based on fixed loads for houses. These loads are relatively independent of house size, i.e. stoves, washing machines, etc.
Variable Demand Component - The component of the peak demand equation that varies by house size, i.e. air-conditioning, heating, lighting and some discretionary loads.
Diversity/Diversity Curve - Relates actual aggregated peak demand of multiple homes at a common point such as a transformer to the simple summation of the individual peak demands.

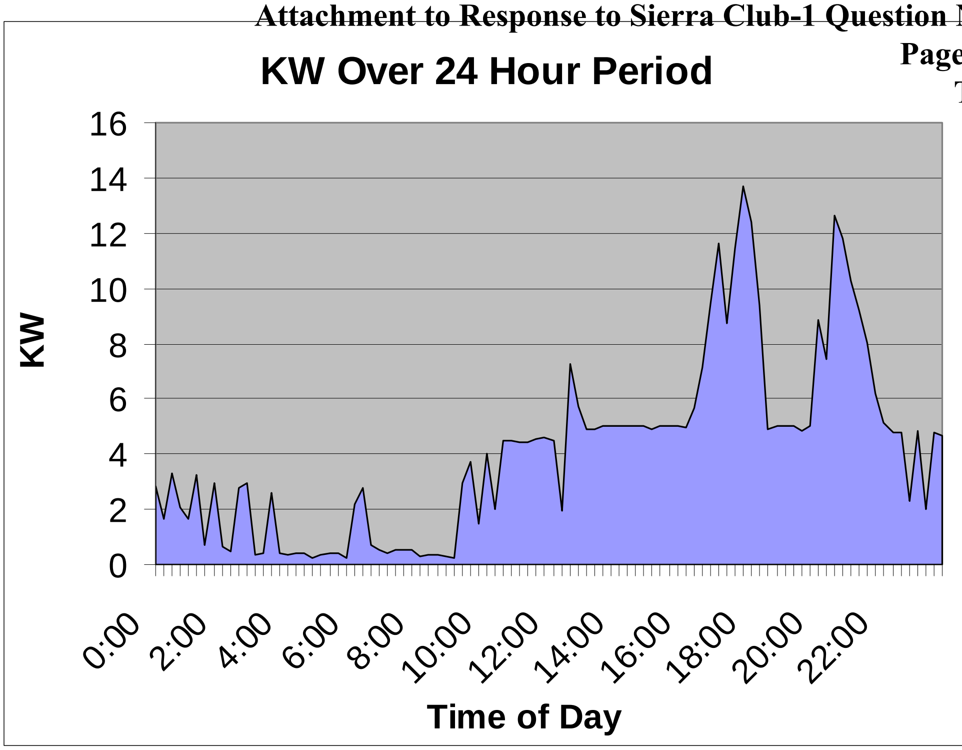

Figure 1 - Typical Load Profile on a Peak Day (Using a 15 Minute Rolling Demand)

<u>Study Methodology:</u>

An extensive number of load survey meters were already placed on both the KU and LG&E systems for the purpose of capacity planning. However, only a single record, the peak 15 minute demand for the year was utilized and all other data was discarded. For this study, the unused 15 minute demand data was tapped and analyzed. The quality of data was first verified by taking out any houses that contained obviously bad data, such as homes with large peaks in the middle of a power outage, or no data for a large portion of the year. The size of the houses and fuel type were then verified by using property tax records where possible and from original customer survey questionnaires where not. Databases were then built to store the data, and a program written by Rich Jones, Sr. Engineer - Electric Policies & Standards, was used to extract and analyze the data using the methods found in the Appendix.

From the data collected, several key pieces of data were utilized for the houses considered valid:

- House size in square feet
- Fuel type (full electric or gas and electric)
- 15 minute peak demand
- 15 minute rolling peak demand

To analyze peak loads, actual 15 minute and rolling 15 minute peaks were extracted from the data and plotted against house size by fuel type.

To obtain the diversity data, 36 random combinations were run for each group size, from 2 to 7 customers within a given house size range. The data was averaged across runs and curves were developed and compared against the existing diversity projections. The final representation of the diversity curve is a percentage factor of the simple summation of individual demands by number of customers. The curves for peak demand and diversity can be found in the Appendix.

To compute the final diversity and demand equations for homes, the 4 period (1-hour) average 15 minute rolling peak was used instead of the absolute maximum 15 minute peak demand during the year. This decision was based on the fact that transformers have a high tolerance for overloads over a short period of time, and can easily withstand instantaneous and short duration peak load. In fact transformers are routinely subjected to significant short term overloads, as much as 200% due to cold load pickup following power outages. It is believed that a sustained high load level over a one-hour period will better reflect on a transformer's true capacity rather than short duration peaks potentially preceded by and/or followed by periods of low demand.

For the peak demand, a linear expression was used for several reasons:

1. To make the equation easy to use
2. To get a high confidence level for the larger houses which we did not have much data
3. It was a good fit to the data

There was fairly high confidence level for the peak KW equation of more than 90% for both the house types, FERS and RS. This is a practical level, and leaves off the few outliers in the data that would otherwise make load projections unacceptably conservative. Several of the outliers that were significantly above their peers were investigated. It is believed that outliers in general represent homes with uncommon and/or difficult to project usage patterns or unusual loads such as pool heaters or other such high demand loads. They could also represent homes with inaccurate data relating to house size, fuel mix, etc.

The results of this study only utilized data from the LG&E load research meters. The primary reasons for this included quality of data and accurate house size and fuel use information that was taken from customer surveys and validated against local property records. The KU data was not included in this particular study mainly because we did not have sufficient information and the quality of data needed to do a complete evaluation. Most of the houses didn't have a size associated with them, and most of those that did had the meters installed for only a portion of the year. In some cases on the KU side, data manually patched into empty records during power outages to fill records was also found to be corrupt because it was inconsistent with typical data for the home. This made for too many inconsistencies to perform an accurate analysis. An attempt will be made to supplement the LG&E data with KU data in future studies.

Study results

After compiling all the data, it was determined the previous peak load equations needed to be modified. The previous projections were found to be somewhat lower than what the actual data indicated so new equations were developed. A confidence level of above 90% was used to determine the new equations. This was done to leave the outliers out of the load projections but include virtually all the rest of the practical data. The new equations for peak load are:

$$RS : PeakLoad(KW) = \left[House\,Size(1000sq-ft)*3.4\right]+6$$
$$FERS : PeakLoad(KW) = \left[House\,Size(1000sq-ft)*6.5\right]+6$$

For both of the equations, the fixed portion was to be approximately the same as previous equations, and was only slightly altered. However, a much larger variable demand was found for both house types, RS and FERS, which appears to reflect more than just the heating/air conditioning and lighting loads as previously thought. This additional variable load can potentially be explained by additional discretionary loads such as TV's, computers and other discretionary devices that can reasonably be expected to increase in number and size in larger houses. A slightly more liberal curve was fitted to FERS data in recognition that transformer can sustain higher load levels on winter peaking homes than on summer peaking homes.

The diversity data appears to be very consistent with the existing diversity equations. The data was analyzed both by house size, and as an averaged value for all house sizes. Both came out very close to the existing calculations and the following equations should be continued to use.

$$RSDiversity = .55 + \frac{.25}{\#Homes} + \frac{.2}{\sqrt{\#Homes}}$$
$$FERSDiversity = .52 + \frac{.38}{\#Homes} + \frac{.1}{\sqrt{\#Homes}}$$

The main weakness of this study was the lack of data on larger house sizes. This made it hard to determine the correct peak demand slope for larger homes, instead of the just the portion below 3000 sq-ft. For future studies, more data points for all home sizes, but mainly data on larger houses is recommended. However homes less than 3000 sq-ft are the most common on both the KU and LG&E system and there were sufficient data points in this study to provide a good analysis. It is believed that the lack of data on larger homes may have resulted in peak demand projections for homes greater than 3500 sq-ft being more conservative than need be.

The main strength of this study is it uses real data to determine the loadings of houses of all sizes and validate the diversity curves. It has also given much insight into the residential loading profiles (high, but relatively short duration of peak loads in comparison to routine loading). The following example can illustrate how this data can be used.

Example: House 1 has 2,500 sqft, and house 2 has 2,000 sqft, both are RS and are to be put on a transformer, with a estimated power factor of .95 (95%).

$$House(1): Peak\ KW = 2.5 * 3.4 + 6 = 14.5KW$$
$$House(2): Peak\ KW = 2.0 * 3.4 + 6 = 12.8KW$$

$$House(1): Peak\ KVA = \frac{14.5}{.95} = 15.26KVA$$
$$House(2): Peak\ KVA = \frac{12.8}{.95} = 13.47KVA$$

$$TotalKVA = 15.26 + 13.47 = 28.74KVA$$
$$TotalDiversifiedKVA = 28.74 * \left[.55 + \frac{.25}{2} + \frac{.2}{\sqrt{2}} \right] = 28.74 * .8164 = 23.46KVA$$

A 25KVA transformer would be used instead of a 37.5KVA unit implied by the simple sum of individual demands.

<u>Where to go from here</u>

This study would benefit from being performed over a longer time period, as well as from including KU data. It could also benefit from the inclusion of more data on larger houses. A study over a different year would help to further validate the data, and show the study year was representative of typical usage and not abnormal due to weather, economic factors or other causes. Future studies could feasibly be done on a yearly basis to track the trend of electricity use over time, as well as by house size. Future studies could also benefit by moving existing load research meters to different homes to increase the sample size.

Appendix

Appendix A: Data

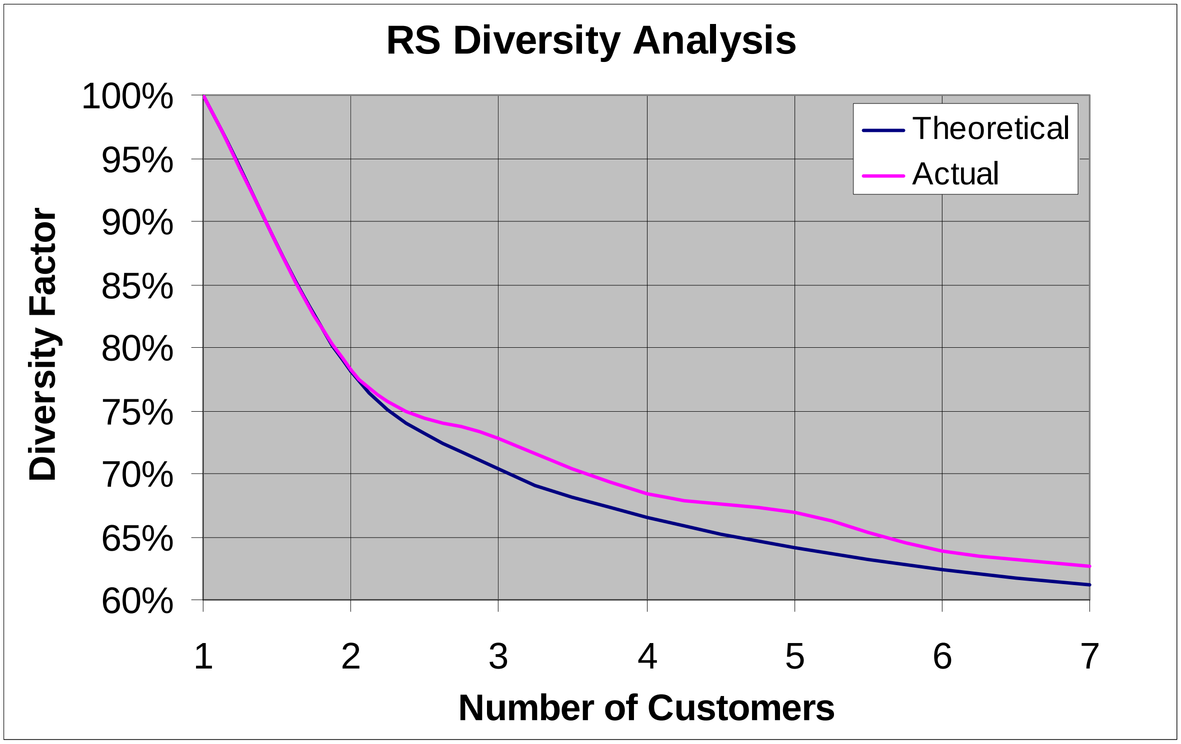

Figure 1) Diversity curves, both calculated and observed, for gas and electric customers.

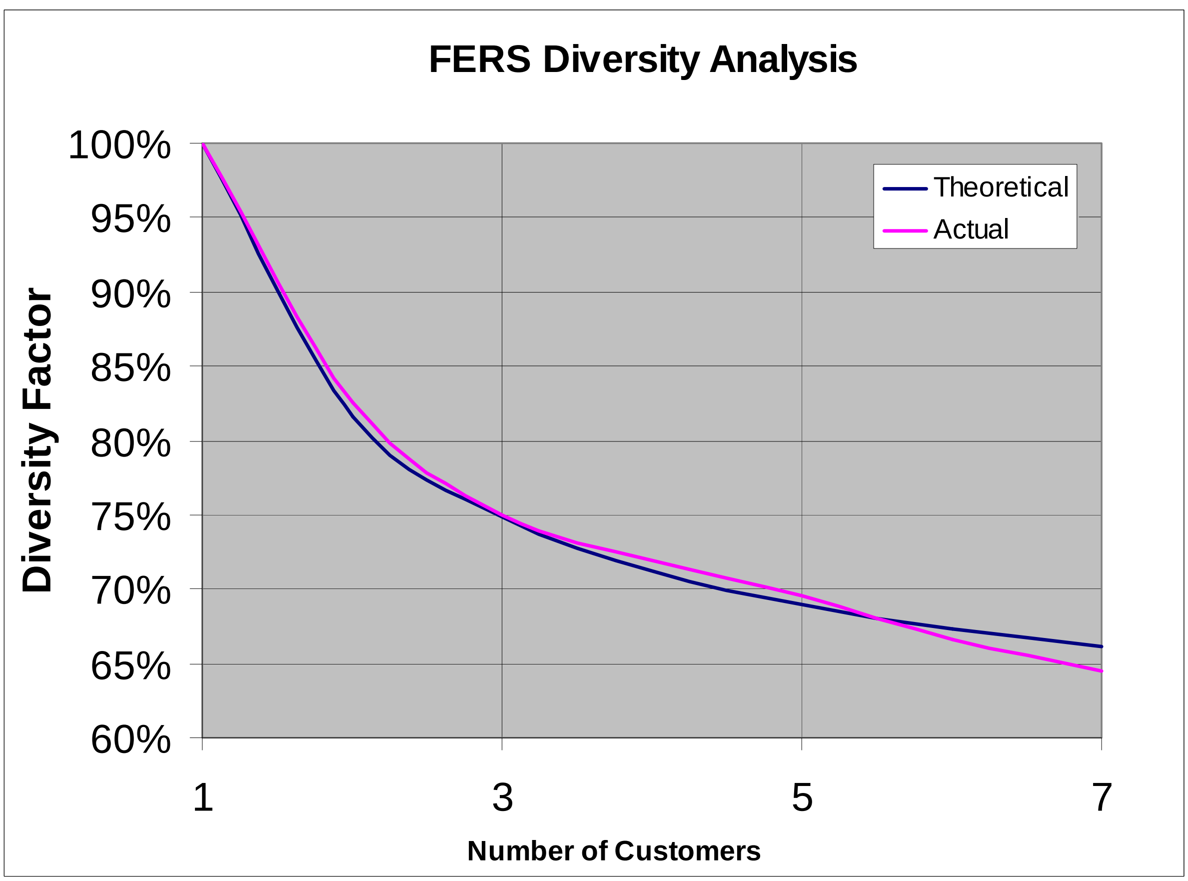

Figure 2) Diversity curves, both calculated and observed, for all electric customers.

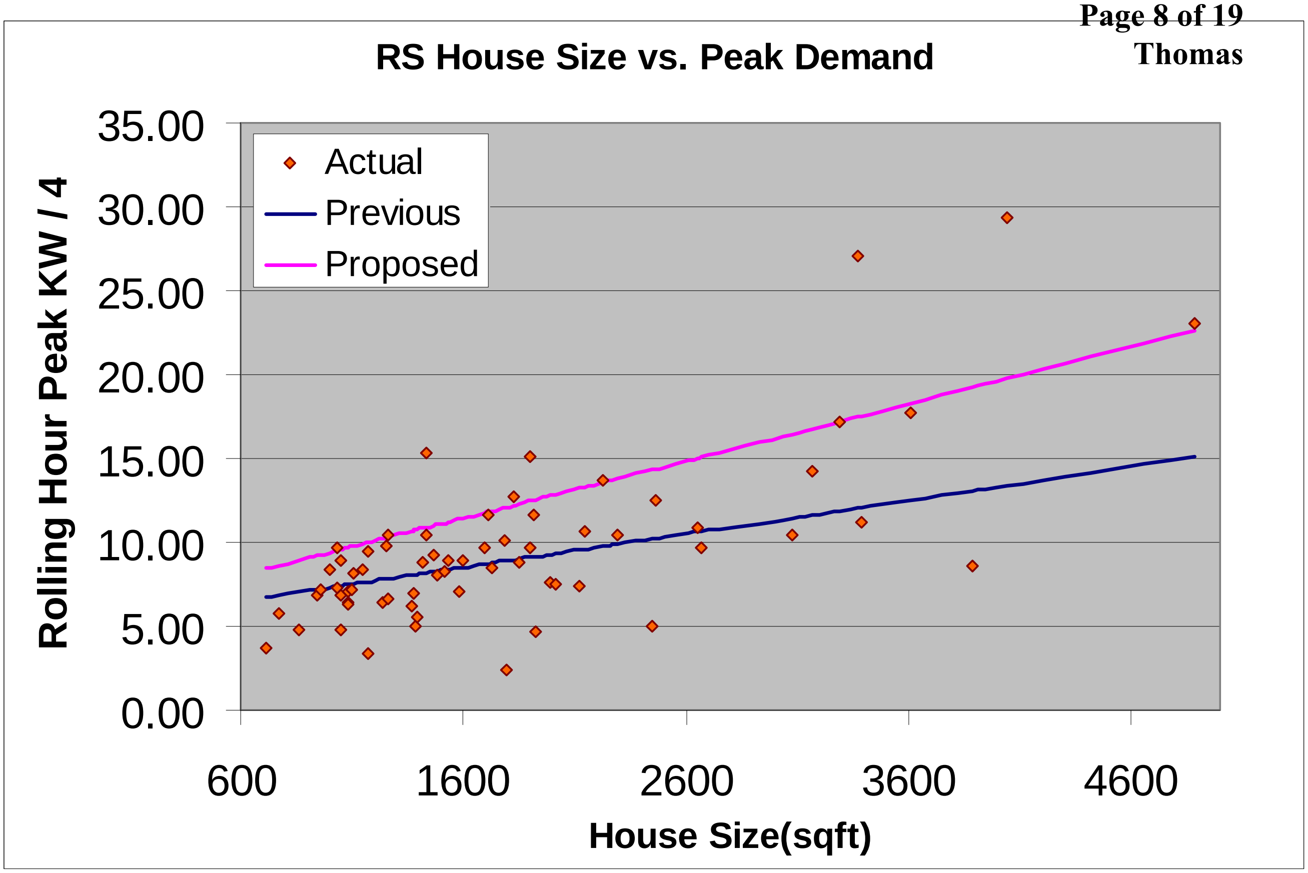

Figure 3) The rolling hour average of gas and electric customers versus house size.

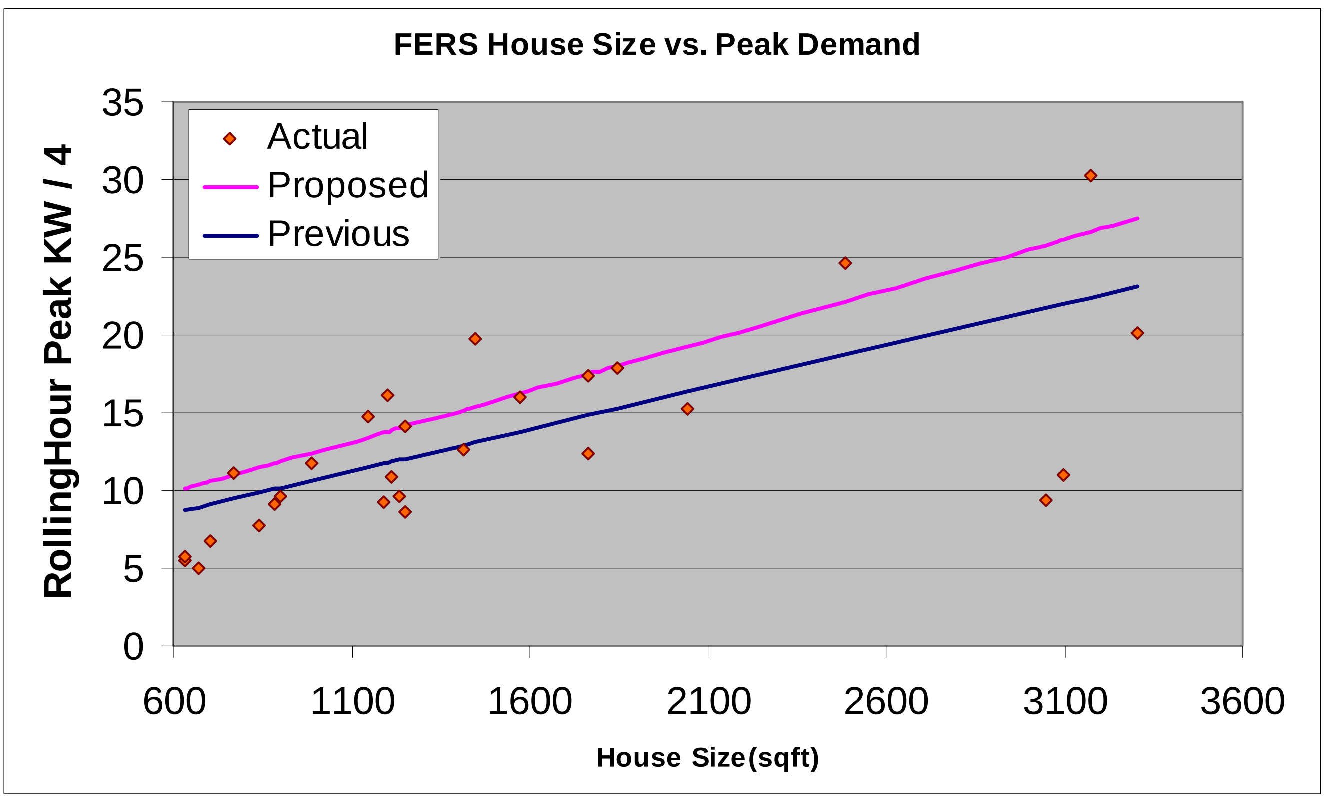

Figure 4) The rolling hour average of all electric customers versus house size.

Table 1) FERS peak and rolling peak data.

	House Size	15 Min Peak KW	Rolling Peak 15 Min Average	Average Rolling Peak / Peak %
R394	633	7.01	5.52	78.67%
R385	635	8.65	5.75	66.47%
R413	670	8.11	4.97	61.22%
R408	704	10.35	6.80	65.68%
R384	770	11.42	11.09	97.09%
R268	838	9.43	7.72	81.89%
R357	886	12.76	9.07	71.06%
R397	900	12.51	9.60	76.72%
R265	988	20.66	11.72	56.74%
R290	1144	17.63	14.79	83.86%
R262	1188	12.10	9.21	76.12%
R291	1200	18.52	16.18	87.38%
R314	1210	18.06	10.87	60.20%
R293	1234	16.32	9.67	59.22%
R284	1248	22.32	14.15	63.41%
R402	1250	14.00	8.61	61.46%
R340	1413	19.71	12.59	63.89%
R297	1447	23.56	19.79	84.00%
R261	1575	23.08	15.97	69.19%
R319	1763	20.44	12.36	60.47%
R298	1764	22.52	17.35	77.03%
R285	1847	26.16	17.84	68.20%
R296	2044	19.07	15.22	79.81%
R312	2486	30.24	24.62	81.42%
R282	3046	12.04	9.34	77.57%
R400	3099	14.60	11.06	75.75%
R306	3172	33.64	30.21	89.80%
R308	3305	25.60	20.15	78.71%

Table 2) RS peak and rolling peak data.

	House Size	15 Min Peak KW	Rolling Peak 15 Min Avg	Average Rolling Peak / Peak %		House Size	15 Min Peak KW	Rolling Peak 15 Min Avg	Average Rolling Peak / Peak %
R356	714	6.0	3.69	61.09%	R252	1530	12.0	8.94	74.50%
R351	768	7.6	5.79	76.18%	R203	1585	8.4	7.09	84.81%
R217	860	6.1	4.80	78.82%	R390	1600	10.7	8.96	83.90%
R228	940	7.2	6.80	94.97%	R295	1696	11.3	9.68	85.82%
R346	957	9.8	7.13	73.05%	R231	1710	13.0	11.65	89.89%
R273	1000	10.3	8.34	80.81%	R279	1730	10.6	8.44	79.92%
R244	1034	8.9	7.24	81.14%	R355	1786	11.6	10.06	86.43%
R224	1036	11.6	9.64	83.10%	R380	1794	2.6	2.37	90.46%
R375	1050	9.8	8.87	90.51%	R281	1825	14.8	12.74	85.85%
R259	1053	5.2	4.74	91.86%	R378	1849	11.4	8.84	77.54%
R393	1053	8.3	6.88	82.69%	R391	1898	18.3	15.08	82.49%
R256	1080	7.1	6.36	89.83%	R274	1904	11.3	9.66	85.34%
R403	1083	7.9	7.06	89.59%	R208	1914	13.3	11.61	87.42%
R404	1083	7.9	6.30	79.55%	R280	1925	6.4	4.64	72.50%
R399	1100	8.0	7.22	90.70%	R392	1993	8.8	7.61	86.48%
R232	1104	9.7	8.12	83.88%	R352	2013	8.0	7.50	93.28%
R219	1144	10.9	8.38	76.74%	R377	2120	9.0	7.38	82.37%
R202	1176	3.7	3.40	92.26%	R236	2146	12.3	10.67	86.61%
R230	1176	10.7	9.46	88.25%	R292	2230	16.6	13.66	82.49%
R255	1236	8.8	6.46	73.74%	R347	2292	12.6	10.40	82.28%
R361	1256	11.4	9.77	86.00%	R362	2448	7.2	4.96	69.27%
R241	1260	7.4	6.63	89.11%	R266	2463	12.7	12.45	98.19%
R275	1263	13.2	10.45	79.41%	R288	2652	13.5	10.88	80.47%
R229	1372	7.0	6.18	88.79%	R254	2668	12.1	9.68	79.87%
R373	1381	8.3	6.97	84.18%	R337	3076	12.6	10.42	82.52%
R389	1389	5.6	5.00	89.93%	R336	3165	15.4	14.29	92.55%
R396	1396	6.5	5.56	85.28%	R335	3289	19.0	17.22	90.63%
R257	1419	11.8	8.82	75.00%	R311	3371	36.6	27.09	74.10%
R276	1434	11.2	10.39	92.77%	R258	3385	13.6	11.25	82.48%
R387	1435	16.7	15.37	92.15%	R309	3612	20.5	17.68	86.16%
R267	1470	11.9	9.27	77.77%	R226	3884	11.0	8.64	78.83%
R350	1485	9.8	8.00	81.97%	R301	4046	30.8	29.33	95.35%
R242	1512	10.2	8.21	80.81%	R317	4889	25.6	23.00	89.98%

The Workings of the Diversity Program

Before Executing the Code:

Before starting this program the user can enable or disable customers for the analysis via the home size table. This is intended to afford a workaround when a customer's profile information is incomplete or contains erroneous entries that the user considers inappropriate for use in calculations.

The home exclude from analysis option check box group can be used to exclude certain home type, such as apartments or mobile homes from consideration. The user can specify in this program setup phase customer types to exclude from the analysis.

A few addition comments on home information are noted below. Homes sizes for LG&E were determined from local Property Evaluation records and are the actual values for the living space as recorded therein. The KU information was developed from the appliance survey conducted by the Marketing, and Forecast & Load Research Groups. They are based on ranges of home sizes per the table below. The values recorded in the database are the mid point of the ranges (well almost). For the low end 750 square feet is used and for the upper end 3700 square feed is used.

Category	Range	Database Value Used
1	Under 800 sq. ft.	750 sq. ft.
2	801—1000 sq. ft.	900 sq. ft.
3	1001—1400 sq. ft.	1200 sq. ft.
4	1401—1800 sq. ft.	1600 sq. ft.
5	1801—2200 sq. ft.	2000 sq. ft.
6	2201—2600 sq. ft.	2400 sq. ft.
7	2601—2900 sq. ft.	2750 sq. ft.
8	2901—3200 sq. ft.	3050 sq. ft.
9	3201—3500 sq. ft.	3350 sq. ft.
10	Over 3500 sq. ft.	3700 sq. ft.

Programming Notes:

CalDivcmd_click – is a form based program that calculates coincident and non-coincident peaks for both intervals and rolling hours for different combinations of residential customers. Groups of customers that can be used in these combinations are established by parameters such as home size (square feet of living space) ranges and whether or not the home has electric heat.

This program calculates summer and winter interval and rolling hour peaks; it also determines interval and rolling hour coincident and non-coincident peaks, but for the entire year instead of for winter and summer periods.

Programming Specifics:

There were several programs developed to get, format, and analysis profile data for residential diversity studies. Only, one is of importance to the end-user, however. That is the topic of this writing. The intent is for this to serve as an abbreviated user-guide for this diversity program.

Because of database (db) limitations and speed considerations the data is stored in two dbs one for LG&E and one for KU. The program is initiated from within the databases. The final location of the database is not yet determined, but they are presently located as shown below:

	Location Server	Folder	Db name
LG&E	Pdestandards on Fs1	MV90db	LGETransformer_sizing.mdb
KU	Pdestandards on Fs1	MV90db	KUTransformer_sizing.mdb

Running the program:

1. Open the desired db.
2. Under "Objects" click the "Forms" tab.
3. Open the form named "Diversityfrm".
4. You are now in the program; the form controls all execution of procedures.
    a. Completing the main form is your next step.
        i. Enter a range for the home sizes you desire as requested on the form.
        ii. Click the "Electric Heat?" option, if you want home with electric heat in this run of the routines. If this option is not clicked the returns will be for homes without electric heat. There is no option to intermingle electric heat and non-electric heat homes.
        iii. Check the any home type you wish to exclude.
    b. Clicking the button labeled "Diversity for Class" gets things moving
    c. A common dialog box will open requesting the name and location for a file to store the programs output. This will create four files
        i. One will be named "Customers.sav" This contains a list of customers in each combination generated (see below)
        ii. Summary.txt it will contain the summary output, customer individual peaks, individual rolling peaks, coincident peaks, non-coincident peaks, rolling coincident peaks, rolling non-coincident peaks.
            1. Times for the peaks are stored for all except the non-coincident values.
            2. Both summer and winter peaks are stored except for coincident and non-coincident entries which are for the entire year.
        iii. The other is the file as you named in the above step. It contains you requested output.
        iv. All files plus a file named "errlog.txt" will be stored in the folder you select from the common dialog box.
    d. A table name 'CusSummaryInfo' is also populated by the routine. It contains the times of peaks and the peaks for both summer and winter periods. Interval and rolling hour peaks are stored.
    e. Next, an inputbox is displayed that tells you the number of good finds and requests you to enter the number of customers to be grouped into each combination set [min=2, max=16].
    f. The program then opens another form entitled "Setup for Calculations"
        i. The first box on the form is locked i.e. the user cannot change the value in it. This box tells how many combinations you can have from the parameters requested thus far.

ii. If the number of combinations is large the program will appear to stall while running. If you wish to use all combinations simple type "Y" in the second box; you need no entry in the third box in this case—skip to step iv below

iii. The third box is used to limit the amount of output to a workable subset of the total combinations. It generates the number random combination sets that are entered in this box form the list of all available combinations as shown in the first box.

iv. Click the button labeled "Continue". The program is placed in a wait state until this button is clicked; in fact you cannot break the program until this form is completed.

5. How do you interpret the progam's main output or peak contributors.

a. This output is a cryptic looking file; it is meant to be imported into a spreadsheet.

i. It is a common delimited file, the first line is the column headers.

ii. The user should use a program such as notepad to replace all quotes (") with nothing before importing the file.

iii. The detail lines include

1. The first field, column, is the yearly interval peak for one customer in the combination set

2. The second field is the time of the customer's interval yearly peak.

3. The following fields are the loads/demands on each of the other customers that occurred at the time of the peak in 5.a.ii.1 above.

4. The final two lines in the combinations sets are slightly different

a. Next to last line lists coincident values.

i. The first column is the coincident peak for the combination of customers

ii. The next column is the time of the coincident peak

iii. This is followed by the customer demands contributing to the coincident peak

b. The last line lists non-coincident values

i. The first column is the non-coincident peak for the combination of customers

ii. The next column contains a time, but it is meaningless; its only there for consistency of the spreadsheet import procedure.

iii. This is followed by the customer demands contributing to the non-coincident peak.

6. How do you interpret the program's summary output?

a. The summary output file is a cryptic looking file; it is meant to be imported into a spreadsheet.

i. It is a common delimited file; the first line is the column headers.

ii. The user should use a program such as notepad to replace all quotes (") with nothing before importing the file.

iii. Each detail line indicates the customers in a given set of the combinations.

iv. Abbreviations used in column headers are explained below.

1. Cus – mean customer; it is followed by a number indicating the first, second, third … last customer in a given combination set. As such, you will have a Cus heading for each customer in a combination set.

2. Somewhere in each column header (except as noted below) will be a number indicating the first, second, third …customer in a given set of combinations as stated in (5.a.iv.1) above.

3. ToPk – shows the time of peak for a customer. This is the ending time for interval peaks.

4. TRolling Pk—indicates the ending time of the one hour rolling peak.
5. A 'W' in the abbreviations indicated a winter values the absences of the 'W' means it is a summer value.

Note: The remaining column headers follow the last customer output for a given combination of customers and are combination summaries, thus, they contain no number in their descriptions. **These are totaled and not averaged values**.

6. Coin – the coincident peak for a given combination of customers.
7. Coin Time—time of the coincident peak.
8. Rhr coin pk—The rolling hour coincident peak for the given combination of customers
9. Rcoin Time—time of the rolling hour coincident peak
10. Noncoin pk—non-coincident peak for a given combination of customers
11. Rnoncoin—the rolling hour non-coincident peak for the given combination of customers.

b. The "customer.sav" file – contains grouping of customers that correspond to the line-by-line output of the main output file outlined in (5.a) above. It also contains a summary line at the end that given some information concerning choices the user made in generating the main output.
c. A table named 'CusSummaryInfo' is populated as necessary when the program is run. It contains individual customer summary information. Note that the program does not overwrite entries already in the table; you must delete current entries before running the program in order to perform an update to a customer already on the table. Fields in the table are listed below.
    i. The customer's id
    ii. The year of the data being analyzed
    iii. Summer interval peak time
    iv. Summer interval peak usage
    v. Winter interval peak time
    vi. Winter interval peak usage
    vii. Summer rolling hour peak ending interval time
    viii. Summer rolling hour peak total usage
    ix. Winter rolling hour peak ending interval time
    x. Winter rolling hour peak total usage

You can break program execution at any time [except as noted above] by pressing Ctrl and Break simultaneously and clicking "end" on the form that the system displays.

Before Executing the Code:

Before starting this program the user can enable or disable customers for the analysis via the home size table. This is intended to afford a workaround when a customer's profile information is incomplete or contains erroneous entries that the user considers inappropriate for use in calculations.

The home exclude from analysis option check box group can be used to exclude certain home type, such as apartments or mobile homes from consideration. The user can specify in this program setup phase customer types to exclude from the analysis.

Programming Notes:

CalDivcmd_click – is a form based program that calculates coincident and non-coincident peaks for both intervals and rolling hours for different combinations of residential customers. Groups of customers that can be used in these combinations are established by parameters such as home size (square feet of living space) ranges and whether or not the home has electric heat.

This program calculates summer and winter interval and rolling hour peaks; it also determines interval and rolling hour coincident and non-coincident peaks, but for the entire year instead of for winter and summer periods.

Setting up a Run:

This displays a common dialog box used to allow the user to specify the file that will contain output of the calculated values. The folder chosen in the dialog box will also specify the location of all other support output files whose names are hard coded inside the program.

The user fills out the Diversityfrm that controls all operations and then clicks "Diversity for Class". The program now completes the following step:

- Once the user completes the above step, the procedure creates an array that contains all customers that meet the specified criteria and returns the number of customers found (number of good finds).
    - Queries the database for homes meeting the user criteria and creates a recordset for those customers.
    - Checks that you have at least 2 good finds.
    - Loads the customer's in the recordset into an array—customer array
    - Closes the recordset
    - The functions then returns the number of good finds.
    - Calculate the number of combinations for the number of good finds (n) taken number of customers specified for a combination set (r) at a time and return the number of combinations calculated.
    - Establish DLSV start time for the analysis period—**this is hard coded and used for LG&E only**.
    - Display a form that allows the users to specify the number of combinations to used in the analysis.
        - Delay the program in the main form so the form will completely load

        - Place the program in the main form in a wait loop until you get feedback from this form that it has completed.
        - The user specifies the number of customers ® to be included in each combination set. This number must be > 0, <16, and < = the number of good finds (n).
        - Compute the number of combination for the n customers taken r at a time.

- Build an (r x (number of combinations) indexing array. Each row will contain pointers to all customers in that combination set i.e. the indexes point to the position of the customer information in the customer array. This array will contain an exhausted list of all combinations.
- When a subset of all combinations is specified, build a sampling array with its values randomly generate numbers that pointer into the array of all combinations to identify particular combination sets. That is a number of let's say 10 points to the 10th combination in the set of all combinations. Otherwise simply step through the population of combinations one at time starting with combination set 1 and ending with the last combination set.
- Loop until you process all combinations as specified by the user.
    - Set the start interval (hard coded)
    - Initialize various class pointers, arrays of query defs, arrays of recordsets, and holders of calculated values.
    - Loop until you have processed all customers in a given combination set (a row of the combination array)
        - Assemble the query defs
        - Open the corresponding recordsets
        - Check that the recordset contains data
    - End loop of rows of the combination array
    - Loop until the end interval (hard coded) has been processed
        - Add an hour to the time if the DLVS interval has been reached (Notice the rounding here. This is necessary because adding time interval-by-interval is not the same as simply entering a time because of rounding error.
        - Loop on each customer in a combination set.
            - Match the current recordset time to the programs' interval time.
            - Check for a PO status
            - When you do not have a PO status – update the peak_data_structure or winpeak_data_structure as appropriate to determine the summer and winter peaks respectively. Note that the change of season dates are hardcoded throughout the program. Otherwise skip this update.
            - Check for new coincident and non-coincident interval peaks
            - Add current interval load to the rolling hour value for the current customer. This occurs regardless of season such that at the change of season the first rolling value within a year for a new season will be the current interval plus the 3 previous intervals of the former season.
            - Call a routine to add the current load to the end of a linked list for the current customer. (Add zero if the interval status is "PO").
            - If you have processed more than 4 intervals for the customer
                - Retrieve a value from the head of this customers linked list
                - Subtract the retrieved value form the rolling hour value for this customer.
                - Delete the interval load on the head of this customers linked list.
            - End if process more than 4 intervals
            - Check for a new rolling hour peak
            - Check for a new interval coincident peak
            - Check for a new interval non-coincident peak.
            - Move to the next record in the record set

            - Get the next customer in the Cluster
        - End loop for customers in a combination set.
        - Initialize the rolling coincident and non-coincident values.
        - Calculate the current rolling coincident and non-coincident peaks. (You must use the greater of the winter and summer values in this calculation.)
    - End interval loop
    - If first time to this point then write an output header line
    - Write the calculated values for the current combination set
        - Write summary
        - Write Rudy Stuff
        - Populate the customer summary information (CusSummaryInfo) table if necessary.
    - Close the recordsets for the combination set.
    - Reset the rolling peak coincident and non-coincident values
    - Delete all current class pointers
- End of loop for all specified combinations
- Write a summary of user selections
- Close files
- Close db
- End the program.

Differences between KU and LG&E Energy Corp.

- All reference to DLSV must be comment out before compiling and running on the KU side
- The profile table is prefixed with ‘KU on the KU side.

Appendix C: Process

The purpose of this data collection was to validate the calculated data for both the diversity factors, and the KW peak demand by household. This validation was done in a multi-step process.

Extrapolating the individual peak KW and house size:

1) Run the program "LGETransformer_Sizing3.mbd"* and use the form Diversityform.
2) Enter house size ranges in intervals <=16, then set a cluster size to match the number of houses in the range.
3) Retrieve the data reference numbers, which are in order, from the file Customers.sav+, and put them in a spreadsheet.
4) From the file summary.txt+, edit out all the quotation marks and import the information into a spreadsheet. From this file, the rolling peak and the 15 minute peak can then be extrapolated, and are appropriately labeled. The data can then be organized as desired.
5) From the table "Homestbl" in the access database, cross-reference the data reference number of the homes to the house size, and add it to the spreadsheet.

Validating diversity factors:

1) For gas homes, start by choosing a range of homes that contains approximately 9-12 homes, this will give at least 36 entries for each cluster size.
2) Continue to the next page and start with a cluster size of two, and run the program. The output can be taken from the file "output.txt"+ and imported into excel after removing the quotation marks.
3) From this data, take the average of the rolling coincident peaks and store it in another spreadsheet.
4) Repeat steps 2 and 3 for cluster sizes of 3-7.
5) Repeat steps 1 through 4 until all house sizes are included.
6) To validate the diversity factors, take average of the rolling peak data and divide it by four. This will be the peak value the data is compared against. Then divide the peak value by the average value from each cluster size in each house range and plot it against the current values.
7) Repeat steps 1 through 6 for all electric homes.

**These files should be located in the pdestandards/mv90db directory.*
+These files should be located in the same directory as the file prompted by the program.

Data Format:

The final data from the study is kept in 2 separate files:

1) RHrFERSDemand.xls: This file contains all the data pertaining to full electric houses.
2) RHrGasDemand.xls: This file contains all the data pertaining to houses with gas heat.

Each of these workbooks contains many worksheets. The 'Peak Data' worksheet in each contains the information about the peaks of each house in the data set. This includes the rolling hour maximum, and the 15 min peak, as well as the house size and calculated peak.

The next set of sheets are the Graph sheets, which contain the average values over the range and cluster size, as well as the current calculated values used.

The final sets of sheets are the Data sheets, which contain the raw data collected from the Access program mentioned above. They are formatted such that each 'paragraph' of data is one run of the program for a cluster size, beginning with 2 and ending with 7.

Diversity: The formula for diversity appears to be correct, based on the data analysis. For the RS customers, there was a maximum difference between the diversity factors of 2.89%, and for the FERS a maximum difference of 1.61%. This low percentage agrees with the calculations very well, and therefore the calculations are assumed to be correct.

Peak Load: After reviewing the data, the previous calculations were thought to be a bit low, as can be seen in figures (3) and (4). Thus, using a confidence of 95%, we found several possibilities for a new equation for each of the conditions, and proceeded to refine them. The final equations, shown in yellow, are thought to cover the majority of the points on the line, and only exclude the outlying possibilities. The final equations used were:

RS: Peak Load (KW) = House Size (sqft) * .0034 + 6
FERS: Peak Load (KW) = House Size (sqft) * .0065 + 6

A linear function was chosen mainly for its ease of use, but the lack of data on the larger house sizes also came into play.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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, ll. 10-19.

a) Please provide the rationale for not increasing the basic service charge to $21.47 per month, as indicated by the cost of service study.

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.

c) Please provide copies of all presentations to Company management or the Company's Board of Directors regarding consideration of the amount by which to increase the basic service charge and of the decision to increase the basic service charge to $18.00 per month.

A-5. a) Both the testimonies of Dr. Blake and Mr. Conroy discuss the reasons for increasing the Basic Service Charge ("BSC") toward cost of service. For ease of implementation and communication to customers, LG&E and KU proposed a BSC that is the same for each Company and a whole number. Therefore, since $18.00 was below the amount determined from cost of service for each Company, it was proposed as the BSC for both KU and LG&E.

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.

c) The Company did not make any presentations to management or the Board of Directors on the decision to increase the BSC. The Company's rate design philosophy is to develop rates that reflect the cost of providing service whereby fixed costs are recovered through fixed charges and variable costs are recovered through variable charges. The decision to increase the BSC to $18.00 was based on this principle.

From: Larry Feltner(lfeltner@theprimegroupllc.com)
To: Conroy, Robert
CC:
BCC:
Subject: Re: Customer Charges
Sent: 10/29/2014 11:28:18 AM -0400 (EDT)
Attachments:

Robert,

I'll try to get you something soon. I am on the phone with Clay and P am about a problem with the gas study.

Thanks

Larry

-----Original Message-----
From: Conroy, Robert
Sent: Wednesday, October 29, 2014 10:53 AM
To: 'jwernert@theprimegroupllc.com'
Cc: Larry Feltner ; Marty Blake
Subject: RE: Customer Charges

Do you have the LG&E numbers comparable to the below?

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

-----Original Message-----
From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 10:18 AM
To: Conroy, Robert
Cc: Larry Feltner; Marty Blake
Subject: Customer Charges

Robert,

For rate design, how many classes would you like to propose going to cost-based customer charges? The only one I remember discussing specifically was Residential and for KU after the increase Larry sent to you, the Residential class is showing a $21.47 customer charge which is slightly higher than we had discussed. You had tossed around the $18 number internally but I wanted to see what your stomach was for going in closer to what the Study is showing. Below are the calculated customer charges for all of the classes for KU:

Residential: $21.47
GS Single Phase: $38.45
GS Three Phase: $58.97
AES Single Phase: $78.75
AES Three Phase: $96.92
PS Secondary: $82.27

PS Primary: $173.17
TOD Secondary: $213.27
TOD Primary: $316.15
RTS: $1001.93
FLS: $1340.82

Thanks,

Jeff Wernert

-- The information contained in this transmission is intended only for the person or entity to which it is directly addressed or copied. It may contain material of confidential and/or private nature. Any review, retransmission, dissemination or other use of, or taking of any action in reliance upon, this information by persons or entities other than the intended recipient is not allowed. If you received this message and the information contained therein by error, please contact the sender and delete the material from your/any storage medium.

From: jwernert@theprimegroupllc.com(jwernert@theprimegroupllc.com)
To: Conroy, Robert
CC: Larry Feltner; Marty Blake
BCC:
Subject: Re: Customer Charges
Sent: 10/29/2014 10:56:19 AM -0400 (EDT)
Attachments:

Larry is looking at LG&E rates but I believe the residential rate
after the increase is just under $20.

Jeff

Quoting "Conroy, Robert" <Robert.Conroy@lge-ku.com>:

> Do you have the LG&E numbers comparable to the below?
>
>
>
> 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
>
>
>
> -----Original Message-----
> From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
> Sent: Wednesday, October 29, 2014 10:18 AM
> To: Conroy, Robert
> Cc: Larry Feltner; Marty Blake
> Subject: Customer Charges
>
> Robert,
>
> For rate design, how many classes would you like to propose going to
> cost-based customer charges? The only one I remember discussing
> specifically was Residential and for KU after the increase Larry
> sent to you, the Residential class is showing a $21.47 customer
> charge which is slightly higher than we had discussed. You had
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> PS Primary: $173.17
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> FLS: $1340.82
>
> Thanks,

>
> Jeff Wernert
>
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> sender and delete the material from your/any storage medium.

From: Larry Feltner(lfeltner@theprimegroupllc.com)
To: Conroy, Robert
CC:
BCC:
Subject: Re: Customer Charges
Sent: 10/29/2014 10:38:24 AM -0400 (EDT)
Attachments:

When would you like to talk? Marty is out of the office until lunch. I am the only one here. If you want to do it now, that is fine with me. If you want to wait on Marty, lets do it after lunch.

Thanks

Larry

-----Original Message-----
From: Conroy, Robert
Sent: Wednesday, October 29, 2014 10:33 AM
To: 'jwernert@theprimegroupllc.com'
Cc: Larry Feltner ; Marty Blake
Subject: RE: Customer Charges

Can we have a quick call to discuss?

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

-----Original Message-----
From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 10:18 AM
To: Conroy, Robert
Cc: Larry Feltner; Marty Blake
Subject: Customer Charges

Robert,

For rate design, how many classes would you like to propose going to cost-based customer charges? The only one I remember discussing specifically was Residential and for KU after the increase Larry sent to you, the Residential class is showing a $21.47 customer charge which is slightly higher than we had discussed. You had tossed around the $18 number internally but I wanted to see what your stomach was for going in closer to what the Study is showing. Below are the calculated customer charges for all of the classes for KU:

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FLS: $1340.82

Thanks,

Jeff Wernert

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From: jwernert@theprimegroupllc.com(jwernert@theprimegroupllc.com)
To: Conroy, Robert
CC: Larry Feltner; Marty Blake
BCC:
Subject: Re: Customer Charges
Sent: 10/29/2014 10:37:35 AM -0400 (EDT)
Attachments:

Robert,

I'm in a meeting until 11:30 but am available anytime after that.
Would you like me to give you a call when I'm free?

Jeff

Quoting "Conroy, Robert" <Robert.Conroy@lge-ku.com>:

> Can we have a quick call to discuss?
>
>
>
> 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
>
>
>
> -----Original Message-----
> From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
> Sent: Wednesday, October 29, 2014 10:18 AM
> To: Conroy, Robert
> Cc: Larry Feltner; Marty Blake
> Subject: Customer Charges
>
> Robert,
>
> For rate design, how many classes would you like to propose going to
> cost-based customer charges? The only one I remember discussing
> specifically was Residential and for KU after the increase Larry
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> Thanks,
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> Jeff Wernert
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> sender and delete the material from your/any storage medium.

From: jwernert@theprimegroupllc.com(jwernert@theprimegroupllc.com)
To: Conroy, Robert
CC: Larry Feltner; Marty Blake
BCC:
Subject: Customer Charges
Sent: 10/29/2014 10:18:10 AM -0400 (EDT)
Attachments:

Robert,

For rate design, how many classes would you like to propose going to cost-based customer charges? The only one I remember discussing specifically was Residential and for KU after the increase Larry sent to you, the Residential class is showing a $21.47 customer charge which is slightly higher than we had discussed. You had tossed around the $18 number internally but I wanted to see what your stomach was for going in closer to what the Study is showing. Below are the calculated customer charges for all of the classes for KU:

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AES Single Phase: $78.75
AES Three Phase: $96.92
PS Secondary: $82.27
PS Primary: $173.17
TOD Secondary: $213.27
TOD Primary: $316.15
RTS: $1001.93
FLS: $1340.82

Thanks,

Jeff Wernert

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Malloy, John; Conroy, Robert; Bruner, Cheryl; Huff, David; Cockerill, Butch
CC:
BCC:
Subject: Updated Rate Schedule Review 10-29-2014.docx
Sent: 10/30/2014 08:32:40 AM -0400 (EDT)
Attachments: Rate Schedule Review 10-29-2014.docx;

All,
Attached is the updated document we reviewed yesterday. Thanks for all your input and feedback.

-Steve

ELECTRIC

Rate RS

- Align basic service charge with customer-related costs from cost of service study to achieve an appropriate Basic Service Charge (Increase from $10.75/month to approximately $18/month)
  - Percentage increase in bill for low usage customers will be significantly greater than high usage customers

[redacted]

Redacted as Unresponsive

Curtailable Service Rider (CSR)

- Leave CSR pricing unchanged
- Remove hours of buy-through interruption and provision for buy-through curtailment
- Maximum of 100 hours of physical curtailment at the Company's sole discretion
- Clarify tariff and contract language to specify what it means to be interrupted, i.e. kVA vs kW
- Add a provision to require demonstration/certification of the customer's ability to comply with physical curtailment

[redacted]

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

Redacted as Unresponsive

[redacted]

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Conroy, Robert
CC:
BCC:
Subject: Rate Schedule Review 10-29-2014.docx
Sent: 10/28/2014 02:05:43 PM -0400 (EDT)
Attachments: Rate Schedule Review 10-29-2014.docx;

Please review and let me know your thoughts

ELECTRIC

Rate RS

- Align basic service charge with customer-related costs from cost of service study to achieve an appropriate Basic Service Charge (Increase from \$10.75/month to approximately \$18/month)
    - Percentage increase in bill for low usage customers will be significantly greater than high usage customers

Redacted as Unresponsive
[redacted]

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- Clarify tariff and contract language to specify what it means to be interrupted, i.e. kVA vs kW
- Add a provision to require demonstration/certification of the customer's ability to comply with physical curtailment

Redacted as Unresponsive
[redacted]

Attachment to Response to Sierra Club 1-5(b)
Page 17 of 25
Conroy/M.Blake

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

From: Conroy, Robert(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=CONROYR)
To: 'Larry Feltner'
CC:
BCC:
Subject: RE: Customer Charges
Sent: 10/29/2014 11:34:41 AM -0400 (EDT)
Attachments:

That is fine. I spoke to Jeff on the KU and he was going to coordinate with you on the LG&E.

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

-----Original Message-----
From: Larry Feltner [mailto:lfeltner@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 11:28 AM
To: Conroy, Robert
Subject: Re: Customer Charges

Robert,

I'll try to get you something soon. I am on the phone with Clay and P am about a problem with the gas study.

Thanks

Larry

-----Original Message-----
From: Conroy, Robert
Sent: Wednesday, October 29, 2014 10:53 AM
To: 'jwernert@theprimegroupllc.com'
Cc: Larry Feltner ; Marty Blake
Subject: RE: Customer Charges

Do you have the LG&E numbers comparable to the below?

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

-----Original Message-----
From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 10:18 AM
To: Conroy, Robert
Cc: Larry Feltner; Marty Blake
Subject: Customer Charges

Robert,

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AES Single Phase: $78.75
AES Three Phase: $96.92
PS Secondary: $82.27
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TOD Secondary: $213.27
TOD Primary: $316.15
RTS: $1001.93
FLS: $1340.82

Thanks,

Jeff Wernert

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From: Conroy, Robert(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=CONROYR)
To: 'jwernert@theprimegroupllc.com'
CC: Larry Feltner; Marty Blake
BCC:
Subject: RE: Customer Charges
Sent: 10/29/2014 10:53:00 AM -0400 (EDT)
Attachments:

Do you have the LG&E numbers comparable to the below?

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

-----Original Message-----
From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 10:18 AM
To: Conroy, Robert
Cc: Larry Feltner; Marty Blake
Subject: Customer Charges

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AES Three Phase: $96.92
PS Secondary: $82.27
PS Primary: $173.17
TOD Secondary: $213.27
TOD Primary: $316.15
RTS: $1001.93
FLS: $1340.82

Thanks,

Jeff Wernert

From: Conroy, Robert(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=CONROYR)
To: 'Larry Feltner'
CC:
BCC:
Subject: RE: Customer Charges
Sent: 10/29/2014 10:49:25 AM -0400 (EDT)
Attachments:

I will give you a quick call.

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

-----Original Message-----
From: Larry Feltner [mailto:lfeltner@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 10:38 AM
To: Conroy, Robert
Subject: Re: Customer Charges

When would you like to talk? Marty is out of the office until lunch. I am the only one here. If you want to do it now, that is fine with me. If you want to wait on Marty, lets do it after lunch.

Thanks

Larry

-----Original Message-----
From: Conroy, Robert
Sent: Wednesday, October 29, 2014 10:33 AM
To: 'jwernert@theprimegroupllc.com'
Cc: Larry Feltner ; Marty Blake
Subject: RE: Customer Charges

Can we have a quick call to discuss?

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

-----Original Message-----
From: jwernert@theprimegroupllc.com [mailto:jwernert@theprimegroupllc.com]
Sent: Wednesday, October 29, 2014 10:18 AM
To: Conroy, Robert

Cc: Larry Feltner; Marty Blake
Subject: Customer Charges

Robert,

For rate design, how many classes would you like to propose going to cost-based customer charges? The only one I remember discussing specifically was Residential and for KU after the increase Larry sent to you, the Residential class is showing a $21.47 customer charge which is slightly higher than we had discussed. You had tossed around the $18 number internally but I wanted to see what your stomach was for going in closer to what the Study is showing. Below are the calculated customer charges for all of the classes for KU:

Residential: $21.47
GS Single Phase: $38.45
GS Three Phase: $58.97
AES Single Phase: $78.75
AES Three Phase: $96.92
PS Secondary: $82.27
PS Primary: $173.17
TOD Secondary: $213.27
TOD Primary: $316.15
RTS: $1001.93
FLS: $1340.82

Thanks,

Jeff Wernert

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From: Conroy, Robert(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=CONROYR)
To: 'jwernert@theprimegroupllc.com'
CC: Larry Feltner; Marty Blake
BCC:
Subject: RE: Customer Charges
Sent: 10/29/2014 10:33:58 AM -0400 (EDT)
Attachments:

Can we have a quick call to discuss?

Robert M. Conroy
Director, Rates
LG&E and KU Services Company
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For rate design, how many classes would you like to propose going to cost-based customer charges? The only one I remember discussing specifically was Residential and for KU after the increase Larry sent to you, the Residential class is showing a $21.47 customer charge which is slightly higher than we had discussed. You had tossed around the $18 number internally but I wanted to see what your stomach was for going in closer to what the Study is showing. Below are the calculated customer charges for all of the classes for KU:

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Thanks,

Jeff Wernert

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 6

Responding Witness: Dr. Martin J. Blake

Q-6. Reference Martin Blake, p. 21, ll. 3-7.

a) Please explain why the Company believes that intra-class subsidies should be avoided. Please cite to all relevant economic literature relied on as the basis for this belief.

b) Is Dr. Blake aware of any economic rationale or ratemaking principle for maintaining intra-class subsidies? Please explain.

c) Please cite to all relevant economic literature relied on as the basis for the assertion that the "ratemaking principle" for avoiding intra-class subsidies is the recovery of "fixed costs" through basic service charges.

d) Is it Dr. Blake's contention that demand-related generation, transmission, and distribution costs are "fixed costs"? If so, does Dr. Blake believe that recovering such demand-related fixed costs through energy charges would create intra-class subsidies? Please explain.

e) Under the Company's current rate design for residential customers, does Dr. Blake believe that demand-related generation, transmission, and distribution costs should be recovered through the basic service charge or through the energy charge? Please explain.

A-6. See also the responses to AG 1-19 and Question No. 17

a) Intra-class subsidies should be avoided in order to send accurate price signals regarding the services being provided and to avoid some customers in a class paying more than their fair share of the costs assigned for recovery to that class while other customers in the class pay less than their fair share. The criterion that I use for determining fairness is whether the charge accurately reflects the cost of providing service to a customer. In a regulatory context, rates are regarded as fair if cost recovery is based on what caused the cost to be incurred. I developed both my Direct Testimony and the response to this data request based on my experience as an economist, a state regulatory commissioner, a utility executive and a consultant. I did not rely on any economic literature in developing my Direct Testimony or this response.

b) There is no economic rationale for maintaining intra-class subsidies. Historically, fixed costs have been recovered using a kWh charge for some customer classes, such as residential and small commercial customers, because of ease of calculation and the additional cost of meters that record coincident peak and non-coincident peak demands. This may still be appropriate where the class is relatively homogeneous and non-volumetric fixed costs are not recovered using the kWh charge. KU is proposing to remove non-volumetric fixed costs from the kWh energy charge in this proceeding.

c) The basis for my contention that intra-class subsidies can be avoided by recovering fixed costs through fixed charges, including basic service charges, is based on mathematics rather than on the economic literature. Mathematically, if a fixed cost is “variablized” and recovered on a kWh basis rather than recovered through a fixed charge, customers consuming less than the class average will pay less than the fixed cost that they should be charged, customers consuming exactly the class average will pay the amount of fixed cost that they should be charged and customers consuming more than the class average will pay more than the fixed cost that they should be charged. This can be demonstrated using any fixed cost that should be recovered through a fixed charge, variablizing this charge, and calculating the amounts of fixed cost recovered from customers at various kWh usage levels. In this case, fixed cost recovery will vary by kWh usage level and will differ from the fixed amount that should be recovered from each customer.

d) Yes, and the customer-related distribution costs are also fixed costs. Furthermore, there are various types of fixed costs that have different cost drivers and should be recovered using different rate components. Generation plant, fixed operations and maintenance (O&M) costs, and the demand charges associated with purchased power are classified as demand-related fixed costs while fuel, the energy charges associated with purchased power, and variable O&M are classified as energy-related variable costs. The driver for demand-related fixed generation costs is coincident peak demand because this corresponds to the process for planning and acquiring generation resources. All transmission plant and O&M costs are classified as demand-related fixed costs. The driver for demand-related fixed transmission costs is coincident peak demand because this corresponds to the process for planning and acquiring transmission resources. Distribution resources are classified as demand-related volumetric fixed costs and customer-related non-volumetric fixed costs. The cost driver for demand-related volumetric fixed distribution costs is non-coincident peak demand and the cost driver for customer-related non-volumetric fixed distribution costs is the number of customers served. Non-volumetric fixed distribution costs do not vary with customer usage levels, while volumetric fixed distribution costs vary with the demand that customer place on the system. Non-volumetric fixed distribution costs include the minimum amount of equipment that any customer must have in place to have access to the electric grid. This minimum system includes the meter, the service drop, the transformer and some minimum amount of poles and conductor running back to the distribution substation, and because it is the absolute minimum that a customer can get by with, it is the same for all customers. Once the cost of this minimum system is determined, each customer needs at least the minimum system to receive service from the utility. Volumetric fixed distribution costs are driven by the load that the customer places on the system. For example, a customer with a large electric motor may need a larger service, transformer and conductor than a customer without a large motor. The driver for these volumetric fixed distribution costs is a customer's non-coincident peak demand, i.e. the customer's maximum use regardless of when it occurs. This non-coincident peak demand is driven by the customer's stock of electric using equipment. Recovering any of these demand-related or customer-related generation, transmission or distribution fixed costs through a kWh demand charge would have the impact of variablizing these fixed costs and would result in intra-class subsidies as explained in the response to 6(c) above.

e) Ideally, the demand-related generation and transmission fixed costs would be recovered using a coincident peak demand charge, the demand-related distribution fixed costs would be recovered using a non-coincident peak demand charge, the customer-related distribution fixed costs would be recovered using a fixed monthly customer charge and the energy-related costs would be recovered suing a kWh charge. Ideally, the demand-related fixed costs and customer-related fixed costs would not be recovered using an energy charge as this variabilizes these costs and results in intra-class subsidies. Historically, residential demand-related fixed costs have been recovered using a kWh charge because of ease of calculation and the cost of the metering technology needed to measure coincident and non-coincident peak demands. The optional residential demand rate that KU is proposing is a move in the direction of recovering the various types of fixed costs using the rate component that most closely reflects cost causation.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 7

Responding Witness: Dr. Martin J. Blake

Q-7. Reference Martin Blake, p. 21, ll. 7-11.

a) Is it Dr. Blake's contention that the fixed costs to serve residential customers with above-average energy usage are equal to the fixed costs to serve customers with below-average energy usage? Please explain.

b) Please provide copies of all analyses conducted by Dr. Blake or the Company, relied on as the basis for Dr. Blake's assertion that residential customers with above-average energy usage are "paying more than their fair share of fixed costs and margins" under current rates.

A-7. a) The non-volumetric fixed distribution costs, but not the total fixed cost, of serving residential customers with above-average energy usage is equal to the non-volumetric fixed distribution costs to serve customers with below-average energy usage. Because these non-volumetric fixed distribution costs are not related to a customer's usage level and reflect the minimum set of equipment and services necessary to access the electric grid, these non-volumetric fixed distribution costs are the same for all customers in the residential class. As noted above, this minimum set of equipment includes the meter, the service drop, the transformer and some minimum amount of poles and conductor running back to the distribution substation, and because it is the absolute minimum that a customer can get by with, it is the same for all customers.

b) The analysis and accompanying explanation is provided on page 20 of Dr. Blake's Direct Testimony in this proceeding. Based on the cost of service study, the non-volumetric fixed distribution costs and margins are $21.47 per month. With a current basic charge of $10.75, KU is variabilizing $10.72 per customer per month of these non-volumetric fixed distribution costs, which is 0.89 cents per kWh. Customers purchasing more than the class average will end up paying more than $21.47 of these non-volumetric fixed distribution charges per month, and customers purchasing less than the class average will end up paying less than $21.47 of these non-volumetric fixed distribution charges per month. Thus, customers with above average usage are subsidizing the non-volumetric fixed distribution costs of customers with below average usage, i.e. there are intra-class subsidies.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 8

Responding Witness: Dr. Martin J. Blake

Q-8. Reference Martin Blake, p. 22, ll. 12-16.

a) What is the upper limit of the average monthly consumption that defines the "low-usage customers" who would be paying a higher energy bill once the alleged intra-class subsidy is removed?

b) Are the customer types identified on p. 22, ll. 13-14 comprehensive of the sub-class of low-usage customers defined by the threshold establish in (a)? Please explain.

A-8. a) The dividing line between low-usage and high-usage customers is the average usage per customer for the class in question. If a fixed cost is "variablized" and recovered on a kWh basis rather than recovered through a fixed charge, customers consuming less than the class average will pay less than the fixed cost that they should be charged, customers consuming exactly the class average will pay the amount of fixed cost that they should be charged and customers consuming more than the class average will pay more than the fixed cost that they should be charged. Once the intra-class subsidy is removed, all customers would pay the same amount of non-volumetric distribution fixed costs regardless of their relationship to the class average.

b) The types of customers identified are customers who typically have kWh usage that is lower than the class average based on my experience. It is not meant to be a comprehensive list of all customers with usage below the class average.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 9

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

Q-9. Reference Martin Blake, p. 22, ll. 22-23 through p. 23, ll. 1-4.

a) How does the improper economic signal Dr. Blake refers to influence customer behavior?

b) Does KU anticipate that fewer new residential service locations will be established once this "improper economic signal" is corrected?

A-9. a) As noted in my Direct Testimony, recovering non-volumetric distribution fixed costs through a kWh energy charge sends a signal that it is relatively inexpensive to install, operate and maintain the minimum set of equipment necessary to provide service to customers with usage below the class average. It also sends a signal that it is relatively expensive to install, operate and maintain the minimum set of equipment necessary to provide service to customers with usage above the class average. The fact is that the cost of installing, operating and maintaining the minimum set of equipment necessary to provide service to customers is a fixed amount that does not vary with usage level. Variabilizing non-volumetric distribution fixed cost by recovering these costs through a kWh energy charge may encourage customers to initiate service for loads with low kWh usage when other energy solutions may be more cost effective. The cost of installing, operating and maintaining the minimum set of equipment necessary to serve these low usage customers would then be borne by customers with usage above the class average, which would constitute an intra-class subsidy. Additionally, a kWh energy charge may not accurately reflect the cost of the generation and transmission capacity that customers may use in the case of loads that occur primarily on-peak or over a short period of time, such as air conditioning and on-demand water heating. Energy charges assessed on a kWh basis do a fine job of recovering costs that are variable in nature, but do not typically do a good job of accurately recovering fixed costs that customers cause to be incurred.

b) While it is possible that some very small usage customers may discontinue service, the Companies believe this is unlikely to be material. However, going forward, KU would send a better price signal regarding the cost to initiate service to such low usage loads and would not incur the cost of operating and maintaining the minimum set of equipment needed to provide service to customer who disconnected.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 10

Responding Witness: David E. Huff / Dr. Martin J. Blake

Q-10. Reference Martin Blake, p. 23, ll. 12-14.

a) By "fixed production and transmission costs," does Dr. Blake mean demand-related production and transmission plant costs? Please explain.

b) Would Dr. Blake agree that these production and transmission plant costs are "fixed" in the sense that they are sunk? Please explain.

c) Has Dr. Blake or the Company compared the proposed on-peak energy rate against a forecast of the generation and transmission costs avoided by a shift from on-peak to off-peak usage? If so, please provide copies of all workpapers or other documentation of such analyses.

d) Please provide the Company's current forecast of avoided generation, transmission, and distribution costs used to screen DSM measures and programs for cost-effectiveness.

A-10. a) Yes, as well as any other production and transmission cost that is fixed, such as fixed operations and maintenance expenses.

b) Yes, fixed production and transmission plant costs do not change and are frequently referred to as sunk costs.

c) No.

d) Please see attachment for system avoided energy costs. Transmission and distribution capacity costs are pieces of avoided energy costs and are not available as separate values. System avoided capacity cost are $100/kW-yr.

Avoided Energy Costs
$ / kWh

	Winter				Spring			
	Weekday		Weekend		Weekday		Weekend	
	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak
2014	$0.0272	$0.0294	$0.0271	$0.0283	$0.0274	$0.0313	$0.0265	$0.0292
2015	$0.0296	$0.0321	$0.0295	$0.0304	$0.0290	$0.0344	$0.0274	$0.0308
2016	$0.0317	$0.0346	$0.0312	$0.0328	$0.0313	$0.0360	$0.0300	$0.0333
2017	$0.0338	$0.0360	$0.0336	$0.0345	$0.0331	$0.0376	$0.0320	$0.0354
2018	$0.0351	$0.0370	$0.0345	$0.0357	$0.0335	$0.0377	$0.0323	$0.0355
2019	$0.0350	$0.0369	$0.0350	$0.0357	$0.0335	$0.0384	$0.0319	$0.0360
2020	$0.0368	$0.0385	$0.0367	$0.0372	$0.0348	$0.0398	$0.0339	$0.0367
2021	$0.0381	$0.0393	$0.0383	$0.0389	$0.0368	$0.0419	$0.0363	$0.0388
2022	$0.0398	$0.0413	$0.0396	$0.0402	$0.0389	$0.0430	$0.0384	$0.0402
2023	$0.0396	$0.0418	$0.0394	$0.0405	$0.0388	$0.0433	$0.0383	$0.0401
2024	$0.0407	$0.0434	$0.0402	$0.0412	$0.0399	$0.0450	$0.0394	$0.0415
2025	$0.0425	$0.0455	$0.0420	$0.0432	$0.0418	$0.0459	$0.0407	$0.0426
2026	$0.0455	$0.0478	$0.0449	$0.0459	$0.0447	$0.0482	$0.0442	$0.0458
2027	$0.0468	$0.0493	$0.0466	$0.0476	$0.0456	$0.0495	$0.0449	$0.0471
2028	$0.0513	$0.0522	$0.0510	$0.0523	$0.0501	$0.0541	$0.0497	$0.0517
2029	$0.0521	$0.0542	$0.0518	$0.0531	$0.0510	$0.0552	$0.0505	$0.0525
2030	$0.0550	$0.0567	$0.0546	$0.0555	$0.0538	$0.0576	$0.0533	$0.0553
2031	$0.0559	$0.0582	$0.0555	$0.0571	$0.0553	$0.0608	$0.0543	$0.0562
2032	$0.0562	$0.0605	$0.0554	$0.0570	$0.0550	$0.0594	$0.0540	$0.0565
2033	$0.0576	$0.0614	$0.0568	$0.0594	$0.0566	$0.0621	$0.0556	$0.0584

	Summer				Autumn			
	Weekday		Weekend		Weekday		Weekend	
	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak
2014	$0.0270	$0.0321	$0.0268	$0.0296	$0.0284	$0.0310	$0.0278	$0.0292
2015	$0.0290	$0.0362	$0.0277	$0.0319	$0.0301	$0.0336	$0.0292	$0.0314
2016	$0.0321	$0.0377	$0.0304	$0.0346	$0.0324	$0.0352	$0.0315	$0.0336
2017	$0.0337	$0.0392	$0.0319	$0.0360	$0.0339	$0.0360	$0.0336	$0.0350
2018	$0.0333	$0.0394	$0.0321	$0.0362	$0.0338	$0.0366	$0.0335	$0.0352
2019	$0.0340	$0.0403	$0.0329	$0.0372	$0.0361	$0.0384	$0.0357	$0.0372
2020	$0.0356	$0.0426	$0.0346	$0.0386	$0.0364	$0.0386	$0.0364	$0.0372
2021	$0.0375	$0.0444	$0.0370	$0.0399	$0.0389	$0.0415	$0.0381	$0.0396
2022	$0.0391	$0.0469	$0.0388	$0.0418	$0.0397	$0.0417	$0.0398	$0.0405
2023	$0.0394	$0.0480	$0.0388	$0.0426	$0.0398	$0.0433	$0.0394	$0.0410
2024	$0.0408	$0.0510	$0.0399	$0.0438	$0.0407	$0.0436	$0.0404	$0.0420
2025	$0.0423	$0.0497	$0.0417	$0.0446	$0.0426	$0.0466	$0.0421	$0.0443
2026	$0.0453	$0.0529	$0.0447	$0.0473	$0.0455	$0.0478	$0.0449	$0.0466
2027	$0.0464	$0.0542	$0.0459	$0.0491	$0.0469	$0.0512	$0.0466	$0.0492
2028	$0.0508	$0.0599	$0.0506	$0.0536	$0.0511	$0.0542	$0.0507	$0.0527
2029	$0.0518	$0.0626	$0.0510	$0.0544	$0.0522	$0.0556	$0.0512	$0.0532
2030	$0.0547	$0.0660	$0.0542	$0.0597	$0.0551	$0.0580	$0.0547	$0.0560
2031	$0.0558	$0.0670	$0.0552	$0.0596	$0.0564	$0.0600	$0.0558	$0.0578
2032	$0.0565	$0.0654	$0.0551	$0.0594	$0.0563	$0.0600	$0.0559	$0.0582
2033	$0.0577	$0.0680	$0.0571	$0.0608	$0.0584	$0.0639	$0.0558	$0.0592

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 11

Responding Witness: Dr. Martin J. Blake

Q-11. Reference Martin Blake, p. 24, ll. 17-26 and p. 25, ll. 1-10.

a) Please confirm that the time periods shown in the tables are correct.

A-11. a. The on-peak and off-peak periods for the demand and energy rates are correct in Dr. Blake's Direct testimony.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 12

Responding Witness: Dr. Martin J. Blake

Q-12. Reference Martin Blake, p. 25, ll. 16-30.

a) Would the price signal to customers to reduce their load during the on-peak periods be greater if these customers paid a lower basic service charge and correspondingly higher on-peak rates? Please explain.

A-12. a. Yes, but it would not accurately reflect the cost of serving customers. The reason for setting rates in a manner that reflects cost causation rather than rates designed to elicit a specific behavior is one of fairness; namely setting charges for service so that the customer pays for what the customer actually uses. This cost causative approach to ratemaking is an approach that has been adopted in numerous regulatory and legal proceedings. Rates designed to elicit specific behaviors without regard to cost causation could be regarded as arbitrary, because they do not meet the cost causation standard that is typically used to assess whether a rate is fair, just and reasonable. Including non-volumetric fixed costs in the distribution demand component that is recovered using a kWh charge would send an incorrect price signal regarding the cost of the minimum set of facilities necessary to provide a customer with access to the electric grid as well as an incorrect price signal regarding the demand-related distribution costs that are recovered using a kWh energy charge for residential customers. The price signal sent would be that non-volumetric fixed costs vary by usage level, which is not correct. By definition these non-volumetric distribution costs do not vary by usage level. If non-volumetric fixed costs are recovered using a kWh charge, low usage customers would pay less than the full amount of these non-volumetric fixed distribution costs while customers with above average usage would pay more than the full amount of these non-volumetric fixed distribution costs. Furthermore, the charge for recovering volumetric fixed distribution costs would be higher than these costs would justify.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 13

Responding Witness: Dr. Martin J. Blake

Q-13. Reference Exhibits MJB-5, MJB-6, and MBJ-7.

a) Please provide working electronic spreadsheet versions, with all cell formulas and file linkages intact, of these exhibits.

b) Please provide working electronic versions, with all cell formulas and file linkages intact, of all linked spreadsheet files.

c) Please provide copies of all workpapers, including electronic spreadsheets with cell formulas and file linkages intact, relied on to derive these exhibits.

A-13. a.-c. See the response to PSC 2-60. The attachment provided in response to PSC 2-60 lists all files submitted in response to the request for exhibits, schedules, and workpapers from Dr. Blake, Mr. Conroy, and Mr. Blake. The spreadsheets for Exhibits MJB-5, MJB-6, and MJB-7 are included in this list.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 14

Responding Witness: Dr. Martin J. Blake

Q-14. Reference Exhibits MJB-8 and MJB-9.

a) Please provide a working electronic version, with all cell formulas and file linkages intact, of the cost of service spreadsheet model relied on to derive these exhibits.

b) Please provide working electronic versions, with all cell formulas and file linkages intact, of all spreadsheet files linked to the cost of service spreadsheet model.

A-14. a-b. See the response to PSC 2-60. The attachment provided in response to PSC 2-60 lists all files submitted in response to the request for exhibits, schedules, and workpapers from Dr. Blake, Mr. Conroy, and Mr. Blake. The spreadsheets for Exhibits MJB-8 and MJB-9 are included in this list.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 15

Responding Witness: Dr. Martin J. Blake

Q-15. Reference Exhibit MJB-10.

a) Please provide a working electronic spreadsheet version, with all cell formulas and file linkages intact, of this exhibit.

b) Please provide working electronic versions, with all cell formulas and file linkages intact, of all linked spreadsheet files.

A-15. See the response to PSC 2-60. The attachment provided in response to PSC 2-60 lists all files submitted in response to the request for exhibits, schedules, and workpapers from Dr. Blake, Mr. Conroy, and Mr. Blake. The spreadsheets for Exhibits MJB-10 are included in this list

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 16

Responding Witness: Dr. Martin J. Blake

Q-16. Reference Exhibit MJB-11.

a) Please provide a working electronic spreadsheet version, with all cell formulas and file linkages intact, of this exhibit.

b) Please provide working electronic versions, with all cell formulas and file linkages intact, of all linked spreadsheet files.

A-16. See the response to PSC 2-60. The attachment provided in response to PSC 2-60 lists all files submitted in response to the request for exhibits, schedules, and workpapers from Dr. Blake, Mr. Conroy, and Mr. Blake. The spreadsheets for Exhibits MJB-11 are included in this list.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 17

Responding Witness: Robert M. Conroy

Q-17. Reference Testimony of Robert Conroy, p. 18, ll. 1-4.

a) What does Mr. Conroy mean by the phrase "more accurate" with regard to the effect on the "energy-pricing signal to customers" from the proposed increase to the basic service charge? Is it Mr. Conroy's contention that the energy charge under the Company's proposal will more accurately reflect the economic value of a reduction in customer load? Please explain.

b) In Mr. Conroy's opinion, which rate design would provide the "more accurate energy-pricing signal to customers": (1) setting the energy charge at the utility's average variable cost; (2) setting the energy charge at the utility's short-run marginal cost; or (3) setting the energy charge at the utility's long-run marginal cost? Please explain and provide citation to the economic literature supporting Mr. Conroy's opinion in this regard.

c) What does Mr. Conroy mean by the term "better," in the phrase "better energy-efficiency behavioral and investment decisions"?

d) Is it Mr. Conroy's contention that an increased basic service charge will not reduce the incentive for residential customers to alter their behavior to consume less energy, to invest in more energy-efficient technologies, or to participate in the Company's DSM programs? Please explain.

e) Has the Company evaluated or discussed the impact of the proposed increase in the basic service charge on participation in its residential demand-side management programs? If so, please provide all documents relating to that evaluation or discussion. If not, why not?

f) Please provide a copy of the Company's most recent study of marginal costs.

A-17. a) With regard to the first part of the question, the concept is simple and fully explained in the testimony of Dr. Blake at pages 19-23 of his testimony. In short, basic cost-causation principles dictate that utilities should recover fixed costs through fixed charges and variable costs through variable charges. KU's electric cost of service study in its 2012 base rate case showed that the customer-specific fixed cost of providing electric service to the average residential customer was $18.82 per month. The Basic Service Charge awarded to KU in that case and in effect today is $10.75 per month, meaning that KU's current residential per-kWh energy rates are designed to recover from an average customer an average of over $8 per month of customer-specific non-volumetric fixed costs through volumetric energy charges. In other words, KU's current volumetric energy rates are relatively higher than they should be—and are therefore inaccurate—because they have been designed to recover a large portion of customer-specific non-volumetric costs.

KU's cost-of-service study in this case shows that the customer-specific fixed cost of providing electric service to the average residential customer will increase to $21.47 per month in the future test period. Therefore, the current Basic Service Charge, if not increased, will be even more inaccurate going forward, as will energy charges in the future if the Basic Service Charge is not increased because an even larger amount of variable costs will have to be recovered through them. It follows that increasing KU's residential Basic Service Charge to $18.00 per month will create a more accurate Basic Service Charge precisely because the fixed, non-volumetric charge will more closely reflect the fixed costs it is intended to recover, and it will result in a more accurate volumetric energy charge that recovers less fixed, non-volumetric cost. It is the Companies' view that having rates that more accurately reflect the underlying costs they are intended to recover will provide better pricing signals—more accurate signals—to customers.

Concerning the second part of the question, it is not Mr. Conroy's contention that KU's proposed rates "will more accurately reflect the economic value of a reduction in customer load." It is neither KU's duty nor its prerogative to propose or charge base rates based on "the economic value of a reduction in customer load"; rather, KU has proposed base rates for all rate classes based on its actual cost of serving customers and has not attempted to account for costs KU does not incur. To the extent "the economic value of a reduction in customer load" might justify additional or different incentives for customers to engage in DSM-EE, KU addresses such value, incentives, and analysis through its DSM-EE filings, programs, and cost-recovery mechanism, not through base rates or base rate proceedings.

b) The Company disagrees with the premise of the question. As indicated above, the rates charged should reflect the cost of providing service. For reference on the principles of electricity pricing, see the text book on electric ratemaking written by Lawrence J. Vogt, P.E. titled *Electric Pricing: Engineering Principles and Methodologies* (CRC Press, Taylor & Francis Group, 2009).

c) Moving fixed costs from a variable charge (energy price) to a fixed charge (BSC) will more accurately reflect the cost of producing the energy consumed. Thus customers will have better information (more accurate variable costs) when making a decision to invest in energy efficiency or otherwise reduce consumption.

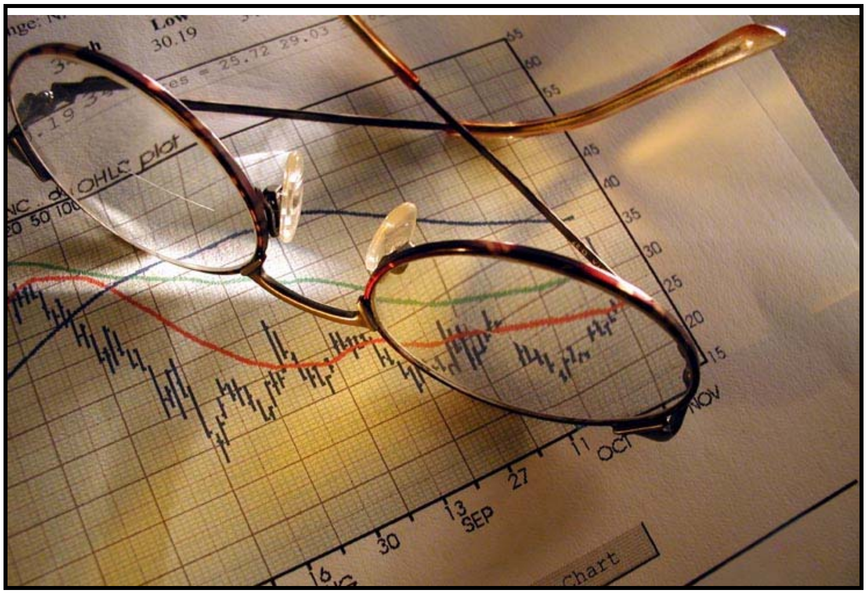
d) See the response to AG 1-9.

e) No. See the responses above and the response to AG 1-9.

f) See attached.

Louisville Gas & Electric Company
Kentucky Utilities Company
Marginal Cost of Service Study

March 2014



Prepared by:

The Prime Group

Priority Cost of Service, Rate and Regulatory Support

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Table of Contents

Executive Summary

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' marginal cost of providing electric service.

Marginal cost is defined as the change in total cost with respect to a small change in demand (or "output"). In this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. Results are tabulated herein and in Table ES-1.

Table ES-1.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	Marginal Cost of Service	
	LG&E	KU
Production Demand (per KW of Added NCP Demand)	$1.98	$1.98
Production Energy (per KWH of Added Energy)	$0.02619	$0.02619
Transmission (per KW of Added NCP Demand)	$1.66	$1.65

Marginal production demand cost and its calculation is best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource acquisitions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Perhaps most often, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it. Using the production cost model and the information from the Companies' 2013 Business Plan, the marginal production demand costs are associated with advancing a combined cycle combustion turbine from 2025 to 2024 in-service. The calculation of an Economic Carrying Charge is used to determine the costs of advancing this capital asset by one year.

Marginal production energy costs are derived from the combined-Company variable costs for the twelve months ended December, 2013.

Marginal transmission costs are determined using a similar approach to the production demand. The plant additions are derived from FERC Form 1 data from 1991 to 2013 and are used with the application of an Economic Carrying Charge Rate to determine the marginal transmission cost for LG&E and KU.

Marginal distribution costs are not calculated because the responsibility for such costs are governed by the Line Extension Plan established by KU and LG&E and approved by the Commission in Case Nos. 2012-00221 and 2012-00222 respectively.

This analysis may be utilized to support the commitment made by the Companies in a recent proceeding, *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost study presented herein is applicable for such a demonstration.

Introduction

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' typical marginal costs of delivering electricity.

Marginal cost is defined as the change in total cost with respect to a small change in demand, or output. In this report "output" will be used in place of "demand" to avoid confusion with the standard way that the term "demand" is used in the industry to represent the maximum amount of power utilized during any interval over a specified period of time. Therefore, in this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. The report includes summary tables of the results.

The marginal costs are determined using the resource planning tools that the Companies rely on for development of their Integrated Resource Plan ("IRP"), which is formally prepared every three years and which was most recently filed with the Kentucky Public Service Commission ("the Commission") on April 21, 2011, in Case No. 2011-00140. The costs included in this filing are based on the Companies' 2013 Resource Assessment which was developed to reflect the most recent changes in the Companies' planning resource requirements to meet their projected growth in output. The study is also based on preliminary data from the Companies' official books and records as reflected on the Form 1 filings with the Federal Energy Regulatory Commission ("FERC"). Form 1 data utilized includes system peak demand data (in MW) and transmission and distribution cost data (in $) by FERC account. Cost escalation factors were determined using the Consumer Price Index ("CPI") data from the U.S. Department of Labor Bureau of Labor Statistics and/or the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman Index"), as appropriate for the particular type of cost to be escalated.

Marginal costs have several applications. In most jurisdictions in the U.S., the most common application of marginal cost studies by utilities is for designing economic development or other incentive rates. Similarly, the marginal costs are also utilized for analyzing discounted rates provided to certain customers pursuant to special contracts. Another application is for the development of particular components of other rate offerings, e.g. determining rate differentials for use in time-differentiated rates, such as time-of-use or critical-peak-pricing rate schedules.

In particular for LG&E and KU, this analysis may be utilized to support the commitment made by the Companies in a recent proceeding, *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost data presented herein, or in subsequent studies, is applicable for such a demonstration.

Marginal Cost Theory

Marginal cost is defined as an infinitesimal change in total cost with respect to an infinitesimal change in output. Mathematically, marginal cost can be represented as the partial derivative of total cost to output, and can be stated as follows:

$$MC = \frac{\partial C}{\partial q}$$

where

MC	=	Marginal Cost
∂C	=	Infinitesimal change in Total Cost
∂q	=	Infinitesimal change in Output

In the context of discrete cost and output, marginal cost can be *estimated* as follows:

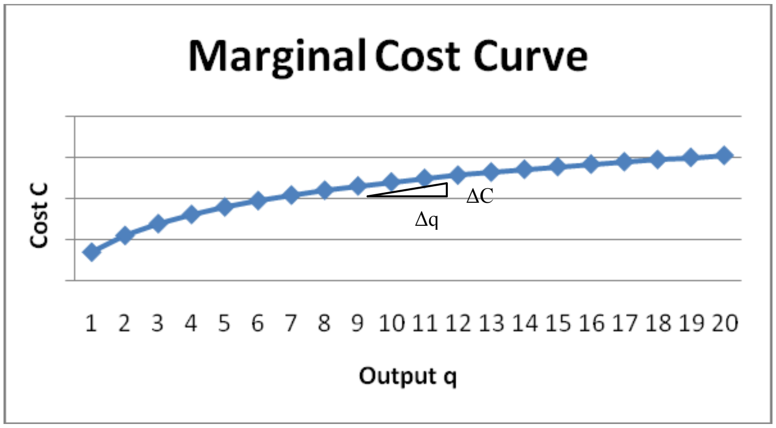
$$MC = \frac{\Delta C}{\Delta q}$$

where

MC	=	Marginal Cost
ΔC	=	Change in Total Cost
Δq	=	Change in Output

Graphically, the marginal cost is the slope of the line resulting from the graph of the total cost C and the total output q, as shown in Figure 1.

Figure 1. Cost vs. Output Curve



In the figure, "output" refers to total megawatts of capacity or megawatt hours of energy required, so that marginal cost is the change in total system cost relative to a small change in total system output.

Marginal Production Demand Cost

The marginal demand costs for production are the changes in capacity costs associated with serving changes in demand on the electric system.

Recall that marginal cost is broadly defined as the change in total cost with respect to a small change in output. In this instance, the "output" refers to total megawatts of generating capacity required, so that marginal cost is the change in total system capacity cost relative to a small change in total system demand.

Marginal production demand cost and its calculation is best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource acquisitions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Perhaps most often, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it.[1]

To evaluate the change in capacity costs, a base case is defined that specifies the capacity (and associated capacity cost) required to meet the Companies' base demand forecast for the planning

[1] Charles J. Cicchetti, et al, *The Marginal Cost and Pricing of Electricity: An Applied Approach* (Cambridge, MA: Ballinger Publishing Co., 1977), 8.

period. Other scenarios are then developed in which the total system demand is increased by set increments, and the capacity acquisitions required to meet those incremental demands are determined. The net present value of the capacity costs in the base case is then compared to the net present value of the capacity costs for the incremental cases to determine the change in capacity cost associated with the change in total system demand.

The base case is based on the Companies' 2013 Resource Assessment which incorporates the recent announcement of the construction of the new combined cycle natural gas plant at the Green River Generating Station. The Resource Assessment is similar to the Companies' filed IRP in that it identifies the capacity resources needed to meet the Companies' forecast load plus the target reserve margin for a fifteen-year planning horizon on a least-cost basis. The plan includes both supply-side and demand-side resources, but for this assessment only the supply-side resources are considered. The Resource Assessment is summarized in Table 1.

Thus the base case is essentially the same as the 2011 IRP with the exception of the 2x1 Combined Cycle Combustion turbine which was recently announced at the Green River generating station being excluded. The cases with incremental total system demand are then prepared and compared to the base case.

Another way to consider this approach is to consider a stable system (the base case). The initial condition is then perturbed (by a small increase in system demand), and equilibrium is re-established (by adjustments to the resource acquisition plan). This process is repeated for several incremental perturbations (i.e. by incremental increases to system demand in blocks of say 25 MW). The cost of the stable base case are then compared to the costs of the stable incremental cases to determine the marginal cost (at whatever increment first requires a change to the resource acquisition plan).

Incremental demands of 25 MW, 50 MW, 75 MW and 100 MW were evaluated to assess the impacts on the resource plan and the associated costs.

The timing of the generation additions needed to meet demand obligations in each year of the planning period for all of the scenarios are determined by the detailed resource planning computer model Strategist®, which the Companies routinely use in the IRP and in other generation planning and forecast evaluations. The capacity costs associated with the supply resource additions listed are included in the IRP. The primary source of the capital cost estimates from the IRP is the EPRI TAG, a report funded by the sponsors of EPRI's Program 9. This is described in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III of the 2011 IRP.

Table 1.
2013 Resource Assessment

Year	Resource
2011	38 MW DSM Initiatives
2012	58 MW DSM Initiatives
2013	59 MW DSM Initiatives
2014	68 MW DSM Initiatives
2015	61 MW DSM Initiatives
2016	61 MW DSM Initiatives **-797 MW Coal Unit Retirements at Cane Run, Green River, and Tyrone** **907MW 3x1 Combined Cycle Combustion Turbine**
2017	61 MW DSM Initiatives
2018	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**
2019	58 MW DSM Initiatives
2020	58 MW DSM Initiatives
2021	58 MW DSM Initiatives
2022	58 MW DSM Initiatives
2023	58 MW DSM Initiatives
2024	58 MW DSM Initiatives
2025	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**

Notes:
- DSM initiatives are incremental proposed programs including one program with annual savings that do not accumulate.
- Unit ratings for new units and retirements are summer net ratings.

The cases and the impacts on the resource plan are summarized in Table 2.

Increasing the total system demand by 25 MW or by 50 MW does not require any change to the resource acquisition plan in the Resource Assessment; those resources are sufficient to meet this incremental demand and there is no incremental capacity cost relative to the Resource Assessment costs for these additions.

Table 2.
Case Summary for Marginal Cost Evaluation

Case	Incremental Demand	Change to Resource Acquisition Plan?
Base	n/a	n/a
Case 1	25 MW	No
Case 2	50 MW	No
Case 3	75 MW	Yes
Case 4	100 MW	Yes

Increasing the total system demand by 75 to 100 MW, however, requires that the resource acquisition plan in the Business Plan be revised in order to meet the incremental demand obligations. The acquisition of a 3x1 Combined Cycle CT must be advanced from 2025 to 2024 in order to meet the incremental 75 MW obligation. This change is highlighted in Table 3. (Other portions of the plan that do not differ, including all of the demand-side options, are not included for the sake of simplicity.)

Table 3.
Change in Resource Plan for Incremental 50 to 100 MW Demand

Year	Base Case	+75 MW Case to +100 MW Case
2024		3x1 Combined Cycle Combustion Turbine
2025	3x1 Combined Cycle Combustion Turbine	

To determine the change in capacity costs associated with the advancement of the 3x1 Combined Cycle from 2025 to 2024, the *Economic Carrying Charge* is calculated. The Economic Carrying Charge is the economic cost of advancing or delaying the present value of revenue requirements associated with capital expenditures. This computation is described in Attachment A.

The marginal production demand cost is the monthly value of the Economic Carrying Charge Rate ("ECRR") applied to the present value revenue requirement ("PVRR") of the capital asset. The computation of both the PVRR of the capital asset and the Economic Carrying Charges are provided in Attachment B. Because the fixed O&M expenses were negligible in comparison to the asset costs, they were not included in the analysis.

Based on the computations included in Attachments A and B, the marginal production demand cost on a Coincident Peak ("CP") basis is $3.24 per month. Using an average coincidence factor from the last KU and LG&E rate cases, the CP marginal cost value is converted to a Non-Coincident Peak ("NCP") marginal cost value of $1.98 per month. Because the LG&E and KU generating units are jointly operated and dispatched to meet the combined demands of the LG&E and KU systems, a single value is provided for the marginal production demand cost on a joint Company basis. For evaluating an economic development offer, it would be necessary to adjust the NCP marginal cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Production Energy Cost

The marginal production energy cost is derived from the same twelve months of actual average variable production cost data for the LG&E/KU system as was evaluated for the Transmission related expenditures. Specifically, the Company provided data for the twelve months ended December 2013 pertaining to the total costs for fuel, consumables (including scrubber reactants and other reagents), ash and waste disposal, and emission allowances. The total generation from the corresponding twelve months was then used to calculate a total average variable cost, on an annual combined-Company basis. This computation is described in Attachment C. Because the preponderance of LG&E and KU's generating assets are base-load resources, average marginal energy costs will not differ materially from average energy costs on an annual basis.

The marginal production energy cost per KWH of additional energy is $0.02619. Again, it would be necessary to adjust the marginal energy cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Transmission Cost

The marginal transmission cost is calculated using the Economic Carrying Charge approach outlined above, but with different source data. The general approach of applying an ECRR to the PVRR of the capital asset is followed; however, in the case of transmission, the capital asset is not a new generating unit but instead represents the value of additional transmission plant.

Recall that marginal costs are defined as the change in total cost with respect to a small change in output. For discrete costs and output, the formula is:

$$MC = \frac{\Delta C}{\Delta q}$$

where

MC	=	Marginal Transmission Cost
ΔC	=	Change in Total Cost of Transmission Plant
Δq	=	Change in system demand

The plant data is derived from the Companies' Transmission Costs as reported on the FERC Form 1 filings.[2] Data from 1991 through 2013 was compiled for KU and LG&E transmission. To determine the change in plant from one year to the next -- i.e. to identify the incremental plant -- the annual change in net plant reported on the FERC Form 1 for KU and LG&E were calculated. The net change was then indexed to 2013 dollars using factors from the Handy-Whitman Index. The indexed change in transmission plant is ΔC. The data for KU and LG&E system demands in MW from 1991 through 2013 was also compiled from the FERC Form 1 filings.[3] The change in demand from one year to the next is Δq. In this way, the amount for each year-to-year increment is calculated as ΔC / Δq. The average amount for the multi-year period is then calculated. The calculations of the additional transmission investments for KU and LG&E are shown in Attachment D.

The average transmission addition amount for KU is then input as the PVRR in the determination of the Economic Carrying Charge, as demonstrated in Attachment E. The determination of the ECRR is identical to the approach used for marginal production demand costs, where the PVRR, inflation rate, weighted average cost of capital, and other factors described in Attachment A are used to determine the cost value on a CP basis. The CP value is then converted to an NCP value using the average coincidence factor from the most recent KU and LG&E rate cases. The entire process is repeated for LG&E, as demonstrated in Attachment F. Because the fixed O&M expenses were negligible in comparison to the asset costs, they were not included in the analysis.

For KU, the marginal transmission cost per KW of additional NCP demand is $1.65. For LG&E, the marginal transmission cost per KW of additional NCP demand is also $1.66. Again, it would be necessary to adjust the marginal transmission cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

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[2] FERC Form 1, Page 206, Line No. 58.
[3] FERC Form 1, Page 410b, Column D

Marginal Distribution Cost

The marginal distribution cost for KU and LG&E in theory could be calculated using the same approach as the marginal transmission costs. However, from a ratemaking and policy standpoint, distribution and transmission differ. For distribution, the Companies established a Line Extension Plan, most recently approved on December 20, 2012 by the Commission for KU and LG&E in Case Nos. 2012-00221 and 2012-00222 respectively. The Line Extension Plan is applicable in all service territory where the Companies do not have existing facilities to meet the electric service needs of its retail customers. The plan specifies how the costs for normal line extensions and other line extensions will be handled. This practice makes moot the determination of a marginal distribution cost for the system at large because any individual facility addition, and its particular costs, will be considered on an actual-cost and specific-customer basis, pursuant to the Line Extension Plan.

Summary

The marginal costs for KU and LG&E for Production Demand, Production Energy, and Transmission are summarized in Table 4.

Table 4.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$1.98	$1.98
Production Energy (per KWH of Added Energy)	$0.02619	$0.02619
Transmission (per KW of Added NCP Demand)	$1.66	$1.65

Attachments

Computation of the Economic Carrying Charges Associated With Delaying a Planned Generating Resource by a Fixed Number of Years

Economic carrying charges are the economic costs of advancing (moving forward) or delaying (moving backwards) the present value revenue requirements associated with a capital expenditure. In other words, an economic carrying charge is a measurement of the effect on a utility's present value revenue requirements (PVRR) of advancing or delaying the installation of a utility resource. For example, if an increase in load causes a generating resource to be moved forward *a* years, the economic carrying charges measures the effect on PVRR of moving the resource forward *m* years. Economic carrying charges are often calculated assuming a=1 (i.e., moving the resource forward one year).

Where:

ECC = Economic Carrying Charges

ECCR = Economic Carrying Charge Rate

PVRR = Present value revenue requirement for the asset in current dollars.

g = Annual Inflation Rate

r = Weighted Cost of Capital

L = Life of the asset

i = index factor representing every L years

a = the number of years that the asset is advanced

m = the number of years prior to when the asset is installed after taking into consideration the number of years *a* that the asset is advanced, necessary to reflect the carrying charge rate in current year dollars.

$$ECC = \frac{(1+g)^m}{(1+r)^m}\left[\sum_{i=0}^{\infty} PVRR\ \frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty} PVRR\frac{(1+g)^{Li}}{(1+r)^{Li}}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1 - \frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1 - \frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\left(\frac{(1+g)^{L}}{(1+r)^{L}}\right)^i\right\}\right]$$

$$= PVRR\,\frac{(1+g)^m}{(1+r)^m}\left[\left(1 - \frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1 - \frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

The last step in the above derivation converts a infinite geometric series to a fixed value. Mathematically, a geometric series converges to the following value as long as $0 \leq x \leq 1$:

$$\sum_{i=0}^{\infty} x^i = \frac{1}{1-x}$$

(See, for example, Walter Rudin, *Principles of Mathematical Analysis* (McGraw-Hill, Inc.; 1976) at 61.) In the context of an economic carrying charge, the infinite series shown in the penultimate line of the above derivation will converge to a known value as long as $g < r$.

The Economic Carrying Charges (ECC) can also be calculated by multiplying the PVRR by an Economic Carrying Charge Rate (ECCR) (i.e. ECC = PVRR x ECCR), where the ECCR is calculated as follows:

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1 - \frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1 - \frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Economic Carrying Charge of New Combined Cycle CT Addition

Assumptions	Values
Inflation Rate (g)	1.80%
Weighted Cost of Capital (r)	7.28%
Year Scheduled to be Installed	2025
Year Installed After Load Addition	2024
a	1
Current Year	2014
m	10
PVRR	1128.17
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	2.95%
Coincidence Factor	61.20%

Annual Value (CP) =	**$**	**38.89**
Annual Value (NCP) =	**$**	**23.80**
Monthly Value (CP) =	**$**	**3.24**
Monthly Value (NCP) =	**$**	**1.98**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New Combined Cycle CT Addition

Assumptions:

Investment		948.06
Book Life		40
Tax Life		20
Composite Tax Rate		37.0575%
Property Tax Rate		0.40%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	1,128
Levelized Revenue Requirement	$	87
Levelized Carrying Charge Rate		9.22%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 948						
1		$ 24	$ 924	$ 36	$ 913	$ 4	$ 4
2		24	901	68	844	17	21
3		24	877	63	781	15	36
4		24	853	59	722	13	49
5		24	830	54	668	11	60
6		24	806	50	618	10	70
7		24	782	46	572	8	78
8		24	758	43	529	7	85
9		24	735	42	486	7	92
10		24	711	42	444	7	99
11		24	687	42	402	7	106
12		24	664	42	360	7	113
13		24	640	42	317	7	120
14		24	616	42	275	7	126
15		24	593	42	233	7	133
16		24	569	42	190	7	140
17		24	545	42	148	7	147
18		24	521	42	106	7	154
19		24	498	42	63	7	161
20		24	474	42	21	7	168
21		24	450	21	(0)	(1)	167
22		24	427	-	(0)	(9)	158
23		24	403	-	(0)	(9)	149
24		24	379	-	(0)	(9)	141
25		24	356	-	(0)	(9)	132
26		24	332	-	(0)	(9)	123
27		24	308	-	(0)	(9)	114
28		24	284	-	(0)	(9)	105
29		24	261	-	(0)	(9)	97
30		24	237	-	(0)	(9)	88
31		24	213	-	(0)	(9)	79
32		24	190	-	(0)	(9)	70
33		24	166	-	(0)	(9)	61
34		24	142	-	(0)	(9)	53
35		24	119	-	(0)	(9)	44
36		24	95	-	(0)	(9)	35
37		24	71	-	(0)	(9)	26
38		24	47	-	(0)	(9)	18
39		24	24	-	(0)	(9)	9
40		24	(0)	-	(0)	(9)	0

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New Combined Cycle CT Addition

Assumptions:

Investment	$	948
Book Life		40
Tax Life		20
Composite Tax Rate		37.0575%
Property Tax Rate		0.40%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	1,128
Levelized Revenue Requirement	$	87
Levelized Carrying Charge Rate		9.22%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 920	$ 16	$ 51	$ 4	$ 30	$ 125	0.932108	116
2	880	15	49	4	29	120	0.868825	104
3	841	14	47	3	28	116	0.809839	94
4	805	14	45	3	26	112	0.754857	85
5	770	13	43	3	25	108	0.703608	76
6	736	13	41	3	24	105	0.655839	69
7	704	12	39	3	23	101	0.611312	62
8	673	11	38	3	22	98	0.569809	56
9	643	11	36	3	21	95	0.531124	50
10	612	10	34	3	20	91	0.495064	45
11	582	10	32	3	19	88	0.461453	41
12	551	9	31	3	18	85	0.430124	36
13	520	9	29	3	17	81	0.400922	33
14	490	8	27	2	16	78	0.373703	29
15	459	8	26	2	15	75	0.348331	26
16	429	7	24	2	14	71	0.324682	23
17	398	7	22	2	13	68	0.302639	21
18	367	6	21	2	12	65	0.282092	18
19	337	6	19	2	11	61	0.262940	16
20	306	5	17	2	10	58	0.245089	14
21	283	5	16	2	9	55	0.228449	13
22	269	5	15	2	9	54	0.212939	11
23	254	4	14	2	8	52	0.198482	10
24	239	4	13	2	8	50	0.185007	9
25	224	4	12	1	7	49	0.172446	8
26	209	4	12	1	7	47	0.160739	8
27	194	3	11	1	6	45	0.149826	7
28	179	3	10	1	6	44	0.139654	6
29	164	3	9	1	5	42	0.130172	5
30	149	3	8	1	5	40	0.121335	5
31	213	4	12	1	7	47	0.113097	5
32	190	3	11	1	6	44	0.105419	5
33	166	3	9	1	5	42	0.098262	4
34	142	2	8	1	5	39	0.091590	4
35	119	2	7	0	4	37	0.085372	3
36	95	2	5	0	3	34	0.079576	3
37	71	1	4	0	2	31	0.074173	2
38	47	1	3	0	2	29	0.069138	2
39	24	0	1	0	1	26	0.064444	2
40	(0)	(0)	(0)	(0)	(0)	24	0.060069	1
Net Present Value Revenue Requirement								$ 1,128

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New Combined Cycle CT Addition

Assumptions:

Investment	$ 948
Book Life	40
Tax Life	20
Composite Tax Rate	37.0575%
Property Tax Rate	0.40%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 1,128
Levelized Revenue Requirement	$ 87
Levelized Carrying Charge Rate	9.22%

Year	Cumulative Present Value Revenue Requirement	Annual Carrying Charge Rate
0	$ -	
1	116	13.14%
2	221	12.68%
3	315	12.25%
4	399	11.83%
5	476	11.43%
6	544	11.05%
7	606	10.68%
8	662	10.32%
9	712	9.97%
10	757	9.62%
11	798	9.27%
12	834	8.92%
13	867	8.57%
14	896	8.22%
15	922	7.87%
16	945	7.52%
17	966	7.16%
18	984	6.81%
19	1,000	6.46%
20	1,014	6.11%
21	1,027	5.85%
22	1,038	5.67%
23	1,049	5.50%
24	1,058	5.32%
25	1,066	5.14%
26	1,074	4.97%
27	1,081	4.79%
28	1,087	4.61%
29	1,092	4.44%
30	1,097	4.26%
31	1,102	4.97%
32	1,107	4.69%
33	1,111	4.42%
34	1,115	4.14%
35	1,118	3.87%
36	1,121	3.60%
37	1,123	3.32%
38	1,125	3.05%
39	1,127	2.77%
40	1,128	2.50%

Louisville Gas and Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	45.53%	3.74%	1.70%	37.06%	1.07%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	54.47%	10.25%	5.58%		5.58%
			7.28%		6.65%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Kentucky Utilities and Louisville Gas and Electric Company
Marginal Energy Costs
12 Months ending December 2013

Variable Materials and Disposal		Amount
Scrubber Reactant Ex	$	23,484,789
Nox Reduction Reagent (Ammonia)	$	8,538,835
Sorbent Injection (Hydrated Lime/Trona)	$	13,722,029
Activated Carbon	$	1,241,046
Consumables	**$**	**46,986,699**
Other Waste Disposal	$	2,467,177
Bottom Ash Disposal		
Fly Ash Disposal		
Disposal	**$**	**2,467,177**
Emission Allowances	**$**	**380,397**

Fuel		Amount
FUEL-COAL - TON	$	838,407,861
START-UP OIL -GAL	$	5,395,782
STABILIZATION OIL - GAL	$	3,868,153
START-UP GAS - MCF	$	2,889,196
STABILIZATION GAS - MCF	$	3,980,060
FUEL-GAS - MCF	$	44,106,360
FUEL-OIL - GAL	$	67,049
FUEL - GAS - INTRACOMPANY	$	1,411,504
Total Fuel	**$**	**900,125,966**
Total Variable Costs	**$**	**949,960,239**

Generation	
KWH GENERATED-COAL - (STAT ONLY)	35,475,320,000
KWH GENERATED-HYDRO - (STAT ONLY)	299,955,000
KWH GEN-OTH PWR-OIL - (STAT ONLY)	165,000
KWH GEN-OTH PWR-GAS - (STAT ONLY)	502,659,900
Total Generation	**36,278,099,900**

Marginal Energy Cost ($/MWh)	**$**	**26.19**

Summary by Fuel Type

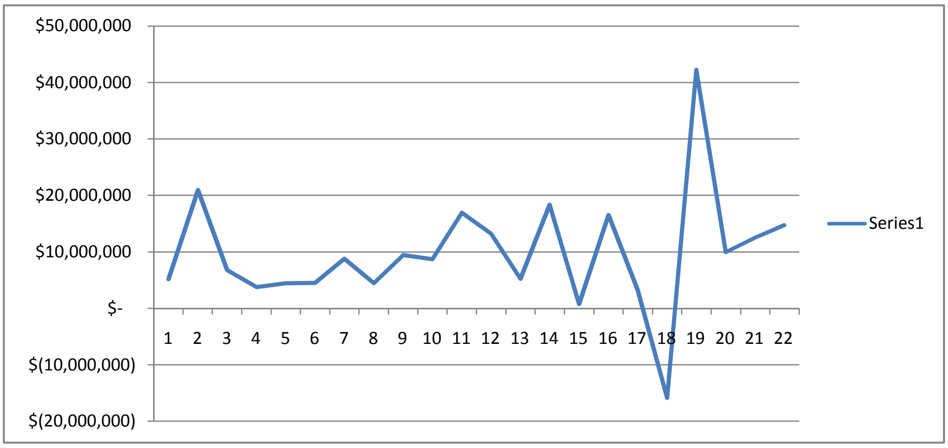
	Coal	Gas	Hydro	Total
Non Fuel	$ 49,834,273			$ 49,834,273
Fuel	$ 854,541,052	$ 45,584,913		$ 900,125,966
Total Cost	$ 904,375,325	$ 45,584,913		$ 949,960,239
Gen	35,475,320,000	502,824,900	299,955,000	36,278,099,900
$/MWh	$ 25.49	$ 90.66	$ -	$ 26.19

	LG&E Transmission Plant				
	Δc	Index Factor	ΔC	Δq (MW)	ΔC/Δq ($/MW)
1992-1993	$ 2,502,618	2.08	$ 5,202,638	-831	$ (6,261)
1993-1994	10,430,423	2.01	20,949,165	843	24,851
1994-1995	3,525,333	1.92	6,754,515	278	24,297
1995-1996	2,077,112	1.83	3,798,697	689	5,513
1996-1997	2,484,298	1.80	4,470,982	862	5,187
1997-1998	2,555,243	1.77	4,513,058	-205	(22,015)
1998-1999	5,104,923	1.72	8,793,665	737	11,932
1999-2000	2,561,086	1.74	4,466,835	92	48,553
2000-2001	5,691,294	1.66	9,466,865	581	16,294
2001-2002	5,423,958	1.60	8,698,870	-2	(4,349,435)
2002-2003	10,653,371	1.59	16,925,516	1749	9,677
2003-2004	8,373,198	1.58	13,231,996	-1743	(7,592)
2004-2005	3,587,061	1.46	5,229,569	457	11,443
2005-2006	13,566,451	1.35	18,346,421	1601	11,459
2006-2007	628,196	1.24	779,331	-69	(11,295)
2007-2008	14,477,762	1.14	16,534,064	1012	16,338
2008-2009	3,114,846	1.05	3,283,740	-1261	(2,604)
2009-2010	(14,692,544)	1.08	(15,855,648)	-1121	14,144
2010-2011	39,820,209	1.06	42,242,190	1629	25,931
2011-2012	9,532,005	1.04	9,955,929	-667	(14,926)
2012-2013	12,274,434	1.02	12,522,562	-44	(284,604)
2013-2014	14,715,648	1.00	14,715,648	-14	(1,051,118)
Average	$ 7,200,315		$ 9,773,937	208	$ 47,021

Coincidence Factor	50.43%			412	$ 23,713

	KU Transmission Plant				
	Δc	Index Factor	ΔC	Δq (MW)	ΔC/Δq ($/MW)
1992-1993	$ 14,300,089	2.08	$ 29,728,143	-221	$ (134,516)
1993-1994	5,897,637	2.01	11,845,212	1581	7,492
1994-1995	6,316,884	1.92	12,103,109	799	15,148
1995-1996	11,888,561	1.83	21,742,226	1287	16,894
1996-1997	8,078,988	1.80	14,539,727	1740	8,356
1997-1998	11,197,661	1.77	19,777,254	60	329,621
1998-1999	10,373,914	1.72	17,869,952	1061	16,843
1999-2000	6,477,271	1.74	11,297,123	1101	10,261
2000-2001	15,603,236	1.66	25,954,331	1799	14,427
2001-2002	7,949,408	1.60	12,749,152	-1008	(12,648)
2002-2003	5,335,747	1.59	8,477,155	3083	2,750
2003-2004	28,277,474	1.58	44,686,321	-2117	(21,108)
2004-2005	9,891,977	1.46	14,421,493	1320	10,925
2005-2006	12,637,263	1.35	17,089,845	2747	6,221
2006-2007	4,075,797	1.24	5,056,376	-61	(82,891)
2007-2008	13,775,133	1.14	15,731,640	2069	7,603
2008-2009	8,843,391	1.05	9,322,899	-1096	(8,506)
2009-2010	98,028	1.08	105,788	-880	(120)
2010-2011	98,256,593	1.06	104,232,844	1914	54,458
2011-2012	29,530,077	1.04	30,843,392	-685	(45,027)
2012-2013	33,266,071	1.02	33,938,546	-764	(44,422)
2013-2014	37,942,046	1.00	37,942,046	1266	29,970
Average	$ 17,273,329		$ 22,702,481	682	$ 33,308

Coincidence Factor	71.96%			947	$ 23,968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$30,000,000
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$(10,000,000)
$(20,000,000)
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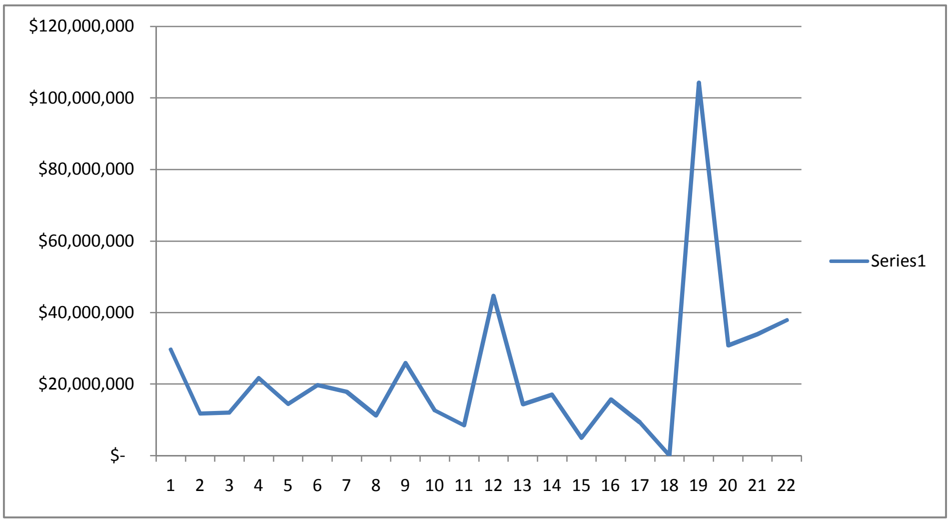
Series1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$20,000,000
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1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22
Series1

Kentucky Utilities Transmission Cost
Economic Carrying Charge of Transmission Capacity Addition

Assumptions	Values
Inflation Rate (g)	1.80%
Weighted Cost of Capital (r)	7.28%
Year Scheduled to be Installed	2014
Year Installed After Load Addition	2014
a	0
Current Year	2014
m	0
PVRR	39.39
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	4.98%
Coincidence Factor	71.96%

Monthly Value (CP) =	$	**2.30**
Monthly Value (NCP) =	$	**1.65**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Kentucky Utilities
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$ 33.308
Book Life	40
Tax Life	20
Composite Tax Rate	37.0575%
Property Tax Rate	0.32%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 39
Levelized Revenue Requirement	$ 3
Levelized Carrying Charge Rate	9.17%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 33						
1		$ 1	$ 32	$ 1	$ 32	$ 0	$ 0
2		1	32	2	30	1	1
3		1	31	2	27	1	1
4		1	30	2	25	0	2
5		1	29	2	23	0	2
6		1	28	2	22	0	2
7		1	27	2	20	0	3
8		1	27	2	19	0	3
9		1	26	1	17	0	3
10		1	25	1	16	0	3
11		1	24	1	14	0	4
12		1	23	1	13	0	4
13		1	22	1	11	0	4
14		1	22	1	10	0	4
15		1	21	1	8	0	5
16		1	20	1	7	0	5
17		1	19	1	5	0	5
18		1	18	1	4	0	5
19		1	17	1	2	0	6
20		1	17	1	1	0	6
21		1	16	1	0	(0)	6
22		1	15	-	0	(0)	6
23		1	14	-	0	(0)	5
24		1	13	-	0	(0)	5
25		1	12	-	0	(0)	5
26		1	12	-	0	(0)	4
27		1	11	-	0	(0)	4
28		1	10	-	0	(0)	4
29		1	9	-	0	(0)	3
30		1	8	-	0	(0)	3
31		1	7	-	0	(0)	3
32		1	7	-	0	(0)	2
33		1	6	-	0	(0)	2
34		1	5	-	0	(0)	2
35		1	4	-	0	(0)	2
36		1	3	-	0	(0)	1
37		1	2	-	0	(0)	1
38		1	2	-	0	(0)	1
39		1	1	-	0	(0)	0
40		1	0	-	0	(0)	0

Kentucky Utilities
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$	33
Book Life		40
Tax Life		20
Composite Tax Rate		37.0575%
Property Tax Rate		0.32%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	39
Levelized Revenue Requirement	$	3
Levelized Carrying Charge Rate		9.17%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 32	$ 1	$ 2	$ 0	$ 1	$ 4	0.932108	4
2	31	1	2	0	1	4	0.868825	4
3	30	1	2	0	1	4	0.809839	3
4	28	0	2	0	1	4	0.754857	3
5	27	0	2	0	1	4	0.703608	3
6	26	0	1	0	1	4	0.655839	2
7	25	0	1	0	1	4	0.611312	2
8	24	0	1	0	1	3	0.569809	2
9	23	0	1	0	1	3	0.531124	2
10	22	0	1	0	1	3	0.495064	2
11	20	0	1	0	1	3	0.461453	1
12	19	0	1	0	1	3	0.430124	1
13	18	0	1	0	1	3	0.400922	1
14	17	0	1	0	1	3	0.373703	1
15	16	0	1	0	1	3	0.348331	1
16	15	0	1	0	0	2	0.324682	1
17	14	0	1	0	0	2	0.302639	1
18	13	0	1	0	0	2	0.282092	1
19	12	0	1	0	0	2	0.262940	1
20	11	0	1	0	0	2	0.245089	0
21	10	0	1	0	0	2	0.228449	0
22	9	0	1	0	0	2	0.212939	0
23	9	0	0	0	0	2	0.198482	0
24	8	0	0	0	0	2	0.185007	0
25	8	0	0	0	0	2	0.172446	0
26	7	0	0	0	0	2	0.160739	0
27	7	0	0	0	0	2	0.149826	0
28	6	0	0	0	0	2	0.139654	0
29	6	0	0	0	0	1	0.130172	0
30	5	0	0	0	0	1	0.121335	0
31	7	0	0	0	0	2	0.113097	0
32	7	0	0	0	0	2	0.105419	0
33	6	0	0	0	0	1	0.098262	0
34	5	0	0	0	0	1	0.091590	0
35	4	0	0	0	0	1	0.085372	0
36	3	0	0	0	0	1	0.079576	0
37	2	0	0	0	0	1	0.074173	0
38	2	0	0	0	0	1	0.069138	0
39	1	0	0	0	0	1	0.064444	0
40	0	0	0	0	0	1	0.060069	0

Net Present Value Revenue Requirement $ 39

Kentucky Utilities
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$ 33
Book Life	40
Tax Life	20
Composite Tax Rate	37.0575%
Property Tax Rate	0.32%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 39
Levelized Revenue Requirement	$ 3
Levelized Carrying Charge Rate	9.17%

Year	Cumulative Present Value Revenue Requirement	Annual Carrying Charge Rate
0	$ -	
1	4	13.06%
2	8	12.61%
3	11	12.17%
4	14	11.76%
5	17	11.36%
6	19	10.98%
7	21	10.61%
8	23	10.26%
9	25	9.91%
10	26	9.56%
11	28	9.21%
12	29	8.86%
13	30	8.51%
14	31	8.17%
15	32	7.82%
16	33	7.47%
17	34	7.12%
18	34	6.77%
19	35	6.42%
20	35	6.07%
21	36	5.81%
22	36	5.64%
23	37	5.46%
24	37	5.29%
25	37	5.11%
26	37	4.94%
27	38	4.76%
28	38	4.59%
29	38	4.42%
30	38	4.24%
31	38	4.95%
32	39	4.68%
33	39	4.41%
34	39	4.13%
35	39	3.86%
36	39	3.59%
37	39	3.32%
38	39	3.04%
39	39	2.77%
40	39	2.50%

Louisville Gas and Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	45.53%	3.74%	1.70%	37.06%	1.07%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	54.47%	10.25%	5.58%		5.58%
			7.28%		6.65%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Louisville Gas & Electric Transmission Cost
Economic Carrying Charge of Transmission Capacity Addition

Assumptions	**Values**
Inflation Rate (g)	1.80%
Weighted Cost of Capital (r)	7.28%
Year Scheduled to be Installed	2014
Year Installed After Load Addition	2014
a	0
Current Year	2014
m	0
PVRR	56.55
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	4.98%
Coincidence Factor	50.43%

Monthly Value (CP) =	**$**	**3.29**
Monthly Value (NCP) =	**$**	**1.66**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$ 47.021
Book Life	40
Tax Life	20
Composite Tax Rate	37.0575%
Property Tax Rate	0.54%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 57
Levelized Revenue Requirement	$ 4
Levelized Carrying Charge Rate	9.32%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 47						
1		$ 1	$ 46	$ 2	$ 45	$ 0	$ 0
2		1	45	3	42	1	1
3		1	43	3	39	1	2
4		1	42	3	36	1	2
5		1	41	3	33	1	3
6		1	40	2	31	0	3
7		1	39	2	28	0	4
8		1	38	2	26	0	4
9		1	36	2	24	0	5
10		1	35	2	22	0	5
11		1	34	2	20	0	5
12		1	33	2	18	0	6
13		1	32	2	16	0	6
14		1	31	2	14	0	6
15		1	29	2	12	0	7
16		1	28	2	9	0	7
17		1	27	2	7	0	7
18		1	26	2	5	0	8
19		1	25	2	3	0	8
20		1	24	2	1	0	8
21		1	22	1	-	(0)	8
22		1	21	-	-	(0)	8
23		1	20	-	-	(0)	7
24		1	19	-	-	(0)	7
25		1	18	-	-	(0)	7
26		1	16	-	-	(0)	6
27		1	15	-	-	(0)	6
28		1	14	-	-	(0)	5
29		1	13	-	-	(0)	5
30		1	12	-	-	(0)	4
31		1	11	-	-	(0)	4
32		1	9	-	-	(0)	3
33		1	8	-	-	(0)	3
34		1	7	-	-	(0)	3
35		1	6	-	-	(0)	2
36		1	5	-	-	(0)	2
37		1	4	-	-	(0)	1
38		1	2	-	-	(0)	1
39		1	1	-	-	(0)	0
40		1	(0)	-	-	(0)	(0)

Louisville Gas & Electric
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$	47
Book Life		40
Tax Life		20
Composite Tax Rate		37.0575%
Property Tax Rate		0.54%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	57
Levelized Revenue Requirement	$	4
Levelized Carrying Charge Rate		9.32%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 46	$ 1	$ 3	$ 0	$ 1	$ 6	0.932108	6
2	44	1	2	0	1	6	0.868825	5
3	42	1	2	0	1	6	0.809839	5
4	40	1	2	0	1	6	0.754857	4
5	38	1	2	0	1	5	0.703608	4
6	37	1	2	0	1	5	0.655839	3
7	35	1	2	0	1	5	0.611312	3
8	33	1	2	0	1	5	0.569809	3
9	32	1	2	0	1	5	0.531124	3
10	30	1	2	0	1	5	0.495064	2
11	29	0	2	0	1	4	0.461453	2
12	27	0	2	0	1	4	0.430124	2
13	26	0	1	0	1	4	0.400922	2
14	24	0	1	0	1	4	0.373703	1
15	23	0	1	0	1	4	0.348331	1
16	21	0	1	0	1	4	0.324682	1
17	20	0	1	0	1	3	0.302639	1
18	18	0	1	0	1	3	0.282092	1
19	17	0	1	0	1	3	0.262940	1
20	15	0	1	0	0	3	0.245089	1
21	14	0	1	0	0	3	0.228449	1
22	13	0	1	0	0	3	0.212939	1
23	13	0	1	0	0	3	0.198482	1
24	12	0	1	0	0	3	0.185007	0
25	11	0	1	0	0	2	0.172446	0
26	10	0	1	0	0	2	0.160739	0
27	10	0	1	0	0	2	0.149826	0
28	9	0	0	0	0	2	0.139654	0
29	8	0	0	0	0	2	0.130172	0
30	7	0	0	0	0	2	0.121335	0
31	11	0	1	0	0	2	0.113097	0
32	9	0	1	0	0	2	0.105419	0
33	8	0	0	0	0	2	0.098262	0
34	7	0	0	0	0	2	0.091590	0
35	6	0	0	0	0	2	0.085372	0
36	5	0	0	0	0	2	0.079576	0
37	4	0	0	0	0	2	0.074173	0
38	2	0	0	0	0	1	0.069138	0
39	1	0	0	0	0	1	0.064444	0
40	(0)	(0)	(0)	(0)	(0)	1	0.060069	0
Net Present Value Revenue Requirement								$ 57

Louisville Gas & Electric
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$ 47
Book Life	40
Tax Life	20
Composite Tax Rate	37.0575%
Property Tax Rate	0.54%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 57
Levelized Revenue Requirement	$ 4
Levelized Carrying Charge Rate	9.32%

Year	**Cumulative Present Value Revenue Requirement**	**Annual Carrying Charge Rate**
0	$ -	
1	6	13.28%
2	11	12.82%
3	16	12.38%
4	20	11.96%
5	24	11.55%
6	27	11.16%
7	30	10.79%
8	33	10.44%
9	36	10.08%
10	38	9.73%
11	40	9.37%
12	42	9.02%
13	43	8.66%
14	45	8.31%
15	46	7.96%
16	47	7.60%
17	48	7.25%
18	49	6.89%
19	50	6.54%
20	51	6.18%
21	51	5.92%
22	52	5.74%
23	53	5.56%
24	53	5.38%
25	53	5.20%
26	54	5.02%
27	54	4.84%
28	54	4.66%
29	55	4.48%
30	55	4.30%
31	55	5.00%
32	56	4.72%
33	56	4.44%
34	56	4.17%
35	56	3.89%
36	56	3.61%
37	56	3.33%
38	56	3.06%
39	56	2.78%
40	57	2.50%

Louisville Gas and Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	45.53%	3.74%	1.70%	37.06%	1.07%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	54.47%	10.25%	5.58%		5.58%
			7.28%		6.65%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 18

Responding Witness: Robert M. Conroy

Q-18. Reference Robert Conroy, p. 19, ll. 19-20 through p. 20, ll. 1-2.

a) Was the average monthly consumption of 1,200 kWh for residential customers derived using historical data or forecasted data for the future test year? If the former, please describe the time period for the historical data.

b) Over the same time period as that used to derive the average monthly consumption for all residential customers (1,200 kWh), please calculate and provide the average monthly consumption for residential low-income customers (defined, for example, as those customers eligible to participate in the WeCare energy efficiency, FLEX payment, or WinterCare programs).

c) Over the same time period as that used to derive the average monthly consumption for all residential customers (1,200 kWh), please provide the number of residential customers whose average monthly consumption falls between:

i) 0 kWh and 500 kWh;
ii) 501 kWh and 750 kWh;
iii) 751 kWh and 1,000 kWh;
iv) 1,001 kWh and 1,200 kWh;
v) 1,201 kWh and 1,500 kWh;
vi) 1,501 kWh and 2,000 kWh;
vii) 2,001 kWh and 2,500 kWh;
viii) 2,501 kWh and 3,000 kWh.

d) Over the same time period as that used to derive the average monthly consumption for all residential customers (1,200 kWh), please provide the average monthly consumption over all residential customers whose average monthly consumption falls between:

i) 0 kWh and 500 kWh;
ii) 501 kWh and 750 kWh;
iii) 751 kWh and 1,000 kWh;

iv) 1,001 kWh and 1,200 kWh;
v) 1,201 kWh and 1,500 kWh;
vi) 1,501 kWh and 2,000 kWh;
vii) 2,001 kWh and 2,500 kWh;
viii) 2,501 kWh and 3,000 kWh.

e) Over the same time period as that used to derive the average monthly consumption for all residential customers (1,200 kWh), please provide the number of low-income residential customers whose average monthly consumption falls between:

i) 0 kWh and 500 kWh;
ii) 501 kWh and 750 kWh;
iii) 751 kWh and 1,000 kWh;
iv) 1,001 kWh and 1,200 kWh;
v) 1,201 kWh and 1,500 kWh;
vi) 1,501 kWh and 2,000 kWh;
vii) 2,001 kWh and 2,500 kWh;
viii) 2,501 kWh and 3,000 kWh.

f) Over the same time period as that used to derive the average monthly consumption for all residential customers (1,200 kWh), please provide the average monthly consumption over all low-income residential customers whose average monthly consumption falls between:

i) 0 kWh and 500 kWh;
ii) 501 kWh and 750 kWh;
iii) 751 kWh and 1,000 kWh;
iv) 1,001 kWh and 1,200 kWh;
v) 1,201 kWh and 1,500 kWh;
vi) 1,501 kWh and 2,000 kWh;
vii) 2,001 kWh and 2,500 kWh;
viii) 2,501 kWh and 3,000 kWh.

A-18. a. The average monthly consumption of 1,200 kWh was derived using forecasted data for the future test year. It is derived from the total annual forecasted energy consumption for the residential class divided by the forecasted number of residential customers.

b. The Company's forecast is for the residential class as a whole and does not distinguish customers who may or may not be eligible for low-income assistance. Therefore, the information is not available.

c. The Company forecasts the residential class as a whole and does not have specific consumption levels for individual customers. Therefore, the information does not exist to perform the requested calculation.

d. See the response to part c.

e. See the response to part b.

f. See the response to part b.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 19

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

Q-19. Reference Robert Conroy, p. 20, ll. 5-7.

a) Please provide copies of all e-mails, memoranda, or other correspondence between the Company and Dr. Blake regarding the development and design of the two proposed optional rate schedules for residential customers.

b) Please provide copies of all e-mails, memoranda, or other documentation provided to the Company by Dr. Blake of his proposed rate designs for the two optional rate schedules.

c) Please provide copies of all memoranda, reports, or other documentation of the Company's evaluation of the rate designs proposed by Dr. Blake for the two optional rate schedules.

A-19. a) The Company did not consult with Dr. Blake concerning the development or design of the proposed optional rate schedules for residential customers; rather, Dr. Blake provided only the rate designs for the schedules. Therefore, no responsive documents exist.

b) See attached.

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. There are no non-privileged documents responsive to this request.

From: Marty Blake(marty.blake.prime@gmail.com)
To: Conroy, Robert
CC:
BCC:
Subject: Re: Residential TOD
Sent: 10/17/2014 12:41:04 PM -0400 (EDT)
Attachments:

For the demand TOU option you need to describe how the monthly billing demand is measured. In my testimony, I said that it was maximum integrated hurly demand during the on-peak period. Tif this is not correct, please tell me how demand is measured. The appropriate language needs to be added to the tariff.

Marty Blake
The Prime Group LLC
502-425-7882

------ Original Message ------
From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
To: "Marty Blake - Prime Group" <marty.blake.prime@gmail.com>
Sent: 10/17/2014 10:42:15 AM
Subject: Residential TOD

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

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From: Marty Blake(marty.blake.prime@gmail.com)
To: Conroy, Robert
CC:
BCC:
Subject: Re[2]: Residential TOD
Sent: 10/17/2014 12:48:30 PM -0400 (EDT)
Attachments:

In writing testimony, another issue with regard to TOU rates occurred to me. Why is it appropriate to have a short on-peak period that does not include an intermediate peak for demand rates yet the energy rate includes a rather lenghty intermediate peak period. Since you are talking about the underlying costs for the same residential class, this difference is hard to explain. I am drawing a blank on justifying this difference. Can you provide an argument for this difference? I am pretty sure that this question will get asked and we need a good response.

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> Subject: Residential TOD
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Subject: Re: Residential TOD

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> The Prime Group LLC
> 502-425-7882
> ------ Original Message ------
> From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
> To: "Marty Blake - Prime Group" <marty.blake.prime@gmail.com>
> Sent: 10/17/2014 10:42:15 AM
> Subject: Residential TOD
>
> > **Robert M. Conroy**
> > *Director, Rates*
> > *LG&E and KU Services Company*
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CC:
BCC:
Subject: Re: Residential TOD
Sent: 10/17/2014 12:41:04 PM -0400 (EDT)
Attachments:

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Marty Blake
The Prime Group LLC
502-425-7882

------ Original Message ------
From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
To: "Marty Blake - Prime Group" <marty.blake.prime@gmail.com>
Sent: 10/17/2014 10:42:15 AM
Subject: Residential TOD

Robert M. Conroy
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From: Marty Blake(marty.blake.prime@gmail.com)
To: Conroy, Robert
CC:
BCC:
Subject: Re[4]: Residential TOD
Sent: 10/17/2014 03:09:07 PM -0400 (EDT)
Attachments:

That will be a rate that provides much more incentive for customers to shift loads to off-peak periods. It will also avoid the question regarding why there is a difference between the TOU energy and TOU demand with regard to time periods, which is a question I couldn't provide a good response for.

------ Original Message ------
From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
To: "Marty Blake" <marty.blake.prime@gmail.com>
Sent: 10/17/2014 3:05:49 PM
Subject: RE: Re[2]: Residential TOD

> After talking through the issue with others, I am leaning towards changing the TOD Energy to the same two time periods as the TOD Demand.
>
> **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:** Marty Blake [mailto:marty.blake.prime@gmail.com]
> **Sent:** Friday, October 17, 2014 12:49 PM
> **To:** Conroy, Robert
> **Subject:** Re[2]: Residential TOD
>
> In writing testimony, another issue with regard to TOU rates occurred to me. Why is it appropriate to have a short on-peak period that does not include an intermediate peak for demand rates yet the energy rate includes a rather lenghty intermediate peak period. Since you are talking about the underlying costs for the same residential class, this difference is hard to explain. I am drawing a blank on justifying this difference. Can you provide an argument for this difference? I am pretty sure that this question will get asked and we need a good response.
>
> ------ Original Message ------
> From: "Marty Blake" <marty.blake.prime@gmail.com>
> To: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
> Sent: 10/17/2014 12:41:04 PM
> Subject: Re: Residential TOD
>
>> For the demand TOU option you need to describe how the monthly billing demand is measured. In my testimony, I said that it was maximum integrated hurly demand during the on-peak period. Tif this is not correct, please tell me how demand is measured. The appropriate language needs to be added to the tariff.
>>
>> Marty Blake
>> The Prime Group LLC
>> 502-425-7882
>>
>> ------ Original Message ------
>> From: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
>> To: "Marty Blake - Prime Group" <marty.blake.prime@gmail.com>
>> Sent: 10/17/2014 10:42:15 AM
>> Subject: Residential TOD
>>
>>> **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

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KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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. 20-23.

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.

b) Did the Company compare the usage characteristics of Rate LEV customers to that of the residential class more generally? Please explain.

c) Please describe the Company's analysis in determining what changes were needed in the opt-in time-of-day rates when removing the low-emission vehicle eligibility requirement from its opt-in residential time-of-day rate.

A-20. 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.

b) No. The usage characteristics of the Rate LEV customers were compared to their usage characteristics before they changed to the Rate LEV. See the LEV report provided in part a.

c) No analysis was necessary. The Company proposed the time-of-day rates for the reasons discussed in Mr. Conroy's testimony. The Rate LEV is being terminated and those customers have the ability to utilize either proposed time-of-day rate options.

From: Lovekamp, Rick(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=ADMINISTRATIVE/CN=LOVEKAMPR)
To: AaronD.Greenwell@ky.gov
CC:
BCC:
Subject: Case No. 2012-00428 - Joint Parties Report Development (Dynamic Pricing)
Sent: 02/05/2014 11:04:24 AM -0500 (EST)
Attachments: LOUISVILLE-#1051928-v5-Dynamic_Pricing_Section_of_the_Joint_Parties__Report_....DOCX;

Aaron,

In accordance with the Joint Parties plan to address the topics set forth in the Joint Comments filed May 20, 2013, as amended by the findings in the July 17, 2013 Order, the Joint Parties have held meetings and conference calls per the schedule provided at the August 23, 2013 informal conference.

Recently the Joint Parties developed the section on Dynamic Pricing (see attachment).

<<LOUISVILLE-#1051928-v5-Dynamic_Pricing_Section_of_the_Joint_Parties__Report_(2012-00428).DOCX>>

This draft is still preliminary. The content of this section will be reviewed for consistency as the Joint Parties continue to discuss the remaining topics. In addition, the conclusions or recommendations at this point may not be reflective of the entire Joint Parties, while the final report will likely include recommendations from specific Joint Parties along with a collective recommendation for each section.

The Joint Parties would be willing to discuss this section or other sections with the Commission Staff.

The next meeting will be on February 11, 2014 to discuss Cyber Security.

Please contact me with any questions.

Regards,

Rick E. Lovekamp

LG&E and KU Services Company

Manager Regulatory Affairs

Office: 502-627-3780

Cell: 502-403-8840

I. Executive Summary

Several of the utility members of the Joint Parties have provided voluntary dynamic-pricing options to residential customers, both on trial and permanent bases, here in the Commonwealth and in other jurisdictions. The utilities' collective experience is that dynamic pricing for residential customers tends to have low participation and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those utilities' experiences, all of the Joint Parties agree that a utility should consider some or all of the issues discussed in this section before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Parties further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

CAC's position is that low-income advocates are especially concerned about the potential impact on those customers who do not fully understand the complexities of dynamic pricing or lack the technology to fully utilize such rates and inadvertently increase their bills. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

II. Scope of the Dynamic-Pricing Section

This section addresses dynamic pricing for residential customers. It defines dynamic pricing and provides summaries of the Joint-Parties utilities' experiences with dynamic-pricing offerings for residential customers. This section further provides items to consider concerning dynamic pricing, including rate structures, costs and benefits to customers and utilities, possible eligibility criteria for participating in dynamic pricing, educational needs of residential customers who participate in dynamic pricing, and a number of other relevant considerations.

III. Definition of Dynamic Pricing

Dynamic pricing refers to pricing that varies according to the time at which the energy is used. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to the customer via time-based rates or tariffs. There are several different kinds of dynamic pricing:

A. Time of Use ("TOU") or Time of Day ("TOD")

TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

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TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

B. Critical-Peak Pricing ("CPP")

There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally dynamic as TOU rates.

Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR")

PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than that amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

D. Real-Time Pricing ("RTP")

RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

IV. Utilities' Experience with Dynamic Pricing

Several of the utility members of the Joint Parties have experience with dynamic pricing, as described below. The Joint Parties have also assembled a collection of the dynamic-pricing rates currently available to residential customers in Kentucky (see Appendix A), as well as a collection of dynamic-pricing rates the Joint Parties' utility members offer to residential customers in other jurisdictions (see Appendix B).

A. Duke Energy

Generally, Duke Energy offers residential TOU or TOD pricing in which electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices, manage their energy costs by shifting usage to a lower cost period, or reduce their consumption overall.

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Duke Energy's Carolina utilities have offered voluntary residential TOU pricing rates in NC and SC for a number of years. To date, the TOU programs have generated little interest from residential customers. Duke Energy's Florida utility used to have residential TOU rates, but closed them in 2010 due to a lack of customer interest.

Duke Energy's Ohio electric distribution utility (Duke Energy Ohio) has conducted several pilot residential TOU programs since 2010. Duke Energy Ohio currently offers only one residential pilot program, with some relative success. Duke Energy Ohio has tried a number of pilots over the past few years to better understand what residential customers desire in TOU rate offerings. Generally, Duke learned that customers desire three things: Customers wanted the opportunity to achieve meaningful savings, which appears to translate into the ability to save approximately $5 to $20 dollars per month; customers wanted rate structures that had short peak periods during which they would need to curtail their usage; and customers did not like rates that added a lot of complexity and different pricing periods and seasons, as features such as "shoulder" periods make it more difficult to determine appropriate behaviors.

Through these pilot programs, Duke Energy Ohio learned that any successful TOU rates need to be cost-justified to potentially benefit the customer and the utility. A risk with TOU rates is the concept of "natural winners," those customers whose usage historically does not occur during peak periods, resulting in little to no shift in usage. Obviously, a customer who would not have to make any behavioral or usage changes for a TOU offering to lower his or her bill would find the offering more attractive than a customer who would have to shift usage and change behavior. Unfortunately, if no shifting of usage occurs, there will be no system savings, and essentially the utility will simply collect less revenue while incurring the same level of cost. Finally, based on Duke's experiences, residential TOU rates require a higher level of customer sophistication. Customers have become accustomed to paying average rates and have little understanding that the cost of using energy truly varies based upon when you consume it. Therefore, Duke does not believe the Commission should make residential TOU rates mandatory at this time.

B. American Electric Power

Kentucky Power has offered a number of traditional time-of-day/time-of-use rates on a voluntary basis for residential, commercial and industrial customers since the 1980s with relatively low levels of participation. These service offerings generally included relatively lengthy on-peak periods with off-peak periods generally at night and on weekends. In 2010, Kentucky Power expanded the availability of its traditional time-of-use rates to larger customers up to 1,000 kW. Also in 2010, Kentucky Power introduced new time-of-day options for residential and small commercial and industrial customers which included shorter, seasonal on-peak periods as follows:

Winter: Weekdays 7 A.M. to 11 A.M. and 6 P.M to 10 P.M., Nov through Mar
Summer: Weekdays Noon to 6 P.M., May 15 through September 15

As of November 2013, no residential, 78 small commercial and industrial and no large commercial and industrial customers are participating in these new offerings.

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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.

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.

D. Owen Electric Cooperative

Owen offers a variety of voluntary TOU rates for residential, small commercial, and large commercial members. Although Owen has made concerted efforts to promote its TOU rate offerings, participation is relatively low, with 11 residential, 26 small commercial, and 12 large commercial TOU accounts presently in place. Additionally, 187 of Owen Electric's members are currently participating in a voluntary smart home pilot that has a TOU component as part of the program. This two-year pilot, scheduled to end in late 2014, is presently in the measurement and verification analysis phase.

E. Jackson Energy Cooperative

Jackson Energy has a residential Electric Thermal Storage (ETS) TOU rate.[1] Jackson Energy has offered this rate since approximately 1984 and currently has 970 consumers on it.

V. Dynamic-Pricing Considerations

Based on the experiences of the utilities described above, the Joint Parties present below a non-exhaustive list of items a utility may want to consider when formulating dynamic-pricing offerings:

A. Rate and tariff considerations

1. **Opt-in versus opt-out.** The utilities among the Joint Parties have demonstrated that only a small percentage of residential customers will opt into dynamic pricing rates. Therefore, if a utility's goal is to have relatively high participation in an opt-in dynamic-pricing offering, it may consider offering incentives to participate; however, the cost of incentives must be weighed against the potential benefits.

   CAC's position is that there is no reason, at this time, to ever require that customers participate in dynamic pricing for any reason.

2. **Rate structure.** The rates a utility will choose for any dynamic-pricing structure will differ depending on the goal of the dynamic-pricing program. For example, a utility seeking to create behavioral change, such as significant load-shifting, may want to create greater differences between the various dynamic rates than if the utility's goal is to send purely cost-based pricing signals. Also, a utility may want to introduce a demand component in a dynamic-pricing structure for residential customers to provide customers an incentive to decrease demand during peak periods rather than increasing customers' energy rates beyond the underlying energy cost of production.

3. **Minimum contract terms.** A utility may consider using a minimum contract term, such as a one-year minimum commitment, to guard against possible gaming by customers who choose to participate in dynamic pricing during months of the year when such rates will reduce their bills and then move back to standard rates during months when they will not be able to save. Minimum contract terms may also be desirable in a pilot program where a utility seeks to have longitudinal data from a stable set of customers.

4. **Waiting periods between rate-switching.** Another option to deter gaming is to bar a customer who stays on a dynamic pricing rate for less than a year from participating in dynamic pricing again for a set period of time (or perhaps permanently).

[1] Information about Electric Thermal Storage is available at: http://www.steffes.com/off-peak-heating/ets.html.

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5. **Complexity and dynamism.** More complex or dynamic rates create a greater risk of confusing customers and customer-service representatives. Also, dynamic-pricing rates that require customer notice, e.g., variable-CPP or RTP rates, require reliable means of communicating with customers. Providing the necessary communication channels could add cost to a dynamic-pricing program. In addition, more complex or dynamic rates could add cost to a utility's customer-information and billing systems.

6. **Criteria for customers to participate in dynamic pricing.** Dynamic rates may offer customers a chance to decrease their bills, but customers who do not or cannot follow the incentives may increase their bills, perhaps significantly. Therefore, a utility may want to limit eligibility for dynamic rates to customers who have a satisfactory payment history.

7. **Hold-harmless trial period.** A utility may want to consider offering customers a chance to test-drive a dynamic-pricing rate by holding the customer harmless relative to the standard residential rate for a limited trial period. This could allow customers to determine if they can respond to the dynamic rate's incentives without risk of financial harm, and may increase participation in dynamic pricing by removing a barrier to entry.

B. <u>Technological considerations</u>

1. **Customer-facing technology.** A utility should consider the technology a customer will need to have to participate in a dynamic-pricing rate. The amount of technology will vary depending on the rate, e.g., a TOU rate will require relatively less technology than will an RTP rate to allow a customer to respond to the rate's incentives. A utility may want to consider technology some customers already possess, e.g., smart phones, to help meet customer-facing technology needs more economically.

2. **Utility technology.** As noted in the previous section, more complex or dynamic rates will require relatively greater investments in utility systems to support the rates. Necessary technology upgrades could include, but not be limited to, billing-system upgrades, website upgrades, and other infrastructure improvements.

C. <u>Customer education and marketing considerations</u>

Most residential customers are accustomed to a single, flat, year-round energy rate. For any number of those customers to move successfully to any variety of dynamic pricing will likely require a thorough customer-education effort to maximize good outcomes and ensure a positive customer experience. The means of carrying out such an effort are addressed in the Customer Education section of this report. The content of the effort will vary depending on the dynamic rate a utility chooses to deploy, but at a minimum such an effort should include information on the rate itself, opt-in or opt-out, minimum contract terms (if any), waiting periods

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between rate-switching (if any), criteria for participation, and the hold-harmless trial period (if any).

Customer-service representatives will also need training to ensure they can competently handle questions that dynamic-pricing may create.

D. Other considerations

1. **Customer costs.** In deciding what kind of dynamic pricing, if any, to pursue, a utility should consider the investments customers might have to make to participate, e.g., costs customers would have to incur to respond to pricing signals, both to receive notice of the pricing change and to adjust usage to respond to the signals. A utility should also inform customers up front about the minimum technology requirements for participating in a dynamic rate. For example, a customer might need to purchase a particular kind of thermostat or have a computer or smartphone with certain software to be able to participate in certain kinds of dynamic rates; a utility should communicate such requirements to customers up front. Also, a utility should provide customers a non-exhaustive list of possible ways to reduce their bills under any offered dynamic rate.

2. **Equity considerations.** Some dynamic-pricing rates may create natural winners and losers. For example, customers who are not home during normal working hours may naturally benefit from TOU rates where peak periods occur during those hours, whereas other customers who are necessarily at home during those hours and incapable of reducing usage may effectively pay a penalty for being unable to change their usage. A utility may want to take into account these equitable considerations when crafting dynamic-pricing rates.

   CAC's position is that dynamic rates could especially impact senior citizens and customers with low-incomes who work non-traditional shifts. A utility must take into account these equitable considerations when crafting dynamic-pricing rates.

3. **Economic justification.** Particularly for opt-in rates, a utility may consider running a cost-benefit analysis to determine if a particular dynamic-pricing structure is likely to produce benefits to participating and non-participating customers.

   CAC's position is that a utility should be able to identify that non-participating customers will not be harmed or bear any costs associated with their decision not to participate.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Dynamic Pricing

Dynamic pricing is consistent with the Smart-Grid Investment Standard in that all dynamic pricing requires metering more sophisticated than traditional electromechanical meters,

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and dynamic-pricing with a variable component, such as variable-CPP or real-time pricing, requires smart meters.

Dynamic pricing is also consistent with the Smart-Grid Information Standard, which requires utilities to provide time-based-pricing information to customers to the extent it is available.

VII. Conclusion

Dynamic-pricing rates can add complexity and create possible confusion for residential customers, who are largely accustomed to simple, straightforward, stable rates. But such rates can also offer customers the opportunity to reduce their bills by responding to incentives that may help utilities reduce overall costs, though some customers likely will not be able to avail themselves of the opportunity. Dynamic pricing is, therefore, not a clear-cut benefit or burden, and the Joint Parties recommend that each utility evaluating the implementation of such rates carefully consider some or all of the issues discussed in this section.

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From: Lovekamp, Rick(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=ADMINISTRATIVE/CN=LOVEKAMPR)
To: Needham, Meredith
CC:
BCC:
Subject: March 11, 2014 Joint Parties Meeting
Sent: 03/11/2014 08:26:57 AM -0400 (EDT)
Attachments: 03-11-14_Meeting Agenda.pdf; LOUISVILLE-#1069645-v6-Cybersecurity_Section_of_the_Joint_Parties__Report_(2....DOCX; Dynamic_Pricing_Section_of_the_Joint_Parties__Report_Staff edits.docx; Natural Gas 8-22-2013 Draft.pdf;

Meredith,

Attached are the documents for today's meeting.

Agenda

<<03-11-14_Meeting Agenda.pdf>>

Cyber Security Section Draft

<<LOUISVILLE-#1069645-v6-Cybersecurity_Section_of_the_Joint_Parties__Report_(2012-00428).DOCX>>

Dynamic Pricing Section – KPSC Comments

<<Dynamic_Pricing_Section_of_the_Joint_Parties__Report_Staff edits.docx>>

Natural Gas Framework

<<Natural Gas 8-22-2013 Draft.pdf>>

Regards,

Rick

I. Executive Summary

Several of the utility members of the Joint Parties have provided voluntary dynamic-pricing options to residential customers, both on trial and permanent bases, here in the Commonwealth and in other jurisdictions where some of the utilities' affiliates operate. The utilities' collective experience is that dynamic pricing for residential customers tends to have low participation and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those utilities' experiences, all of the Joint Parties agree that a utility should consider some or all of the issues discussed in this section before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Parties further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

CAC's position is that low-income advocates are especially concerned about the potential impact on low-income customers who typically do not fully understand the complexities of dynamic pricing or lack the technology to fully take advantage of such rates, which could inadvertently result in higher bills for those customers. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

II. Scope of the Dynamic-Pricing Section

This section addresses dynamic pricing for residential customers. It defines dynamic pricing and provides summaries of the Joint-Parties utilities' experiences with dynamic-pricing offerings for residential customers. This section further provides items to consider concerning dynamic pricing, including rate structures, costs and benefits to customers and utilities, possible eligibility criteria for participating in dynamic pricing, educational needs of residential customers who participate in dynamic pricing, and a number of other relevant considerations.

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Dynamic pricing refers to pricing that varies according to the time at which the energy is consumed. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to the customer via time-based rates or tariffs. Dynamic pricing offers customers the opportunity to reduce their bills by responding to incentives to shift load from peak periods, and may help utilities reduce overall costs. There are several different kinds of dynamic pricing:

A. Time of Use ("TOU") or Time of Day ("TOD")

TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing

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TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

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There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally lacking in dynamism as TOU rates.

Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR")

PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than the baseline amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

D. Real-Time Pricing ("RTP")

RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

IV. Utilities' Experience with Dynamic Pricing

Several of the utility members of the Joint Parties have experience with dynamic pricing, as described below. The Joint Parties have also assembled a collection of the dynamic-pricing rates currently available to residential customers in Kentucky (see Appendix A), as well as a collection of dynamic-pricing rates the Joint Parties' utility members' affiliates offer to residential customers in other jurisdictions (see Appendix B).

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established and known to consumers in advance, allowing them to vary their usage in response to such prices, manage their energy costs by shifting usage to a lower cost period, or reduce their consumption overall.

Duke Energy's Carolina utilities have offered voluntary residential TOU pricing rates in NC and SC for a number of years. To date, the TOU programs have generated little interest from residential customers. Duke Energy's Florida utility used to have residential TOU rates, but closed them in 2010 due to a lack of customer interest.

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Winter:	Weekdays 7 A.M. to 11 A.M. and 6 P.M to 10 P.M., Nov through Mar
Summer:	Weekdays Noon to 6 P.M., May 15 through September 15

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As of November 2013, no residential, 78 small commercial and industrial and no large commercial and industrial customers are participating in these new offerings.

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.

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.

D. Owen Electric Cooperative

Owen offers a variety of voluntary TOU rates for residential, small commercial, and large commercial members. Although Owen has made concerted efforts to promote its TOU rate offerings, participation is relatively low, with 11 residential, 26 small commercial, and 12 large commercial TOU accounts presently in place. Additionally, 187 of Owen Electric's members are currently participating in a voluntary smart home pilot that has a TOU component as part of the program. This two-year pilot, scheduled to end in late 2014, is presently in the measurement and verification analysis phase.

E. Jackson Energy Cooperative

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Jackson Energy has a residential Electric Thermal Storage (ETS) TOU rate.[1] Jackson Energy has offered this rate since approximately 1984 and currently has 970 consumers on it.

V. Dynamic-Pricing Considerations

Based on the experiences of the utilities described above, the Joint Parties present below a non-exhaustive list of items a utility may want to consider when formulating dynamic-pricing offerings:

A. <u>Rate and tariff considerations</u>

1. **Opt-in versus opt-out.** The utilities among the Joint Parties have demonstrated that only a small percentage of residential customers will opt into dynamic pricing rates. Therefore, if a utility's goal is to have relatively high participation in an opt-in dynamic-pricing offering, it may consider offering incentives to participate; however, the cost of incentives must be weighed against the potential benefits.

   CAC's position is that there is no reason, at this time, to ever require that customers participate in dynamic pricing for any reason.

2. **Rate structure.** The rates a utility will choose for any dynamic-pricing structure will differ depending on the goal of the dynamic-pricing program. For example, a utility seeking to create behavioral change, such as significant load-shifting, may want to create greater differences between the various dynamic rates than if the utility's goal is to send purely cost-based pricing signals. Also, a utility may want to introduce a demand component in a dynamic-pricing structure for residential customers to provide customers an incentive to decrease demand during peak periods rather than increasing customers' energy rates beyond the underlying energy cost of production.

3. **Minimum contract terms.** A utility may consider using a minimum contract term, such as a one-year minimum commitment, to guard against possible gaming by customers who choose to participate in dynamic pricing during months of the year when such rates will reduce their bills and then move back to standard rates during months when they will not be able to save. Minimum contract terms may also be desirable in a pilot program where a utility seeks to have longitudinal data from a stable set of customers.

4. **Waiting periods between rate-switching.** Another option to deter gaming is to bar a customer who stays on a dynamic pricing rate for less than a year from participating in dynamic pricing again for a set period of time (or perhaps permanently).

[1] Information about Electric Thermal Storage is available at: http://www.steffes.com/off-peak-heating/ets.html.

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5. **Complexity and dynamism.** More complex or dynamic rates create a greater risk of confusing customers and customer-service representatives. Also, dynamic-pricing rates that require customer notice, e.g., variable-CPP or RTP rates, require reliable means of communicating with customers. Providing the necessary communication channels could add cost to a dynamic-pricing program. In addition, more complex or dynamic rates could add cost to a utility's customer-information and billing systems.

6. **Criteria for customers to participate in dynamic pricing.** Dynamic rates may offer customers a chance to decrease their bills, but customers who do not or cannot follow the incentives may increase their bills, perhaps significantly. Therefore, a utility may want to limit eligibility for dynamic rates to customers who have a satisfactory payment history.

7. **Hold-harmless trial period.** A utility may want to consider offering customers a chance to test-drive a dynamic-pricing rate by holding the customer harmless relative to the standard residential rate for a limited trial period. This could allow customers to determine if they can respond to the dynamic rate's incentives without risk of financial harm, and may increase participation in dynamic pricing by removing a barrier to entry.

B. <u>Technological considerations</u>

1. **Customer-facing technology.** A utility should consider the technology a customer will need to have to participate in a dynamic-pricing rate. The amount of technology will vary depending on the rate, e.g., a TOU rate will require relatively less technology than will an RTP rate to allow a customer to respond to the rate's incentives. A utility may want to consider technology some customers already possess, e.g., smart phones, to help meet customer-facing technology needs more economically.

2. **Utility technology.** As noted in the previous section, more complex or dynamic rates will require relatively greater investments in utility systems to support the rates. Necessary technology upgrades could include, but not be limited to, billing-system upgrades, website upgrades, and other infrastructure improvements.

C. <u>Customer education and marketing considerations</u>

Most residential customers are accustomed to a single, flat, year-round energy rate. For any number of those customers to move successfully to any variety of dynamic pricing will likely require a thorough customer-education effort to maximize good outcomes and ensure a positive customer experience. The means of carrying out such an effort are addressed in the Customer Education section of this report. The content of the effort will vary depending on the dynamic rate a utility chooses to deploy, but at a minimum such an effort should include information on the rate itself, opt-in or opt-out, minimum contract terms (if any), waiting periods

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between rate-switching (if any), criteria for participation, and the hold-harmless trial period (if any).

Customer-service representatives will also need training to ensure they can competently handle questions that dynamic-pricing may create.

D. Other considerations

1. **Customer costs.** In deciding what kind of dynamic pricing, if any, to pursue, a utility should consider the investments customers might have to make to participate, e.g., costs customers would have to incur to respond to pricing signals, both to receive notice of the pricing change and to adjust usage to respond to the signals. A utility should also inform customers up front about the minimum technology requirements for participating in a dynamic rate. For example, a customer might need to purchase a particular kind of thermostat or have a computer or smartphone with certain software to be able to participate in certain kinds of dynamic rates; a utility should communicate such requirements to customers up front. Also, a utility should provide customers a non-exhaustive list of possible ways to reduce their bills under any offered dynamic rate.

2. **Equity considerations.** Some dynamic-pricing rates may create natural winners and losers. For example, customers who are not home during normal working hours may naturally benefit from TOU rates where peak periods occur during those hours, whereas other customers who are necessarily at home during those hours and incapable of reducing usage may effectively pay a penalty for being unable to change their usage. A utility may want to take into account these equity considerations when crafting dynamic-pricing rates.

   CAC's position is that dynamic rates could especially impact senior citizens and customers with low-incomes who work non-traditional shifts. A utility must take into account these equity considerations when crafting dynamic-pricing rates.

3. **Economic justification.** Particularly for opt-in rates, a utility may consider running a cost-benefit analysis to determine if a particular dynamic-pricing structure is likely to produce benefits to participating and non-participating customers.

   CAC's position is that a utility should be able to identify that non-participating customers will not be harmed or bear any costs associated with their decision not to participate.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Dynamic Pricing

Dynamic pricing is consistent with the Smart-Grid Investment Standard in that all dynamic pricing requires metering more sophisticated than traditional electromechanical meters,

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and dynamic-pricing with a variable component, such as variable-CPP or real-time pricing, requires smart meters.

Dynamic pricing is also consistent with the Smart-Grid Information Standard, which requires utilities to provide time-based-pricing information to customers to the extent it is available.

VII. Conclusion

Dynamic-pricing rates can add complexity and create possible confusion for residential customers, who are largely accustomed to simple, straightforward, stable rates. But such rates can also offer customers the opportunity to reduce their bills by responding to incentives that may help utilities reduce overall costs, though some customers likely will not be able to avail themselves of the opportunity. Dynamic pricing is, therefore, not a clear-cut benefit or burden, and the Joint Parties recommend that each utility evaluating the implementation of such rates carefully consider some or all of the issues discussed in this section.

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From: Lovekamp, Rick(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=ADMINISTRATIVE/CN=LOVEKAMPR)
To: 'AaronD.Greenwell@ky.gov'
CC:
BCC:
Subject: Case No. 2012-00428 - Joint Parties Report - Final Draft
Sent: 06/13/2014 02:30:38 PM -0400 (EDT)
Attachments: LOUISVILLE-#1100810-v8-Joint_Parties_Report_(Adm_Case_#2012-00428).DOCX; Appendix D - AGA Natural Gas In A Smart Energy Future.pdf;

Aaron,

In accordance with the Joint Parties plan to address the topics set forth in the Joint Comments filed May 20, 2013, as amended by the findings in the July 17, 2013 Order, the Joint Parties have held meetings and conference calls per the schedule provided at the August 23, 2013 informal conference.

Recently the Joint Parties have developed a final draft of the report (see attached). This version does not reflect any comments from the AG's office. We are hopefully the final report filed with the KPSC on June 30 will incorporate comments of the AG.

<<LOUISVILLE-#1100810-v8-Joint_Parties_Report_(Adm_Case_#2012-00428).DOCX>> <<Appendix D - AGA Natural Gas In A Smart Energy Future.pdf>>

Please contact me with any question

Regards,

Rick E. Lovekamp

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

CONSIDERATION OF THE	)	
IMPLEMENTATION OF SMART GRID AND	)	**CASE NO. 2012-00428**
SMART METER TECHNOLOGIES	)	

REPORT OF THE JOINT UTILITIES:
ATMOS ENERGY CORPORATION, BIG RIVERS ELECTRIC CORPORATION, BIG SANDY RURAL ELECTRIC COOPERATIVE CORPORATION, BLUE GRASS ENERGY COOPERATIVE CORPORATION, CLARK ENERGY COOPERATIVE, INC., COLUMBIA GAS OF KENTUCKY, INC., CUMBERLAND VALLEY ELECTRIC, DELTA NATURAL GAS COMPANY, INC., DUKE ENERGY KENTUCKY, INC., EAST KENTUCKY POWER COOPERATIVE, INC., FARMERS RURAL ELECTRIC COOPERATIVE CORPORATION, FLEMING-MASON ENERGY COOPERATIVE, GRAYSON RURAL ELECTRIC COOPERATIVE CORPORATION, INTER-COUNTY ENERGY COOPERATIVE CORPORATION, JACKSON ENERGY COOPERATIVE CORPORATION, JACKSON PURCHASE ENERGY CORPORATION, KENERGY CORP., KENTUCKY POWER COMPANY, KENTUCKY UTILITIES COMPANY, LICKING VALLEY RURAL ELECTRIC COOPERATIVE CORPORATION, LOUISVILLE GAS AND ELECTRIC COMPANY, MEADE COUNTY RURAL ELECTRIC COOPERATIVE CORPORATION, NOLIN RURAL ELECTRIC COOPERATIVE CORPORATION, OWEN ELECTRIC COOPERATIVE, INC., SALT RIVER ELECTRIC COOPERATIVE CORPORATION, SHELBY ENERGY COOPERATIVE, INC., SOUTH KENTUCKY RURAL ELECTRIC COOPERATIVE CORPORATION, AND TAYLOR COUNTY RURAL ELECTRIC COOPERATIVE CORPORATION

WITH COMMENTS BY:
THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY BY AND THROUGH HIS OFFICE OF RATE INTERVENTION
AND
THE COMMUNITY ACTION COUNCIL FOR LEXINGTON-FAYETTE, BOURBON, HARRISON AND NICHOLAS COUNTIES, INC.

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Filed: June 30, 2014

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Executive Summary

On July 17, 2013, the Kentucky Public Service Commission ("Commission") issued an order directing the Joint Utilities,[1] the Attorney General of the Commonwealth of Kentucky by and through His Office of Rate Intervention ("AG"), and the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC") to examine collaboratively nine topics related to smart technologies and their deployment in Kentucky: customer privacy, opt-out provisions, customer education (including health-related education), dynamic pricing, Automated Meter Reading ("AMR") and Advanced Metering Infrastructure ("AMI") deployment (including prepaid meters and remote disconnections),[2] cyber-security, cost recovery for smart-technology deployments and obsolete equipment, how natural gas companies might participate in the electric smart grid, and whether the Commission should adopt the Smart Grid Investment and Information Standards proposed in the federal Energy Independence and Security Act of 2007 ("EISA 2007").[3] This report is the final product of that collaborative effort, which has spanned nearly a year.

The sections that follow provide detailed discussions of the nine topics the Commission directed the Joint Utilities, AG, and CAC to address, including useful background information and analytical frameworks for considering these issues. As the Joint Utilities, AG, and CAC anticipated before beginning their collaborative effort, they reached different levels of consensus on different topics:[4]

- **Customer Privacy**
  - Joint Utilities: Customer privacy is an important issue independent of smart-technology considerations. But there are already federal and state legal protections in place concerning customer information in utilities' possession, and government and industry groups are working to develop even more robust voluntary standards for utilities to consider. Moreover, Kentucky's utilities have already gone beyond the legal requirements in place today to ensure that only appropriate use is made of customer information. Therefore, Joint Utilities conclude that a new mandatory customer-privacy standard is not necessary at this time, including the customer data provisions of the EISA 2007 Smart-Grid Information Standard. Instead, the Joint Utilities propose a list of terms to define and substantive items for utilities to consider when reviewing customer-privacy policies and practices, which the

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[1] Except as otherwise noted at various points herein, "Joint Utilities" includes all the parties named as Joint Utilities on the cover page of this report and in Appendix A.
[2] The Joint Utilities have renamed this section "Distribution Smart-Grid Components."
[3] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 7-8 (July 17, 2013).
[4] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Joint Comments at 7 (May 20, 2013).

Commission may find useful when addressing smart-grid or other customer-privacy-related utility proposals.

- AG:

- CAC: CAC supports utilities' efforts to maintain customer privacy. Aggregated customer information is often helpful to CAC in its effort to provide assistance to low-income customers in paying their bills and in its mission as an advocate for low-income customers. Information should be readily available to CAC for these purposes and in regulatory proceedings. Utilities benefit from this low-income assistance. The utilities should absorb the costs of providing this information.

- **Opt-Out Provisions**

  - Joint Utilities: Customer concerns over purported health and privacy impacts of smart meters have caused some states to require utilities to offer opt-out provisions from smart-meter deployments. But requiring utilities to offer opt-outs from smart-meter deployments has potentially significant cost and operational impacts for utilities and customers, both those who choose to opt out and those who do not. Determining how to allocate the direct and indirect costs of opt-out provisions among customers who opt out and those who do not is also a challenging issue. Therefore, the Joint Utilities agree the cost impacts and reduced operational capabilities (to both opting-out customers and all other customers) of requiring opt-out arrangements are not generally beneficial on the whole. Moreover, Duke, AEP, and several cooperatives have considerable experience with meter deployments, and have found ways to work directly with customers through customer education (see below) to accomplish overall program goals without opt-out requirements. Instead, a case-by-case approach using some or all of the analytical framework this section presents may be an appropriate approach to evaluate opt-outs.

  - AG:

  - CAC: If a utility does offer opt-out alternatives, customers should not be penalized for choosing to opt-out.

- **Customer Education**

  - Joint Utilities: Customer education is likely to increase the success of any smart-meter deployment. By ensuring customers

EXECUTIVE SUMMARY

understand the benefits and features of the smart technology being deployed, a deploying utility can help minimize customer concerns and objections while increasing the likelihood that projected benefits will be realized as customers engage with the technology and use it to improve their energy consumption. Therefore, the Joint Utilities recommend that each utility deploying smart meters consider using some of the customer-education topics (e.g., privacy issues) and channels (e.g., mass media) addressed in this section.

- AG:

- CAC: Customer education should be mandatory as smart meters are deployed.

- **Dynamic Pricing**

  - Joint Utilities: The Joint Utilities' collective experience is that dynamic pricing for residential customers tends to have low participation, and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those experiences, the Joint Utilities agree that a utility should consider some or all of the issues discussed in this section (e.g., rate structures and contract terms) before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Utilities further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

  - AG:

  - CAC: Low-income advocates are especially concerned about the potential impact on low-income customers who typically do not fully understand the complexities of dynamic pricing or lack the technology to fully take advantage of such rates, which could inadvertently result in higher bills for those customers. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

- **Distribution Smart-Grid Components**

EXECUTIVE SUMMARY

- Joint Utilities: Although distribution smart-grid components can provide benefits to customers and add value to utilities' distribution systems, there are a number of items utilities might consider before investing in such systems, including items related to technological obsolescence, prepaid metering, and remote connection and disconnection of utility service, all of which can impact customers. But adding another layer of regulation, i.e., the EISA 2007 Smart-Grid Investment Standard, to the Commission's already robust oversight authority is not necessary to ensure utilities make only prudent investments; rather, the Commission's existing authority concerning base rates, Certificates of Public Convenience and Necessity and Construction Work Plans (collectively "CPCNs"), and non-base-rate recovery mechanisms is sufficient to protect customers while maintaining regulatory efficiency.

- AG:

- CAC: No comments.

- **Cyber-Security**

  - Joint Utilities: Utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks; on the issue of cyber-security, all stakeholders' interests and incentives are aligned. But existing mandatory and voluntary cyber-security standards, frameworks, and guidelines are sufficient; adding such regulations or rules at the state level may serve to weaken rather than strengthen utilities' ability to thwart cyber-attacks by slowing their ability to adapt to the ever-changing threat. The cyber-security focus should be on a utility's ability to evolve with emerging threats, not on its compliance with cyber-security standards based on legacy threat profiles. A mature, effective cyber-security process is one that is continuously evolving based on emerging threat intelligence and threat vectors or actions. Therefore, additional regulations or requirements at the state level are not necessary or advisable.

  - AG:

  - CAC: Utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks.

- **Cost Recovery**

EXECUTIVE SUMMARY

  - Joint Utilities: Because utilities may and are deploying smart technologies under different circumstances, in different ways, at different paces, and to different extents, there cannot be a one-size-fits-all approach to cost recovery for, or review of, smart-technology deployments. Instead, to encourage the most economically rational yet innovative uses and deployments of smart technologies, the Joint Utilities believe: (1) all forms of cost recovery should be available for utilities to consider and propose to the Commission, including traditional base rates, existing cost-recovery mechanisms (e.g., demand-side management ("DSM") riders), and new riders or surcharge mechanisms; (2) utilities proposing smart-technology deployments that will necessitate retiring existing utility assets with unrecovered book life should take the cost of those retirements into account in their cost-benefit analyses and be able to recover that cost if the deployment is prudent; and (3) additional smart-grid-specific review proceedings or criteria are unnecessary for smart-grid deployments because existing cost-recovery and other review proceedings and mechanisms are sufficient, including CPCN proceedings and various kinds of rate proceedings. The Joint Utilities therefore continue to oppose the imposition of the EISA 2007 Smart-Grid Investment Standard or any derivative thereof.

  - AG:

  - CAC: No comments.

- **How Natural Gas Companies Might Participate in the Electric Smart Grid**

  - Joint Utilities: Kentucky's natural-gas local distribution companies ("LDCs") have in some ways pioneered deploying automated and smart technologies among utility operations, having deployed Supervisory Control and Data Acquisition ("SCADA") in their distribution systems and AMR in meter reading for many years. Having already achieved the efficiencies associated with those technologies, though, means that LDCs and their customers may have less to gain from further smart-technology deployments. Also, there are a number of benefits or efficiencies that electric smart technologies might provide or enable that would not benefit LDCs, such as time-of-use or dynamic pricing and remote-reconnection capabilities. Nonetheless, the LDCs among the Joint Utilities remain committed to seeking economical means of participating in the electric smart grid or developing an independent gas smart grid.

EXECUTIVE SUMMARY

- AG:

- CAC: No comments.

- **EISA 2007 Smart Grid Information and Investment Standards**

  - Joint Utilities: Smart technologies, both customer-facing and grid-deployed, hold much promise for maintaining and increasing the quality of utility service while reducing costs. But each utility must have the flexibility to propose solutions that are prudent for its customers, solutions that will vary depending on geography, customer density, existing system constraints and resources, and a host of other factors. Also, smart technologies continue to advance and mature at a rapid pace, and there is no industry consensus about which technologies every utility must deploy. Therefore, the Joint Utilities continue to hold the position they expressed in their May 20, 2013 Joint Comments in this proceeding, namely that each utility's unique circumstances and the pace of technological change make it unnecessary, and likely counterproductive, to impose uniform, one-size-fits-all standards, such as the EISA 2007 Smart Grid Information and Investment Standards. The better approach is to use the Commission's existing authority to ensure the prudence of utility proposals and deployments concerning smart technologies, as the Commission currently does concerning all utility operations and investments.

  - AG:

  - CAC: No comments.

The Joint Utilities, AG, and CAC have appreciated the opportunity to meet to share views and learn from one another on these issues; however, including Case No. 2008-00408, the predecessor case to this case, the Commission and the Joint Utilities, AG, and CAC have been examining these issues, and particularly the EISA 2007 Smart Grid Standards, for five and a half years. The Joint Utilities have not changed their views during that time. Moreover, the Joint Utilities have made additional investments in smart and advanced technologies in the interim that have been subject to the Commission's existing rate and other review processes; none of the Joint Utilities believes these reviews have provided inadequate opportunities to review such investments for the parties desiring to seek such review. Therefore, the Joint Utilities' unanimous view is that the Commission should issue a final order closing this case without further proceedings and declining to impose the EISA 2007 Smart Grid Information Standard, the EISA 2007 Smart Grid Investment Standard, or any other smart-technology-related standard.

[AG]

DEFINITIONS AND SCOPE

Definitions and Scope

Broadly, this report addresses issues concerning Kentucky utilities' deployment and use of advanced or smart technologies, primarily in the electric grid. The Joint Utilities define "advanced" or "smart" technologies in this report to comprise two categories of components:

- Meters and related system elements that communicate energy usage information to a utility and its customers in ways that allow customers to manage their energy usage and provide the utility with more dynamic information to use in managing the electric system; and
- Grid-management technologies such as communication networks and intelligent controls that enable utilities to operate more reliably and efficiently the electric system while providing more visibility and security for system operators.

More particularly, this report addresses issues concerning Kentucky utilities' deployment and use of advanced or smart technologies only with regard to the nine topics the Commission prescribed: customer privacy, opt-out provisions, customer education (including health-related education), dynamic pricing, AMR and AMI deployment (including prepaid meters and remote disconnections),[5] cyber-security, cost recovery for smart-technology deployments and obsolete equipment, how natural gas companies might participate in the electric smart grid, and whether the Commission should adopt the EISA 2007 Smart Grid Investment and Information Standards.[6] The scope of this report is strictly limited to those topics.

Each of the first eight topics of this report has implications for the potential adoption of one or both of the EISA 2007 Smart Grid Investment and Information Standards. Therefore, in addition to the ninth substantive section of this report that exclusively addresses these standards, each of the other eight sections provides a brief discussion of how the Joint Utilities' views on the topic inform their views on the EISA 2007 standards.

[5] The Joint Utilities have renamed this section "Distribution Smart-Grid Components."
[6] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 7-8 (July 17, 2013).

CUSTOMER PRIVACY

Customer Privacy

I. Executive Summary

Customer privacy is an important issue independent of smart-technology considerations. Kentucky's utilities already gather, maintain, and protect sensitive customer information, including account information, sometimes banking information, and energy-usage information. As discussed below, there are already federal and state legal protections in place concerning customer information in utilities' possession, and government and industry groups are working to develop even more robust voluntary standards for utilities to consider. Kentucky's utilities have already gone beyond the legal requirements in place today; each utility member of the Joint Utilities has a voluntary customer-privacy policy or practice in force to ensure that only appropriate use is made of customer information. Therefore, the Joint Utilities conclude that a new mandatory customer-privacy standard is not necessary at this time, including the customer data provisions of the EISA 2007 Smart-Grid Information Standard. Instead, the Joint Utilities propose a list of terms to define and substantive items for utilities to consider when reviewing customer-privacy policies and practices, which list the Commission may find useful when addressing smart-grid or other customer-privacy-related utility proposals.

II. Scope of the Customer-Privacy Section

This section addresses rights and responsibilities concerning Kentucky utilities' gathering and authorized use of customer information, including customers' and other parties' access to such information. This section does not directly address unauthorized access to customer information, which the Cyber-Security Section of this report addresses.

III. Existing Customer-Privacy Law

There are existing federal and Kentucky statutes that apply to utilities to protect the privacy of personally identifiable customer information, including, but not limited to, social security numbers, dates of birth, and financial account information. Kentucky's utilities supplement these regulations with voluntary customer-privacy policies or practices designed to further protect proprietary data, including customers' utility-specific account information. These existing legal requirements and oversight by responsible governmental entities, in conjunction with utilities' voluntary customer-privacy policies or practices, adequately ensure the protection of utility customers' privacy, negating any potential need for additional privacy statutes or regulations.

At the federal level, the Federal Trade Commission ("FTC"), under its authority to police and penalize unfair or deceptive trade practices (15 U.S.C. § 45) and the authority of the federal Fair Credit Reporting Act (15 U.S.C. § 1681), has issued and enforced a Red-Flags Rule (16 CFR § 681.1), which requires each utility to develop a written "red-flags program" to detect, prevent, and minimize the damage that could result from identity theft. Although there is no standard red-flags checklist utilities must use, utilities may use multiple means to protect their customers from identity theft or fraud, including checking alerts, notifications or warnings from

CUSTOMER PRIVACY

a consumer reporting agency, carefully reviewing suspicious documents, verifying suspicious personally identifying information, investigating suspicious activity relating to a covered account, and taking into account notices from victims of identity theft, law enforcement authorities, or others suggesting that an account may have been opened fraudulently.

More broadly, federal and Kentucky consumer-protection statutes prohibit utilities and other businesses from engaging in unfair or deceptive trade practices.[7] The Federal Trade Commission has construed its statutory authority concerning such practices to include the ability to take enforcement actions against businesses that violate their own voluntary privacy policies.[8] The FTC has vigorously used its authority to protect customers: "As of May 1, 2011, the FTC has brought 32 legal actions against organizations that have violated consumers' privacy rights, or misled them by failing to maintain security for sensitive consumer information."[9] Therefore, utilities' voluntary privacy policies are not aspirational; rather, they are enforceable standards with which utilities must comply.

The Kentucky statute most directly applicable to utilities' use of customer information is KRS 278.2213(5), which limits a utility's ability to share confidential customer information with its affiliates: "No utility employee shall share any confidential customer information with the utility's affiliates unless the customer has consented in writing, or the information is publicly available or is simultaneously made publicly available." The Commission has the authority to penalize violations of this restriction under KRS 278.990, including the imposition of civil fines or criminal penalties.

Finally, customers harmed by their utilities' privacy-policy violations may have causes of action against the offending utilities.[10] This enforcement mechanism, along with all the others described above, give Kentucky utilities ample reasons to take all reasonable steps to protect their customers' privacy.

IV. Voluntary Standards for Customer Privacy

In addition to legal requirements concerning customer privacy, government entities and industry groups are working on voluntary customer-privacy standards that utilities may adopt. The Joint Utilities support these efforts, and will continue to monitor these and other developments, and may voluntarily adopt all or portions of such standards to the extent they are appropriate for their customers.

A. The U.S. Department of Energy ("DOE") and Federal Smart Grid Task Force Voluntary Code of Conduct

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[7] *See* 15 U.S.C. § 45; KRS 367.170.
[8] *See* http://www.ftc.gov/opa/reporter/privacy/privacypromises.shtml
[9] *Id.*
[10] *See, e.g.*, KRS 446.070, which provides a private right of action to recover any damages incurred as a result of the violation of any Kentucky statute.

CUSTOMER PRIVACY

The U.S. Department of Energy and the Federal Smart Grid Task Force are facilitating a multi-stakeholder process to develop a Voluntary Code of Conduct ("VCC") for utilities and third parties providing consumer energy use services that will address privacy related to data enabled by smart-grid technologies. The Federal Smart Grid Task Force met twice in 2013 and has posted a draft set of possible VCC elements.[11]

B. The Energy Service Provider Interface ("ESPI") standard

The North American Energy Standards Board ("NAESB") and the National Institute of Standards and Technology ("NIST") have developed an ESPI standard. The ESPI standard contemplates a framework where the customer information collected by a utility is transferred to "data custodians" who would then, pursuant to certain rules and guidelines, authorize third parties to access the customer information. The purpose of the ESPI standard is to support the development of innovative products that will allow consumers to better understand their energy usage and to make more economical decisions about their usage. The NAESB ESPI standard provides model business practices, use cases, models, and an XML schema that describe the mechanisms by which the orchestrated exchange of energy usage information may be enabled.[12]

V. Current Customer-Privacy Protections of Utilities in Kentucky

In addition to complying with all applicable legal requirements and other industry standards concerning customer privacy, each of the Joint Utilities already has a voluntary customer-privacy policy or practice to protect its customers' information. These policies and practices vary, but all serve to ensure that Kentucky utilities appropriately use and share customer information.

VI. Joint Utilities' Customer-Privacy Proposal

Every utility should have a customer-privacy policy or practice, but the content of each policy or practice must address each utility's unique blend of services and customers. Although the precise terms of each utility's policy or practice will necessarily differ, each utility's policy or practice may define some or all of the terms and address some or all of the items below.

A. Possible privacy-related definitions

Defining some or all of the following terms may help to clarify a utility's customer-privacy policy or practice. This list is intended to be illustrative, not exhaustive or prescriptive:

1. Utility. It may be helpful for a utility to clarify whether it intends "utility" to include the utility's contractors or other agents with whom it is necessary to share customer information.

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[11] https://www.smartgrid.gov/news/doe_addresses_privacy_data_enabled_smart_grid_technologies_convenes_multistakeholder_process

[12] http://www.naesb.org/ESPI_standards.asp

CUSTOMER PRIVACY

2. Customer. A utility may want to define who is a customer or other authorized user for the purposes of its privacy policy or practice. Note that KAR 5:006, Section 1, defines “customer” as “a person, firm, corporation, or body politic applying for or receiving service from a utility.”

3. Third party. This definition may relate to the definition of “utility” and “customer,” and may include governmental entities or agents, non-profit utility-assistance organizations, or non-contractor businesses with which the utility interacts.

4. Privacy. This definition will likely state that privacy is the non-disclosure of customer information to third parties without the customer’s consent. The remainder of the utility’s privacy policy will flesh out when customers may reasonably expect the utility to assure privacy.

5. Customer information. A utility may delineate what information is operational data versus customer information, the latter of which might be subject to privacy protections.

6. Operational data. If a utility defines “customer information,” it may define “operational data” to clarify which kinds of information are subject to privacy protections and which are not. Operational data may include, but not be limited to, general utility information and data about system operations.

7. Personally identifiable information. A utility’s privacy policy or practice may seek to permit the utility to disclose certain information about customers to people or entities other than the customers themselves. If so, the utility may define a set of information it will not disclose, barring a legal obligation to do so, as “personally identifiable information.” Personally identifiable information will presumably be a subset of customer information.

8. Anonymous. A utility may want to define how customer information may be disclosed to parties other than the customer while protecting the identity of that specific customer.

9. Aggregate. A utility may define when and how it may disclose customer information combined in one data set. The utility may also want to address how it will ensure each customer’s personally identifiable information is kept confidential when making such disclosures.

10. Consent. A utility may define what constitutes a customer’s consent to disclose any or all customer information under a variety of circumstances.

CUSTOMER PRIVACY

What constitutes adequate consent may differ depending on the scope of the disclosure and the kind of party to whom the utility will make the disclosure.

11. Utility use. A utility may define, likely in an illustrative, non-exhaustive way, when the utility may use a customer's information without first obtaining the customer's consent.

B. Checklist items

A utility may also address the following items in a customer-privacy policy or practice:

1. Scope; covered data. A privacy policy or practice may clearly state what kinds of information and which parties the policy or practice addresses, as well as what kinds of information and which parties it does not address.

2. Availability and access. A privacy policy or practice may address the terms and conditions on which the utility will make customer information available to the utility, customers, and third parties (possibly including government agents or entities, including law enforcement and regulatory agencies), as well as how such parties may access customer information. The terms of availability and access may differ depending on who is seeking the customer information, the precise kind of customer information at issue, and the purpose for accessing the customer information.

VII. Other Customer-Privacy Issues a Utility May Address

Utilities may address other issues concerning customer privacy, including, but not limited to, the issues listed below, either in their customer-privacy policies or practices or by other means.

A. Cost recovery for providing customer information

A utility's reasonable costs to make customer information available to requesting customers or in the context of a regulatory proceeding should be recoverable through the utility's base rates. For example, a utility's reasonable costs to build and maintain a website that customers can use to access account and usage information should be recoverable through base rates. But utilities should be permitted to establish reasonable charges to provide customer information to non-customers because such costs are not necessary for providing service and should be borne by the cost-causers.

B. Aggregation

Except as legally required, e.g., in the context of a regulatory or legal proceeding, utilities should not be required to provide aggregated customer information. Any obligation to provide aggregated customer information to non-customer and non-regulatory requesting parties could potentially divert utility resources from important utility functions, and may create an unnecessary privacy-violation risk.

C. Enforcement

A utility may address the means for enforcing its customer-privacy policy, perhaps by providing means of addressing perceived privacy concerns with customers in addition to those provided by law.

D. Liability

Utilities safeguard important customer information every day. As noted above, there are existing legal standards and obligations utilities must meet to protect the privacy of customer information. But utilities that desire to provide stronger protections for customers than those legally required create additional liability concerns for themselves; as discussed above, federal and state laws create potential liability for violations of purely private and voluntary customer-privacy policies. This liability may take the form of civil penalties levied by regulators or civil actions brought by aggrieved customers. This is a significant disincentive for utilities to implement more robust customer-privacy policies.

A possible means of reducing or removing this disincentive would be a new statutory framework that would limit or eliminate utilities' civil liability for merely negligent violations of their own voluntary customer-privacy policies. Such a framework would still serve to punish truly bad actors, such as those who violate customers' privacy intentionally or by gross negligence. But it would protect utilities whose intent and actions demonstrate their commitment to greater customer privacy protections than those currently prescribed by law.

E. Rights and responsibilities concerning customer information

A utility's privacy policy or practice may include a thorough delineation of the utility's and the customer's respective rights and responsibilities regarding customer information.

VIII. Customer-Privacy Aspects of the EISA 2007 Information Standard

Certain portions of the EISA 2007 Information Standard have customer-privacy implications. The Joint Utilities address them below:

"Customers shall be able to access their own information at any time through the Internet and by other means of communication elected by the electric utility for smart grid applications."

The Joint Utilities oppose making this provision mandatory. Kentucky's utilities do and will provide cost-effective means for customers to access their own data, which may include access via the Internet. But what is cost-effective for one utility may not be for another, and each utility's customers have different needs and desires concerning access to their information.

CUSTOMER PRIVACY

Therefore, the best approach is for each utility to address its customers' needs economically, not subject to a one-size-fits-all mandate; however, if the Commission determines to implement such a requirement, it must allow utilities to recover the cost to build and maintain systems needed to provide the required information.

"Other interested persons shall be able to access information not specific to any customer through the Internet."

The Joint Utilities oppose this requirement as unnecessary, potentially costly, and risky. Meeting such a requirement will impose costs on utilities to implement and maintain systems to provide the necessary information and keep it current. Also, the terms "other interested persons" and "information not specific to any customer" are vague at best, and would need to be clarified before such a standard could be considered. Finally, utilities should provide aggregated data only on request and with appropriate safeguards; any other approach could create potential customer-privacy concerns.

"Customer-specific information shall be provided solely to that customer."

The Joint Utilities oppose this requirement because utilities must be able to provide certain customer-specific information to contractors in order to provide economical service to their customers. Also, utilities occasionally need to provide such information to legal or regulatory authorities, as well as to credit-reporting agencies to determine credit requirements. Certainly utilities should provide customer-specific information to people or entities other than the customer only if strict privacy safeguards are in place.

IX. Conclusion

The significant legally required and voluntarily implemented customer-privacy protections Kentucky's utilities have in place today negate any need for a new mandatory customer-privacy standard. Each utility's policy or practice will likely be different to meet the unique needs of the utility and its customers, but the list proposed above provides a useful framework of concepts for each utility and the Commission to consider when evaluating customer-privacy-related utility proposals. This voluntary-checklist approach will ensure utilities have the flexibility they need to continue to provide safe, reliable, and economical service while protecting their customers' privacy.

X. AG Comments

XI. CAC Comments

Non-profit agencies that assist utility customers with bill payment should not be charged for customer information requested in regulatory proceedings or in connection with providing the assistance. Aggregated customer information should be provided to a non-profit agency that assists utility customers with bill payment if such information is needed to facilitate that assistance.

OPT-OUT PROVISIONS

Opt-Out Provisions

I. Executive Summary

Customer concerns over purported health and privacy impacts of smart meters have caused some states to require utilities to offer opt-out provisions from smart-meter deployments. But requiring utilities to offer opt-outs from smart-meter deployments has potentially significant cost and operational impacts for utilities and customers, both those who choose to opt out and those who do not. Determining how to allocate the direct and indirect costs of opt-out provisions among customers who opt out and those who do not is also a challenging issue. This section provides an analytical framework for utilities and regulators to consider when evaluating the merits and consequences of various opt-out approaches.

II. Scope of the Opt-Out Section

This section addresses the cost and operational impacts of customer opt-outs from technological or informational components of large-scale utility deployments of smart meters. These include impacts to utilities and customers, as well as reductions in service levels and service-offering constraints to customers who choose to opt out, as well as cost increases associated with opt-out provisions.

This section does not address opt-outs from AMR metering. The Joint Utilities believe no opt-outs should be permitted from AMR deployments, and a number of utilities have already deployed AMR system-wide. Therefore, this section addresses only smart-meter (AMI) deployments.

III. Customer Concerns Related to Opt-Outs

Generally, a smart-technology deployment creates the greatest benefits relative to its costs if it is ubiquitous. To the extent a smart-technology deployment involves smart meters, allowing individual customers to opt out, particularly to opt out of the technology deployment, eliminates ubiquity, reducing the benefits of the overall deployment and creating additional costs for the utility and its customers. Therefore, utilities tend not to have cost or operational reasons to support opt-outs.

Some individual customers, however, have raised concerns in smart-meter deployments to argue in favor of opt-outs (or simply to oppose a smart-meter deployment at all). The two primary objections such customers raise are that smart meters will adversely affect their health and that smart meters invade their privacy. With respect to health, some members of the public believe that the electromagnetic radiation smart meters emit can cause adverse health effects, notwithstanding significant scientific evidence to the contrary.[13] Customers' privacy concerns arise from the belief that smart meters can record and report to utilities and other government agencies customers' electricity usage on an interval basis, notwithstanding utilities' assurances that smart meters are not "surveillance devices," and that utilities guard customer information

[13] http://www.whatissmartgrid.org/smart-grid-101/fact-sheets/radio-frequency-and-smart-meters

OPT-OUT PROVISIONS

gathered from smart meters with the same privacy protections used to protect all customer information.[14]

A smaller subset of customers have the mistaken impression that any digital meter is a smart meter capable of at least one-way communications, and want to opt-out of any digital-meter installation. The Joint Utilities oppose opt-outs of any kind for digital meters with no communications capabilities for two reasons: (1) such meters are essentially identical to older electromechanical meters; and (2) the Joint Utilities do not believe electromechanical meters are being manufactured domestically today, making any opt-out from a non-communicating digital meter impracticable at best.

IV. How Utilities and Other States Have Addressed Opt-Outs

Several of the Joint Utilities have deployed smart-meter technology and have addressed the customer concerns described above, as well as opt-outs and opt-out requirements in other states.

The unanimous view of the Joint Utilities that have made significant smart-meter deployments is that customer education and high-touch customer service are crucial to overcoming customer objections, regardless of the availability of opt-outs. For example, Duke Energy's Ohio smart-meter rollout involved sending postcards to customers before swapping out their existing meters with smart meters, calling the same customers one to two weeks prior to swap-out, and following up with letters. For customers who voiced concerns and did not want a smart meter installed, Duke's customer-service team would contact the customers, including one-on-one visits, to address their concerns. Duke indicated that this high-touch customer service and communication approach satisfied the concerns of nearly all of their Ohio customers, and the same approach seems to be having similar success in the Carolinas, where Duke is now deploying smart meters.

American Electric Power ("AEP") has used similar processes to respond to customers expressing concerns with smart-meter installations in Texas, Ohio, Oklahoma, and Indiana. When provided with answers responsive to their questions, the vast majority of customer concerns are alleviated, and they no longer object to smart-meter installations. AEP's experience is that the percentage of customers that continue to object to smart-meter installations after having their concerns addressed is less than 0.01%.

The distribution cooperative members of the Joint Utilities have had similar experiences with their AMR and smart-meter deployments in Kentucky. By providing pre-deployment information to customers and having direct contact with customers expressing concerns, the cooperatives have been able to address most of their customers' objections or concerns. There have been a few instances where this approach has been unsuccessful, but they have been rare.

[14] http://www.whatissmartgrid.org/smart-grid-101/fact-sheets/data-privacy-and-smart-meters

OPT-OUT PROVISIONS

There are opt-out requirements in some other states where AEP has operations. For example, AEP Texas recently received approval from the Public Utility Commission of Texas for its compliance filing to establish opt-out rates. AEP Texas will now charge opting-out customers an up-front opt-out charge in addition to an ongoing monthly opt-out charge. Further, Duke Energy stated there are currently no opt-out requirements in any of the six jurisdictions in which they operate (North Carolina, South Carolina, Florida, Indiana, Kentucky, and Ohio), and that Duke has not offered opt-outs in any of those jurisdictions.

The Public Utilities Commission of Ohio approved a residential customer "advanced meter" opt-out rule on December 18, 2013, during its regularly scheduled rule-review process that occurs every five years.[15] The updated rules became effective May 29, 2014. The new opt-out rule defines an advanced meter as "any electric meter that meets the pertinent engineering standards using digital technology and is capable of providing two-way communications with the electric utility to provide usage and/or other technical data." The rule requires also that costs incurred by an electric utility to provide advanced meter opt-out service shall be borne only by customers who elect to receive an advanced meter opt-out service. The electric utilities are to file on or before June 28, 2014, an advanced meter opt-out tariff that will include a one-time fee and a recurring fee for the optional residential opt-out service.

More broadly, most states do not have smart-meter opt-out policies. The states that do have such policies range from Vermont, where state statute requires utilities to offer opt-outs at no cost to their customers,[16] to Texas, where the commission has issued an administrative regulation requiring transmission and distribution utilities to offer opt-outs and have tariffs stating the initial and ongoing charges opting-out customers must pay.[17] Although the costs associated with opt-outs will vary by utility, an example of the initial and ongoing charges for opting-out customers the Joint Utilities' research uncovered was in Oregon, where Portland Gas and Electric charges opting-out residential customers an initial opt-out fee of $254 and a monthly opt-out charge of $51.[18] Because each utility and the Commission will need to calculate costs on a utility-by-utility basis, those fees may not be indicative of the opt-out fees appropriate for Kentucky's utilities.

The Joint Utilities' research indicates that the size of the opting-out population is relatively small for most utilities that offer opt-outs. An article by Chris King of eMeter looked at opt-out programs in a handful of states: Maine, California, Texas, Michigan and Nevada. In his research, Maine had the highest percentage of customers choosing to opt out (1.4%),[19] and

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[15] *In the Matter of the Commission's Review of Chapter 4901:1-10, Ohio Administrative Code, Regarding Electric Companies*, Public Utilities Commission of Ohio Case No. 12-2050-EL-ORD, Finding and Order (Dec. 18, 2013).
[16] *See* http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=077&Section=02811 (information on Vermont Senate Bill 214).
[17] *See* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.133/25.133.pdf.
[18] *See* Non-Network Residential Meter Rates at: http://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_300.pdf
[19] *See* http://www.elp.com/articles/powergrid_international/print/volume-17/issue-11/features/smart-meter-opt-out-policies-explain.html.

OPT-OUT PROVISIONS

the average percentage of opting-out customers of the utilities studied was 0.4%.[20] But even one opting-out customer can create significant costs, as discussed below.

V. Opt-Out Considerations

The Joint Utilities present below an analytical framework for considering opt-outs that may help a utility or regulator understand the effects of pursuing a particular opt-out approach.

A. Opt-Out Costs

Although utilities would bear certain opt-out costs in the short term, customers would bear the increased costs in the long term. The list below, though not exhaustive, contains a number of important costs for utilities and regulators to consider, regardless of whether the costs are socialized or charged to the cost-causers:

1. Increased meter-reading costs. One of the chief cost savings smart meters provide is automated meter reading, eliminating much of a utility's cost for labor, vehicle dispatch and operation (including cost and liability associated with possible vehicle collisions), and data systems associated with manual meter-reading.

2. Increased meter-inventory costs. Carrying an inventory of smart and traditional meters, meter parts, and meter-service equipment, both on utilities' service trucks and in their warehouses, increases inventory costs relative to carrying only one variety of such equipment.

3. Increased staffing costs. In addition to labor costs associated with manual meter-reading in the field, opt-outs would create other additional labor and staffing costs relative to a no-opt-out approach, including back office and customer service costs associated with addressing customer questions, service issues, and data entry and management, all of which would differ between smart-meters and traditional meters.

4. Increased system-planning costs. Smart meters give utilities insights into the performance of their distribution systems that traditional meters cannot provide, including load and voltage data that enable utilities to improve and make more efficient their system planning and operation. A sufficiently low saturation of smart meters in a given area could compromise that improvement, adding a relative cost to a utility's system planning.

5. Increased system-restoration costs. Smart meters help utilities find and repair outages more quickly and with greater precision, which helps

[20] *Id.*

reduce system-restoration costs and outage durations. Opt-outs would compromise this advantage.

6. Costs for changing meters for opt-outs (pulling smart meters). Customers who move into premises already equipped with smart meters and choose to opt out will create costs to replace their existing smart meters with traditional meters. The cost such customers create could actually be double the initial meter swap cost; when new, non-opting-out customers subsequently occupy the premises vacated by opting-out customers, more meter swaps will be necessary.

7. Reduced line-loss-reduction opportunity. Smart meters help detect line losses. When used with other smart technology, this information can be used to more efficiently plan and operate distribution circuits. Reduced concentrations of such meters due to opt-outs reduce that capability.

8. Decreased theft detection; decreased hazard reduction. Smart meters can help minimize theft of service and reduce potential hazards from meters that are supposed to be idle by reporting electric usage. Also, smart meters have thermocouples that can detect certain unsafe operating conditions, such as hot sockets, undetectable by traditional meters.

9. Reduced opportunity to find missing meters. Smart meters' communications capabilities can help utilities find missing meters; traditional meters lack such capabilities.

10. Reduced opportunity to identify malfunctioning meters early. A utility may not detect a malfunctioning standard meter for some time, resulting in the need to estimate billing for the malfunction period. Smart meters help identify their own malfunctioning early, which minimizes the amount of estimated billing. A customer that opts-out would lose this benefit. With an AMI meter, the utility has the ability to monitor the non-communicating meters and investigate and mitigate to minimize estimated billing. Also, AMI systems support the identification of failed metering equipment, enabling utilities to repair or replace such meters more quickly. This reduces the amount of time a utility would have to use estimated billing

11. Additional service costs. Smart meters enable a utility's customer service team to "ping" a customer's meter to determine if it is functioning properly, which could avoid a customer's having to pay for an unnecessary service call. AMR meters have only one-way communications, and therefore do not permit "pinging."

B. Operational Impacts of Opt-Outs

OPT-OUT PROVISIONS

In addition to cost impacts, opt-outs have operational impacts that affect utilities and customers who do not opt out. For example, to the degree opt-outs reduce a utility's ability to monitor the condition of the grid, opting-out customers can negatively impact the utility's ability to serve all other customers, as well. Therefore, utilities and regulators may want to consider the following non-exhaustive list of operational impacts caused by opt-outs:

1. Staffing. Maintaining, servicing, and providing customer service for what would essentially be two distribution systems—one automated, one traditional—will place additional demands on utility personnel.

2. Technology. In addition to the cost impact, there is an operational impact of maintaining two sets of meters, meter parts, and meter-servicing equipment.

3. System planning. Opt-outs will require additional engineering analysis relative to system planning with ubiquitous smart meters.

4. System restoration and individual restoration. As discussed in the utility costs section above, smart meters can help reduce system, circuit, and individual restoration times. The absence of such meters relatively increases the difficulty and time associated with restoration.

5. Reliability and power quality. Smart meters can help maintain distribution system reliability and power quality, e.g., by interrogating particular meters concerning voltage issues.

6. Remote connections and disconnections. Utilities can perform service connections and disconnections nearly instantaneously with smart meters equipped to do so, and without the need to dispatch service personnel.

7. Off-cycle meter readings. In addition to normal meter readings, smart meters reduce the need for utility personnel to travel to customer premises to perform off-cycle meter readings, e.g., when a customer ends service at a particular premise. Opt-outs reduce this operational benefit.

8. Safety impacts. Fewer dispatches of utility personnel resulting from smart-meter deployments should reduce vehicular accidents, slips and falls, and other potential safety issues. Opt-outs will reduce this operational benefit.

9. Customer safety. As discussed in the utility costs section, smart meters can inform utilities about hazardous operating conditions that may impact customers' safety, including hot sockets and bad connections.

10. Availability of products and services. Smart meters enable utilities to offer customers enhanced products and services relative to what a utility can offer with traditional meters; customers without smart meters would

OPT-OUT PROVISIONS

therefore be unable to use such products and services. These could include:

a. Dynamic pricing

b. Enhanced energy efficiency

c. Increased ability for customers to understand energy usage

d. Prepaid service

11. Physical privacy, security, and convenience. Particularly for customers who currently have indoor analog meters, smart meters will increase privacy, security, and convenience by reducing a utility's need or means to access its customers' premises. Therefore, customers opting out of such meters might actually reduce their relative privacy, security, and convenience.

12. Ongoing system reconfiguration. Opting-out, as typically considered, is not a static condition, which can have significant cost impacts on serving customers. For instance, if the smart-meter communications network is arranged optimally for universal coverage and a customer subsequently opts out, the ability of a utility to monitor the condition of that circuit and reach other customer meters for communications can easily be disrupted, essentially creating a blind spot in the network. This situation could require expensive reconfiguration of the network to accommodate. If other customers elect to opt out and opt in again over time, the constant reconfiguration of the system could quickly overwhelm the operational and cost benefits of the technology upgrade itself.

13. Meter testing. Because the number of opting-out customers is likely to be small, existing meter-testing requirements (807 KAR 5:041 §16) will require most, if not all, opting-out customers' meters to be tested annually to ensure a statistically valid sample in accordance with the sampling technique the serving utility uses for all other meter groups.

14. Regional Transmission Organization ("RTO") impact. For utilities that are members of RTOs, a customer opt-out feature may impact the ability of those utilities to optimize RTO power purchases or sales.

C. Defining "Opt-Out"

A threshold issue to consider when addressing opt-outs is what an opt-out entails. As typically considered, an opt-out requirement for smart metering is opting out of the technology entirely, i.e., a customer's refusal to have a smart meter installed on the customer's premises.

OPT-OUT PROVISIONS

Technology opt-outs are what the state standards and approaches above have assumed and required.

Another kind of opt-out that may be technically feasible in some, but certainly not all, smart-meter deployments is an informational opt-out. An informational opt-out would permit a utility to install a smart meter, but would allow each customer to decide the kinds of information the utility could collect remotely. For example, a customer could find daily meter readings to be a privacy problem and ask the utility to read the meter only once per billing period. This kind of informational opt-out would permit a smart meter to perform some useful functions, e.g., report outages, while potentially satisfying a customer's particular privacy concerns.

But informational opt-outs, even where technically feasible, might still fail to address customers' concerns. For example, such an opt-out would not address customers' health concerns about communicating meters. Also, some customers might not believe that utilities are collecting only the information they say they are collecting. These issues cast serious doubt on the usefulness of informational opt-outs' ability to allay customer concerns.

In addition to being potentially unsatisfying to customers who have concerns about smart meters, informational opt-outs have considerable costs. Some are utility-wide, such as the costs of designing and building a system capable of handling such opt-outs and training customer-service personnel to use it to address customer requests. Some costs would impact customers choosing to opt out, such as losing the ability to monitor daily usage patterns that could be useful to the customer's energy-conservation efforts. And depending on the information customers could choose to refuse to provide, informational opt-outs, like technology opt-outs, could impair the overall effectiveness of a utility's smart-meter deployment.

Regarding the costs described in Section V.A. "Opt-Out Costs" above, the following costs would not apply to informational opt-outs, though all the remaining costs listed in that section would apply:

- Increased meter-reading costs
- Increased meter-inventory costs
- Increased system-restoration costs
- Costs for changing meters for opt-outs (pulling smart meters)
- Reduced line-loss-reduction opportunity
- Decreased theft detection; decreased hazard reduction
- Reduced opportunity to find missing meters
- Additional service costs

OPT-OUT PROVISIONS

Regarding the operational impacts described in Section V.B. "Operational Impacts of Opt-Outs" above, the following impacts would not apply to informational opt-outs, though all the remaining impacts listed in that section would apply:

- Technology
- System restoration and individual restoration
- Reliability and power quality
- Remote connections and disconnections
- Off-cycle meter readings
- Safety impacts
- Customer safety
- Physical privacy, security, and convenience
- Ongoing system reconfiguration
- Meter testing

With regard to technical feasibility, informational opt-outs might be workable for some smart-meter deployments but not others, principally based on the underlying technology for back-haul communications. For power-line-carrier-based deployments, informational opt-outs might be feasible if the appropriate smart components were in place. For radio-frequency-based deployments, informational opt-outs would pose such significant operational challenges as to be infeasible, i.e., informational opt-outs are impracticable with radio-frequency based deployments.

D. Customer education

Regardless of whether a utility offers opt-outs or what kind of opt-outs it offers, it should consider engaging in a pre-deployment customer-education campaign to address potential customer concerns about smart meters. Pre-deployment campaigns may include information about when and how meter changes will occur, the benefits of smart meters to individual customers and the utility as a whole, and new or enhanced services that will follow smart-meter installation. Utilities should provide accurate and reliable information to address any health and privacy concerns some customers may have about smart meters. The utility may also want to consider focused efforts to assist objecting customers by contacting them individually to hear their concerns and provide objective data to correct any misinformation they might have received, as well as to provide information on the cost of opting out and the services and benefits the customer would forgo by opting out.

OPT-OUT PROVISIONS

E. Other issues

In addition to the cost and operational issues above, utilities and regulators may want to consider the following issues concerning opt-outs:

1. Meter availability. To the best of the Joint Utilities' knowledge, analog meters are no longer being manufactured domestically.

2. Systems with existing smart-meter deployments. Several of the Joint Utilities have already deployed smart meters, some across their entire service territories. Introducing opt-outs in those territories would create real and new, not relative and potential, costs.

3. Assigning opt-out costs. As discussed above in the section concerning how other states and utilities are addressing opt-outs, there is no consensus concerning whether opt-outs should be permitted at all, and to the extent they are permitted, whether those opting out should bear the full cost of their decision (and how to calculate that cost), or whether opt-out costs should be fully socialized across each customer class. Basic cost-causation principles, including preventing subsidies between customers of the same rate class, support requiring customers who opt out to bear the full cost of their choice; however, if opt-outs are permitted, making each customer bear the full opt-out cost may prohibit some customers from opting out. Each utility and the Commission must address these issues if the utility offers opt-outs.

4. Opt-out exceptions. Utilities must have the right to refuse to honor opt-out requests in certain situations, such as where safety, access, or meter tampering must be addressed. In particular, customers who have indoor meters should not be permitted to opt out unless they move their meters outside at their expense. Utilities deploy smart meters in these situations today, and opt-outs should not constrain utilities' ability to do so.

5. Rate design and cost-of-service-study impacts. In addition to assisting with system planning, smart-meter data can improve the precision of rate design and cost-of-service studies. For example, demand and usage data may help utilities better understand which customers and customer classes are imposing demands on utility systems and which are not, which may help utilities to craft rates that more accurately recover costs from cost-causers. Permitting too many opt-outs of any kind may reduce this benefit.

OPT-OUT PROVISIONS

VI. EISA 2007 Smart-Grid Investment and Information Standards and Opt-Outs

Opt-outs, particularly technology opt-outs, are contrary to the overall thrust of the EISA 2007 Smart-Grid Investment and Information Standards. Opt-outs will inhibit a customer's ability to obtain timely information about usage and participate in dynamic pricing, and a critical mass of opt-outs may cause a planned smart-technology deployment to cease to be economical. Because the EISA 2007 Smart-Grid Standards were intended to encourage states and utilities to implement smart-grid technology, allowing customers to opt out would undermine the objectives of the EISA 2007 Smart-Grid Investment and Information Standards.

VII. Conclusion

All of the Joint Utilities agree that the analytical framework above is a fair representation of the costs, impacts, and other challenging issues opt-outs present.

Further, all of the Joint Utilities agree that the cost impacts and reduced operational capabilities (to both opting-out customers and all other customers) of requiring opt-out arrangements are not generally beneficial on the whole. As each utility's customers and potential (or actual) smart-meter deployment arrangements are unique, a case-by-case approach using some or all of the analytical framework presented above may therefore be an appropriate approach to evaluate opt-outs. Therefore, the Joint Utilities oppose any across-the-board, one-size-fits-all opt-out requirement for smart-meter deployments, but support each utility's ability to propose opt-outs appropriate for their customers and systems.

VIII. AG Comments

IX. CAC Comments

Customers should not be penalized for opting out. Further, although the Joint Utilities in this section have addressed the advantages of smart meter deployment, and costs, operational, and convenience impacts of opt-outs, they have not included the human impacts associated with opt-out issues. The ability to instantaneously remotely disconnect a customer for non-payment, though clearly an advantage to the utilities, can have devastating consequences for the low-income customers who struggle to keep heat on in the winter and air conditioning on in the summer, particularly the low-income elderly and those who suffer from certain illnesses. Simultaneous disconnection can prevent these low-income customers from having the ability to seek last-minute resources to avoid the shut-off. It is CAC's experience that last-minute avoidance is common, especially during the winter months. This consequence should be mitigated as smart meters are deployed.

CUSTOMER EDUCATION

Customer Education

I. Executive Summary

Customer education about the benefits of smart technology is critical to gaining customer acceptance and use of this technology. Several of the Joint Utilities have successfully used customer-education efforts, including pre- and post-deployment measures, to permit customers to increase the benefits of smart-meter deployments and address customers' concerns. Based on those utilities' successes, all of the Joint Utilities agree that each utility deploying smart meters should consider using some combination of the customer-education measures discussed in this section.

II. Scope of the Customer-Education Section

This section addresses customer education for utility deployments of smart meters. It includes summaries of certain utilities' experiences with customer education for smart-meter deployments, as well as lists of possible education topics, communication channels, and parties to engage in customer-education efforts concerning smart-meter deployments.

III. How Utilities Have Addressed Customer Education in Smart-Meter Deployments

Several of the Joint Utilities have deployed smart-meters and engaged in customer-education efforts associated with those deployments.

A. Duke Energy

Duke Energy has already designed a publicly accessible grid modernization webpage, with high-level information about grid modernization, frequently asked questions, and videos or external educational resources. Customers can find that webpage on their own if they have some interest in the topic or navigate through the site. As Duke Energy rolls out smart meters, customer-notice materials provide additional information related to installation at a customer's location as well as linking back to the Duke Energy grid modernization webpage for background information.

Duke Energy's proactive approach to communications with customers around smart meter deployment has involved:

- Sending postcards ahead of installation or having account managers reach out to large business customers;
- Canvassing neighborhoods to arrange for installation appointments if customer interaction is necessary to exchange meters, and leaving door hangers for customers that are not then available, so the customers can call to schedule an appointment;

CUSTOMER EDUCATION

- Making outbound calls to schedule installation appointments (when necessary) if prior attempts to schedule an appointment were unsuccessful;

- Sending letters for customers that still are unreachable to set meter exchange appointments;

- Sending a certification letter around 30-60 days after a smart meter was successfully installed and certified; and

- Sending a post-certification postcard two weeks after certification to direct customers to their Duke Energy web portal (different from general grid modernization webpage), so they can monitor their energy usage online.

B. American Electric Power

AEP has taken a simple, proactive, and transparent approach to educating customers about smart meters. Information about AMI meters and grid modernization, including frequently asked questions and videos, are available on the utility websites where these technologies are being deployed (AEP Ohio, AEP Texas, Indiana Michigan Power, and Public Service Company of Oklahoma). In addition to web resources, AEP utilities have:

- Communicated with customers multiple times via U.S. mail to announce the project and educate customers on the benefits of the meters prior to installation.

- Contacted each customer by phone prior to installing a new meter and left a detailed door hanger with the customer after installation was completed.

- Promoted through direct mail consumer programs and reinforced the benefits of the meters six months after installation.

- Dedicated customer service representatives to answer customers' questions and concerns.

- Spoken at many community and government meetings and with media outlets about the benefit of the meters, technology, and consumer programs available.

- Developed mobile exhibits to educate customers and local leaders on the benefits of the programs. The exhibits have been part of numerous community events and meetings.

C. Owen Electric Cooperative

Member education was a key element of Owen Electric's smart-meter deployment from 2006 to 2009. Owen used a host of communication channels to engage and educate its membership, including the Cooperative's member newsletter, billing inserts, door hangers,

CUSTOMER EDUCATION

website, and direct conversations with individual members. Additionally, Owen used informational presentations to area officials, chambers of commerce, and civic and community groups to engage the community in the discussion.

For ongoing member education, Owen maintains a webpage and other materials devoted to smart meters and AMI technologies. Having well-trained customer service representatives and supervisors equipped to address member concerns and questions related to smart meters remains a priority. Owen believes it is crucial to offer personal (high-touch) attention to customers with smart meter/grid concerns.

IV. Customer-Education Topics

Based on the experiences of the utilities described above, the Joint Utilities present a non-exhaustive list of topics a utility may want to address in a customer-education effort for a smart-meter deployment. Utilities may want to address some or all of these topics or other topics at different times and in different ways with some or all customers depending on the stage of the regulatory or deployment process for a particular smart-meter proposal or deployment. For example, a utility may want to address certain topics as part of a broad-based pre-deployment communications plan, and others it may want to address in follow-up communications with customers who have questions or concerns.

A. System description

Customers may want to understand what the utility is deploying. This could include describing the smart meter itself, including its capabilities and features (e.g., automated meter-reading, two-way communications, power quality reporting, and fault detection), as well as how the smart meter fits in the utility's overall smart-technology deployment.

B. What to expect

A utility may want to inform its customers what they can expect from a smart-meter deployment. For example, customers accustomed to having meters read visually may want to know that their meters are indeed being read even though the customers are not receiving visits from a meter-reader. Also, a utility may want to provide customers with a schedule or timeline for when to expect activities to take place.

C. Benefits

Describing smart meters' benefits may help improve customer acceptance of the technology, as well as increase the realized benefits of a deployment by empowering customers to engage with smart technology's features. Some benefits a utility may want to include in its customer-education efforts are:

1. Better billing dispute resolution. Detecting meter errors or abnormal usage patterns early may help minimize the impact of billing disputes and lead to more rapid resolution of disputes that arise.

CUSTOMER EDUCATION

2. Helping customers understand their energy use. Smart meters can provide customers a more granular view of their energy usage patterns than traditional meters can provide. This additional information can empower customers to reduce or otherwise improve their energy usage. A utility may want to inform customers about how to access this additional information, such as through an online information portal.

3. Earlier notification of outages. The serving utility may want to inform customers that smart meters may lead to earlier notification of outages due to enhanced outage reporting capabilities and precise outage-location information.

4. Rate options. If a utility is offering new rate options associated with a smart-meter deployment, such as prepaid service or dynamic pricing (including time-of-use or time-of-day rates), it may want to communicate the new rate options to customers during its customer-education effort.

5. Improved meter-reading accuracy. Smart meters can result in fewer meter-reading mistakes by removing potential human error from the reading and recording process, and may result in fewer estimated meter reads.

6. Reduces need to go on customers' premises. Customers may anticipate relatively increased safety, as well as enhanced privacy, resulting from a reduced need for utility personnel to enter customers' premises due to smart meters.

D. Radio-frequency emissions

Some customers have received misinformation about the health effects of smart meters. Therefore, the utility deploying smart meters may want to provide accurate information about the small amounts of smart-meter radio-frequency ("RF") emissions. In particular, a utility may want to provide information about compliance with Federal Communications Commission ("FCC") standards, or provide studies from independent third parties such as the U.S. Department of Energy showing the safety of smart meters. It may also be instructive to compare the RF emitted by smart meters to RF emitted by items customers commonly use, such as microwaves, televisions, and cell phones.

E. Opt-out availability and costs

If a utility offers opt-outs from a smart-meter deployment, it should inform customers of customer-specific costs of opting out. A utility may want to include opt-out-cost information even if the costs are socialized to help customers understand the impacts of their decisions on other customers.

F. Privacy

CUSTOMER EDUCATION

A utility deploying smart meters may want to inform its customers of the information the utility will collect from the smart meters and how it will protect and use that information. Perhaps equally useful would be to inform customers what kinds of information the utility will not collect, e.g., information about which appliances a customer is using from moment to moment.

V. Communications Channels for Customer Education

Based on the experiences of the utilities described above, the Joint Utilities present below a non-exhaustive list of communication channels that may be available to a utility in its customer-education effort for a smart-meter deployment:

A. Door hangers

Door hangers can be useful pre-deployment to inform customers about local installation scheduling, as well as to provide other brief customer education.

B. Bill inserts and newsletters

Bill inserts and newsletters can provide more in-depth information concerning a smart-meter deployment. They can be used to educate customers pre-deployment, but can also be used to remind customers about smart-meter benefits, ways to use smart-meter-provided data, and post-deployment rate options.

C. Phone calls, text messages, and e-mail

Phone calls, text messages, and e-mail made by automated means can provide customers pre-deployment scheduling and contact information. Personal phone calls and e-mail can also help provide more in-depth education, and can address concerns for customers with objections to smart-meter installations.

D. Face-to-face meetings

Face-to-face meetings may assist in addressing the concerns of customers who object to smart-meter deployments.

E. Customer service representatives

Customer service representatives can be a crucial to any customer-education effort. They can address customers' concerns and provide valuable information about how customers can use smart-meter information to improve their energy usage. They can also inform customers about rate options available with smart meters.

F. Social media

CUSTOMER EDUCATION

Social media, including Facebook and Twitter, can be used to provide scheduling information and high-level customer education, as well as an interactive public question-and-answer platform.

G. Websites

Websites can provide full-spectrum customer education about smart-meter deployments. This can include in-depth customer education about all aspects of a deployment. Also, a utility's website would likely be the portal a customer would use to access account information, including any enhanced information a smart meter would provide.

H. Mass media advertising and public service announcements

Mass media advertising and public service announcements ("PSAs"), including newspaper, radio, and television advertising, can provide broad and brief customer education about overall deployment information, including contact information for customers with questions or concerns and website information for customers seeking more in-depth information. In addition to utility advertising, the Commission could provide PSAs about smart-meter deployments.

I. Partner organizations

Partner organizations such as local government (e.g., mayor, county judge-executive, county clerks, city councils, and city managers), civic organizations, and community action agencies, could help disseminate useful information about a deployment, and can address some questions and concerns.

J. Community forums

Community forums could be efficient means of addressing multiple customers' individual questions and concerns. With appropriate permissions and disclosures, videos of such forums could be useful tools to post on utilities' websites to address questions customers might have.

VI. Parties that Can Assist with Customer-Education Efforts

Several non-utility entities could assist in providing customer education concerning smart-meter deployments if utilities engage and educate them pre-deployment. These entities include, but are not limited to:

A. Local government

Mayors, county judge-executives, county clerks, city councils, and city managers could all be helpful resources in providing customer education because customers often approach local government with questions or concerns about utility activities.

CUSTOMER EDUCATION

B. Civic groups

Homeowners' associations, community action agencies, and other civic organizations have memberships and client bases that already turn to them for help in utility matters. Therefore, these organizations could be useful partners in customer education concerning smart-meter deployments.

C. Trade organizations

The Kentucky Industrial Utility Customers, Inc., the Kentucky Association of Manufacturers, the Kentucky Retail Federation, and other trade organizations could be valuable partners in distributing industry-specific information to customers during smart-meter deployments

D. Kentucky Public Service Commission

The Commission could be a valuable partner in customer education by providing reliable and independent information to customers inquiring about smart-meter deployments.

VII. EISA 2007 Smart-Grid Investment and Information Standards and Customer Education

Customer education supports the EISA 2007 Smart-Grid Investment and Information Standards. Customer education tends to increase the realized benefits of smart-meter investments, consistent with the Smart-Grid Investment Standard's consideration of cost-effectiveness. Likewise, customer education supports the tenets of the Smart-Grid Information Standard by directing customers to the enhanced usage information smart meters provide, as well as possible dynamic pricing options utilities may provide after a smart-meter deployment.

But as described above, utilities are already engaging in customer education concerning smart-technology deployments absent any imposition of the EISA 2007 standards. Indeed, the EISA 2007 standards do not directly address or require customer education; though customer education may support the goals of the EISA 2007 standards, the standards do not support customer education. Therefore, customer education and its benefits do not provide any reason to implement either of the EISA 2007 standards, and the Joint Utilities continue to oppose them.

VIII. Conclusion

Customer education, including some of the items discussed above, is likely to increase the success of any smart-meter deployment. By ensuring customers understand the benefits and features of the smart technology being deployed, a deploying utility can help minimize customer concerns and objections while increasing the likelihood that projected benefits will be realized as customers engage with the technology and use it to improve their energy consumption. Therefore, the Joint Utilities recommend that each utility deploying smart meters consider using some of the customer-education measures addressed in this section.

CUSTOMER EDUCATION

IX. AG Comments

X. CAC Comments

Customer education should be mandatory when smart meters are deployed.

DYNAMIC PRICING

Dynamic Pricing

I. Executive Summary

Several of the Joint Utilities have provided voluntary dynamic-pricing options to residential customers, both on trial and permanent bases, here in the Commonwealth and in other jurisdictions where some of the Joint Utilities' utility affiliates operate. Their collective experience is that dynamic pricing for residential customers tends to have low participation, and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those utilities' experiences, all of the Joint Utilities agree that a utility should consider some or all of the issues discussed in this section before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Utilities further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

II. Scope of the Dynamic-Pricing Section

This section addresses dynamic pricing for residential customers. It defines dynamic pricing and provides summaries of the Joint-Parties utilities' experiences with dynamic-pricing offerings for residential customers. This section further provides items to consider concerning dynamic pricing, including rate structures, costs and benefits to customers and utilities, possible eligibility criteria for participating in dynamic pricing, educational needs of residential customers who participate in dynamic pricing, and a number of other relevant considerations.

III. Definition of Dynamic Pricing

Dynamic pricing refers to pricing that varies according to the time at which the energy is consumed. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to a customer via time-based rates or tariffs. There are several different kinds of dynamic pricing.

A. Time of Use or Time of Day

TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

DYNAMIC PRICING

B. Critical-Peak Pricing ("CPP")

There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally lacking in dynamism as TOU rates.

Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR")

PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than the baseline amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

D. Real-Time Pricing ("RTP")

RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

IV. Utilities' Experience with Dynamic Pricing

Several of the Joint Utilities have experience with dynamic pricing, as described below. The Joint Utilities have also assembled a collection of the dynamic-pricing rates currently available to residential customers in Kentucky (see Appendix B), as well as a collection of dynamic-pricing rates the Joint Utilities' utility affiliates in other jurisdictions offer to residential customers (see Appendix C).

A. Duke Energy

Generally, Duke Energy offers residential TOU or TOD pricing in which electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices, manage their energy costs by shifting usage to a lower cost period, or reduce their consumption overall.

Duke Energy's Carolina utilities have offered voluntary residential TOU pricing rates in North Carolina and South Carolina for a number of years. To date, the TOU programs have generated little interest from residential customers. Duke Energy's Florida utility used to have residential TOU rates, but closed them in 2010 due to a lack of customer interest.

Duke Energy's Ohio electric distribution utility (Duke Energy Ohio) has conducted several pilot residential TOU programs since 2010. Duke Energy Ohio currently offers only one residential pilot program. Duke Energy Ohio has tried a number of pilots over the past few years to better understand what residential customers desire in TOU rate offerings. Generally, Duke Energy Ohio learned that customers desire three things: (1) an opportunity to achieve meaningful savings, which appears to translate into the ability to save approximately \$5 to \$20 dollars per month; (2) rate structures that had short peak periods during which customers would need to curtail their usage; and (3) rates without a lot of complexity and different pricing periods and seasons, as features such as "shoulder" periods make it more difficult to determine appropriate behaviors.

Through these pilot programs, Duke Energy Ohio learned that any successful TOU rates need to be cost-justified to potentially benefit the customer and the utility. A risk with TOU rates is the concept of "natural winners," those customers whose usage historically does not occur during peak periods, resulting in little to no shift in usage. Obviously, a customer who would not have to make any behavioral or usage changes for a TOU offering to lower his or her bill would find the offering more attractive than a customer who would have to shift usage and change behavior. Unfortunately, if no shifting of usage occurs, there will be no system savings, and essentially the utility will simply collect less revenue while incurring the same level of cost. Finally, based on Duke's experiences, residential TOU rates require a higher level of customer sophistication. Customers have become accustomed to paying average rates and have little understanding that the cost of using energy truly varies based upon when you consume it.

B. American Electric Power (Kentucky Power Company)

Kentucky Power has offered a number of traditional TOD or TOU rates on a voluntary basis for residential, commercial, and industrial customers since the 1980s with relatively low levels of participation. These service offerings generally included relatively lengthy on-peak periods with off-peak periods generally at night and on weekends. In 2010, Kentucky Power expanded the availability of its traditional time-of-use rates to larger customers up to 1,000 kW. Also in 2010, Kentucky Power introduced new time-of-day options for residential and small commercial and industrial customers which included shorter, seasonal on-peak periods as follows:

Winter:	Weekdays 7 a.m. to 11 a.m. and 6 p.m. to 10 p.m., November through March
Summer:	Weekdays noon to 6 p.m., May 15 through September 15

As of April 2014, no residential, 77 small commercial and industrial, and no large commercial and industrial customers are participating in these new offerings.

C. LG&E and KU

DYNAMIC PRICING

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 May 2014, LG&E had 19 customers on Rate LEV, and KU had 5 customers on the rate.

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 high-demand hours 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.

D. Owen Electric Cooperative

Owen offers a variety of voluntary TOU rates for residential, small commercial, and large commercial members. Although Owen has made concerted efforts to promote its TOU rate offerings, participation is relatively low, with 11 residential, 26 small commercial, and 10 large commercial TOU accounts presently in place. Additionally, 178 of Owen's members are currently participating in a voluntary smart-home pilot that has a TOU component as part of the program. This two-year pilot, scheduled to end in late 2014, is presently in the measurement-and-verification-analysis phase.

E. Jackson Energy Cooperative

DYNAMIC PRICING

Jackson Energy has a residential Electric Thermal Storage ("ETS") TOU rate.[21] Jackson Energy has offered this rate since approximately 1984 and currently has 940 consumers on it.

V. Dynamic-Pricing Considerations

Based on the experiences of the utilities described above, the Joint Utilities present below a non-exhaustive list of items a utility may want to consider when formulating dynamic-pricing offerings:

A. Rate and tariff considerations

1. Opt-in versus opt-out. The Joint Utilities have demonstrated that only a small percentage of residential customers will opt into dynamic-pricing rates. Therefore, if a utility's goal is to have relatively high participation in an opt-in dynamic-pricing offering, it may consider offering incentives to participate; however, the cost of incentives must be weighed against the potential benefits.

2. Rate structure. The rates a utility will choose for any dynamic-pricing structure will differ depending on the goal of the dynamic-pricing program. For example, a utility seeking to create behavioral change, such as significant load-shifting, may want to create greater differences between the various dynamic rates than if the utility's goal is to send purely cost-based pricing signals. Also, a utility may want to introduce a demand component in a dynamic-pricing structure for residential customers to provide customers an incentive to decrease demand during peak periods rather than increasing customers' energy rates beyond the underlying energy cost of production.

3. Minimum contract terms. A utility may consider using a minimum contract term, such as a one-year minimum commitment, to guard against possible gaming by customers who choose to participate in dynamic pricing during months of the year when such rates will reduce their bills and then move back to standard rates during months when they will not be able to save. Minimum contract terms may also be desirable in a pilot program where a utility seeks to have longitudinal data from a stable set of customers.

4. Waiting periods between rate-switching. Another option to deter gaming is to bar a customer who stays on a dynamic pricing rate for less than a year from participating in dynamic pricing again for a set period of time (or perhaps permanently).

[21] Information about Electric Thermal Storage is available at: http://www.steffes.com/off-peak-heating/ets.html.

DYNAMIC PRICING

5. Complexity and dynamism. More complex or dynamic rates create a greater risk of confusing customers and customer-service representatives. Also, dynamic-pricing rates that require customer notice, e.g., variable-CPP or RTP rates, require reliable means of communicating with customers. Providing the necessary communication channels could add cost to a dynamic-pricing program. In addition, more complex or dynamic rates could add cost to a utility's customer-information and billing systems.

6. Criteria for customers to participate in dynamic pricing. Dynamic rates may offer customers a chance to decrease their bills, but customers who do not or cannot follow the incentives may increase their bills, perhaps significantly. Therefore, a utility may want to limit eligibility for dynamic rates to customers who have a satisfactory payment history.

7. Hold-harmless trial period. A utility may want to consider offering customers a chance to test-drive a dynamic-pricing rate by holding the customer harmless relative to the standard residential rate for a limited trial period. This could allow customers to determine if they can respond to the dynamic rate's incentives without risk of financial harm, and may increase participation in dynamic pricing by removing a barrier to entry.

B. Technological considerations

1. Customer-facing technology. A utility should consider the technology a customer will need to have to participate in a dynamic-pricing rate. The amount of technology will vary depending on the rate, e.g., a TOU rate will require relatively less technology than will an RTP rate to allow a customer to respond to the rate's incentives. A utility may want to consider technology some customers already possess, e.g., smart phones, to help meet customer-facing technology needs more economically.

2. Utility technology. As noted in the previous section, more complex or dynamic rates will require relatively greater investments in utility systems to support the rates. Necessary technology upgrades could include, but not be limited to, billing-system upgrades, website upgrades, and other infrastructure improvements.

C. Customer education and marketing considerations

Most residential customers are accustomed to a single, flat, year-round energy rate. Dynamic pricing offers customers the opportunity to reduce their bills by responding to incentives to shift load from peak periods, and may help utilities reduce overall costs. For any number of those customers to move successfully to any variety of dynamic pricing will likely require a thorough customer-education effort to maximize good outcomes and ensure a positive customer experience. The means of carrying out such an effort are addressed in the Customer Education section of this report. The content of the effort will vary depending on the dynamic rate a utility chooses to deploy, but at a minimum such an effort should include information on the rate itself, opt-in or opt-out, minimum contract terms (if any), waiting periods between rate-switching (if any), criteria for participation, and the hold-harmless trial period (if any).

Customer-service representatives will also need training to ensure they can competently handle questions that dynamic-pricing may create.

D. Other considerations

1. Customer costs. In deciding what kind of dynamic pricing, if any, to pursue, a utility should consider the investments customers might have to make to participate, e.g., costs customers would have to incur to respond to pricing signals, both to receive notice of the pricing change and to adjust usage to respond to the signals. A utility should also inform customers up front about the minimum technology requirements for participating in a dynamic rate. For example, a customer might need to purchase a particular kind of thermostat or have a computer or smartphone with certain software to be able to participate in certain kinds of dynamic rates; a utility should communicate such requirements to customers up front. Also, a utility should provide customers a non-exhaustive list of possible ways to reduce their bills under any offered dynamic rate.

2. Equity considerations. Some dynamic-pricing rates may create natural winners and losers. For example, customers who are not home during normal working hours may naturally benefit from TOU rates where peak periods occur during those hours, whereas other customers who are necessarily at home during those hours and incapable of reducing usage may effectively pay a penalty for being unable to change their usage. A utility may want to take into account these equity considerations when crafting dynamic-pricing rates.

3. Economic justification. Particularly for opt-in rates, a utility may consider running a cost-benefit analysis to determine if a particular dynamic-pricing structure is likely to produce benefits to participating and non-participating customers.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Dynamic Pricing

Dynamic pricing is consistent with the Smart-Grid Investment Standard in that all dynamic pricing requires metering more sophisticated than traditional electromechanical meters, and dynamic-pricing with a variable component, such as variable-CPP or real-time pricing, requires smart meters.

DYNAMIC PRICING

Dynamic pricing is also consistent with the Smart-Grid Information Standard, which requires utilities to provide time-based-pricing information to customers to the extent it is available.

But as shown above, some of the Joint Utilities and their utility affiliates in other jurisdictions have offered residential customers (and other customers) different kinds of dynamic-pricing rates without imposition of the EISA 2007 Smart Grid Standards. Therefore, though these standards are consistent with dynamic pricing, their imposition is not necessary for utilities to create such rates. For this reason and the others addressed in this report, the Joint Utilities continue to oppose the EISA 2007 Smart Grid Standards.

VII. Conclusion

Dynamic-pricing rates can add complexity and create possible confusion for residential customers, who are largely accustomed to simple, straightforward, stable rates. But such rates can also offer customers the opportunity to reduce their bills by responding to incentives that may help utilities reduce overall costs, though some customers likely will not be able to avail themselves of the opportunity. Dynamic pricing, therefore, is not a clear-cut benefit or burden, and the Joint Utilities recommend that each utility evaluating the implementation of such rates carefully consider some or all of the issues discussed in this section. The Joint Utilities further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval, a position that is consistent with the Joint Utilities' prior testimony in this proceeding.

VIII. AG Comments

IX. CAC Comments

CAC's position is that low-income advocates are especially concerned about the potential impact on low-income customers who typically do not fully understand the complexities of dynamic pricing or lack the technology to fully take advantage of such rates, which could inadvertently result in higher bills for those customers. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

CAC further believes:

- There is no reason, at this time, to ever require that customers participate in dynamic pricing for any reason.
- Dynamic rates could especially impact senior citizens and customers with low-incomes who work non-traditional shifts. A utility must take into account these equity considerations when crafting dynamic-pricing rates.

DYNAMIC PRICING

- A utility should be able to verify that non-participating customers will not be harmed or bear any costs associated with their decision not to participate.

DISTRIBUTION SMART-GRID COMPONENTS

Distribution Smart-Grid Components

I. Executive Summary

The Joint Utilities have deployed smart technologies in their respective distribution systems as those technologies have demonstrated value or otherwise been determined to be advisable. Certain utilities describe the current state of their distribution smart-technology components in this section. This section also describes available smart-grid components for distribution systems, breaking those components into four categories: switches and valves, voltage stabilization, meters, and communications infrastructure and systems. The Joint Utilities further address three topics (and items related to those topics) utilities might consider when evaluating potential distribution smart-grid investments: technological obsolescence, prepaid metering, and remote connection and disconnection of utility service. Finally, the Joint Utilities address the effect the EISA 2007 Smart-Grid Investment Standard would have on utilities' ability to deploy distribution smart-grid technologies in a rational way, and recommend again that the Commission not adopt the standard, relying instead on the Commission's ample existing review authority concerning base rates, CPCNs, and non-base-rate recovery mechanisms.

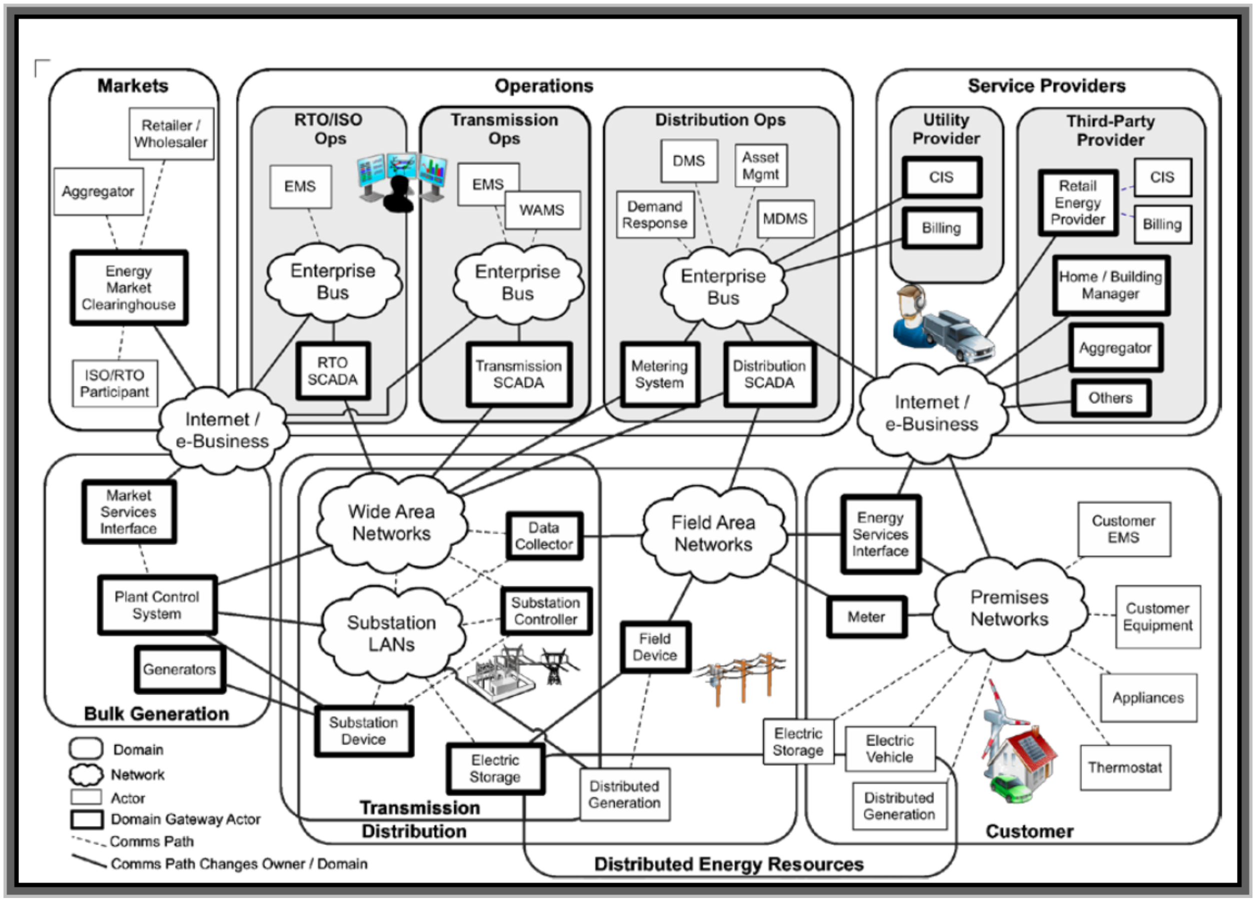
II. Scope of the Distribution Smart-Grid Components Section

This section addresses smart-grid technology for electric and gas utility distribution systems, providing a catalog of currently available smart-grid technologies for such systems and addressing several related issues, namely (a) the challenge of technological obsolescence, (b) prepaid metering, and (c) remote connections and disconnections.

This section does not address smart-grid technology in transmission, generation, or customer-facing applications, e.g., in-home displays for residential customers. Therefore, using the terminology of the National Institute of Standards and Technology diagram below, this section addresses only components in the distribution and distribution-operations domains:[22]

[22] *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0* at 43 (available at http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf).

DISTRIBUTION SMART-GRID COMPONENTS



III. Joint Utilities' Current Deployments of Distribution Smart-Grid Technologies

All of the Joint Utilities deploy some form of distribution smart-grid technology. Each utility provided information concerning its particular deployments in response to the Commission Staff's First Request for Information in this proceeding.[23] Also, the Kentucky Smart Grid Roadmap Initiative's "Smart Grids in the Commonwealth of Kentucky: Final Report of the Kentucky Smart Grid Roadmap Initiative" provides summaries of the utilities' smart-grid-related deployments as of 2012.[24] For ease of reference, several of the Joint Utilities provide below summaries of their current deployments of distribution smart-grid technologies.

A. American Electric Power (Kentucky Power Company)

Kentucky Power has deployed AMR, Distribution Automation – Circuit Reconfiguration ("DA-CR"), Volt/VAR Optimization ("VVO"), and SCADA. AMR has been fully deployed in Kentucky Power for a number of years and provides benefits such as the efficient and timely collection of customer energy data with reduced operating costs. DA-CR and VVO technologies are not fully deployed, but Kentucky Power continues to evaluate and plan for additional

[23] In particular, please see the utilities' responses to Commission Staff Request Nos. 96-102 and 113.
[24] The Commission has incorporated the report in the record of this proceeding.

DISTRIBUTION SMART-GRID COMPONENTS

installations. Currently, there are nine distribution circuits with DA-CR technology and another nineteen being implemented. Similarly, twenty-one distribution circuits have VVO technology installed with four more under development. DA-CR and VVO installations have already demonstrated benefits to customers. DA-CR installations have improved customer reliability by reducing the duration of outages and VVO installations have provided measureable reductions in the demand for energy. In addition, SCADA installations provide the communication infrastructure to support DA-CR and VVO technologies. Approximately thirty-eight percent of distribution substations and approximately ninety percent of transmission substations are equipped with SCADA.

B. Duke Energy Kentucky

Duke Energy Kentucky has installed four self-healing teams (described in greater detail in Section IV.A.) as part of its normal reliability improvement process, when and where appropriate. Duke Energy Kentucky considers the self-healing technology to be smart-grid-related technology, as it includes two-way communications with distribution-system devices allowing for remote operations, although its functions are typically performed automatically. An efficiency benefit to the utility is that the self-healing team is able to automatically identify the section of the circuit where the fault occurred, which results in less assessment time from crews by being able to travel directly to a problem as opposed to patrolling the entire circuit to find the problem. Self-healing teams are also a benefit to customers because they reduce the duration of a sustained outage. Additionally, Duke Energy Kentucky uses some AMI meters that were installed as part of a pilot of a two-way automatic communications system ("TWACS") about eight years ago. Duke Energy Kentucky decided not to proceed with a large-scale deployment of this technology.

C. LG&E and KU

LG&E and KU have deployed four SCADA systems (KU, LG&E electric, LG&E gas, and downtown Louisville), and have installed about 90,000 AMR meters (electric and gas) across their service territories. LG&E is currently deploying approximately 1,500 advanced meters and related infrastructure in its downtown Louisville network as part of a project to gather enhanced engineering information for network planning. Also, LG&E and KU recently applied to the Commission in Case No. 2014-00003 to deploy up to 10,000 advanced meters and related infrastructure through its proposed Advanced Metering Systems customer offering.

D. Jackson Energy Cooperative

Jackson Energy offers prepaid metering as a voluntary option to its consumers.

Participation in prepaid metering allows consumers to monitor their daily usage and take steps to conserve energy. Research into similar prepaid metering programs by other utilities indicated that consumers reduced their usage by as much as 12 percent. Initially Jackson Energy saw energy reductions of 16 percent by prepaid metered consumers compared to their non-prepaid-metered neighbors. Over time the percentage has dropped to 8 percent. Again, these reductions resulted from customers more carefully monitoring their usage, not from any function of the prepaid meters.

Additional benefits to customers of prepaid metering include no deposit, no late charges and no disconnect or reconnect fees.

Jackson Energy currently has over 3,000 prepaid-metered consumers.

Jackson Energy was able to implement prepaid metering by utilizing the AMI system that was already in place.

E. Owen Electric Cooperative

Since 2009, Owen has been engaged in pilot projects that focused on the installation, study, reporting, and advancement of several budding smart-grid technologies. The U.S. Department of Energy ("DOE") provided a grant, managed by Kentucky Department for Energy Development and Independence ("DEDI") within the Energy and Environmental Cabinet, for Owen's first two pilots. The first pilot focused on the self-healing of an area of the system that was far from a service center and had 17 miles of distribution exposure to 900 members. Through smart-switch automation, an alternate feeder from the same source has reduced member interruption duration times by 78% during "healing" events since the fall of 2011. A "Beat the Peak" program was the second pilot in the state grant. This project was designed to gauge participants' willingness to voluntarily reduce electrical consumption during system peaks. Participants were furnished in-home devices that signaled system peak load conditions. Members were alerted, via text messaging or email, of an approaching system peak.

The second grant was through the DOE and administered by the National Rural Electric Cooperative Association. The projects were diverse in nature and were chosen to continue Owen's two-fold smart-grid mission. This mission is to provide new energy-management tools to members in the face of increasing environmental regulation (retail costs) of the power industry, combined with a measured improvement in both the quality and reliability of the power delivered.

The results and ongoing efforts are as follows:

1. SCADA system upgrade – The 1987 vintage SCADA system was replaced by a system equipped with advanced substation and downstream automation capabilities. The self-healing projects have enhanced the performance of the advanced SCADA technology Owen has installed.

2. In addition to increased situational awareness provided by the SCADA upgrade, there are two other key benefits Owen is learning to utilize. The first is substation-device-fault-event information, such as fault type and magnitude, which Owen can now utilize to direct field personnel to specific trouble sites. This information has also shown benefit in allowing the detection of downstream-device operations and manually detecting an

DISTRIBUTION SMART-GRID COMPONENTS

outage prior to member outage calls being received. This capability, when leveraged with Owen's existing Outage Management System ("OMS") and OMS-AMI interoperability, directly benefits Owen's membership with a higher level of confidence and responsiveness. Secondly, Owen has begun utilizing substation-bus-voltage reduction in coordination with its engineering model and verified end-of-line voltages from its AMI system to execute an initial Conservation Voltage Reduction program at no additional cost. This has allowed Owen to reduce its peak demand charges and operate more cost effectively for its membership. Owen's voltage-reduction capabilities were advantageous during a recent system-wide emergency conservation request to reduce energy utilization for the overall electrical grid stability.

3. Smart Home – The pilot project was launched in 2012 and serves 178 member homes. It is presently in the measurement-and-verification ("M & V") phase and will come to a close in 2014. In just the few short years since the pilot was begun there have been significant changes in advanced meter technology and the availability of new member engagement tools such as smart phones, smart applications, Green Button,[25] and commercially available smart thermostats. Future deployment of a Smart Home will reflect these changes and will be dependent on the results of the M & V phase.

4. Volt-Var Optimization – A substation and its associated feeders have been chosen for analysis of the impacts that advanced voltage and Var control would have on a distribution system. Demand reduction, loss reduction, improved voltage regulation, and reactive power management are planned outcomes.

5. Communications System Upgrade – Owen discovered at the outset of its Smart Grid endeavors that robust communication systems are vital. A major upgrade that incorporated fiber optic paths to critical points has been put into place. The increased communication capacity has improved Owen's automated metering and SCADA capability and is necessary for future distribution automation projects.

Another self-healing project improves reliability by providing emergency backup to a large power account with critical operations in northern Kentucky. The self-healing systems saved Owen's members considerable investments by eliminating the need for on-site backup generation.

Additionally, Owen recently implemented a meter-data-management system that enables members to view their usage via a member portal. Owen also recently gained Commission

[25] *See* http://www.energy.gov/data/green-button.

approval to offer a prepaid-metering program to its members. By offering members access to their usage in a more timely and convenient manner, Owen believes that members will be better equipped to manage their energy consumption.

F. Jackson Purchase Energy Corporation

Distribution Automation. Jackson Purchase Energy Corporation ("JPEC") operates a Distribution Automation scheme around the Kentucky Oaks Mall that includes commercial and residential areas. This switching scheme involves multiple reclosers located in substations and tie points on feeder circuits, all communicating with each other by the use of fiber optics. When the system senses a fault, reclosers communicate with each other and operate to isolate the fault to a small line section instead of an entire feeder. This operation may mean isolating the end of a line or transferring load from one substation or feeder to another, thereby isolating the faulted line section. This information is then sent to JPEC's OMS system and dispatchers know instantaneously that a service interruption has occurred and a crew needs to be dispatched.

Voltage Conservation. Using SCADA and AMI, Jackson Purchase Energy can lower the voltage profile of most of its circuits by controlling circuit regulators or substation voltage, which in turn reduces JPEC's system peak. Using system modeling software, JPEC can determine which meters on a circuit need to be monitored for end of line voltage. Then, using the AMI system, end-of-line voltage is reported back to the SCADA system and analyzed by a program that then sends a command to the circuit regulators to either increase or decrease voltage to the circuit. The program requires a forecasted load input and will automatically initiate or terminate when JPEC's system load falls within a certain percentage of the forecasted load.

G. Natural-gas local distribution companies (LDCs)

The three natural-gas-only LDC members of the Joint Utilities have implemented meters that can be read remotely. Each has some difference in circumstances. None of the three LDCs has any current plans to implement AMI or to go beyond the automated meter reading equipment plans below.

Delta Natural Gas for many years has had 100% remote meter reading so that meter readings can be gathered efficiently with devices installed on each meter that transmit meter reads for use in the company's billing system for calculating and rendering billings to customers.

Columbia Gas obtained Commission approval, as a part of its recently concluded rate case, to add meter reading devices on 100% of its meters.[26] The devices will be similar to Delta's equipment, and the installation is scheduled to be completed in 2014.

Atmos Energy has transmitter devices on about 500 of its Kentucky meters as a pilot program. This is the Sensus FlexNet System, which uses a transmitter installed on existing

[26] *In the Matter of: Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates for Gas Service*, Case No. 2013-00167, Order (Dec. 13, 2013).

meters to collect and transmit hourly meter readings from the gas meter to a central data base. The system uses communications devices installed on towers. Meter readings are utilized for customer billing and automation of service orders that require the collection of a meter reading to fulfill various customer service requests. One meter reading per day is entered into the customer account record. The daily readings are used to satisfy requests to collect a reading for move in/move out and other meter reading investigation activities. They are also viewable by the customer through Atmos Energy's online account center, where daily usage is graphically displayed for any billing period in question. Also displayed is the daily high, low, and average temperature for comparison.

IV. Overview of Distribution Smart-Grid Components

The Joint Utilities' view is that the distribution smart-grid consists of four basic categories of intelligent electrical devices: switches and valves, voltage stabilization, meters, and communications and SCADA. Members of the Joint Utilities provide an overview of each category of components below by describing their experience with the technology:

A. Switches and valves (Duke Energy)

Duke Energy has deployed self-healing technology as part of its grid modernization efforts in other states as well as Kentucky. Self-healing technology, which provides an immediate benefit of increased system reliability, uses distribution line power devices such as switches, programmable reclosers, and circuit breakers that are automated and thus capable of communicating via an intelligent control system. The control system, communications system, and power line devices all work together as a "team," collectively serving to identify, communicate, and isolate the portion of the distribution system affected by a fault or other problem, thus minimizing the impact to others. When a fault occurs and a substation locks out, the self-healing team locates the fault, isolates the fault by opening switches immediately upstream and downstream of the fault, and restores power to the sections of the grid not affected by the fault.

B. Voltage stabilization (Kentucky Power)

Kentucky Power has installed VVO technology on twenty-one distribution circuits with four additional installations in progress. VVO installations in Kentucky were preceded by installations at several of Kentucky Power's affiliate companies in Ohio, Indiana, and Oklahoma, with proven results to reduce peak demand and energy consumption for customer loads, as well as delivering reliability benefits. VVO is a smart-grid technology because it allows the distribution grid to automatically detect and react to voltage conditions along the entire length of a distribution circuit and optimize around a more narrow voltage range. A "real world" example of VVO's capability and reliability benefit was recently showcased when the Commonwealth was hit with record cold temperatures in January 2014. Kentucky Power was able to remotely operate distribution circuits equipped with VVO technology to avoid circuit overloading and rolling outages.

DISTRIBUTION SMART-GRID COMPONENTS

C. Meters (Duke Energy)

Duke Energy's definition of a smart grid or grid modernization includes the deployment of a fully advanced metering system that provides two-way communications between the meter and the back office data systems. Communications from the meter include usage data at regular intervals, off-cycle meter reads, theft or tamper alarms, and power-quality alarms. Communications to the meter include meter-program updates and disconnection or reconnection commands. Additionally, this new two-way-communication path for AMI meters can allow for new customer products and services in the future. For those reasons, Duke Energy considers AMI meters to be integral smart-grid components.

Duke Energy has also deployed AMR meters in various territories to facilitate meter reading across the board or for hard-to-access locations. Those meters are not integrated into the AMI back office data systems and do not have the same functionalities as AMI meters; therefore, Duke Energy does not consider AMR meters to be a part of the smart grid.

D. Communications and SCADA (LG&E-KU)

LG&E operates a secondary network system in the downtown business district of Louisville, KY referred to as the LG&E Downtown Secondary Network ("DTN"). There are five different networks in the DTN system, which together comprise 189 vaults, 408 transformers or network protectors, and 27 primary circuits served from three substations. The distribution system provides service to utility customers using radial distribution circuits, interconnected on the secondary side of the distribution transformers through high-current secondary breakers called network protectors. Each of the networks is designed to withstand a single-circuit outage with sufficient capacity on the remaining circuits and transformers to keep all customers in power.

LG&E's DTN has a network-protector-automation system that enables real-time monitoring of loads, critical equipment, vault information, and remote-control operation of network-protector switches.

Before LG&E installed the network-automation system, there was no monitoring or control capability built into the secondary network system. In the new DTN system, microprocessor relays in the network protector devices provide basic information, including voltage, load, and protector breaker position. The automated system includes a full complement of sensors, providing insight into the status of vaults, including vault temperature, transformer temperature, water level, fire indication, and load flows for vault services and to the network grid. Having the ability remotely to obtain information about the vaults' status and to operate protector breakers should enhance the safety of LG&E's workers, who otherwise would have to enter the vaults to perform those functions.

The DTN's front end is a standalone SCADA system. This system contains a user interface with maps and screens detailing the network protectors and vaults, records status information from the microprocessor relays and sensors, and provides system operators with

DISTRIBUTION SMART-GRID COMPONENTS

real-time status and alarm information and automatically notifies operating personnel of the same through email, phone calls, or text messaging.

In sum, the combination of all the smart technologies LG&E is installing in the DTN should enhance the safe and reliable operation of the system, and position it well to provide additional capabilities in the future, such as asset management and engineering, modeling, and analysis of the DTN.

V. Distribution Smart-Grid Investment Considerations

A utility considering investments in distribution smart-grid technologies might consider the following non-exhaustive list of factors that could impact which technologies to deploy:

A. Obsolescence of distribution smart-grid technologies

A possibly significant consideration when deploying any technology, but particularly when deploying new and rapidly developing technologies, is technological obsolescence. In the high-tech world that encompasses smart-grid technology, vendors can quickly go out of business. Those that survive often move on to new versions of products or entirely new products, ceasing to support previous products in the process. In either event, high-tech products can rapidly become orphan technologies, leaving those who have invested in the technologies with difficulties in continuing to support and maintain them.

In addition to the obsolescence risk the normal high-tech business cycle creates, a utility's own changing needs and the changing demands of its customers may effectively render obsolete otherwise serviceable technologies. By way of analogy, the formerly cutting-edge flip-phone remains an entirely serviceable technology for making phone calls on modern cellular networks; however, the more recent advent of truly high-speed wireless data has rendered such phones obsolete for many people who need or desire to conduct data-intensive business functions remotely, including e-mail and videoconferences. The same kinds of technological advances could render some distribution smart-grid components effectively obsolete before the end of their useful lives as consumers and utilities increasingly expect more from their systems, particularly in terms of data, than previous generations of technology could provide.

In conducting their cost-benefit analyses, utilities might consider not only how the future obsolescence of smart technologies impact costs and benefits, but also how foregoing the benefits of deploying smart technologies today creates opportunity costs for themselves and their customers. Using the same cell-phone analogy discussed above, continuing to use a flip-phone while a better, smarter phone is available results in foregone benefits—an opportunity cost—the phone user should consider when deciding whether to upgrade to a smarter phone.

Another aspect of technological obsolescence a utility might consider is the ongoing viability of currently deployed meters. For example, if electromechanical meters are no longer available from domestic manufacturers (which the Joint Utilities believe to be true), it will be

DISTRIBUTION SMART-GRID COMPONENTS

more difficult and possibly more costly to maintain and repair such meters. Such costs might make it more economical to invest in smart meters as replacements for some utilities.

Therefore, a utility might consider both the obsolescence issue (for both existing meters and potential replacement technology) and the 'loss of benefits' issue when considering distribution smart-grid investments.

B. Prepaid metering

Prepaid metering is by no means a new technology: General Electric offered prepaid electric meters as early as 1899.[27] But the significant advances of smart technology have greatly improved the capabilities of prepaid meters. Prepaid metering using smart meters can provide benefits for customers, eliminating the need for customer deposits, significantly reducing or eliminating connection and disconnection charges, making reconnection nearly instantaneous upon the receipt of funds (which can be done online), and providing another payment option for customers. But prepaid metering could require a change to the process by which community action agencies and other providers of utility assistance payments provide service to their constituents, as well as changes to the requirements of the federal or other aid programs the agencies administer. It could also require changes to current regulations and tariff provisions concerning disconnection and reconnection of service. But as noted above, smart-meter technology would provide the benefit of faster and easier reconnection of service whenever such assistance is provided to customers in need. Therefore, a utility might consider the costs and benefits of prepaid metering when considering distribution smart-grid investments.

C. Remote connection and disconnection of utility service

Remote connections and disconnections require AMI, i.e., two-way communications between a utility and its meters. The ability to connect or disconnect remotely customers' service is therefore a capability a utility might consider when analyzing possible distribution smart-grid investments.

Remote connection and disconnection capability has numerous benefits: decreasing operating expense by eliminating the need to send personnel to disconnect and reconnect service (which must be netted against higher meter costs and possibly increased meter-maintenance costs for smart meters); increasing safety for utility employees; reducing charge-offs of bad debt by more rapidly and broadly shutting off service for non-payment (in accordance with Commission regulations only), which reduces the bad-debt expense other customers ultimately must bear; reducing reconnection times, which would speed the effect of utility assistance payments; and providing the ability to respond more rapidly to inactive accounts and accounts with high turnover, such as apartments.

On the other hand, because remote disconnection capability would permit a utility to disconnect all eligible customers rather than the fraction of such customers the utility can

[27] *See* http://www.watthourmeters.com/history.html; http://www.google.com/patents/US667138; http://www.watthourmeters.com/generalelectric/trw-pp.html.

disconnect today due to resource constraints, some customers who might avoid disconnection (at least for a time) today may not avoid disconnection if their utility installed smart meters. But as noted above, the ability to disconnect a customer rapidly allows for the ability to reconnect the customer rapidly, which means the customer would experience the benefit of shorter periods of time without service. Another benefit of remote connect-disconnect capability is ensuring that the customer does not have the ability to amass an even larger debt to the utility (sometimes compounded by reconnection charges, late-payment fees, and additional deposit requirements). And as noted above, customers, not utilities, are ultimately the ones who must bear bad-debt expense, so minimizing the amount of bad debt has a beneficial impact on rates for all customers.

VI. EISA 2007 Smart-Grid Investment Standard and Distribution Smart-Grid Components

The Joint Utilities continue to oppose adopting the Smart-Grid Investment Standard in Kentucky. Most utilities' investments in distribution smart-grid components to date have been, and are likely to be, incremental, not wholesale replacements of entire categories of existing components with smart components. But taken literally, the Smart-Grid Investment Standard would require every utility to demonstrate to the Commission, presumably through an application process, that any proposed investment in non-smart-grid technologies—no matter how small—would be superior to an investment in comparable smart-grid technologies. This would needlessly multiply proceedings before the Commission and likely harm customers due to increased regulatory compliance costs.

The incremental approach most utilities are taking to making most investments in distribution smart-grid technologies allow the utilities to submit projects to the Commission in many forms. Utilities could submit these investments for Commission review in a base-rate case, a CPCN application, or through a non-base-rate mechanism proceeding. The Commission has existing authority in all of these cases to conduct a review and ensure prudence of the utility investments and expenditures.

VII. Conclusion

Although distribution smart-grid components can provide benefits to customers and add value to utilities' distribution systems, there are a number of items utilities might consider before investing in such systems, including items related to technological obsolescence, prepaid metering, and remote connection and disconnection of utility service, all of which can impact customers. But adding another layer of regulation, i.e., the Smart-Grid Investment Standard, to the Commission's already robust oversight authority is not necessary to ensure utilities make only prudent investments; rather, the Commission's existing authority concerning base rates, CPCNs, and non-base-rate recovery mechanisms is sufficient to protect customers while maintaining regulatory efficiency.

VIII. AG Comments

DISTRIBUTION SMART-GRID COMPONENTS

IX. CAC Comments

Though CAC is open to the possibility of a fair and limited risk process for prepaid metering, it has previously opposed such processes and continues to be concerned. It is CAC's belief that prepaid metering will increase the number of customers facing disconnection and, therefore, the number and duration of families and children exposed to lack of heat in winter or cooling in summer. Recent extreme temperatures in 2014 serve to illustrate the risk. This is especially of concern for households where medical conditions such as asthma can be exacerbated by extreme temperatures. Any prepaid metering program should be very carefully examined and designed in close collaboration with community action agencies or other local providers who work regularly alongside customers with low-income. It should take into consideration households affected by a medical condition and or the homes of seniors and the disabled.

CAC is also concerned that the ability to remotely disconnect a customer could significantly increase the frequency of disconnections, especially among vulnerable populations such as customers with low-incomes and seniors or the disabled. Increased disconnections have been seen in markets where smart grid technology has been deployed. Although there may be some benefits such as a faster reconnect process, CAC is concerned that methods of rapid payment to facilitate such reconnection (internet access, credit cards for phone payment, etc.) are not universally available for the customers at risk of such a disconnection. This issue, because it poses a health threat to vulnerable customers left in extreme cold or heat by a remote or automated disconnection, is perhaps of the greatest concern to CAC of all smart grid issues. Further exploration of this issue is warranted to ensure consideration of special circumstances.

CYBER-SECURITY

Cyber-Security

I. Executive Summary

Cyber-attacks are increasing in intensity and sophistication. As recent breaches of large retailers' payment systems have demonstrated, even well-designed and -built cyber-defenses can be overcome when attackers discover weak links in systems and exploit them.

The Joint Utilities are well aware of the cyber-security threat and take it seriously. Indeed, it is in the utilities' best interests to thwart cyber-attacks; all stakeholders' interests are completely aligned on this issue. So although no cyber-defense is perfect and breaches may occur, Kentucky's utilities are working to prevent and defeat cyber-attacks that threaten their systems and the integrity of their and their customers' data.

Some members of the Joint Utilities are subject to mandatory cyber-security standards to protect the Bulk Electric System. As described below, the entities responsible for enforcing these standards have been vigilant, as have the subject utilities, and the penalties utilities might have to pay for violating the standards are substantial: as much as $1 million per violation per day.

There are also several voluntary cyber-security frameworks and guidelines that Kentucky's utilities consult when designing and implementing their cyber-defenses. These industry standards have the benefit of evolving relatively quickly to help utilities adapt to ever-changing cyber-attack strategies and methods.

In view of the force of existing cyber-security standards, utilities' inherent interest in defeating cyber-attacks, and utilities' use of voluntary cyber-security frameworks and guidelines, the Joint Utilities recommend against implementing any state-level cyber-security regulation or enforcement.

II. Scope of the Cyber-Security Section

This section addresses the mandatory standards with which some Kentucky utilities must comply, as well as voluntary frameworks and guidelines some utilities have adopted, to guard against unauthorized access into utilities' smart-grid-related systems, including unauthorized access to information utilities gather from customers using smart-grid technology. This section addresses cyber-security primarily related to smart-grid components, not utility cyber-security generally. For example, this section does not address the security measures for utilities' websites, which would exist even if utilities did not deploy smart-grid components.

The scope of this section is also separate and distinct from the Customer Privacy Section of this report, which addresses rights and responsibilities concerning Kentucky utilities' gathering and authorized use of customer information, including customers' and other parties' access to such information. This section addresses only safeguards against unauthorized access.

CYBER-SECURITY

III. Cyber-Security Standards Already in Force

The mandatory cyber-security standards in place today are the Critical Infrastructure Protection ("CIP") Standards drafted by the North American Electric Reliability Corporation ("NERC"), approved by the Federal Energy Regulatory Commission ("FERC"), and administered and enforced by NERC and its regional entities, including the SERC Reliability Corporation ("SERC"). (SERC's jurisdiction covers all of Kentucky except its easternmost portion, which is under the jurisdiction of the ReliabilityFirst Corporation.)

Eight of NERC's nine mandatory CIP Standards (version 3) address cyber-security:

- CIP-002: Requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System.

- CIP-003: Requires Responsible Entities to have minimum security management controls in place to protect Critical Cyber Assets.

- CIP-004: Requires personnel with access having authorized cyber or authorized unescorted physical access to Critical Cyber Assets, including contractors and service vendors, to have an appropriate level of personnel risk assessment, training, and security awareness.

- CIP-005: Requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter.

- CIP-006: Addresses implementation of a physical security program for the protection of Critical Cyber Assets.

- CIP-007: Requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the other (non-critical) Cyber Assets within the Electronic Security Perimeter(s).

- CIP-008: Ensures the identification, classification, response, and reporting of Cyber Security Incidents related to Critical Cyber Assets.

- CIP-009: Ensures that recovery plan(s) are put in place for Critical Cyber Assets and that these plans follow established business continuity and disaster recovery techniques and practices.[28]

[28] Quoted from http://www.nerc.com/pa/CI/Comp/Pages/default.aspx. This section does not address NERC CIP-001, which standard concerns sabotage reporting, not cyber-security explicitly.

CYBER-SECURITY

These standards mandate many industry-best-practice processes to protect the computer networks associated with assets considered to be critical to the bulk electric system. In response to the CIP Standards, the entire electric industry has implemented extensive security enhancements for the computer networks associated with critical bulk-electric-system assets, including smart-grid components. Many utilities, including members of the Joint Utilities, have also implemented extensive internal compliance programs to help ensure their compliance with the CIP Standards, often including significant oversight and involvement from their senior leadership and internal self-assessments to test the quality of their implementation.

NERC and its regional entities apply the CIP Standards to all FERC-jurisdictional entities, including all of the electrical-utility members of the Joint Utilities except the distribution cooperatives. The penalties for violating the standards can be severe: NERC and its regional entities may impose fines on a utility of up to $1 million per violation per day, and they may find a utility has committed more than one violation each day.[29]

IV. Voluntary Cyber-Security Frameworks and Guidelines

In addition to the mandatory standards above, the Joint Utilities' electric-utility members are aware of the following non-exhaustive list of voluntary cyber-security frameworks and guidelines, which various Kentucky electric utilities consult when considering cyber-security:[30]

A. National Institute of Standards and Technology Interagency Report ("NISTIR") 7628, "Guidelines for Smart Grid Cyber Security"

The Guidelines for Smart Grid Cyber Security were developed by the Cyber Security Working Group of the Smart Grid Interoperability Panel, a public-private partnership launched by the National Institute of Standards and Technology. These voluntary guidelines address four broad cyber-security topics:

- Cyber Security Strategy. Provides a cyber-security strategy for the smart grid and the specific tasks within the strategy.
- Logical Architecture. Provides a composite high-level view of smart-grid actors and includes an overall logical reference model of the smart grid, as well as information on each of the 22 logical-interface categories in the smart grid.
- High Level Security Requirements. Provides high-level security requirements for each of the smart grid's 22 logical-interface categories.

[29] Sanction Guidelines of the North American Electric Reliability Corporation at 5-7 (available at: http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_4B_SanctionGuidelines_20121220.pdf).

[30] The Joint Utilities are aware of other cyber-security-related frameworks, such as the U.S. Department of Energy's Electricity Subsector Cybersecurity Capability Maturity Model ("C2M2") and the SANS Institute's Top 20 Critical Security Controls ("SANS 20"); however, the Joint Utilities are not addressing them in this report because such cyber-security maturity models and control proposals do not primarily concern the smart grid.

CYBER-SECURITY

- Cryptography and Key Management. Identifies technical cryptographic and key management issues across the scope of systems and devices found in the smart grid, along with potential alternatives.[31]

B. National Rural Electric Cooperatives Association ("NRECA") and Cooperative Research Network ("CRN"), "Guide to Developing a Cyber Security and Risk Mitigation Plan"

The Cooperative Research Network has developed a set of tools that compose the "Guide to Developing a Cyber Security and Risk Mitigation Plan." The purpose of the tools is to enable cooperatives to strengthen their security posture and chart a path of continuous improvement. The tools are:

- A Guide to Developing a Cyber Security and Risk Mitigation Plan. As part of the CRN Regional Smart Grid Demonstration, CRN created a guide to enhance security at the co-ops participating in the demonstration as they acquire and deploy grid components and technologies. Written for co-ops participating in the demonstration, the Guide can be used by any utility.

- Cyber Security Risk Mitigation Checklist. A list of activities and security controls necessary to implement a cyber-security plan, with rationales.

- Cyber Security Plan Template. Co-ops can use this form to create their own cyber-security plan.

- Security Questions for Smart Grid Vendors. CRN is encouraging co-ops to include these questions in their RFPs for smart-grid components. The questions are designed to facilitate a frank and open dialogue on cyber-security with those who make and sell components.

- Interoperability and Cyber Security Plan. The Interoperability and Cyber Security Plan ("ICSP") was the first deliverable produced for the Department of Energy, funded by a matching grant. The ICSP examines risk management, identification of critical cyber-assets, and electronic security perimeters, among other issues.[32]

V. Current Cyber-Security Standards, Guidelines, Oversight, and Enforcement Are Sufficient

As shown above, there are already adequate requirements, enforcement mechanisms, and guidelines concerning cyber-security for utilities' smart-grid systems. Indeed, the recent "Cyber Security Risk Assessment and Risk Mitigation Plan Review for the Kentucky Public Service Commission" shows that responsible agencies are conducting oversight activities even for

[31] http://www.nist.gov/smartgrid/upload/nistir-7628_total.pdf.
[32] https://groups.cooperative.com/smartgriddemo/public/CyberSecurity/Pages/default.aspx.

CYBER-SECURITY

electric utilities not subject to mandatory cyber-security requirements.[33] Therefore, additional cyber-security requirements, oversight, and enforcement at the state level are not necessary.

Worse than unnecessary, additional prescriptive requirements in this area could prove to compound rather than mitigate cyber-threats. Cyber-attacks and the threat they pose are constantly evolving, making cyber-security regulatory requirements, particularly ones that lock utilities into particular technologies or protocols, potentially dangerous. Utilities must have sufficient flexibility to adapt to threats as they develop and change; regulatory strictures constraining that flexibility could prove to be fatal straitjackets, not safeguards. Additional regulatory mandates might diminish utilities' ability to make their best risk-mitigation decisions to prioritize IT security resources. Instead, state-level mandates could create an opportunity to push the focus of those resources to risks that utilities might consider to be very low compared to other risks.

Moreover, additional regulations and requirements may provide a counterproductive and false sense of security. No economically rational set of cyber-defenses can provide complete security from cyber-attacks, but mere compliance with a set of regulations could create a false impression of impregnability that erodes vigilance. It is in all stakeholders' interests for utilities to stay focused on defeating threats, not complying with regulations.

Another area of concern is that state-level requirements could create a completely new risk for utilities, namely a risk of rules that are inconsistent or inefficient when compared to existing federal regulation. Assuming a state rule is written differently than a federal rule, there is a possibility of inconsistent or inefficient expectations. Inconsistent rules would promote confusion, not security, and the resulting inefficiencies would result in higher costs to customers.

Finally, all stakeholders' interests—customers', regulators', and utilities'—are completely aligned concerning cyber-security; it is in no stakeholder's interest for cyber-attacks to succeed. For that reason, Kentucky's utilities strive to comply with applicable requirements and consider voluntary guidelines when implementing cyber-security measures.[34] Although some cyber-attacks may succeed no matter how robust utilities' defenses, Kentucky's utilities are working diligently to protect their systems and their customers. Therefore, additional regulation or oversight at the state level will not serve to enhance utilities' smart-grid cyber-security.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Cyber-Security

The EISA 2007 Smart Grid Investment Standard would require an electric utility, prior to undertaking investments in non-advanced grid technologies, to demonstrate that it considered an investment in comparable smart-grid technologies by evaluating a number of factors, including total costs, cost-effectiveness, and security. Cyber-security would certainly affect these three factors, but that does not support adopting the standard. Utilities already consider these factors when making investment decisions and proposals to the Commission. Moreover, as the Joint

[33] Available at: http://www.naruc.org/Publications/FINAL%20KY%20SERCAT%202013_for%20posting.pdf.
[34] Joint Utilities' utility members' responses to the Commission Staff's First Request for Information, dated February 27, 2013, Question No. 104, which address cyber-security measures the utilities have implemented.

CYBER-SECURITY

Utilities have already argued, the Commission already possesses all the regulatory authority it needs to address these three factors, as well as all the others in the standard except one. The Joint Utilities therefore continue to oppose implementing the EISA 2007 Smart-Grid Investment Standard in Kentucky.

The Smart-Grid Information Standard does not have direct cyber-security implications. To the extent the standard would require utilities to implement smart technologies to provide customers the required information, existing investment reviews (see above) already may address cyber-security for such technologies. Cyber-security concerning the delivery of information to customers, e.g., through a web portal, is not directly related to smart-grid components, but rather is part of each utility's cyber-security for existing web sites and other customer-information-delivery systems.

VII. Conclusion

None of the Joint Utilities takes cyber-security lightly; rather, all agree that utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks. On the issue of cyber-security, all stakeholders' interests and incentives are aligned. But the Joint Utilities further agree that existing mandatory and voluntary cyber-security standards, frameworks, and guidelines are sufficient, and that adding such regulations or rules at the state level may serve to weaken rather than strengthen utilities' ability to thwart cyber-attacks by slowing their ability to adapt to the ever-changing threat; indeed, in today's threat environment, the ability to remain agile and evolve cyber-security defenses, tools, procedures and overall defensive posture is critical to a utility's ability to protect against emerging cyber threats. The cyber-security focus should be on a utility's ability to evolve with emerging threats, not on their compliance with cyber-security standards based on legacy threat profiles. A mature effective cyber-security process is one that is continuously evolving based on emerging threat intelligence and threat vectors or actions. Therefore, additional regulations or requirements at the state level are not necessary or advisable.

VIII. AG Comments

IX. CAC Comments

Utilities should work diligently to take reasonable measures to prevent and defeat cyber-attacks.

HOW NATURAL GAS COMPANIES MIGHT PARTICIPATE IN THE ELECTRIC SMART GRID

How Natural Gas Companies Might Participate in the Electric Smart Grid

I. Executive Summary

As the Commission acknowledged in its order opening this proceeding, "Smart Grid and Smart Meter issues are predominantly focused on the electric industry."[35] Though that is true, Kentucky's natural-gas local distribution companies (LDCs) have in some ways pioneered deploying automated and smart technologies among utility operations, having deployed SCADA in their distribution systems and AMR in meter reading for many years. But having already achieved the efficiencies associated with those technologies means that LDCs and their customers may have less to gain from further smart-technology deployments. Also, there are a number of benefits or efficiencies that electric smart technologies might provide or enable that would not benefit LDCs, such as time-of-use or dynamic pricing and remote-reconnection capabilities. Nonetheless, the LDCs among the Joint Utilities remain committed to seeking economical means of participating in the electric smart grid or of developing an independent gas smart grid.

II. Scope of the Natural Gas Participation Section

This section addresses Kentucky's natural-gas LDCs' current deployments of automated and smart technologies, the ways in which the electric smart grid and the gas smart grid differ, and issues related to future involvement of the natural-gas LDCs in the electric smart grid.

III. Natural-Gas LDCs' Current Deployments

A. Atmos Energy

Atmos Energy has approximately 500 wireless meter reading ("WMR") devices in Kentucky. Those devices are all centralized in Livermore, Kentucky, and were installed in 2011. Atmos Energy anticipates installing additional WMR devices in Kentucky over time.

Atmos Energy uses a SCADA system to electronically monitor its distribution system. The SCADA system is located within Atmos Energy's Gas Control department, which monitors the distribution system 24/7. The SCADA system monitors key flow points on the system and the Gas Control department can remotely control valves, pressures, and flows at those locations. The SCADA system cannot remotely control meters at a customer's premise.

B. Columbia Gas

Columbia Gas began utilizing AMR devices on hard-to-reach meters in 2009 as part of its meter-replacement program. The AMR devices that Columbia Gas deploys provide a simple digital reading of the mechanical meter register. Only the customer's meter reading is

[35] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 8 (Oct. 1, 2012).

HOW NATURAL GAS COMPANIES MIGHT PARTICIPATE IN ELECTRIC SMART GRID

communicated by the AMR device using radio technology to transmit the meter reading to a specially equipped company vehicle driving through neighborhoods. Columbia Gas is installing AMR devices on all residential and commercial meters in 2014.

Columbia Gas uses a SCADA system to electronically monitor gas flows on its distribution system. The SCADA system is part of the Gas Control department and monitors key flow points on the system. The Gas Control department is staffed 24 hours a day, every day of the year, and can remotely control critical valves, regulators, and flows at certain locations on Columbia Gas's system, but not meters at an individual customer premise.

C. Delta Natural Gas

Delta Gas installed remote meter reading many years ago on 100% of its system. This process utilizes devices installed on each meter that transmit meter reads to use in customer billing. Delta has no current plans to implement smart meters (AMI) or to go beyond the current automated meter reading used with its customers. The current system does not provide hourly or daily data, and does not provide any information back to the customer. Meters are read monthly.

Delta utilizes a SCADA system to monitor gas flows electronically on its system. Delta operates a 24/7 gas control function as a part of its normal operations. This system monitors key flow points on Delta's system and provides for remote-controlled valves, pressure, and flow controls on some of those points. Delta does not control valves remotely or electronically for meters at a customer's premise.

D. Duke Energy

Duke Energy Kentucky uses a SCADA system to electronically monitor and control its gas transmission and distribution systems 24/7. The SCADA system monitors key flow points on the system for flow, pressure, and odorant-injection rates. Gas Control uses SCADA to remotely control, valves, regulators, and pumps. The SCADA system does not monitor or control equipment on a customer's premise.

Combination gas and electric utility companies may have the unique ability to leverage smart-grid back-office systems to provide customers with enhanced data that may not otherwise be cost-effective for a stand-alone natural-gas utility to implement. This shared back-office communication infrastructure across common platforms may provide for additional customer-usage information obtained through automated meter-reading capabilities. For example, gas meters and electric meters could communicate through the same communication-relay point that backhauls data to the company's central processing systems. Sharing common infrastructure could allow combination utilities to more efficiently build out the infrastructure necessary to provide automated-metering services for both gas and electric.

As an example, Duke Energy Ohio's gas and electric customers benefit from a shared communication infrastructure as described above. Today, both gas and electric meter reads travel a common communication path back to the Company's central processing systems. After gas and electric meter reads are confirmed, customers are able to login to their individual customer internet portal page to view their previous daily usage information for both gas and electric.

E. LG&E

As have the other LDCs, LG&E has deployed gas SCADA equipment enabling 24/7 electronic monitoring of more than 9,000 data points at over 260 locations within LG&E's gas system. LG&E's SCADA system enables remote control of equipment at 39 of those locations. The locations monitored or controlled include city-gate stations, gas-regulator stations, compressor stations, underground-gas-storage-field equipment, pipeline valves, and large-volume-customer-metering sites. LG&E does not remotely control equipment at customer-metering sites.

On the customer-facing side of its gas business, LG&E has deployed over 32,000 AMR devices installed on gas meters which are difficult to access. The AMR devices utilize a radio transmitter to transmit meter readings to meter-reading vehicles when the vehicles make their scheduled patrols.

IV. How the Smart Grid Differs for Electric Utilities and Natural-Gas LDCs

There are several important differences between electric and gas utilities and the services they provide that affect how gas utilities might participate in the smart grid.

A. Natural-gas LDCs do not use time-of-use or dynamic-pricing structures

Natural-gas LDCs purchase natural gas days, weeks, or months ahead of the time they supply gas to their customers. Therefore, time-based or other dynamic-pricing regimes do not make sense for LDC customers, reducing the potential economic benefit of providing hourly or real-time pricing and consumption information to customers.

B. Much retail natural-gas use is not truly discretionary or easily adjustable

Retail customers, and particularly residential customers, tend to use natural gas in non-discretionary ways. For example, a typical retail natural-gas customer may have a gas furnace, a gas water heater, and a gas stove and oven. Of those items, only the stove and oven use may be meaningfully discretionary; when temperatures drop, customers must keep their homes warm. Even if a customer desires to reduce gas use somewhat by turning down a thermostat, adjusting a water-heater setting is not something customers are likely to do with any frequency. This is particularly true when natural-gas prices are low.

C. There are not many, if any, smart-grid-related operational savings beyond those the natural-gas LDCs already capture through AMR

For example, safety requirements would prevent natural-gas LDCs from using a remote reconnection feature of smart gas meters (if such meters exist; to the Joint Utilities' knowledge, there are no smart gas meters with remote connection or disconnection capabilities). This limits the additional operational benefits smart meters might provide beyond the meter-reading savings the natural-gas-only LDCs in Kentucky have captured through AMR.

D. Natural-gas-only LDCs cannot benefit from the cost-sharing between electric and gas smart-grid communications as readily as combined electric and gas utilities

For combined electric and gas utilities, the ability to share a single communications network for electric and gas smart components might help make a smart-grid deployment more economical for both kinds of utility service. For example, Duke Energy Ohio uses a single communications network for its electric and gas meters, as well as a combined customer-information portal. But it will be harder for natural-gas-only LDCs to realize the savings of using a combined communications system. The gas-only LDCs among the Joint Utilities serve customers across multiple electric-utility territories; for each LDC to coordinate its smart components' communications systems with multiple electric providers' communications systems would be challenging at best. Therefore, it seems unlikely that LDC smart-grid deployments would benefit from sharing costs with electric utilities, reducing the relative economic attractiveness of such potential deployments.

V. Future Considerations

Although a gas smart grid faces challenges that differ from the electric smart grid, the LDCs among the Joint Utilities believe it is important to stay informed about developments that may change the value proposition a gas smart grid—or an integrated gas and electric smart grid—can offer. There are initiatives in this regard that the LDCs are monitoring or participating in to ensure they are aware of relevant developments. For example, the Gas Technology Institute ("GTI") is working on gas smart-meter and smart-grid areas. (Appendix D to this report is a two-page document from the American Gas Association summarizing some of GTI's work on how the gas and electric smart grids might complement and integrate with each other.) GTI set up a Gas Technology Working Group within the Smart Grid Interoperability Panel ("SGIP"). They plan to investigate the interaction between the gas delivery and electric power delivery systems with respect to interoperability standards, common technological paradigms, and associated system implementations. A major emphasis will be an investigation of the advantages available to both industries with the development of interoperability standards that will foster the integration of gas systems into the electric-centric smart grid.

The LDCs further believe their participation in this case has increased their awareness of what their electric-utility colleagues are doing in the smart-grid arena, which may contribute to future collaboration and cooperation between electric and gas utilities in Kentucky.

HOW NATURAL GAS COMPANIES MIGHT PARTICIPATE IN ELECTRIC SMART GRID

VI. EISA 2007 Smart-Grid Investment and Information Standards

The proposed EISA 2007 Smart-Grid Investment and Information Standards explicitly apply only to electric utilities, and therefore would not apply by their own terms to natural-gas LDCs. That notwithstanding, the Joint Utilities agree that any natural-gas smart-technology deployment should be economical.

VII. Conclusion

Although there are potentially fewer benefits to additional smart-technology deployments and higher hurdles to such deployments for LDCs, Kentucky's LDCs among the Joint Utilities remain committed to seeking economical means to improve information flow to their customers through smart-grid participation.

VIII. AG Comments

IX. CAC Comments

No comments.

COST RECOVERY

Cost Recovery

I. Executive Summary

For utilities to invest with confidence in smart-grid technologies to improve the service and information their customers receive, they must have reasonable assurance of cost recovery for their prudent investments and for the remaining book costs of the existing equipment or facilities the smart-grid facilities will replace. There is nothing novel about this concept; it is an axiom of regulated-utility investments, whether for smart technologies or otherwise.

But because utilities may and are deploying smart technologies under different circumstances, in different ways, at different paces, and to different extents, there cannot be a one-size-fits-all approach to cost recovery for, or review of, smart-technology deployments. Instead, to encourage the most economically rational yet innovative uses and deployments of smart technologies: (1) all forms of cost recovery should be available for utilities to consider and propose to the Commission, including traditional base rates, existing cost-recovery mechanisms (e.g., demand-side management ("DSM") riders), and new riders or surcharge mechanisms; (2) utilities proposing smart-technology deployments that will necessitate retiring existing utility assets with unrecovered book life should take the cost of those retirements into account in their cost-benefit analyses and be able to recover that cost if the deployment is prudent; and (3) additional smart-grid-specific review proceedings or criteria are unnecessary for smart-grid deployments because existing cost-recovery and other review proceedings and mechanisms are sufficient, including CPCN proceedings and various kinds of rate proceedings. In particular concerning the last point, the Joint Utilities continue to oppose the imposition of the EISA 2007 Smart-Grid Investment Standard or any derivative thereof due to the sufficiency of existing review mechanisms and criteria.

II. Scope of the Cost Recovery Section

This section addresses the appropriate means of cost recovery for smart-technology investments, including the unrecovered cost of obsolete technologies replaced by smart technologies. This section addresses also the sufficiency of existing review mechanisms and criteria for evaluating the prudence of smart-technology investments.

III. Utilities' Past and Current Cost-Recovery Approaches for Smart-Technology Investments

A. AEP

The recovery of Smart Grid investments such as AMI meters and Distribution Automation – Circuit Reconfiguration (DA-CR) is similar to other types of distribution investments, which require a return on and of capital investments and recovery of operations and maintenance expenses. Several of the AEP state jurisdictions, including Ohio, Kentucky, Michigan, Indiana, Tennessee, Virginia, and West Virginia, have deployed AMR meters, which are not considered to be smart-grid technology. In addition, AMI meters are installed in parts of Ohio, Oklahoma, Texas, and a small concentration in Indiana. AEP's cost-recovery methods for its smart-grid investments are base rates in Oklahoma (see Cause No. PUD 200800144), a rider mechanism in Ohio (see Case Nos. 08-917-EL-SSO, 08-918-EL-SSO, 11-346-EL-SSO and 11-348-EL-SSO), and a customer surcharge in Texas (see Docket No. 36928). Future smart-grid investments in Indiana would be recoverable through base rates or a rider mechanism.

Cost recovery of Energy Efficiency/Demand Response ("EE/DR") programs, including Volt/VAR Optimization (VVO), is similar to smart-grid programs, except that almost exclusively these costs are recovered through riders or trackers. EE/DR riders are utilized in all of AEP's operating companies that offer EE/DR programs to recover program costs, net lost revenues, and shared savings. Traditional EE/DR programs are expensed, meaning no capital costs are involved. VVO is different in that it provides EE/DR savings, but is predominately a capital expense. Both the Michigan Public Service Commission and the Indiana Utility Regulatory Commission have approved plans for Indiana Michigan Power ("I&M") to qualify VVO as an energy-efficiency program. In Indiana, carrying cost and depreciation for VVO are recoverable through the existing EE/DR rider (see Cause No. 43827 DSM 3). In Michigan, I&M has authority to defer costs associated with VVO for recovery in the next base-rate case (see Case No. U-17353).

B. Atmos Energy

As part of a stipulation in a 2010 Colorado rate case, Atmos Energy was allowed to file for expedited approval of a pilot program in a separate docket to charge a surcharge for the installation of approximately 35,000 AMI devices in Greeley, Colorado. The surcharge was charged to both residential and commercial customers state-wide. The pilot program expanded over subsequent years to include Atmos Energy's entire Colorado system of 112,000 residential and commercial meters. The surcharge is no longer in effect because the program has been completed.

C. Columbia Gas

As part of a general rate case in 2013, Columbia Gas received approval to install AMR devices throughout its 30-county service area in 2014, and was granted cost recovery in the forward-looking test year utilized in its filing.[36]

D. Cooperatives

Three distribution cooperatives have sought regulatory treatment concerning the write-off of the cost of meters that were being retired and the associated accumulated depreciation in conjunction with the deployment of AMI.

1. Taylor County RECC. In September 2008, Taylor County filed Case No. 2008-00376, an application with the Commission requesting approval of a deferral plan for retiring meters. Taylor County had been granted a CPCN

[36] *See In the Matter of: Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates for Gas Service*, Case No. 2013-00167, Order (Dec. 13, 2013).

in Case No. 2006-00286 to install solid state AMI meters which would replace mechanical meters. As a result of the installation, Taylor County determined it would experience a $1.2 million extraordinary property loss. Taylor County sought approval from the U.S. Department of Agriculture's Rural Utilities Service ("RUS") to defer the extraordinary property loss and proposed to amortize the resulting regulatory asset over a period of five years. RUS informed Taylor County that Commission authorization for the deferral must be granted before it would approve the proposed plan. In its December 2008 Order in Case No. 2008-00376, the Commission approved Taylor County's request to establish a regulatory asset and amortize that asset over five years for accounting purposes only.

In August 2012 Taylor County filed Case No. 2012-00023 an application to adjust its rates. In its March 2013 Order, the Commission agreed with Taylor County that the appropriate service life for the AMI system was 15 years. Noting that the previously established retired meter regulatory asset would be fully amortized by April 2014, the Commission extended the amortization period three years from the date of the March 2013 Order. The Commission stated this approach was consistent with its practice in rate proceedings involving amounts that remain to be fully amortized.

2. Shelby Energy Cooperative. In March 2012, Shelby Energy filed Case No. 2012-00102, an application with the Commission requesting approval to establish a regulatory asset for the write-off of retired mechanical meters and the associated accumulated depreciation. Shelby Energy had been granted a CPCN in Case No. 2010-00244 to install an AMI system which would replace mechanical meters. As a result of the installation, Shelby Energy determined it would experience a loss of approximately $444,000. Shelby Energy sought approval from the RUS and the Commission to defer the loss and proposed to amortize the resulting regulatory asset over a period of five years. The RUS gave its approval to implement Shelby Energy's proposed plan, but noted that the Commission must authorize the deferral and subsequent recovery of costs. In its April 2012 Order in Case No. 2012-00102, the Commission approved Shelby Energy's request to establish a regulatory asset and amortize that asset over five years for accounting purposes only. The Commission noted that the recovery of the amortization in rates would be considered if raised by Shelby Energy in its next rate case.

3. South Kentucky RECC. In June 2011, South Kentucky filed Case No. 2011-00096, an application to adjust its rates. In its application, South Kentucky sought approval of a 15-year service life for its AMI system and annual depreciation expense on the full cost of the investment in the AMI system. The Commission had granted South Kentucky a CPCN for the AMI system in January 2010 in Case No. 2009-00489. In its March 2012

COST RECOVERY

Order in Case No. 2011-00096 the Commission agreed with the use of a 15-year service life for the AMI system. The Commission reduced the allowed annual depreciation expense to recognize that approximately 49 percent of the investment had been funded through a U. S. Department of Energy grant.

Also in its 2011 rate application, South Kentucky determined it would realize a loss of approximately $3.7 million on the early disposition of its existing mechanical meters. South Kentucky requested that this loss be recognized as a regulatory asset and allow for rate-making purposes the amortization of the loss over a five-year period. In its March 2012 Order the Commission found the special accounting treatment to be reasonable, but determined an amortization period of 15 years was appropriate instead of the proposed five-year period. Citing RUS accounting requirements, the Commission stated that South Kentucky's depreciation rates were determined utilizing the whole life method and under that method, losses would not have been charged against revenue unless an accounting treatment alternative to that prescribed by the RUS was allowed. South Kentucky had sought an alternative treatment when it requested regulatory asset treatment, which the Commission approved. The Commission concluded that the use of the whole life method should not impact the amortization period. The Commission further observed that had the remaining life method been utilized to calculate depreciation rates, the loss on the mechanical meters would have been recognized for accounting and rate-making purposes over the 15-year life of the AMI project. Consequently, the Commission required the regulatory asset to be amortized over 15 years.

South Kentucky sought rehearing on the annual depreciation expense and regulatory asset amortization decisions. In its May 2012 rehearing Order, the Commission confirmed its original decisions. The Commission also noted the five-year amortization periods authorized for Taylor County and Shelby Energy were approved for accounting purposes only and had no impact on the rates charged by either utility and paid for by their respective customers.

E. Delta Natural Gas

Delta Gas installed remote meter reading starting in 1996. Devices were installed on meters to transmit meter readings for customer billing. Delta installed these gradually over a period of years, completing 100% of its meters in 2003. As investments were made in adding these meter reading devices to automate Delta's meter reading, the investments were recorded as assets of Delta and then were included in subsequent general rate cases as rate base investment.

F. Duke Energy

COST RECOVERY

Duke Energy has received special cost recovery treatment for grid modernization investments in some of the jurisdictions in which it operates. As an example, Duke Energy Ohio was granted annual rider recovery for its smart grid investment program in Ohio. These investments included a full deployment of AMI and various distribution-automation ("DA") oriented investments. Duke Energy Ohio files annually with the Public Utilities Commission of Ohio reports detailing the program implementation progress along with associated costs. Duke Energy Ohio also received approval to include in base rates accelerated depreciation of equipment rendered obsolete due to the smart grid program.

G. LG&E and KU

In Case No. 2007-00117, LG&E applied for, and the Commission approved, DSM cost recovery of the non-customer-specific costs of LG&E's three-year responsive-pricing and smart-metering pilot program. The program involved deploying over 1,400 smart meters to residential and small commercial customers, as well as other forms of technology designed to enable customers to understand and better control their energy usage. LG&E recovered about $2 million through its DSM mechanism for the pilot program.

LG&E and KU recently proposed in their current DSM case, Case No. 2014-00003, to recover the cost of deploying up to 10,000 total advanced meters across the LG&E and KU service territories, as well as related support and communications technologies. All told, LG&E and KU propose to recover a total of about $5.7 million in capital and operating and maintenance costs for the Advanced Metering Systems offering for the years 2015 through 2018.

IV. Cost-Recovery Considerations for Smart Technology

There are several valid rate options for utilities to consider for cost recovery of possible smart-technology deployments. All options should be available for utilities to consider and propose to the Commission to remove possible obstacles to economical and innovative smart-technology deployments.

A. Base rates

Particularly for investments that do not involve large or rapid capital outlays, base rates (set using an historical test year) are an option for utilities to consider for recovering the costs of smart-technology deployments. Such cases provide an opportunity for thorough, deep review of the prudence of such investments. Using forecasted test years is also an option, particularly for utilities considering larger or more rapid capital outlays.

B. Existing cost-recovery mechanisms

Some smart-technology deployments may be natural candidates for cost recovery through existing riders or surcharge mechanisms. For example, smart-meter deployments may be ideal for DSM cost recovery due the explicit statutory directive in KRS 278.285(1)(h) for the Commission to consider in a utility's DSM plan "[n]ext-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being

COST RECOVERY

read by the utility either remotely or from the exterior of the home." Other future smart technologies may have environmental benefits that would qualify them for cost recovery through utilities' environmental-surcharge mechanisms. Using established cost-recovery mechanisms has the benefit of thorough prudence review proceedings and well-established procedures for cost recovery.

C. New rider mechanisms

Cost recovery though new riders or surcharge mechanisms may be appropriate for some smart-technology deployments, such as those that require relatively high or unpredictable capital investments. The Commission has clear authority to approve such mechanisms when it determines they are appropriate.[37] Rider mechanisms, whether existing or new, have the advantages of increasing transparency and ensuring accurate cost recovery through periodic true-up and review proceedings. Also, riders tend to decrease the relative cost of debt capital by better ensuring capital recovery.

D. Recovering investments in facilities replaced by smart components

In addition to preserving rate options for recovering the costs of smart-technology investments, it is crucial for the Commission to permit utilities to recover the remaining book value of the obsolete equipment or facilities the smart technologies replace. Requiring utilities simply to absorb those unrecovered costs—turning them into genuinely stranded cost—would necessarily slow the deployment of smart technology in Kentucky, and likely to customers' detriment. The better approach is for utilities to take into account the unrecovered cost of obsolete equipment when performing cost-benefit analyses to evaluate possible smart-technology deployments. This will ensure economical deployments, both protecting utilities' financial health and delivering benefits to customers. The Commission has recognized the need to provide means for utilities to recover the remaining book value of obsolete equipment in new-meter-deployment cases by approving regulatory assets for the unrecovered costs of replaced equipment and amortizing the assets over reasonable terms of years.[38] The Joint Utilities agree with this approach, which protects customers from rate shock through gradualism while ensuring utilities have full cost recovery.

E. CPCN proceedings are not necessary for all smart-technology deployments

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[37] *Kentucky Public Service Commission v. Commonwealth of Kentucky ex rel. Conway*, 324 SW 3d 373, 374 (Ky. 2010) ("We hold that so long as the rates established by the utility were fair, just, and reasonable, the PSC has broad ratemaking power to allow recovery of such costs outside the parameters of a general rate case and even in the absence of a statute specifically authorizing recovery of such costs.").

[38] *See In the Matter of: Request of Shelby Energy Cooperative for Approval to Establish a Regulatory Asset in the Amount of $443,562.75 and Amortize the Amount Over a Period of Five (5) Years*, Case No. 2012-00102, Order (Apr. 16, 2012) (approving requested regulatory asset for remaining book value of meters being replaced with AMI meters, and approving five-year amortization of regulatory asset); *In the Matter of: Filing of Taylor County Rural Electric Cooperative Corporation Requesting Approval of Deferred Plan for Retiring Meters*, Case No. 2008-00376, Order (Dec. 9, 2008) (approving requested regulatory asset for remaining book value of meters being replaced with AMR meters, and approving five-year amortization of regulatory asset).

COST RECOVERY

Finally, although CPCN proceedings may be necessary for certain new and large smart-technology deployments, the Commission should not require such proceedings for all smart-technology deployments. Many smart-technology deployments are merely replacements or upgrades of existing utility equipment, not new construction requiring a CPCN. Some utilities may choose to seek CPCNs for smart-technology proposals to obtain some assurance of future cost recovery (particularly when utilities intend to seek base-rate recovery) even when CPCNs would not be strictly necessary; this option should remain available to utilities. But creating a blanket rule requiring all utilities to seek CPCNs for any smart-technology deployments might impermissibly conflict with KRS 278.020 and would likely slow the deployment of smart technologies in Kentucky by erecting unnecessary cost and time barriers to their deployment.

V. EISA 2007 Smart-Grid Investment and Information Standards

The Joint Utilities continue to oppose adopting the EISA 2007 Smart Grid Investment Standard on numerous grounds articulated throughout this Report. With respect solely to cost recovery, the Joint Utilities oppose the standard because it would potentially limit cost-recovery options, which in turn could slow or eliminate otherwise economical smart-technology deployments in Kentucky.

Similarly, the Joint Utilities continue to oppose the EISA 2007 Smart Grid Information Standard on numerous grounds. With respect to cost recovery, the Joint Utilities oppose the standard because it could create an obligation to deploy smart technologies, and particularly smart meters, without regard for whether such deployments would be economical or whether utilities making such deployments would have assurance of full cost recovery not just of the deployments themselves but also the unrecovered costs of any replaced equipment.

VI. Conclusion

A key to ensuring that Kentucky's utilities deploy smart technologies beneficially is the assurance of full and timely recovery of the prudent costs of such deployments, as well as the unrecovered costs of replaced equipment. Having a wide variety of cost-recovery options will help address the unique circumstances of each utility and each potential deployment, in turn reducing barriers to economical and innovative smart-technology deployments in Kentucky.

VII. AG Comments

VIII. CAC Comments

No comments.

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

EISA 2007 Smart Grid Information and Investment Standards

I. Executive Summary

The Joint Utilities continue to believe that smart technologies, both customer-facing and grid-deployed, hold much promise; indeed, as detailed at various points in this report, all of the utility members of the Joint Utilities have deployed advanced or smart technologies in different ways and degrees. But not all technologies are sensible to deploy in all circumstances, and each utility must have the flexibility to propose solutions that are prudent for their customers. These solutions will vary depending on geography, customer density, existing system constraints and resources, and a host of other factors. Also, smart technologies continue to advance and mature at a rapid pace, and there is no industry consensus about which technologies every utility must deploy. Moreover, none of the jurisdictions in which the Joint Utilities' utility affiliates operate has adopted either of the EISA 2007 Smart Grid Standards. Therefore, the Joint Utilities continue to hold the position they expressed collectively in their May 20, 2013 Joint Comments in this proceeding, namely that each utility's unique circumstances and the pace of technological change make it unnecessary, and likely counterproductive, to impose uniform, one-size-fits-all standards, such as the EISA 2007 Smart Grid Information and Investment Standards. The better approach is to use the Commission's existing authority to ensure the prudence of utility proposals and deployments concerning smart technologies, as the Commission currently does concerning all utility operations and investments.

II. The Joint Utilities Unanimously Agree the Commission Should Not Adopt the EISA 2007 Smart Grid Information Standard

The Joint Utilities continue to oppose unanimously any adoption of the EISA 2007 Smart Grid Information Standard because it could require utilities to make uneconomical investments. The standard would require utilities to provide customers direct access to a wide array of data without regard for the costs or benefits of providing the data:

- Prices: Purchasers and other interested persons shall be provided with information on time-based electricity prices in the wholesale electricity market, and time-based electricity retail prices or rates that are available to the consumers.

- Usage: Purchasers shall be provided with the number of electricity units, expressed in kWh, purchased by them.

- Intervals and Projections: Updates of information on prices and usage shall be offered on a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

> - Sources: Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent that it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.
>
> - Customer data: Customers shall be able to access their own information at any time through the internet and by other means of communication elected by the electric utility for smart grid applications. Other interested persons shall be able to access information not specific to any customer through the Internet. Customer-specific information shall be provided solely to that customer.[39]

The current offering of residential time-based or time-of-use pricing options is limited to voluntary programs, and such pricing options have not yet been widely adopted in Kentucky. Therefore, there is no need to require utilities to provide the extensive pricing, interval, and projection information the EISA 2007 Smart Grid Information Standard requires. Moreover, the EISA 2007 Smart Grid Information Standard takes no account of the economics of serving the different customers and service territories in Kentucky; rather, it would impose a one-size-fits-all requirement that all utilities provide their customers the same kinds of information in presumably similar, if not identical, ways. Such a standard could require utilities to make currently uneconomical investments in customer-facing information technology.

Instead, the Commission should continue to use its existing review processes and authority to ensure utilities are providing customers the information they need in economical ways. That will allow the Commission's review of information provision to customers to recognize each utility's unique characteristics, including the unique costs and benefits of providing certain kinds of information in certain ways to each utility's customers.

III. The Joint Utilities Unanimously Agree the Commission Should Not Adopt the EISA 2007 Smart Grid Investment Standard

The Joint Utilities continue to oppose unanimously any adoption of the EISA 2007 Smart Grid Investment Standard because it would be largely redundant while potentially stifling useful innovation in smart-technology proposals, including potential cost-recovery methods. The standard would require as follows:

> Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of

[39] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 5 (Oct. 1, 2012).

> the State demonstrate to the State that the electric utility considered an investment in a qualified Smart Grid system based on appropriate factors, including:
>
> - total costs;
> - cost-effectiveness;
> - improved reliability;
> - security;
> - system performance; and
> - societal benefit.
>
> The EISA 2007 Smart Grid Investment Standard also requires each state to consider rate recovery of Smart Grid capital expenditures, operating expenses, and other costs related to the deployment of smart grid technology, including a reasonable return on the capital expenditures. As part of the rate recovery consideration, each state is to also consider recovery of the remaining book-value of obsolete equipment associated with smart grid deployment.[40]

Because the Commission already has the ability and duty to review the costs and benefits of utility proposals, the proposed standard is unnecessary; moreover, intervention by advocates such as the AG already helps ensure the thorough review of utility proposals. In addition to being largely redundant, the proposed standard may inhibit useful innovation to the extent it introduces constraints on what can be considered when utilities make smart-grid-related proposals, including constraints on costs and benefits to consider, as well as cost-recovery methods. Therefore, the Commission should decline to adopt the EISA 2007 Smart Grid Investment Standard in favor of continuing to use its existing authority to review utility proposals to ensure they are cost-effective and that each utility's means of cost recovery is appropriate on a case-by-case basis.

IV. Conclusion

The Joint Utilities do not oppose the economical use of smart technologies. But the Joint Utilities do oppose mandatory standards that could require uneconomical investments, stifle innovation, or otherwise curtail each utility's ability to implement what is most economical and sensible for its customers and service territory. Moreover, it is noteworthy that none of the jurisdictions in which the Joint Utilities' utility affiliates operate have adopted either of the EISA 2007 Smart Grid Standards. The Joint Utilities therefore oppose the EISA 2007 Smart Grid Information and Investment Standards, and the Commission should not adopt them.

[40] *Id.* at 4.

EISA 2007 SMART GRID INFORMATION AND INVESTMENT STANDARDS

IX. AG Comments

X. CAC Comments

No comments.

CONCLUSION AND RECOMMENDATIONS

Conclusion and Recommendations

The analytical tools and frameworks provided in this report are the culmination of over five and a half years of examination of smart-grid related issues by the Joint Utilities. These tools and frameworks, operating as voluntary guidelines, may assist utilities when considering smart-technology investments and deployments. But it remains the well- and long-examined view of all of the Joint Utilities that the Commission should not impose any mandatory, uniform guideline or rule for utilities' use of smart technologies. Instead, the Commission should continue to rely on time-tested and proven review processes to review the prudence of utility smart-technology investments and deployments. The Joint Utilities therefore unanimously recommend that the Commission issue a final order closing this case without further proceedings and declining to impose the EISA 2007 Smart Grid Information Standard, the EISA 2007 Smart Grid Investment Standard, or any other smart-technology-related standard.

[AG]

APPENDIX A: ABBREVIATIONS AND ACRONYMS

Appendix A: Abbreviations and Acronyms

AEP	American Electric Power
AG	Attorney General of the Commonwealth of Kentucky by and through His Office of Rate Intervention
AGA	American Gas Association
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
C2M2	U.S. Department of Energy's Electricity Subsector Cybersecurity Capability Maturity Model
CAC	Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc.
CIP	Critical Infrastructure Protection
Commission	Kentucky Public Service Commission
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical-Peak Pricing
CRN	Cooperative Research Network
DA	Distribution Automation
DA-CR	Distribution Automation – Circuit Reconfiguration
DSM	Demand-Side Management
DTN	LG&E Downtown Secondary Network
EE/DR	Energy Efficiency/Demand Response
EISA 2007	Energy Independence and Security Act of 2007
ESPI	Energy Service Provider Interface
FERC	Federal Energy Regulatory Commission
FTC	Federal Trade Commission

APPENDIX A: ABBREVIATIONS AND ACRONYMS

GTI	Gas Technology Institute
I&M	Indiana-Michigan Power
Joint Utilities	Atmos Energy Corporation, Big Rivers Electric Corporation, Big Sandy Rural Electric Cooperative Corporation, Blue Grass Energy Cooperative Corporation, Clark Energy Cooperative, Inc., Columbia Gas of Kentucky, Inc., Cumberland Valley Electric, Delta Natural Gas Company, Inc., Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Farmers Rural Electric Cooperative Corporation, Fleming-Mason Energy Cooperative, Grayson Rural Electric Cooperative Corporation, Inter-County Energy Cooperative Corporation, Jackson Energy Cooperative Corporation, Jackson Purchase Energy Corporation, Kenergy Corp., Kentucky Power Company, Kentucky Utilities Company, Licking Valley Rural Electric Cooperative Corporation, Louisville Gas and Electric Company, Meade County Rural Electric Cooperative Corporation, Nolin Rural Electric Cooperative Corporation, Owen Electric Cooperative, Inc., Salt River Electric Cooperative Corporation, Shelby Energy Cooperative, Inc., South Kentucky Rural Electric Cooperative Corporation, and Taylor County Rural Electric Cooperative Corporation
kWh	Kilowatt-hour
KU	Kentucky Utilities Company
LDC	Local Distribution Company
LG&E	Louisville Gas and Electric Company
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency Report
NRECA	National Rural Electric Cooperatives Association
OMS	Outage Management System
PSA	Public Service Announcement
PTR	Peak-Time Rebate
RECC	Rural Electric Cooperative Corporation

APPENDIX A: ABBREVIATIONS AND ACRONYMS

RF	Radio Frequency
RTO	Regional Transmission Organization
RTP	Real-Time Pricing
RUS	U.S. Department of Agriculture's Rural Utilities Service
SANS 20	SANS Institute's Top 20 Critical Security Controls
SCADA	Supervisory Control and Data Acquisition
SERC	SERC Reliability Corporation
SGIP	Smart Grid Interoperability Panel
TOD	Time of Day
TOU	Time of Use
TWACS	Two-Way Automatic Communications System
VCC	Voluntary Code of Conduct
VVO	Volt/VAR Optimization

APPENDIX B: DYNAMIC PRICING RATES CURRENTLY AVAILABLE IN KENTUCKY

Appendix B: Dynamic Pricing Rates Currently Available in Kentucky

AEP Kentucky Power Company

None; not applicable.

Big Rivers Electric Corporation's Members

Meade County Rural Electric Cooperative Corporation
Schedule 3 A: Three Phase Power Service, 0 KVA – 999 KVA, Optional Time-of-Day (TOD) Rate
Schedule 4: Large Power Service, 1000 KVA and Larger (TOD)

East Kentucky Power Cooperative, Inc.'s Members

Big Sandy RECC
Off Peak Marketing Rate – Included with Schedule A-1 Farm & Home (Electric Thermal Storage ("ETS"))

Blue Grass Energy
GS-3 (Residential and Farm Time-of-Day Rate)

Clark Energy
Schedule D: Time of Use Marketing Service (ETS)

Cumberland Valley Electric
Marketing Rate – Attached to Schedule 1 – Rate for Residential, Schools and Churches (ETS)

Farmers RECC
Schedule RM – Residential Off-Peak Marketing – ETS

Fleming-Mason Energy
Schedule RSP-ETS, Residential and Small Power – ETS
Schedule RSP- Time of Day, Residential and Small Power

Grayson RECC
Schedule 3 – Off-Peak Marketing Rate (ETS)
Schedule 10 – Residential Time of Day

Inter-County Energy
Schedule 1-A Farm and Home Marketing Rate (ETS)

Jackson Energy

APPENDIX B: DYNAMIC PRICING RATES CURRENTLY AVAILABLE IN KENTUCKY

Schedule 11 – Residential Service – Off Peak Retail Marketing Rate (ETS)

Owen Electric

Schedule I-A Farm and Home – Off-Peak Marketing Rate (ETS)
Schedule 1-B1 – Farm & Home – Time of Day
Schedule 1-B2 – Farm & Home – Time of Day
Schedule 1-B3 – Farm & Home – Time of Day
Schedule 1-B4 – Smart Home Pilot – Time of Day

Salt River Electric

Schedule A-5-TOD Farm and Home Service (Time of Day)
Schedule A-5T-TOD Farm and Home Service Taxable (Time of Day)

Shelby Energy

Off-Peak Retail Marketing Rate (ETS)

South Kentucky RECC

Marketing Rate – Attached to Schedule A Residential, Farm and Non-Farm Service (ETS)

Taylor County RECC

Schedule R-1 Residential Marketing Rate (ETS)

Kentucky Utilities Company and Louisville Gas and Electric Company

Kentucky Utilities Company

Sheet No. 79 – Pilot Program – Low Emission Vehicle Service (LEV)

Louisville Gas and Electric Company

Sheet No. 79 – Pilot Program – Low Emission Vehicle Service (LEV)

APPENDIX C: JOINT PARTIES' RESIDENTIAL DYNAMIC-PRICING RATES IN OTHER JURISDICTIONS

Appendix C: Joint Utilities' Residential Dynamic-Pricing Rates in other Jurisdictions

AEP[41]

Ohio Power Company - Columbus Southern Power Rate Zone[42]

Experimental Critical Peak Pricing Service (CPP)
Experimental Residential Real-Time Pricing Service (RTP)

Public Service Company of Oklahoma

Variable Peak Pricing Residential Service (VPPRS)[43]

[41] AEP does not consider TOD rates to be dynamic pricing.
[42] https://www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2014-04-17_AEP_Ohio_Standard_Tariff.pdf.
[43] https://www.psoklahoma.com/global/utilities/lib/docs/ratesandtariffs/Oklahoma/RPSSchedules_01-27-2012.pdf.

APPENDIX D: AMERICAN GAS ASSOCIATION: NATURAL GAS IN A SMART ENERGY FUTURE

Appendix D: American Gas Association: Natural Gas in a Smart Energy Future

From: Ilickovic, Darko(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E026460)
To: Lovekamp, Rick
CC:
BCC:
Subject: RE: LEV Report
Sent: 01/08/2014 08:55:15 AM -0500 (EST)
Attachments: LEV Pilot Report v3.docx;

Rick,

Attached is the updated version per our last internal discussion from October.

<<LEV Pilot Report v3.docx>>

Thanks,

Darko

From: Lovekamp, Rick
Sent: Wednesday, January 08, 2014 7:16 AM
To: Ilickovic, Darko
Subject: LEV Report

Darko,

I will add to the filing calendar that LG&E/KU will file the LEV report with the KPSC on January 31, 2014. Can you send out the latest draft of the report for internal review?

I will setup a meeting so we can discuss and make sure everybody is signed off on the approach.

Regards,

Rick E. Lovekamp

Manager Regulatory Affairs

Office: 502-627-3780

Cell: 502-403-8840

Pursuant to the Kentucky Public Service Commission's Final Orders in Case No. 2009-0548 and in Case No. 2009-00549, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies") respectively hereby file a report as provided for in AVAILABILITY OF SERVICE, 4), Original Sheet No. 79.

The Low Emission Vehicle ("LEV") pilot program was designed as a three-year pilot program available up to one hundred customers otherwise served under Rate Schedule RS (residential) 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

Currently, the Companies have a total of only nine customers participating in the program (six LG&E and three 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 on the LEV pilot program realized decrease in total monthly bill during the same billing cycle from being billed on the pilot 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 eliminate any potential for problems.

The program allows the Companies to evaluate existing electric distribution infrastructure on an individual basis, before it could cause problems. However, the pilot provides no guaranteed mechanism to 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 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 time-of-use pricing rate structure and potentially shifting energy demand to off peak periods in general. Furthermore, this program could be perceived favorably by all residential customers who may be interested in a rate structure providing more control over their electric utility billing. Consequently, the low number of participants in the program over the last three years and the desire to have more participants leads the Companies to propose continuance of the existing program.

From: Needham, Meredith(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E026103)
To: Lovekamp, Rick
CC:
BCC:
Subject: FW: 2012-00428 - Joint Parties/ Frameworks
Sent: 04/01/2014 04:31:55 PM -0400 (EDT)
Attachments: LOUISVILLE-#1069645-v2-Cybersecurity_Section_of_the_Joint_Parties__Report_(2....DOCX; LOUISVILLE-#1056833-v4-Distribution_Smart-Grid_Components_Section_of_the_Joi....DOCX; LOUISVILLE-#1051928-v5-Dynamic_Pricing_Section_of_the_Joint_Parties__Report_....DOCX; LOUISVILLE-#1022815-v6-Customer-Privacy_Section_of_Joint_Parties_Report_(201....DOCX; LOUISVILLE-#1032883-v9-Opt-Out_Section_of_Joint_Parties_Report_(2012-00428).DOCX; LOUISVILLE-#1046536-v6-Customer_Education_Section_of_the_Joint_Parties__Repo....DOCX;

Rick,

You may not need all of these, but I had Duncan send them to me about a month ago. I wasn't sure if you had the last drafts of each of them we've completed so far readily available for what you planned to do with them.

IF you don't need them ….. hit the delete key above!

THANKS!
Meredith

Meredith Needham
LG&E and KU Energy LLC
502.627.2680

DRAFT

I. Executive Summary

Several of the utility members of the Joint Parties have provided voluntary dynamic-pricing options to residential customers, both on trial and permanent bases, here in the Commonwealth and in other jurisdictions. The utilities' collective experience is that dynamic pricing for residential customers tends to have low participation and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those utilities' experiences, all of the Joint Parties agree that a utility should consider some or all of the issues discussed in this section before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Parties further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

CAC's position is that low-income advocates are especially concerned about the potential impact on those customers who do not fully understand the complexities of dynamic pricing or lack the technology to fully utilize such rates and inadvertently increase their bills. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

II. Scope of the Dynamic-Pricing Section

This section addresses dynamic pricing for residential customers. It defines dynamic pricing and provides summaries of the Joint-Parties utilities' experiences with dynamic-pricing offerings for residential customers. This section further provides items to consider concerning dynamic pricing, including rate structures, costs and benefits to customers and utilities, possible eligibility criteria for participating in dynamic pricing, educational needs of residential customers who participate in dynamic pricing, and a number of other relevant considerations.

III. Definition of Dynamic Pricing

Dynamic pricing refers to pricing that varies according to the time at which the energy is used. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to the customer via time-based rates or tariffs. There are several different kinds of dynamic pricing:

A. Time of Use ("TOU") or Time of Day ("TOD")

TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

B. Critical-Peak Pricing ("CPP")

There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally dynamic as TOU rates.

Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR")

PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than that amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

D. Real-Time Pricing ("RTP")

RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

IV. Utilities' Experience with Dynamic Pricing

Several of the utility members of the Joint Parties have experience with dynamic pricing, as described below. The Joint Parties have also assembled a collection of the dynamic-pricing rates currently available to residential customers in Kentucky (see Appendix A), as well as a collection of dynamic-pricing rates the Joint Parties' utility members offer to residential customers in other jurisdictions (see Appendix B).

A. Duke Energy

Generally, Duke Energy offers residential TOU or TOD pricing in which electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices, manage their energy costs by shifting usage to a lower cost period, or reduce their consumption overall.

DRAFT

Duke Energy's Carolina utilities have offered voluntary residential TOU pricing rates in NC and SC for a number of years. To date, the TOU programs have generated little interest from residential customers. Duke Energy's Florida utility used to have residential TOU rates, but closed them in 2010 due to a lack of customer interest.

Duke Energy's Ohio electric distribution utility (Duke Energy Ohio) has conducted several pilot residential TOU programs since 2010. Duke Energy Ohio currently offers only one residential pilot program, with some relative success. Duke Energy Ohio has tried a number of pilots over the past few years to better understand what residential customers desire in TOU rate offerings. Generally, Duke learned that customers desire three things: Customers wanted the opportunity to achieve meaningful savings, which appears to translate into the ability to save approximately $5 to $20 dollars per month; customers wanted rate structures that had short peak periods during which they would need to curtail their usage; and customers did not like rates that added a lot of complexity and different pricing periods and seasons, as features such as "shoulder" periods make it more difficult to determine appropriate behaviors.

Through these pilot programs, Duke Energy Ohio learned that any successful TOU rates need to be cost-justified to potentially benefit the customer and the utility. A risk with TOU rates is the concept of "natural winners," those customers whose usage historically does not occur during peak periods, resulting in little to no shift in usage. Obviously, a customer who would not have to make any behavioral or usage changes for a TOU offering to lower his or her bill would find the offering more attractive than a customer who would have to shift usage and change behavior. Unfortunately, if no shifting of usage occurs, there will be no system savings, and essentially the utility will simply collect less revenue while incurring the same level of cost. Finally, based on Duke's experiences, residential TOU rates require a higher level of customer sophistication. Customers have become accustomed to paying average rates and have little understanding that the cost of using energy truly varies based upon when you consume it. Therefore, Duke does not believe the Commission should make residential TOU rates mandatory at this time.

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Kentucky Power has offered a number of traditional time-of-day/time-of-use rates on a voluntary basis for residential, commercial and industrial customers since the 1980s with relatively low levels of participation. These service offerings generally included relatively lengthy on-peak periods with off-peak periods generally at night and on weekends. In 2010, Kentucky Power expanded the availability of its traditional time-of-use rates to larger customers up to 1,000 kW. Also in 2010, Kentucky Power introduced new time-of-day options for residential and small commercial and industrial customers which included shorter, seasonal on-peak periods as follows:

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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.

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V. Dynamic-Pricing Considerations

Based on the experiences of the utilities described above, the Joint Parties present below a non-exhaustive list of items a utility may want to consider when formulating dynamic-pricing offerings:

A. Rate and tariff considerations

1. **Opt-in versus opt-out.** The utilities among the Joint Parties have demonstrated that only a small percentage of residential customers will opt into dynamic pricing rates. Therefore, if a utility's goal is to have relatively high participation in an opt-in dynamic-pricing offering, it may consider offering incentives to participate; however, the cost of incentives must be weighed against the potential benefits.

   CAC's position is that there is no reason, at this time, to ever require that customers participate in dynamic pricing for any reason.

2. **Rate structure.** The rates a utility will choose for any dynamic-pricing structure will differ depending on the goal of the dynamic-pricing program. For example, a utility seeking to create behavioral change, such as significant load-shifting, may want to create greater differences between the various dynamic rates than if the utility's goal is to send purely cost-based pricing signals. Also, a utility may want to introduce a demand component in a dynamic-pricing structure for residential customers to provide customers an incentive to decrease demand during peak periods rather than increasing customers' energy rates beyond the underlying energy cost of production.

3. **Minimum contract terms.** A utility may consider using a minimum contract term, such as a one-year minimum commitment, to guard against possible gaming by customers who choose to participate in dynamic pricing during months of the year when such rates will reduce their bills and then move back to standard rates during months when they will not be able to save. Minimum contract terms may also be desirable in a pilot program where a utility seeks to have longitudinal data from a stable set of customers.

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5. **Complexity and dynamism.** More complex or dynamic rates create a greater risk of confusing customers and customer-service representatives. Also, dynamic-pricing rates that require customer notice, e.g., variable-CPP or RTP rates, require reliable means of communicating with customers. Providing the necessary communication channels could add cost to a dynamic-pricing program. In addition, more complex or dynamic rates could add cost to a utility's customer-information and billing systems.

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7. **Hold-harmless trial period.** A utility may want to consider offering customers a chance to test-drive a dynamic-pricing rate by holding the customer harmless relative to the standard residential rate for a limited trial period. This could allow customers to determine if they can respond to the dynamic rate's incentives without risk of financial harm, and may increase participation in dynamic pricing by removing a barrier to entry.

B. <u>Technological considerations</u>

1. **Customer-facing technology.** A utility should consider the technology a customer will need to have to participate in a dynamic-pricing rate. The amount of technology will vary depending on the rate, e.g., a TOU rate will require relatively less technology than will an RTP rate to allow a customer to respond to the rate's incentives. A utility may want to consider technology some customers already possess, e.g., smart phones, to help meet customer-facing technology needs more economically.

2. **Utility technology.** As noted in the previous section, more complex or dynamic rates will require relatively greater investments in utility systems to support the rates. Necessary technology upgrades could include, but not be limited to, billing-system upgrades, website upgrades, and other infrastructure improvements.

C. <u>Customer education and marketing considerations</u>

Most residential customers are accustomed to a single, flat, year-round energy rate. For any number of those customers to move successfully to any variety of dynamic pricing will likely require a thorough customer-education effort to maximize good outcomes and ensure a positive customer experience. The means of carrying out such an effort are addressed in the Customer Education section of this report. The content of the effort will vary depending on the dynamic rate a utility chooses to deploy, but at a minimum such an effort should include information on the rate itself, opt-in or opt-out, minimum contract terms (if any), waiting periods

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between rate-switching (if any), criteria for participation, and the hold-harmless trial period (if any).

Customer-service representatives will also need training to ensure they can competently handle questions that dynamic-pricing may create.

D. Other considerations

1. **Customer costs.** In deciding what kind of dynamic pricing, if any, to pursue, a utility should consider the investments customers might have to make to participate, e.g., costs customers would have to incur to respond to pricing signals, both to receive notice of the pricing change and to adjust usage to respond to the signals. A utility should also inform customers up front about the minimum technology requirements for participating in a dynamic rate. For example, a customer might need to purchase a particular kind of thermostat or have a computer or smartphone with certain software to be able to participate in certain kinds of dynamic rates; a utility should communicate such requirements to customers up front. Also, a utility should provide customers a non-exhaustive list of possible ways to reduce their bills under any offered dynamic rate.

2. **Equity considerations.** Some dynamic-pricing rates may create natural winners and losers. For example, customers who are not home during normal working hours may naturally benefit from TOU rates where peak periods occur during those hours, whereas other customers who are necessarily at home during those hours and incapable of reducing usage may effectively pay a penalty for being unable to change their usage. A utility may want to take into account these equitable considerations when crafting dynamic-pricing rates.

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3. **Economic justification.** Particularly for opt-in rates, a utility may consider running a cost-benefit analysis to determine if a particular dynamic-pricing structure is likely to produce benefits to participating and non-participating customers.

   CAC's position is that a utility should be able to identify that non-participating customers will not be harmed or bear any costs associated with their decision not to participate.

VI. EISA 2007 Smart-Grid Investment and Information Standards and Dynamic Pricing

Dynamic pricing is consistent with the Smart-Grid Investment Standard in that all dynamic pricing requires metering more sophisticated than traditional electromechanical meters,

and dynamic-pricing with a variable component, such as variable-CPP or real-time pricing, requires smart meters.

Dynamic pricing is also consistent with the Smart-Grid Information Standard, which requires utilities to provide time-based-pricing information to customers to the extent it is available.

VII. Conclusion

Dynamic-pricing rates can add complexity and create possible confusion for residential customers, who are largely accustomed to simple, straightforward, stable rates. But such rates can also offer customers the opportunity to reduce their bills by responding to incentives that may help utilities reduce overall costs, though some customers likely will not be able to avail themselves of the opportunity. Dynamic pricing is, therefore, not a clear-cut benefit or burden, and the Joint Parties recommend that each utility evaluating the implementation of such rates carefully consider some or all of the issues discussed in this section.

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From: Greenwell, Aaron D (PSC)(adgreenwell@ky.gov)
To: Lovekamp, Rick
CC:
BCC:
Subject: 2012-00428, Smart Grid - Dynamic Pricing
Sent: 03/04/2014 08:12:02 AM -0500 (EST)
Attachments: Dynamic_Pricing_Section_of_the_Joint_Parties__Report_Staff edits.docx;

Rick, attached are the Staff edits. I did not review these in detail so give me a call if you have any questions. Thanks.

Aaron D. Greenwell
Deputy Executive Director
Kentucky Public Service Commission
aarond.greenwell@ky.gov
502-782-2563

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I. Executive Summary

Several of the utility members of the Joint Parties have provided voluntary dynamic-pricing options to residential customers, both on trial and permanent bases, here in the Commonwealth and in other jurisdictions where some of the utilities' affiliates operate. The utilities' collective experience is that dynamic pricing for residential customers tends to have low participation and the dynamic rates that have been implemented sometimes produced net energy-consumption increases. Based on those utilities' experiences, all of the Joint Parties agree that a utility should consider some or all of the issues discussed in this section before offering a dynamic-pricing rate to customers interested in participating in such rate programs. The Joint Parties further agree that utilities should not have an obligation to create dynamic-rate offerings, but rather should have the option to do so subject to Commission approval.

CAC's position is that low-income advocates are especially concerned about the potential impact on low-income customers who typically do not fully understand the complexities of dynamic pricing or lack the technology to fully take advantage of such rates, which could inadvertently result in higher bills for those customers. Efforts should always be made to prevent this from occurring and participation in dynamic pricing should not be a requirement for residential customers. Additionally, the rates of non-participating customers should not be negatively impacted by dynamic pricing offerings.

II. Scope of the Dynamic-Pricing Section

This section addresses dynamic pricing for residential customers. It defines dynamic pricing and provides summaries of the Joint-Parties utilities' experiences with dynamic-pricing offerings for residential customers. This section further provides items to consider concerning dynamic pricing, including rate structures, costs and benefits to customers and utilities, possible eligibility criteria for participating in dynamic pricing, educational needs of residential customers who participate in dynamic pricing, and a number of other relevant considerations.

III. Definition of Dynamic Pricing

Dynamic pricing refers to pricing that varies according to the time at which the energy is consumed. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to the customer via time-based rates or tariffs. Dynamic pricing offers customers the opportunity to reduce their bills by responding to incentives to shift load from peak periods, and may help utilities reduce overall costs. There are several different kinds of dynamic pricing:

A. Time of Use ("TOU") or Time of Day ("TOD")

TOU or TOD rates typically divide a day into two or three groups of hours that have different rates associated with them. For example, a utility might divide the day into peak, intermediate, and off-peak rates, with different hours assigned to each rate, e.g., late evening through early morning would typically be off-peak hours. Each day may have one or two peak periods and may have as many as three intermediate periods. The hours assigned to each pricing period may change seasonally, as well; for example, a summer-peaking utility may have summer TOU periods and different non-summer TOU periods. The rates associated with each period might also change seasonally.

TOU or TOD rates may vary by season, but typically the design is predictable and easy for the customer to understand. Because these rates do not reflect varying cost conditions, they are ordinarily characterized as having little dynamism.

B. Critical-Peak Pricing ("CPP")

There are two types of CPP rates: variable and fixed. Fixed CPP rates are identical to TOU rates with the added feature that during certain days of the year, which are prescribed by tariff, there are a relatively small number of critical-peak hours that have a markedly higher rate than the standard TOU peak rate. Like TOU rates, fixed CPP rates do not reflect varying cost conditions, making them equally lacking in dynamism as TOU rates.

Variable CPP rates, however, add an element of dynamism that TOU and fixed CPP rates do not have because the critical-peak periods are not established by tariff; rather, the implementing utility typically may call a critical peak no more than a certain number of times for certain maximum durations during a year, and may do so on an established amount of notice to customers, usually anywhere from half an hour to several hours.

C. Peak-Time Rebate ("PTR")

PTR rates usually involve establishing a baseline amount of usage for a customer or group of customers and then rewarding those customers with rebates for using less than the baseline amount of energy during peak periods. As with CPP rates, the peaks can be established by tariff or can be called by the utility upon established notice to customers.

D. Real-Time Pricing ("RTP")

RTP rates are the most dynamic of the dynamic-pricing options. Under RTP, customers pay rates linked to the hourly market price for electricity. Customers typically receive hourly prices on a day-ahead or hour-ahead basis.

IV. Utilities' Experience with Dynamic Pricing

Several of the utility members of the Joint Parties have experience with dynamic pricing, as described below. The Joint Parties have also assembled a collection of the dynamic-pricing rates currently available to residential customers in Kentucky (see Appendix A), as well as a collection of dynamic-pricing rates the Joint Parties' utility members' affiliates offer to residential customers in other jurisdictions (see Appendix B).

A. Duke Energy

Generally, Duke Energy offers residential TOU or TOD pricing in which electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year. Prices paid for energy consumed during these periods are pre-

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established and known to consumers in advance, allowing them to vary their usage in response to such prices, manage their energy costs by shifting usage to a lower cost period, or reduce their consumption overall.

Duke Energy's Carolina utilities have offered voluntary residential TOU pricing rates in NC and SC for a number of years. To date, the TOU programs have generated little interest from residential customers. Duke Energy's Florida utility used to have residential TOU rates, but closed them in 2010 due to a lack of customer interest.

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Through these pilot programs, Duke Energy Ohio learned that any successful TOU rates need to be cost-justified to potentially benefit the customer and the utility. A risk with TOU rates is the concept of "natural winners," those customers whose usage historically does not occur during peak periods, resulting in little to no shift in usage. Obviously, a customer who would not have to make any behavioral or usage changes for a TOU offering to lower his or her bill would find the offering more attractive than a customer who would have to shift usage and change behavior. Unfortunately, if no shifting of usage occurs, there will be no system savings, and essentially the utility will simply collect less revenue while incurring the same level of cost. Finally, based on Duke's experiences, residential TOU rates require a higher level of customer sophistication. Customers have become accustomed to paying average rates and have little understanding that the cost of using energy truly varies based upon when you consume it. Therefore, Duke does not believe the Commission should make residential TOU rates mandatory at this time.

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a PPL company

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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

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

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

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

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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 21

Responding Witness: Robert M. Conroy

Q-21. Reference Robert Conroy, p. 23, ll. 13-22 through p. 24, ll. 1-6.

a) Is it Mr. Conroy's contention that the data from the digital meters must be collected through physical visits to the customer's premises?

b) Please describe the process of "transfer[ring] the data into the Company's billing system." Is such data transfer done electronically or manually?

c) Does the Company plan any improvements to its systems for collecting and processing these data to reflect a potentially large increase in the number of customers taking service under Rate RTOD-Energy and Rate RTOD-Demand compared to Rate LEV?

A-21. a) No. Data from Smart Meters (two-way communications) may be collected through physical visit to the meter or remotely through the communication network.

b) Transferring the data, from a physical visit to the meter, into the Company's billing system is done electronically by plugging the hand-held meter reading device into a dock, which then transfers the information in the hand-held device to the billing system.

c) The Company continues to seek opportunities to reduce costs and improve operations where economically justified. The Company will continue to look for improvements in data collection and processing information at the speed of value.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 22

Responding Witness: Robert M. Conroy

Q-22. Reference Robert Conroy, p. 24, ll. 18-20.

a) Is it Mr. Conroy's contention that a higher basic service charge for Rate RTOD-Energy and Rate RTOD-Demand, compared to Rate RS, would be a barrier to customers' interest in taking service under the new rates? Please explain.

A-22. a) As indicated in the testimony, having a higher basic service charge for Rate RTOD-Energy and Rate RTOD-Demand could affect the customer's selection of the optional rates.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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.

a) Please provide the current number of CSR customers and the total CSR customer demand subject to curtailment.

b) Please provide the Company's estimate of the effect of the proposed changes to CSR tariffs on the number of CSR customers or customer demand subject to curtailment. Please provide copies of all workpapers relied on to derive these estimates.

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.

d) Please provide copies of all presentations to Company management or the Company's Board of Directors regarding consideration of changes to the provisions of the CSR tariffs and of the decision to adopt the proposed changes.

e) Please state the basis for the Company's proposal to limit the total hours of curtailment to 100.

f) Has the Company evaluated any additional load control or demand response mechanisms in addition to the CSR? If so, please describe. If not, why not?

A-23. a) KU currently has 5 CSR customers. For planning purposes, KU assumes 81 MW of customer demand subject to curtailment.

b) The Company has not estimated the effect of the proposed changes on the number of CSR customers or the customer demand subject to curtailment.

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.

d) See the response to part c. The Company did not make any presentations to management or the Board of Directors on the consideration of changes to the provisions of the CSR tariffs and of the decision to adopt the proposed changes.

e) This is not a change from the current number of interruptible hours. See the response to PSC 2-24.

f) In Case Number 2014-00003, the Commission approved the Company's DSM Plan that outlined its demand response commitment through 2018. The Company's DSM plan outlined in that case was with consideration of the CSR. In the Company's annual planning processes DSM, CSR, and Generation supply opportunities are given equal priority to determine how to meet forecasted customer energy and demand requirements.

Load duration curve for CSR considerations

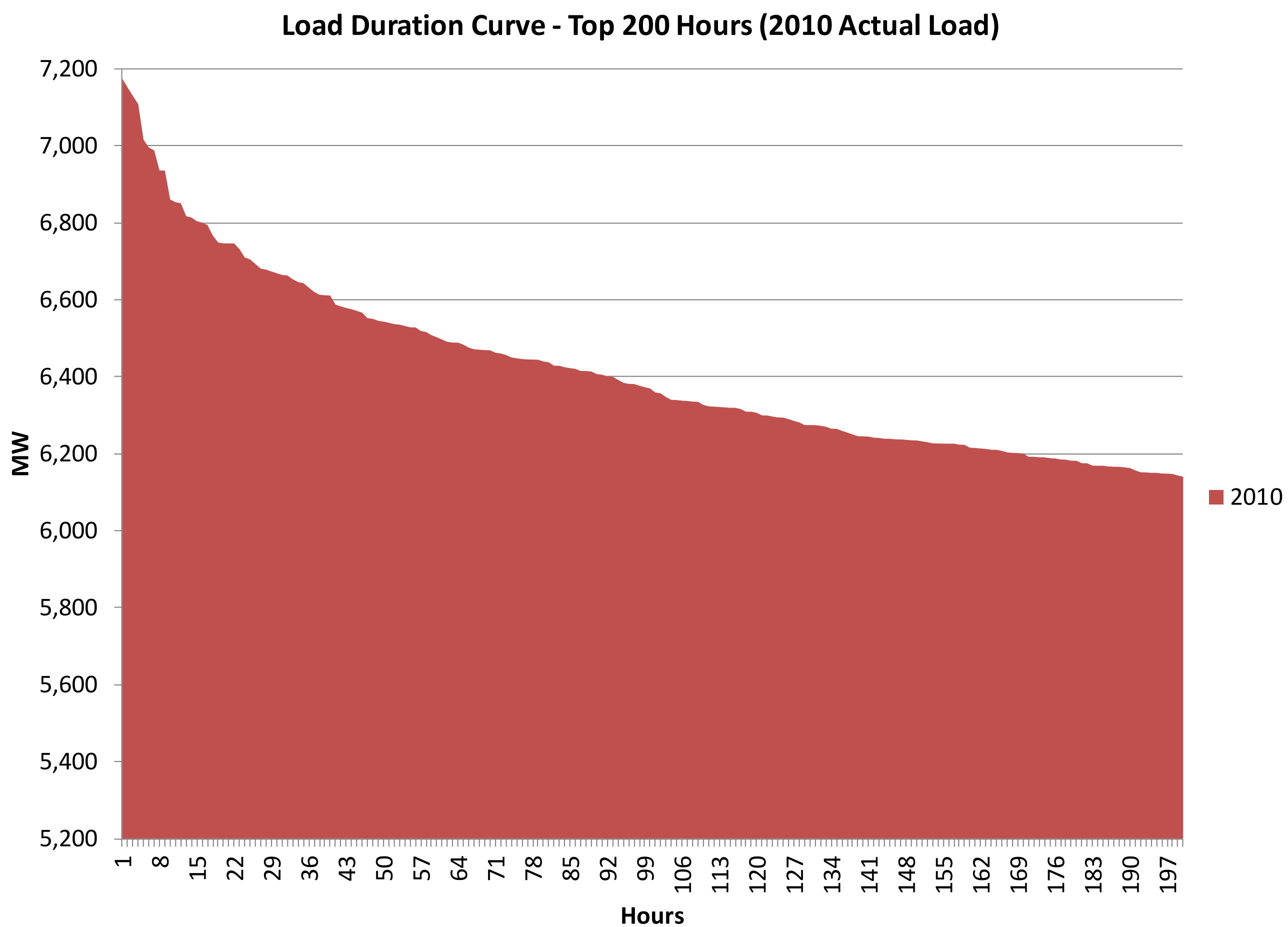
- The need for additional resources (e.g., CSR) is a function of load and unit availability.

- Therefore, load duration curve (LDC) is relevant for CSR discussions.
  - *LDC portrays the amount of time during which particular load levels occur or are exceeded.*
  - *For example, the following chart shows that load exceeded 6,800 MW in 16 hours (out of 8760) in 2010 .*

- However, based on historical data, there's a 5% chance that at least 1,100-1,150 MW will be unavailable. Given the existing resources of 7,931 MW in 2014, therefore, there's a 5% chance that available resources are less than 6,800 MW at any given time.

LG&E KU
PPL companies

Load Duration Curve for Top 200 Hours in 2010



PPL companies

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Malloy, John; Conroy, Robert; Bruner, Cheryl; Huff, David; Cockerill, Butch
CC:
BCC:
Subject: Updated Rate Schedule Review 10-29-2014.docx
Sent: 10/30/2014 08:32:40 AM -0400 (EDT)
Attachments: Rate Schedule Review 10-29-2014.docx;

All,
Attached is the updated document we reviewed yesterday. Thanks for all your input and feedback.

-Steve

ELECTRIC

Rate RS

- Align basic service charge with customer-related costs from cost of service study to achieve an appropriate Basic Service Charge (Increase from $10.75/month to approximately $18/month)
  - Percentage increase in bill for low usage customers will be significantly greater than high usage customers

Redacted as Unresponsive

Curtailable Service Rider (CSR)

- Leave CSR pricing unchanged
- Remove hours of buy-through interruption and provision for buy-through curtailment
- Maximum of 100 hours of physical curtailment at the Company's sole discretion
- Clarify tariff and contract language to specify what it means to be interrupted, i.e. kVA vs kW
- Add a provision to require demonstration/certification of the customer's ability to comply with physical curtailment

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Conroy, Robert
CC:
BCC:
Subject: Rate Schedule Review 10-29-2014.docx
Sent: 10/28/2014 02:05:43 PM -0400 (EDT)
Attachments: Rate Schedule Review 10-29-2014.docx;

Please review and let me know your thoughts

ELECTRIC

Rate RS

- Align basic service charge with customer-related costs from cost of service study to achieve an appropriate Basic Service Charge (Increase from $10.75/month to approximately $18/month)
    - Percentage increase in bill for low usage customers will be significantly greater than high usage customers

Redacted as Unresponsive

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- Maximum of 100 hours of physical curtailment at the Company's sole discretion
- Clarify tariff and contract language to specify what it means to be interrupted, i.e. kVA vs kW
- Add a provision to require demonstration/certification of the customer's ability to comply with physical curtailment

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

[redacted]

[redacted]

Redacted as Unresponsive

[redacted]

Redacted as Unresponsive

From: Oelker, Linn(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E009358)
To: Conroy, Robert
CC: Brunner, Bob; Freibert, Charlie; Martin, Charlie
BCC:
Subject: CSR edits proposed by Power Supply
Sent: 07/14/2014 02:16:23 PM -0400 (EDT)
Attachments: CSR10andCSR30_PowerSupply_proposededits_2014_07_14.docx;

Robert:

Attached are proposed edits to the CSR10 and CSR 30 tariff riders for discussion. These changes, if implemented, are intended to allow Power Supply to curtail the respective customer at any time for any reason for 100 hours in each calendar year. We propose eliminating the Buy-Through Option.

Note we only red-lined the KU versions but other company's riders should be changed.

Please let us know if you have any questions or would like to discuss.

Respectfully,

Linn C. Oelker, P.E.
Manager - Market Compliance
LG&E and KU
Office (502) 627-3245
linn.oelker@lge-ku.com

From: Oelker, Linn(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E009358)
To: Brunner, Bob
CC:
BCC:
Subject: FW: CSR edits proposed by Power Supply
Sent: 08/25/2014 11:14:55 AM -0400 (EDT)
Attachments: CSR10andCSR30_PowerSupply_proposededits_2014_07_14.docx;

From: Oelker, Linn
Sent: Monday, July 14, 2014 2:16 PM
To: Conroy, Robert
Cc: Brunner, Bob; Freibert, Charlie; Martin, Charlie
Subject: CSR edits proposed by Power Supply

Robert:

Attached are proposed edits to the CSR10 and CSR 30 tariff riders for discussion. These changes, if implemented, are intended to allow Power Supply to curtail the respective customer at any time for any reason for 100 hours in each calendar year. We propose eliminating the Buy-Through Option.

Note we only red-lined the KU versions but other company's riders should be changed.

Please let us know if you have any questions or would like to discuss.

Respectfully,

Linn C. Oelker, P.E.
Manager - Market Compliance
LG&E and KU
Office (502) 627-3245
linn.oelker@lge-ku.com

From: Kallam, Karen(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E006057)
To: Woodworth, Steve; Malloy, John; Bruner, Cheryl
CC: Huff, David
BCC:
Subject: RE: Proposed Tariff Changes
Sent: 04/07/2014 04:11:14 PM -0400 (EDT)
Attachments: Customer Service Rate Case Pre-Planning Team - Proposed Tariff Revisions--DE....docx;

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
[redacted] REDACTED FOR PERSONAL PRIVACY
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

From: Malloy, John(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WEB/CN=JOHNMALLOY)
To: Woodworth, Steve
CC: Bruner, Cheryl; Huff, David
BCC:
Subject: RE: Proposed Tariff Changes
Sent: 03/04/2014 10:51:10 AM -0500 (EST)
Attachments:

LG&E/KU - Electric –NMS – Net Metering Service - Sheet #57

Comments – the transferring of credits has much broader implications and thus does not seem wise. We can discuss. Secondly , we need to move this rate back to the variable cost rate of approximately 3.3cents.

KU – Electric – AES – Sheet #12

Comments – This rate and thus discount is unwarranted by the cost causality model, therefore we should seek to keep closed and eliminate if possible. If not possible, elevate rate to more closely reflect appropriate rate. Once at parity, we can close.

LG&E / KU- CSR10 & CSR30 = Sheet # 50 and #51 - Curtailable Service Rider

Comments – discount does not reflect the intrinsic value and should be adjusted more closely align with “call option” valuation.

LG&E – Gas – DGGS – Distributed Generation Gas Service - Sheet #35

Comments - ????????????????????????????

LG&E/KU - Electric –GS - General Service - Sheet #10

Comments – basic service charge a functional of fixed cost which is not the same for single and three phase. Struggle here is we move to a straight, fixed, variable cost model.

LG&E – Gas – VFD - Volunteer Fire Department Service – Sheet #7, DGGS – Distributed Generation Gas Service - Sheet #35

Comments – can we simply eliminate this separate customer class?

Convenience fees will more than likely exceed $3M+

Comments – good idea, alternatively customers who use this payment method should be credited for not using those methods in base rates. Easier to place in base rates.

LG&E / KU – Sheet # 30 - Fluctuating Load Service

Comments – do we need to add a penalty as per NAS discussion?

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. Chervl: Huff. David

Subject: RE: Proposed Tariff Changes

Access denied!

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

John,

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Thanks,

-Steve

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

From: Malloy, John(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WEB/CN=JOHNMALLOY)
To: Woodworth, Steve
CC: Bruner, Cheryl
BCC:
Subject: CSR10 - 30 Tariff
Sent: 09/15/2014 07:30:00 AM -0400 (EDT)
Attachments:

Steve,

We have had several discussions throughout the past year on a Customers ability to "demonstrate" its ability to bring on alternate electrical supplies and / or stop taking electrical service from us when and event is called. This specifically speaks to the Ft. Knox and Toyota discussions. Should we consider language like the AAGS (pasted below) which requires this type of demonstration / certification?

thanks

excerpt from AAGS Tariff sheet 20.1…………………………..

6. Upon commencement of service hereunder, Customer shall be required to certify that Customer's alternate fuel facilities are operational and alternate fuel is on site and capable of use. Company may, at its discretion, verify such certification through physical inspection of Customer's facility. In the event that Customer does not have alternate fuel facilities, Customer shall certify that the processes which utilize gas delivered hereunder are capable of complete discontinuance of natural gas use. Company may request Customer to verify either of the foregoing alternatives on an annual basis on or before October 1 of each year. Failure of Customer to annually certify either of the above alternatives shall result, in the sole discretion of Company, in immediate termination of service under this rate schedule and the immediate transfer to the appropriate firm sales rate schedule, either Rate CGS or Rate IGS.

John P. Malloy
LGE - KU Energy LLC
VP Customer Services
220 West Main Street
Louisville, KY 40202
T 1.502.627.4836
F 1.502.217.2162
[redacted] REDACTED FOR PERSONAL PRIVACY
john.malloy@LGE-KU.com

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Bruner, Cheryl
CC:
BCC:
Subject: FW: CSR10 - 30 Tariff
Sent: 09/15/2014 08:33:53 AM -0400 (EDT)
Attachments:

Any thoughts about operationalizing?

From: Conroy, Robert
Sent: Monday, September 15, 2014 8:21 AM
To: Woodworth, Steve
Subject: Re: CSR10 - 30 Tariff

I am find conceptually adding a requirement. You will have to decide what can be operationalized. The real test is when we call an interruption and the customer cannot comply. Are we then willing to remove them?

Sent from my iPhone

On Sep 15, 2014, at 7:55 AM, "Woodworth, Steve" <Steve.Woodworth@lge-ku.com> wrote:

> Robert,
> See JPM's suggestion below. Although this is for AAGS, we could modify to have customer certify their ability to curtail on an annual basis. Please let me know your thoughts.
>
> -Steve
>
> ---
>
> From: Malloy, John
> Sent: Monday, September 15, 2014 7:30 AM
> To: Woodworth, Steve
> Cc: Bruner, Cheryl
> Subject: CSR10 - 30 Tariff
>
> Steve,
>
> We have had several discussions throughout the past year on a Customers ability to "demonstrate" its ability to bring on alternate electrical supplies and / or stop taking electrical service from us when and event is called. This specifically speaks to the Ft. Knox and Toyota discussions. Should we consider language like the AAGS (pasted below) which requires this type of demonstration / certification?
>
> thanks
>
> excerpt from AAGS Tariff sheet 20.1…………………………..
>
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John P. Malloy
LGE - KU Energy LLC
VP Customer Services
220 West Main Street
Louisville, KY 40202
T 1.502.627.4836
F 1.502.217.2162
[redacted] REDACTED FOR PERSONAL PRIVACY
john.malloy@LGE-KU.com
<image001.jpg>

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Lynch, Michelle; Bruner, Cheryl
CC: McGinnis, Alan
BCC:
Subject: RE: CSR10 - 30 Tariff
Sent: 09/15/2014 03:53:21 PM -0400 (EDT)
Attachments:

Thanks Michelle. Do you and Alan believe it would add value to the CSR process to incorporate this certification? Sounds like your team can operationalize, but I want to make sure we all are in agreement that this requirement makes sense. The certification process could refresh customer's memory on the requirements to curtail and give us something else to fall back on.

-Steve

From: Lynch, Michelle
Sent: Monday, September 15, 2014 3:29 PM
To: Bruner, Cheryl
Cc: Woodworth, Steve; McGinnis, Alan
Subject: RE: CSR10 - 30 Tariff

Good afternoon.

Alan and I just chatted about the option of having an annual certification similar to the one used for AAGS customers. Neither of us found any problems with having customers complete a form annually. We do expect some questions about it the first year, but feel we will be able to address those.

Please let us know if you have any other questions or concerns.

Thanks,
Michelle Lynch, PE
Account Manager, Major Accounts

LG&E and KU
LG&E Center
220 West Main Street
Louisville, KY 40202
Phone: 502-627-2137
Cell: 502-594-6769

Please consider the environment before printing this e-mail

From: Bruner, Cheryl
Sent: Monday, September 15, 2014 8:38 AM
To: McGinnis, Alan; Lynch, Michelle
Cc: Woodworth, Steve
Subject: Fwd: CSR10 - 30 Tariff

Alan/Michelle,
Need feedback promptly please. Reply to all.

Sent from my iPhone

Begin forwarded message:

> From: "Woodworth, Steve" <Steve.Woodworth@lge-ku.com>
> Date: September 15, 2014 at 8:33:53 AM EDT
> To: "Bruner, Cheryl" <Cheryl.Bruner@lge-ku.com>
> Subject: FW: CSR10 - 30 Tariff

Any thoughts about operationalizing?

From: Conroy, Robert
Sent: Monday, September 15, 2014 8:21 AM
To: Woodworth, Steve
Subject: Re: CSR10 - 30 Tariff

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From: Lynch, Michelle(/O=LGE/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=LYNCH, MICHELLEA49)
To: Bruner, Cheryl
CC: Woodworth, Steve; McGinnis, Alan
BCC:
Subject: RE: CSR10 - 30 Tariff
Sent: 09/15/2014 03:28:55 PM -0400 (EDT)
Attachments:

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From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: McGinnis, Alan; Lynch, Michelle; Bruner, Cheryl
CC:
BCC:
Subject: RE: CSR10 - 30 Tariff
Sent: 09/17/2014 06:39:40 AM -0400 (EDT)
Attachments:

Thanks everyone for the feedback.

From: McGinnis, Alan
Sent: Tuesday, September 16, 2014 4:50 PM
To: Woodworth, Steve; Lynch, Michelle; Bruner, Cheryl
Subject: RE: CSR10 - 30 Tariff

Steve –

I spoke to Cheryl about this earlier today. My comments are: an annual certification will allow both the customer and us to review the firm/interruptible amounts annually; gives us the opportunity to verify the phone number; review the tariff with them; discuss the ramifications of non-compliance and <u>have annual documentation of the customer's understanding of the rate</u>.
I do expect those customers currently on a CSR to have some questions.
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Sent: Monday, September 15, 2014 3:53 PM
To: Lynch, Michelle; Bruner, Cheryl
Cc: McGinnis, Alan
Subject: RE: CSR10 - 30 Tariff

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Subject: RE: CSR10 - 30 Tariff

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Phone: 502-627-2137
Cell: 502-594-6769

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>> Subject: CSR10 - 30 Tariff
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john.malloy@LGE-KU.com
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From: McGinnis, Alan(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=MCGINNISA)
To: Woodworth, Steve; Lynch, Michelle; Bruner, Cheryl
CC:
BCC:
Subject: RE: CSR10 - 30 Tariff
Sent: 09/16/2014 04:50:21 PM -0400 (EDT)
Attachments:

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Subject: RE: CSR10 - 30 Tariff

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To: Bruner, Cheryl
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Louisville, KY 40202
Phone: 502-627-2137
Cell: 502-594-6769

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To: McGinnis, Alan; Lynch, Michelle
Cc: Woodworth, Steve
Subject: Fwd: CSR10 - 30 Tariff

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Sent from my iPhone

Begin forwarded message:

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> Date: September 15, 2014 at 8:33:53 AM EDT
> To: "Bruner, Cheryl" <Cheryl.Bruner@lge-ku.com>
> Subject: FW: CSR10 - 30 Tariff
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> **From:** Conroy, Robert
> **Sent:** Monday, September 15, 2014 8:21 AM
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>> **From:** Malloy, John
>> **Sent:** Monday, September 15, 2014 7:30 AM
>> **To:** Woodworth, Steve
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>> **Subject:** CSR10 - 30 Tariff
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Louisville, KY 40202

T 1.502.627.4836

F 1.502.217.2162

[redacted] REDACTED FOR PERSONAL PRIVACY

john.malloy@LGE-KU.com

<image001.jpg>

From: Lynch, Michelle(/O=LGE/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=LYNCH, MICHELLEA49)
To: Woodworth, Steve
CC: McGinnis, Alan; Bruner, Cheryl
BCC:
Subject: RE: CSR10 - 30 Tariff
Sent: 09/16/2014 09:44:55 AM -0400 (EDT)
Attachments:

Good morning Steve.

I know Alan plans to discuss this option further with Cheryl this afternoon.

Yesterday we did chat about how an annual certification will force both the customers and us Account Managers to review the firm chosen as well as the contact phone number. It would also be another fact to defend a penalty for non-compliance.

I appreciate you asking for feedback. Please let me know if you have any other questions.

Thanks,
Michelle Lynch, PE
Account Manager, Major Accounts

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To: McGinnis, Alan; Lynch, Michelle
CC: Woodworth, Steve
BCC:
Subject: Fwd: CSR10 - 30 Tariff
Sent: 09/15/2014 08:38:19 AM -0400 (EDT)
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John P. Malloy
LGE - KU Energy LLC
VP Customer Services
220 West Main Street
Louisville, KY 40202
T 1.502.627.4836
F 1.502.217.2162
[redacted] REDACTED FOR PERSONAL PRIVACY
john.malloy@LGE-KU.com

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Conroy, Robert
CC:
BCC:
Subject: FW: CSR10 - 30 Tariff
Sent: 09/17/2014 06:43:31 AM -0400 (EDT)
Attachments:

Let's discuss this morning too

From: McGinnis, Alan
Sent: Tuesday, September 16, 2014 4:50 PM
To: Woodworth, Steve; Lynch, Michelle; Bruner, Cheryl
Subject: RE: CSR10 - 30 Tariff

Steve –

I spoke to Cheryl about this earlier today. My comments are: an annual certification will allow both the customer and us to review the firm/interruptible amounts annually; gives us the opportunity to verify the phone number; review the tariff with them; discuss the ramifications of non-compliance and have annual documentation of the customer's understanding of the rate.
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Annual certification would be beneficial to us in the event of a non-compliance penalty.

From: Woodworth, Steve
Sent: Monday, September 15, 2014 3:53 PM
To: Lynch, Michelle; Bruner, Cheryl
Cc: McGinnis, Alan
Subject: RE: CSR10 - 30 Tariff

Thanks Michelle. Do you and Alan believe it would add value to the CSR process to incorporate this certification? Sounds like your team can operationalize, but I want to make sure we all are in agreement that this requirement makes sense. The certification process could refresh customer's memory on the requirements to curtail and give us something else to fall back on.

-Steve

From: Lynch, Michelle
Sent: Monday, September 15, 2014 3:29 PM
To: Bruner, Cheryl
Cc: Woodworth, Steve; McGinnis, Alan
Subject: RE: CSR10 - 30 Tariff

Good afternoon.

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Please let us know if you have any other questions or concerns.

Thanks,
Michelle Lynch, PE
Account Manager, Major Accounts

LG&E and KU
LG&E Center

220 West Main Street
Louisville, KY 40202
Phone: 502-627-2137
Cell: 502-594-6769

Please consider the environment before printing this e-mail

From: Bruner, Cheryl
Sent: Monday, September 15, 2014 8:38 AM
To: McGinnis, Alan; Lynch, Michelle
Cc: Woodworth, Steve
Subject: Fwd: CSR10 - 30 Tariff

Alan/Michelle,
Need feedback promptly please. Reply to all.

Sent from my iPhone

Begin forwarded message:

> From: "Woodworth, Steve" <Steve.Woodworth@lge-ku.com>
> Date: September 15, 2014 at 8:33:53 AM EDT
> To: "Bruner, Cheryl" <Cheryl.Bruner@lge-ku.com>
> Subject: FW: CSR10 - 30 Tariff
>
> Any thoughts about operationalizing?
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> ---
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> From: Conroy, Robert
> Sent: Monday, September 15, 2014 8:21 AM
> To: Woodworth, Steve
> Subject: Re: CSR10 - 30 Tariff
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> Sent from my iPhone
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>> From: Malloy, John
>> Sent: Monday, September 15, 2014 7:30 AM
>> To: Woodworth, Steve
>> Cc: Bruner, Cheryl
>> Subject: CSR10 - 30 Tariff
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John P. Malloy

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VP Customer Services
220 West Main Street

Louisville, KY 40202

T 1.502.627.4836

F 1.502.217.2162

[redacted] REDACTED FOR PERSONAL PRIVACY

john.malloy@LGE-KU.com

<image001.jpg>

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Conroy, Robert
CC:
BCC:
Subject: RE: CSR10 - 30 Tariff
Sent: 09/15/2014 08:30:39 AM -0400 (EDT)
Attachments:

Good points Robert. Let me circle back with Cheryl on her thoughts

---

From: Conroy, Robert
Sent: Monday, September 15, 2014 8:21 AM
To: Woodworth, Steve
Subject: Re: CSR10 - 30 Tariff

I am find conceptually adding a requirement. You will have to decide what can be operationalized. The real test is when we call an interruption and the customer cannot comply. Are we then willing to remove them?

Sent from my iPhone

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<image001.jpg>

From: Conroy, Robert(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=CONROYR)
To: Schroeder, Andrea; Woodworth, Steve
CC:
BCC:
Subject: Fwd: CSR edits proposed by Power Supply
Sent: 07/15/2014 07:03:00 AM -0400 (EDT)
Attachments: CSR10andCSR30_PowerSupply_proposededits_2014_07_14.docx; ATT00001.htm;

Sent from my iPhone

Begin forwarded message:

From: "Oelker, Linn" <Linn.Oelker@lge-ku.com>
Date: July 14, 2014 at 2:16:23 PM EDT
To: "Conroy, Robert" <Robert.Conroy@lge-ku.com>
Cc: "Brunner, Bob" <Bob.Brunner@lge-ku.com>, "Freibert, Charlie" <Charlie.Freibert@lge-ku.com>, "Martin, Charlie" <Charlie.Martin@lge-ku.com>
Subject: CSR edits proposed by Power Supply

Robert:

Attached are proposed edits to the CSR10 and CSR 30 tariff riders for discussion. These changes, if implemented, are intended to allow Power Supply to curtail the respective customer at any time for any reason for 100 hours in each calendar year. We propose eliminating the Buy-Through Option.

Note we only red-lined the KU versions but other company's riders should be changed.

Please let us know if you have any questions or would like to discuss.

Respectfully,

Linn C. Oelker, P.E.
Manager - Market Compliance
LG&E and KU
Office (502) 627-3245
linn.oelker@lge-ku.com

From: Conroy, Robert(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=CONROYR)
To: Woodworth, Steve
CC:
BCC:
Subject: Re: CSR10 - 30 Tariff
Sent: 09/15/2014 08:20:35 AM -0400 (EDT)
Attachments:

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Sent from my iPhone

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<image001.jpg>

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Schroeder, Andrea
CC:
BCC: Woodworth, Steve
Subject: FW: CSR10 - 30 Tariff
Sent: 09/17/2014 11:44:27 AM -0400 (EDT)
Attachments:

Andrea,
Based on the information below from Alan, would you craft some language in the CSR to accommodate this certification? Might go under Terms & Conditions.

From: McGinnis, Alan
Sent: Tuesday, September 16, 2014 4:50 PM
To: Woodworth, Steve; Lynch, Michelle; Bruner, Cheryl
Subject: RE: CSR10 - 30 Tariff

Steve –

I spoke to Cheryl about this earlier today. My comments are: an annual certification will allow both the customer and us to review the firm/interruptible amounts annually; gives us the opportunity to verify the phone number; review the tariff with them; discuss the ramifications of non-compliance and have annual documentation of the customer's understanding of the rate.
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Sent: Monday, September 15, 2014 3:53 PM
To: Lynch, Michelle; Bruner, Cheryl
Cc: McGinnis, Alan
Subject: RE: CSR10 - 30 Tariff

Thanks Michelle. Do you and Alan believe it would add value to the CSR process to incorporate this certification? Sounds like your team can operationalize, but I want to make sure we all are in agreement that this requirement makes sense. The certification process could refresh customer's memory on the requirements to curtail and give us something else to fall back on.

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From: Lynch, Michelle
Sent: Monday, September 15, 2014 3:29 PM
To: Bruner, Cheryl
Cc: Woodworth, Steve; McGinnis, Alan
Subject: RE: CSR10 - 30 Tariff

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LG&E and KU
LG&E Center
220 West Main Street
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Phone: 502-627-2137
Cell: 502-594-6769

Please consider the environment before printing this e-mail

From: Bruner, Cheryl
Sent: Monday, September 15, 2014 8:38 AM
To: McGinnis, Alan; Lynch, Michelle
Cc: Woodworth, Steve
Subject: Fwd: CSR10 - 30 Tariff

Alan/Michelle,
Need feedback promptly please. Reply to all.

Sent from my iPhone

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From: "Woodworth, Steve" <Steve.Woodworth@lge-ku.com>
Date: September 15, 2014 at 8:33:53 AM EDT
To: "Bruner, Cheryl" <Cheryl.Bruner@lge-ku.com>
Subject: FW: CSR10 - 30 Tariff

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Sent: Monday, September 15, 2014 8:21 AM
To: Woodworth, Steve
Subject: Re: CSR10 - 30 Tariff

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To: Woodworth, Steve
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<image001.jpg>

From: Woodworth, Steve(/O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=WOODWORTHS)
To: Lynch, Michelle; Bruner, Cheryl
CC: McGinnis, Alan
BCC: Woodworth, Steve
Subject: RE: CSR10 - 30 Tariff
Sent: 09/15/2014 03:53:21 PM -0400 (EDT)
Attachments:

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> John P. Malloy
> LGE - KU Energy LLC
> VP Customer Services
> 220 West Main Street
> Louisville, KY 40202

T 1.502.627.4836
F 1.502.217.2162
[redacted] REDACTED FOR PERSONAL PRIVACY
john.malloy@LGE-KU.com
<image001.jpg>

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 24

Responding Witness: David S. Sinclair

Q-24. Reference David Sinclair, p. 28, ll. 6-18.

a) Please state the number of times that a CSR customer has failed to perform in the last five years.

b) Has the Company evaluated whether the annual certification procedures it proposes to implement will affect participation in the CSR tariff in any way? If so, please provide copies of all e-mail communications, internal memoranda, reports, or other documentation of the Company's consideration of this issue.

A-24. a) In the last five years, KU had three occurrences of CSR customers failing to perform.

b) In the Companies' judgment, the proposed changes to the CSR tariff will not impact participation.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 25

Responding Witness: David S. Sinclair

Q-25. Reference Testimony of Paul Thompson, p. 17, ll. 4-18.

a) Please explain the need for the capacity purchase and tolling agreement in light of the flat sales growth environment the Company is currently experiencing.

A-25. a) The Company determined that the capacity purchase and tolling agreement was necessary in order to maintain a reliable reserve margin at time of system peak. As discussed in LG&E and KU's 2014 Integrated Resource Plan, the target reserve margin is between 16% and 21%. Without additional capacity, between 2015 and 2018 there is a projected reserve margin shortfall, with reserve margins between 12.2% and 14.9%. The capacity purchase and tolling agreement presented a favorable opportunity to ensure adequate generating capacity to reliably meet reserve margin requirements, while minimizing revenue requirements, during this period. The Commission's November 24, 2014 Order in Case No. 2014-00321 approved the capacity purchase and tolling agreement.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 26

Responding Witness: Paul W. Thompson

Q-26. Reference Paul Thompson, p. 22, ll. 15-18.

a) Please provide a copy of any request for permission to continue operating Green River Generating Station units through April 2016. If no such request has yet been submitted, please state whether it is still the Company's intention to submit this request and if so, when it will be filed.

b) Please provide any studies or documentation of the grid reliability concerns presented by the retirement of the Green River Generating Station units.

A-26. a) On December 2, 2014, the Company filed a request for permission to continue operating Green River Generating Station units until April 16, 2016. On January 6, 2015, the Kentucky Division of Air Quality approved the request. Attached are copies of the request and approval correspondence.

b) Please see the attached the reliability study, which was performed to assess the issues involved in the decision to request a one-year extension of the Green River Units 3 and 4 operation. The study identifies solutions for the current reliability concerns which, upon completion, will alleviate the conditions identified by the study.

Please note that the attached reliability study contains non-public transmission function information. FERC's Standards of Conduct for Transmission Providers prohibit providing such information to the marketing-function personnel of any entity, including the Company's own marketing-function employees. The Companies are therefore filing the attached reliability study under a Petition for Confidential Protection to limit the release of this non-public information to marketing function employees, whether of the Company or any other entity. All other entities receiving this information, including the Sierra Club, must similarly keep confidential this information until the Companies post the study for public review. The Companies will notify the Commission when the study becomes public and no longer requires or qualifies for confidential protection.

220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232

CERTIFIED MAIL #7006 2760 0005 5304 1316
RETURN RECEIPT REQUESTED

Date: December 2, 2014

Mr. Sean Alteri, Director
Kentucky Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601

Re: MATS Compliance Extension Request
Kentucky Utilities Company – Green River Generating Station (AI# 3228)

Dear Mr. Alteri:

Kentucky Utilities (KU) is requesting an extension of the compliance date established in 40 CFR 63.9984(b) of the Mercury and Air Toxics Standards (MATS) for the Kentucky Utilities Company (KU) Green River Generating Station until April 16, 2016. The MATS rule establishes National Emissions Standards for Hazardous Air Pollutants applicable to the coal-fired electric generating units located at KU's Green River Station, Units 3 and 4. Each of these units employs a dry electrostatic precipitator (ESP) for control of particulate matter (PM) emissions and low NO_x burners for control of emissions of oxides of nitrogen (NO_x). Additionally, these units use lower sulfur coals to meet their sulfur dioxide (SO_2) limits.

The generating units of KU and its affiliate Louisville Gas and Electric Company (LG&E) are centrally dispatched on a coordinated basis. Consequently, a system-wide evaluation was commenced by the companies prior to publication of the proposed MATS rule to determine the emission reduction capability of all coal-fired units in the KU and LG&E system relative to the MATS targeted hazardous air pollutants. By the time the final MATS rule was published in February, 2012, LG&E and KU had determined that in order to meet continuous compliance with the emission limitations, some of its older coal-fired generation would be retired and all remaining coal-fired generation within the fleet would need additional emissions control.

Green River Units 3 and 4 were two of the units within the LG&E and KU fleet that were determined to be retired in lieu of retrofitting them with new emission controls sufficient to meet the limitations of the MATS rule. Plans were put in place to retire the units by the MATS compliance date of April 16, 2015.

However, an electric grid reliability condition occurred in June 2014 which caused the need for further evaluation of those retirements. As seen in the enclosed letters from LG&E and KU's Transmission Department (LG&E and KU's NERC registered Planning Authority) and TVA (LG&E and KU's NERC registered Reliability Coordinator), operation of KU's Green River Units 3 and 4 are critical to the need for maintaining the reliability of the Bulk Electric System until planned upgrades can be made.

Within the MATS Rule[1], Section VII.F "Compliance Date and Reliability Issues" of the preamble provides comments and EPA's response regarding the extension process relative to continued operation of units in order to avoid risk to electric reliability. Specifically, the preamble states:

> "*While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.*"

This preamble discussion is relevant to and consistent with the circumstances at KU's Green River Station. Accordingly, in order to avoid risk to electric reliability, KU is requesting an extension of the MATS compliance date for the Green River Station emission units 03 and 04 until to April 16, 2016 and that all MATS-related deadlines (i.e., performance testing, boiler tune-up, monitoring, recordkeeping and reporting requirements) be extended consistent with that date.

Pursuant to 40 CFR 63.6(i)(6)(i), KU's request for a compliance extension under paragraph (i)(4) of this section includes the following information:

(A) A description of the controls to be installed to comply with the standard;

Following completion of transmission system improvements and upgrades to ensure continued electric system reliability, the affected coal-fired electrical generation from Green River Station Units 3 and 4 will be retired.

(B) A compliance schedule, including the date by which each step toward compliance will be reached. At a minimum, the list of dates shall include:

(1) The date by which on-site construction, installation of emission control equipment or a process change is planned to be initiated; and
LG&E and KU are already under way with the projects needed to ensure electric system reliability after the retirement of Green River Units 3 and 4. As mentioned in the

[1] 77 Federal Register at 9410/2, February 16, 2012

attached letter from LG&E and KUs Transmission Department, some of the needed transmission line work is expected to be completed by December 31, 2015. Other transmission line work will be completed prior to the summer of 2016.

(2) The date by which on-site construction, installation of emission control equipment or a process change is to be completed.

As stated previously, some of the needed transmission line work is expected to be completed by December 31, 2015. Other transmission line work will be completed prior to the summer of 2016.

(3) The date by which final compliance is to be achieved.

If this extension request is granted, final compliance with the MATS requirements will be achieved by April 16, 2016 with retirement of the KU's Green River Units 3 and 4.

If you have any questions or need any additional information, please contact me or Jason Wilkerson (502-627-4043) at any time.

Respectfully,

Steve Noland

Steve Noland
Manager, Environmental Affairs Air Section
LG&E and KU Energy

cc: Derek Picklesimer, Supervisor
KyDAQ Combustion Section

Thomas Troost, Plant Manager
KU Green River Station

PPL companies

LG&E and KU Services Company
Transmission Strategy & Planning

220 West Main Street
Louisville, Kentucky 40202
T (502) 627-4578

December 2, 2014

Sean Alteri, Director
Kentucky Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, KY 40601

Re: Transmission system reliability impact of retiring Kentucky Utilities Green River Units 3 & 4

Dear Mr. Alteri:

In September 2011, Louisville Gas & Electric Company (LG&E) and Kentucky Utilities Company (KU) announced the retirement of KU's Green River Generating Station Units 3 and 4, to be effective in April 2015. Since then, LG&E and KU have planned its transmission system to reliably accommodate this generation resource retirement. However, recent events on LG&E and KU's transmission network and the interconnected utilities have raised concerns over reliability impacts created by the planned retirement of these units and triggered the need for additional study. These recent events include the uncertainties of operations of the newly expanded Midcontinent Independent System Operator (MISO), recently announced news from Big Rivers Electric Corporation (BREC) that all three generating units at its Coleman station could be offline for several years, and a real-time electric grid reliability operating condition that occurred in June 2014. LG&E and KU's Manager - Environmental Air Section, Steve Noland, requested information necessary for the Division of Air Quality to grant an extension of the Green River operation.

As the NERC registered Planning Authority for the LG&E and KU transmission system, LG&E and KU recently performed a transmission reliability study of the western Kentucky region. LG&E and KU worked closely on this study with their NERC certified Reliability Coordinator, the Tennessee Valley Authority (TVA). For background, under FERC and NERC regulations, the Planning Authority is responsible for long term transmission planning that ensures reliable operations of the LG&E and KU transmission system by coordinating and integrating transmission facilities and service plans, resource plans (e.g. generation supply), and protective relay systems. Additionally, these efforts are generally overseen by TVA, LG&E/KU's Reliability Coordinator since 2006. The Reliability Coordinator has the highest level of authority for reliable operation of the Bulk Electric System(s) it oversees.

The primary purpose of the transmission reliability study was to determine if expected conditions of the Bulk Electric System in the region, including the planned retirement of KU's Green River Units 3 and 4, pose a transmission system reliability risk. The study included contingency analysis based on NERC Transmission Planning (TPL) Reliability Standards and LG&E and KU's Transmission Planning Guidelines. Based on the analysis, the TPL Reliability Standards and Planning Guidelines would be violated under certain operating scenarios. While the study itself cannot be released publicly due to security concerns, the analysis indicates that transmission system reliability will be negatively impacted with the retirement of KU's Green River Units 3 and 4 until other transmission solutions can be implemented.

In addition to identifying violations of the TPL Reliability Standards and the Planning Guidelines, the study also provides recommended solutions to the violations found. Specifically for this scenario involving KU's Green River Units 3 and 4, the study recommends the following components as a solution:

- Delay retirement of KU's Green River Units 3 and 4 until the below projects are complete;
- Complete the Mantanzas (LG&E and KU) – Paradise (TVA) 161 kV facility (TVA has currently scheduled this for completion by December 31, 2015); and
- Add Reactors to the Livingston County – North Princeton 161 kV line and Livingston – Crittenden 161 kV lines (work plan being developed but expected completions prior to summer 2016).

Based on the engineering, procurement and installation time required for the projects identified the above transmission projects are anticipated to be completed by April 16, 2016. It is LG&E/KU's considered opinion that the extension of the operation of KU's Green River Units 3 and 4 - until the completion of the identified projects - is critical to the overall reliability of the transmission system.

As LG&E and KU's Reliability Coordinator, TVA has reviewed the study and supports delaying the retirement of KU's Green River Units 3 and 4 until the other mitigations are in place (see enclosed letter from TVA dated month day, year).

If you have any questions, please contact me at 502-627-4578.

Regards,

Chris Balmer

Chris Balmer
Director, Transmission Strategy and Planning

TVA

Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

December 1, 2014

Mr. Tom Jessee
Vice President, Transmission
LG&E/KU
220 West Main St.
Louisville, KY 40202

Dear Mr. Jessee:

RELIABILITY IMPACT OF RETIRING GREEN RIVER UNITS 3 & 4

First, I would like to express my appreciation for our continued, collaborative efforts between TVA and LG&E/KU to ensure a well-planned and reliable transmission system. Regarding these efforts, and in response to the September 2011 LG&E/KU announcement concerning the retirement of Green River units 3 and 4, our Companies have also continued to plan our transmission systems to reliably accommodate this generation resource retirement. However, uncertain operational impacts of the expanded MISO and the recently announced news from Big Rivers Electric Co-op that all three generating units at its Coleman station could be offline for several years are two such events that were not previously considered. In addition, with the Green River units in service and online this past summer, we observed transmission reliability impacts in real-time requiring risk mitigation actions taken by both LG&E/KU and TVA, as directed by TVA as LG&E/KU's NERC certified Reliability Coordinator.

Taking into account the real-time conditions we experienced this prior summer, the uncertainty in the area, and the recently announced changes that were not previously considered, we believe the retirement of the Green River units do pose a potential transmission reliability risk. Accordingly, as LG&E/KU's Reliability Coordinator, TVA would support delaying the retirement of Green River units 3 and 4 until other mitigations are in place.

Please feel free to contact me should you have any questions or comments in response to our concerns regarding the retirement of the Green River units 3 and 4. I will be happy to discuss further and continue our collaborative efforts to maintain and improve transmission reliability for our systems and that of our neighbors.

Regards,

Armando M Rodriguez

Armando Rodriguez
Senior Manager, Reliability Authority & Regional Operations

Steven L. Beshear
Governor

Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601
www.air.ky.gov

Leonard K. Peters
Secretary

January 6, 2015

Mr. Steve Nolan,
Manager, Environmental Air Section
LG&E KU Energy Company
P.O Box 32010
Louisville, Kentucky 40232

RE: Compliance extension approval for 40 CFR 63, Subpart UUUUU

Permittee Name:	LG&E KU Energy Company
Source Name:	Green River Station
AI/ID/Activity:	3228/21-177-00001/APE20140003
Permit:	V-12-018

Dear Mr. Nolan:

This letter is in response to your letters and additional information received December 2, 2014, requesting a compliance extension to the federal Mercury and Air Toxic Standards (MATS) requirements for the Green River Station located in Muhlenberg County, Kentucky. After reviewing the request, the Division concludes that the submittal contains sufficient information to make a determination regarding the request for an extension of compliance. Furthermore, the Division grants the compliance extension request for Units 3 and 4 until April 16, 2016. This compliance extension applies to the requirements established under 40 CFR 63, Subpart UUUUU.

In accordance with 40 CFR 63.6(i)(4), the conditions of the extension of compliance, specifically the compliance date, granted through this approval letter will be incorporated into the title V permit upon the next significant revision or renewal. If you have further questions regarding this matter, please contact Mr. Derek Picklesimer, Combustion Section Supervisor of the Permit Review Branch at (502) 564-3999, extension 4464.

Sincerely,

Sean Alteri

Sean Alteri
Director

SA/dp

Attachment
Confidential

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 27

Responding Witness: David E. Huff

Q-27. Reference Paul Thompson, p. 61, ll. 8-12.

a) Please provide all documents relating to the air conditioning load control program that has reduced summer peak demand by up to 181 MW. Has the Company considered expanding this program? Please explain.

A-27. a) The documents relating to the Company's most recently proposed continuation and expansion of air conditioning load program are in the record in Case No. 2014-00003. The Commission's November 14, 2014 Order in Case No. 2014-00003 approved the Company's proposed DSM/EE Program, including the air conditioning load program through 2018.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 28

Responding Witness: Dr. William E. Avera / Adrien M. McKenzie

Q-28. Reference Testimony of William E. Avera and Adrien M. McKenzie, generally

a) How do your analyses and conclusions account for the reduced risk faced by the Company's investors should the Company's request to increase its fixed basic service charge for residential customers be granted in full.

b) If your analyses do not account for this proposal, why not?

i) How would your recommendations change if the entire requested basic service charge increase were approved by the Commission?

A-28. a) The analyses and conclusions presented in the Avera/McKenzie testimony were based on estimates of investors' required rate of return for a proxy group of comparable risk utilities. Consideration of a number of objective indicators of risk indicates that this proxy group is representative of the risks that investors would associate with an equity investment in KU. There is no basis to conclude that modification to the fixed basic service charge for residential customers would result in any significant alteration of this relative risk assessment. Moreover, as discussed in the Avera/McKenzie testimony, the utilities in the proxy group benefit from a broad range of regulatory mechanisms, including supportive rate design provisions, trackers to recover costs outside a traditional rate case, and full revenue decoupling. As a result, the proxy group companies provide a sound basis on which to estimate a fair ROE for KU, and approval of changes to the fixed basic service charge would not alter this conclusion.

b) Please refer to the response to subpart (a). The ROE recommendation supported by the Avera/McKenzie testimony would not change as a result of modifications to the basic service charge.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 29

Responding Witness: Robert M. Conroy

Q-29. Reference Testimony of Edwin R. Staton, p. 4, ll. 8-20.

a) If KU's requested increase in the residential basic service charge is approved by the Commission, how will KU's residential basic service charge compare to the average basic service charge of investor-owned utilities across the United States?

A-29. a) The Company has not compared its proposed basic service charge to investor-owned utilities across the United States. The Company's BSC is reflective of its cost of providing service and not the rates charged by other investor-owned utilities. See the response to Question No. 17.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 30

Responding Witness: Edwin R. "Ed" Staton

Q-30. Reference Staton, p.5, ll. 15-18.

a) Please provide a copy of the bill notice discussing the proposed rate adjustment.

A-30. See Tab 6 of the Filing Requirements.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

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

Question No. 31

Responding Witness: Edwin R. "Ed" Staton

Q-31. Reference Staton, pp. 5-11.

a) How many customers are eligible for relief on their electricity bills through the Company's low- and fixed-income assistance programs, including WeCare, FLEX payment, WinterCare Energy Assistance Fund, Home Energy Assistance Fund, and any other programs such as those distributing LIHEAP funds?

b) What is the average monthly energy consumption for customers eligible for relief through all of the programs described in (a)?

A-31. a) The Company makes no determination concerning a customer's eligibility for bill relief, as customer income is neither recorded nor tracked. However, the Company can offer that 91,663 customers received financial assistance on their electric bills at least once and/or participated in the WeCare program during the period January 1, 2010 through January 9, 2015.

b) The average monthly energy consumption for the customers listed in the response to part a) above is 1,371 kWh for the period January 2010 through December 2014.