COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

CASE NO. 2016-00371

TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 23, 2016
# TABLE OF CONTENTS

INTRODUCTION .................................................................................................................. 1

I. FILING REQUIREMENTS ............................................................................................... 2

II. CUSTOMER NOTICE .................................................................................................... 3

III. PROPOSED REVENUE INCREASE AND BILL IMPACT .............................................. 4

IV. ELECTRIC COST OF SERVICE STUDY, RATE DESIGN, AND ALLOCATION OF INCREASE ........................................................................................................... 5
   A. COST OF SERVICE STUDY ....................................................................................... 5
   B. ALLOCATION OF ELECTRIC REVENUE INCREASE ......................................... 8
   C. ELECTRIC RATE DESIGN APPROACH ................................................................. 9
   D. RESIDENTIAL ELECTRIC RATE DESIGN & INCREASE ................................... 9
   E. CHANGES TO TARIFF SHEETS FOR RATES RS, VFD, AND GS ......................... 11
   F. CLOSING THE CURTAINABLE SERVICE RIDER ............................................. 16
   G. THE COMPANY’S CURRENT AMS CUSTOMER OFFERING ................................ 18
   H. PROPOSAL TO ELIMINATE SUPPLEMENTAL OR STANDBY SERVICE RIDER (RIDER SS) ........................................................................................................ 19
   I. ELECTRIC RATES FOR SPECIAL CONTRACT CUSTOMER 1 ................................ 20
   J. OTHER STANDARD RATE SCHEDULES ............................................................. 21
   K. CHANGES TO CABLE TELEVISION ATTACHMENT CHARGES (RATE CTAC), RENAMED POLE AND STRUCTURE ATTACHMENT CHARGES (RATE PSA) ........ 23
   L. CHANGES TO ELECTRIC SPECIAL CHARGES .................................................. 26
   M. CHANGES TO OTHER RIDERS ............................................................................ 27
   N. CHANGES TO ADJUSTMENT CLAUSES .............................................................. 29
   O. CHANGES TO CUSTOMER DEPOSITS ................................................................. 29

V. CHANGES TO ELECTRIC TERMS AND CONDITIONS .............................................. 30

VI. CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY .......................... 35

VII. REQUEST FOR DEVIATIONS FROM CERTAIN METER-RELATED COMMISSION REGULATIONS TO ACCOMMODATE THE COMPANY’S PROPOSED AMS DEPLOYMENT .......................................................... 38
VIII. GAS COST OF SERVICE STUDY, RATE DESIGN, AND ALLOCATION OF INCREASE ................................................................. 42
A. GAS COST OF SERVICE STUDY ................................................................. 42
B. ALLOCATION OF GAS REVENUE INCREASE ........................................... 43
C. RESIDENTIAL GAS SERVICE .................................................................. 44
D. NEW STANDARD RATE FOR SUBSTITUTE GAS SALES SERVICE (RATE SGSS) ................................................................. 46
E. NEW LOCAL GAS DELIVERY SERVICE (RATE LGDS) .................... 48
F. OTHER GAS RATE SCHEDULE CHANGES .............................................. 49
G. CHANGES TO GAS SPECIAL CHARGES AND CUSTOMER DEPOSITS ............................................................................ 51
H. CHANGES TO ADJUSTMENT CLAUSES .................................................. 52

IX. CHANGES TO GAS TERMS AND CONDITIONS ...................................... 54
X. LOW-INCOME CUSTOMER ASSISTANCE .............................................. 57
XI. CONCLUSION .......................................................................................... 62
INTRODUCTION

Q. Please state your name, position, and business address.
A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Louisville Gas and Electric Company (“LG&E” or “Company”) and Kentucky Utilities Company (“KU”) (collectively “Companies”), and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.
A. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?
A. Yes, I have testified before the Commission numerous times, including LG&E’s four most recent base rate cases.1

Q. What are the purposes of your testimony?
A. The purposes of my testimony are: (1) to support certain exhibits required by the Commission’s regulations; (2) to describe the methods by which LG&E informed its customers of the proposed rate adjustment; (3) to present the revenue effects and the bill impacts to the average residential customer; (4) to present LG&E’s recommendation for the allocation of the proposed increases in electric and gas revenues among the customer classes based on the results of the Company’s cost of

---

service study prepared by W. Steven Seelye and The Prime Group in this case; (5) to
discuss and explain the various tariff changes LG&E proposes; (6) to provide
information concerning the Company’s request for certificates of public convenience
and necessity (“CPCNs”) for its proposed Advanced Metering Systems (“AMS”) and
distribution automation (“DA”) deployments; (7) to explain the Company’s requested
deviations from certain meter-related regulations, which deviations are necessary to
accommodate the proposed AMS deployment; and (8) to describe the various ways
LG&E assists customers with low incomes.

I. FILING REQUIREMENTS

Q. Are you supporting certain information required by Commission regulation 807
   KAR 5:001 Section 16(8)?

A. Yes, I am sponsoring the following schedules for the corresponding filing
   requirements:

   • Name, Address, Facts               Section 14(1)   Tab 1
   • Corp. – Incorporation, Good Standing Section 14(2)   Tab 1
   • LLC – Organized, Good Standing      Section 14(3)   Tab 1
   • LP – Agreement                     Section 14(4)   Tab 1
   • Reason for Rate Adjustment         Section 16(1)(b)(1) Tab 2
   • Certificate of Assumed Name        Section 16(1)(b)(2) Tab 3
   • Proposed Tariff                    Section 16(1)(b)(3) Tab 4
   • Proposed Tariff Changes            Section 16(1)(b)(4) Tab 5
   • Statement about Customer Notice    Section 16(1)(b)(5) Tab 6
   • Notice of Intent                   Section 16(2)    Tab 7
II. CUSTOMER NOTICE

Q. Please describe the methods by which LG&E informed its customers of its proposed electric and gas rate adjustments.

A. Notice to the public of the proposed rate adjustments is being given as prescribed in the Commission’s regulations. On November 2, 2016, LG&E delivered a notice of the filing of LG&E’s application, including its proposed rates, to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation through the Commonwealth of Kentucky in which customers affected reside, for publication in the applicable newspapers once a week for three consecutive weeks beginning November 16, 2016.

In addition, LG&E provided notice by certified mail to each special contract customer and telecommunication carrier pole attacher-licensees.

Furthermore, LG&E is posting the notice to the public along with a complete copy of the application for public inspection at the LG&E business office where customers can transact business with the Company, 820 West Broadway, Louisville, Kentucky 40202.

LG&E is also posting a complete copy of its application in this case on its website (www.lge-ku.com), along with a link to the Commission’s website where the case documents are available.
Finally, on November 23, 2016, LG&E began including a notice of the proposed rate adjustments and general statement explaining the application in this case with the bills for its Kentucky retail customers during the course of their regular monthly billing cycle.

III. PROPOSED REVENUE INCREASE AND BILL IMPACT

Q. Please briefly describe the increase in revenues requested by LG&E.

A. LG&E is requesting an 8.5 percent, or approximately $93.6 million, increase in its annual electric revenue, and a 4.2 percent, or approximately $13.8 million a year, increase in its annual gas revenue. Kent W. Blake and Paul W. Thompson describe in their testimonies the primary drivers of the needed revenue increases.

Q. If the Commission approves the proposed base rates, what will be the percentage increases in monthly residential electric and gas bills?

A. The average monthly residential electric bill increase due to the proposed electric base rates will be 9.5 percent, or approximately $9.65, for a residential customer using an average of 957 kWh of electricity. The average monthly residential gas bill increase due to the proposed gas base rates will be 5.0 percent, or approximately $2.99, for a residential customer using an average of 55 Ccf of gas.

Q. How does LG&E’s average electric residential rate compare to the average residential rate of investor-owned utilities across the United States?

A. LG&E strives to ensure its residential customers receive reasonably priced energy. Based on the Edison Electric Institute’s Typical Bills and Average Rates Report Summer 2016, which provides data covering the 12-month period ending June 30, 2016, LG&E’s current average electric residential rate is approximately 20 percent lower than the average residential electric rate of investor-owned utilities across the
United States. In addition, LG&E’s overall rates for all classes remain well below national and regional averages with LG&E 15 percent and 16 percent below such averages, respectively.

Q. Please explain how the Company’s proposed rate increases are consistent with the Company’s customer-service orientation described in Victor A. Staffieri’s testimony.

A. We at LG&E strive every day to provide safe, reliable, and economical utility service to our customers, as well as an excellent customer-service experience. Therefore, as explained in Mr. Staffieri’s testimony, the decision to file for rate increases is a serious matter; we understand it will impact all customers and their experience with the Company. In particular, we understand the needs of low- and fixed-income customers through our numerous engagements and relationships with these customers and their advocates. I will describe in detail later in my testimony a number of initiatives LG&E has for these customers. Our Company’s culture also includes service to the community through donations of personal and shareholder funds and through volunteering in the communities LG&E serves. So when we decide to seek additional revenues through a rate increase, we do so only when necessary to continue providing safe and reliable utility service and excellent customer service, and we do so fully cognizant of the impacts on customers resulting from our request.

IV. ELECTRIC COST OF SERVICE STUDY, RATE DESIGN, AND ALLOCATION OF INCREASE

A. COST OF SERVICE STUDY
Q. Did the Company cause to be prepared an electric cost of service study to be used as the guide to its proposed rate design and the allocation of its requested electric revenue increase?

A. Yes. At my direction, Mr. Seelye and The Prime Group conducted a fully allocated and time-differentiated embedded electric cost of service study for the Company.

Q. Which cost of service methodology did The Prime Group use to perform the Company’s electric cost of service study?

A. Before asking The Prime Group to proceed with a cost of service study to support the Company’s application in this proceeding, I asked The Prime Group to analyze whether it remains appropriate to continue to use the modified Base-Intermediate-Peak (“modified BIP”) methodology the Companies have used in their cost of service studies for many years. As Mr. Seelye discusses in his testimony, The Prime Group ultimately conducted the Company’s electric cost of service study using two methodologies, the modified BIP methodology and a loss of load probability (“LOLP”) methodology. A utility’s LOLP is the probability that a utility system’s total demand will exceed its generation capacity over a given time period taking into consideration relevant factors, including the magnitude of the load and available generating capacity. Because the Companies plan their systems, and particularly their generating capacity requirements, including their reserve margin, based largely on minimizing loss of load within reasonable economic constraints, I believe an LOLP approach to conducting a cost of service study is appropriate. For the purposes of the Company’s LOLP study, The Prime Group used hourly LOLP to allocate fixed production costs to the classes of
customers. Because the Companies plan their generating units’ production on an hourly basis, an hourly LOLP calculation is sensible and appropriate.

As Mr. Seelye discusses in his testimony, the results of the modified BIP and LOLP approaches to a cost of service study are directionally similar. In this application, the Company primarily relied on the results of the LOLP approach to allocate costs between rate classes, but informed that allocation with the results of the modified BIP approach, as well as the ratemaking principle of gradualism.

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

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by LG&E under both the modified BIP method and LOLP method:

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Rate of Return on Rate Base</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
</tr>
<tr>
<td></td>
<td>Modified BIP Method</td>
</tr>
<tr>
<td>Residential – Rate RS, RTOD, VFD</td>
<td>2.65%</td>
</tr>
<tr>
<td>General Service</td>
<td>7.34%</td>
</tr>
<tr>
<td>Power Service</td>
<td></td>
</tr>
<tr>
<td>- Secondary</td>
<td>8.84%</td>
</tr>
<tr>
<td>- Primary</td>
<td>6.49%</td>
</tr>
<tr>
<td>Time of Day Secondary</td>
<td>11.92%</td>
</tr>
<tr>
<td>Time of Day Primary</td>
<td>4.57%</td>
</tr>
<tr>
<td>Retail Transmission Service</td>
<td>3.48%</td>
</tr>
<tr>
<td>Lighting Energy Service</td>
<td>8.01%</td>
</tr>
<tr>
<td>Traffic Energy Service</td>
<td>7.62%</td>
</tr>
<tr>
<td>Lighting and Restricted Lighting Service</td>
<td>5.39%</td>
</tr>
<tr>
<td>Special Contracts</td>
<td>1.94%</td>
</tr>
<tr>
<td>Total System</td>
<td>4.92%</td>
</tr>
</tbody>
</table>
The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect all pro forma adjustments. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. Mr. Seelye discusses the actual adjusted and proposed rates of return in his testimony.

B. ALLOCATION OF ELECTRIC REVENUE INCREASE

Q. What revenue increase is LG&E proposing for electric operations?

A. As shown on Schedule M-2.1-E, LG&E is proposing an increase in electric forecasted test period revenues of $93,617,727, which is calculated by applying the proposed rates to forecasted test period billing determinants and including changes to miscellaneous operating revenues. This increase is slightly lower than the revenue requirement increase of $93,620,781 shown in Schedule A for electric operations because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule.

Q. How does the Company propose to allocate the electric revenue increase to the classes of service?

A. On average, the Company proposes to increase electric revenue across its rate classes by a system average of approximately 8.5 percent. But the results of the Company’s cost of service study show there are notable differences in the rates of return between the Company’s electric rate classes. This means there are some rate classes that are effectively subsidizing other rate classes. Although the Company does not propose to eliminate all interclass subsidies in this proceeding, the Company does propose to recover larger relative portions of the overall revenue increase from rate classes with
lower rates of return and smaller relative portions of the proposed revenue increase from rate classes with higher rates of return. In other words, LG&E is proposing higher percentage increases for rate classes that have low rates of return, and the Company is proposing lower percentage increases for rate classes that have higher rates of return. This approach comports with the longstanding ratemaking principle of gradualism and is consistent with the Company’s past rate-allocation proposals where there have been significant differences in rates of return between rate classes. Mr. Seelye further discusses this approach in his testimony.

C. ELECTRIC RATE DESIGN APPROACH

Q. What is the basic objective of the rate design being proposed?

A. The Company’s proposed rate design continues to bring both the structure and the charges of the rate design in line with the results of the cost of service study. To that end, the Company proposes one structural change to its electric tariff, namely to eliminate its existing Standby or Supplemental Service Rider (Rider SS) in favor of modifying its existing demand-charge structures for Rates TODS (Time-of-Day Secondary Service), TODP (Time-of-Day Primary Service), RTS (Retail Transmission Service), and FLS (Fluctuating Load Service).

In addition to that structural change, the Company is proposing several notable changes to existing rate schedules and charges, including splitting the energy charge into two components solely for educational purposes on the tariff sheets for rate schedules that do not have demand charges and closing the Company’s Curtailable Service Rider to new participation. My testimony addresses changes the Company is proposing to rate structures and the charges supported by the cost of service study.

D. RESIDENTIAL ELECTRIC RATE DESIGN & INCREASE
Q. Does the Company propose to change its Residential Service, Rate RS, rate structure?

A. No. The rate structure will remain the same and consist of a Basic Service Charge and a flat volumetric, per-kWh energy charge. But as I discuss below, the Company is separating the energy charge into two components solely on the tariff sheets—not on customers’ bills—for Rate RS and a few other rate schedules to begin to educate customers, stakeholders, and employees about the two kinds of costs (fixed and variable) recovered through the Company’s volumetric energy charge.

Q. Does the Company propose to bring the rate components in residential electric rates more in line with the cost of service study?

A. Yes. LG&E proposes to increase the monthly residential basic service charge for Rates RS, RTOD-Demand, and RTOD-Energy from $10.75 to $22.00. This charge has not increased for Rate RS since January 2013 (when new rates from the Company’s 2012 rate case first appeared on customers’ bills) even though the Company’s customer-related fixed costs of providing service were greater than $10.75 at that time and have increased since then. (Rates RTOD-Demand and RTOD-Energy were not available to customers until July 2015.) As Mr. Seelye discusses in his testimony, the Company’s electric cost of service study indicates that the customer-related cost for the residential class is $22.04 per customer per month. LG&E is therefore proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service. This cost is discussed more thoroughly in Mr. Seelye’s testimony and is derived in his Exhibit WSS-2.
Q. Would recovering a larger proportion of customer-specific fixed cost through the basic service charge rather than through the energy charge (or demand charge for Rate RTOD-Demand) have the effect of stabilizing customers’ monthly bills?
A. Yes. Increasing the basic service charge will reduce the spikes that customers see in their bills during high-usage months and cause customer bills to be somewhat more level throughout the course of a year. Unexpected surges in utility usage caused by extreme weather conditions can create additional hardships for customers who already have difficulty paying their utility bills in high-usage seasons and can cause other customers to have difficulties for the first time. Increasing the basic service charge to more closely align with customer-specific fixed costs will reduce the amount of fixed costs embedded in energy rates. This relative reduction of volumetric energy rates will help mitigate bill fluctuations caused by energy-usage spikes, including the impacts of any future extreme weather events.

Q. Is the Company proposing any changes to Rate RTOD-Demand?
A. Yes. As Mr. Seelye explains further in his testimony, the Company is changing the structure of the demand charges from separate on-peak and off-peak charges, each of which applies only during certain hours each week, to a base demand charge applicable at all times and an on-peak demand charge that supplements the base demand charge during certain hours of the week. This structure is consistent with other demand rate schedules for large customers. The Company has made small text changes to the text of Rate RTOD-Demand to reflect this change in approach.

E. CHANGES TO TARIFF SHEETS FOR RATES RS, VFD, AND GS

Q. What changes does the Company propose to make to Rate RS, Volunteer Fire Department Service (Rate VFD), and General Service (Rate GS)?
A. For Rates RS, VFD, and GS, the Company is proposing to split the energy charge into two components—fixed-cost recovery and variable-cost recovery—on the tariff sheets solely for educational purposes. The Company does not propose to bill customers two separate energy charges related to the two kinds of cost recovery; indeed, the Company does not propose to show the two components on customers’ bills at all at this time. Rather, splitting the energy charge solely on the tariff sheets as proposed will allow the Commission and interested customers to see how much fixed-cost recovery versus truly variable-cost recovery is embedded in the Company’s volumetric energy rate for those rate schedules. The Company plans to provide additional educational material on this issue to customers periodically by discussing it in bill inserts or customer newsletters enclosed in customers’ bills.

Q. Please explain further the difference between the Company’s fixed and variable costs of providing electric service, and why splitting the energy charge on certain tariff sheets better reflects those costs.

A. The utility industry, and especially the electric utility industry, is a highly capital-intensive business that requires the purchase, operation, and maintenance of large capital assets—fixed costs—to produce a product with comparatively low variable costs per unit (mostly fuel). The large capital assets include generating units (and associated environmental facilities) to make electricity, transmission facilities to move the electricity in bulk and over long distances, and distribution facilities to move the electricity at lower voltages and over shorter distances to the Company’s customers. Also included in fixed-cost assets are the Company’s meters, customer-service and administrative facilities, operations and maintenance facilities and vehicles, and
numerous other assets required simply to have an electric utility available for customers to use at all. The Company chooses the appropriate capacities for its various assets based on customers’ demands on the total system: generation, transmission, and distribution. Because it is uneconomical to store large quantities of electricity to meet fluctuations in customers’ collective demand, the Company must size its facilities to be ready to meet the considerable demand hundreds of thousands of residential, commercial, and industrial customers can place on the Company’s system, all without prior notice: customers expect electricity to be available instantaneously and in any quantity. To provide that kind of service safely, reliably, and economically requires large investments in capital assets and ongoing fixed operations and maintenance costs just to ensure service is available for customers even when they choose not to use much of it at any given time.

But the truly variable cost of providing any given unit of electricity is relatively small. Indeed, compared to the fixed costs of the facilities and people necessary to ensure the ability to produce any electricity, the variable cost of producing a unit of electricity (i.e., fuel and other consumables) is quite small, less than four cents per kWh according to Mr. Seelye’s cost of service study.

In a sense, the Company’s electric operations are similar to buying and owning a car or truck: there is a significant initial capital investment (the cost of the car) required just to have the ability—the capacity—to have a car available at all times; there are certain ownership costs that do not change based on usage (e.g., insurance and taxes); and there are relatively small costs actually to use the car (e.g., a few cents per mile for gas). And part of determining how much to invest in a car or truck depends in
large part on what kinds of demands will be placed on it: will a small commuter vehicle
suffice, or does the vehicle need to haul heavy loads off-road? Just as with cars or
trucks, the capital costs of utility facilities tend to increase with the demands expected
to be placed on them, but there is some component of fixed cost that does not vary with
demand and is simply the cost of having any capacity available at all.

Therefore, looking at the Company’s actual costs, as well as the automotive
analogy, three basic categories of costs emerge naturally: a portion of fixed costs that
do not vary with demand, fixed costs that are related to demand, and variable cost; these
are the categories Mr. Seelye addresses in his testimony and cost of service study. And
most of the Company’s standard rate schedules have rate structures that reflect these
three categories of costs: a fixed monthly Basic Service Charge to collect customer-
specific and demand-invariant fixed costs (i.e. a minimum amount of a transformer,
service lines, meters, meter reading, customer service); a demand charge to collect
demand-variant fixed costs (i.e. generation capacity, transmission lines, distribution
lines, transformers) that is expressed in dollars per kW or kVA of instantaneous
demand; and a relatively low energy charge of a few cents per kWh for energy
consumed irrespective of demand, which recovers base fuel and other consumable costs
of providing energy. Such rate schedules follow basic principles of cost causation by
having charges reflect the Company’s underlying costs.

But the Company has also a number of rate schedules that do not have a demand
charge. As Mr. Seelye notes, the historical reason for that absence is that meters
capable of measuring a customer’s demand have previously been uneconomical to use
for smaller customers. Therefore, the Company’s rate schedules that do not have a
demand charge (Rates RS, RTOD-Energy, VFD, and GS) recover significant amounts of the Company’s fixed costs of serving customers through the schedules’ volumetric energy rates. For example, LG&E’s electric Rate RS currently has an energy rate of $0.08639 per kWh, of which less than $0.04 per kWh is the truly variable cost of producing a kWh of electricity (primarily fuel cost); the remaining charge per kWh provides the Company fixed-cost recovery that the Rate RS Basic Service Charge of $10.75 per month does not cover. But as I discussed above, the Company incurs fixed costs regardless of whether customers actually consume any energy. As discussed in the testimony of Mr. Seelye and as I noted above, the production facilities, transmission and distribution lines, transformers and other facilities, as well as the Company’s personnel, must be in place at all times for customers to receive energy instantaneously when they desire to cool or heat their homes, turn on their lights, power their computers, or watch television. The costs of these facilities and personnel are fixed relative to energy consumption, but to the extent the Company does not recover those costs through the Basic Service Charge, it must recover them through the volumetric energy charge for rate classes that lack a demand charge. Recovering fixed costs through volumetric energy rates can result in unintended but unavoidable subsidies inside each rate class: customers with high usage pay more in fixed-cost recovery, which likely subsidizes customers with low usage.

The Company is therefore proposing in this proceeding to split the energy charge into fixed-cost (Infrastructure Energy Charge) and variable-cost (Variable Energy Charge) components solely on its tariff sheets for rate schedules that currently lack a demand charge, except RTOD-Energy. This Variable Energy Charge will now
represent only the variable cost of production, including base fuel expense. The
Company believes this approach will help educate the customers, stakeholders and
employees about the amount of fixed-cost recovery inherent in the energy charge for
these rate schedules, enabling a better understanding of intra-class subsidies, and more
generally the nature of the charges customers pay. Also, the Company hopes this will
begin helpful discussions about possible rate structure changes in the future that might
better reflect the Company’s underlying cost of service and reduce intra-class subsidies.

F. CLOSING THE CURTAILABLE SERVICE RIDER

Q. Why is the Company closing its Curtailable Service Rider to new participation?

A. As David S. Sinclair explains in his testimony, the Company does not need additional
load participating in CSR to help ensure it can maintain an adequate reserve margin.
Moreover, the Company does not currently anticipate needing additional capacity (in
the form of curtailable load or otherwise) through the end of the forecasted test period.
Therefore, the Company proposes to close the rider to new participation (i.e., no new
participants and no additional curtailable load to be compensated under the rider from
existing participants), allowing existing curtailable load under contract as of the date
new rates go into effect resulting from this proceeding to continue receiving credits
under the rider in return for the Company’s ability to curtail that load under the
conditions stated in the CSR tariff sheets; this closure is reflected in Sheet No. 50 of
the Company’s proposed electric tariff. In doing so, the Company is not proposing to
“grandfather” or continue to allow the current customers under the CSR service
schedule to remain CSR customers for an indefinite period of time, though the
Company is not proposing to remove CSR from its tariff at this time.

Q. Does the Company propose to change the CSR credits?
A. Yes. The Company is proposing new CSR credits of $3.56 per kVA of curtailable demand at transmission voltages and $3.67 per kVA of curtailable demand at primary voltages, while maintaining the current non-compliance charge of $16.00 per kVA. As Mr. Seelye explains in his testimony, the new credits are based on the capacity cost of the Company’s existing resources rather than a potential new generating unit because the Company does not anticipate needing new capacity through the end of the forecasted test period; Mr. Sinclair explains why this change in methodology is appropriate based on the Company’s load forecast and existing generating resources. This results in lower credits than the Company has provided in recent years, but is appropriate due to the Company’s current and likely future generating capacity as compared to its expected load.

Q. Does the Company propose any other change to Rider CSR?

A. Yes. As Mr. Sinclair discusses in his testimony, the Company is proposing to change the Natural Gas Price (“NGP”) component of the Automatic Buy-Through Price provision to better reflect the natural gas spot prices the Company actually faces in the marketplace. The Automatic Buy-Through Price applies to service CSR participants receive during any of the up to 275 hours of curtailments with a buy-through option the Company may request each year. The Company is proposing to change the NGP from the midpoint price for natural gas posted for the day in Platts Gas Daily for Dominion-South Point to the Cash Price for “Natural Gas, Henry Hub” as posted in The Wall Street Journal on-line for the most recent day for which a price is posted that precedes the day in which the buy-through occurred.
The Company is also proposing a non-substantive text addition to clarify that a CSR customer’s choice to curtail rather than buy through during any of the 275 hours of Company-requested curtailment with a buy through option each year does not reduce the 100 hours of physical curtailment the Company may request each year.

G. THE COMPANY’S CURRENT AMS CUSTOMER OFFERING

Q. Now that the Company is proposing to deploy AMS metering across its service territory, what does it propose to do concerning its existing AMS customer offering provided as part of the Company’s demand-side management and energy-efficiency (“DSM-EE”) programs?

A. As Mr. Malloy explains in his testimony, the full deployment of AMS metering across the Company’s service territory obviates the need for any further AMS deployments under the existing AMS customer offering available as a DSM-EE program today. Instead, if the Commission approves the Companies’ proposed full deployment of AMS, customers requesting AMS meters ahead of the Companies’ deployment schedule will receive such meters within a reasonable time to the extent feasible, and will receive it as part of the full AMS deployment, not as part of the AMS Customer Offering. Customers already being served by the DSM-EE AMS customer offering will continue to enjoy the benefits of that offering, and the Company proposes to continue recovering the costs of the offering through its DSM-EE mechanism through the end of the Commission-approved period for the offering, i.e., through the end of 2018. This will ensure the AMS Customer Offering’s participants can continue receiving the offering’s benefits while the Companies fully deploy AMS to all customers.
H. PROPOSAL TO ELIMINATE SUPPLEMENTAL OR STANDBY SERVICE RIDER (RIDER SS)

Q. What is the Company proposing concerning Rider SS?

A. The Company proposes to eliminate the rider; currently no customers take service under it. The purpose of the rider is to ensure that customers whose primary source of power is their own generating resources but who desire the Company to provide what is essentially firm backup service pay the full fixed cost associated with the facilities and personnel necessary to provide that service. But Rider SS is, by its own terms, a voluntary rider, and it depends upon customers self-reporting their use of the Company as a backup service provider; the Company would rarely, if ever, have independent knowledge of a customer’s making such use of the Company’s system. This creates a potential opportunity for customers using the Company for back-up service to free-ride on the Company’s system due to the current demand-charge structures of Rates TODS, TODP, RTS, and FLS.

To address this problem, the Company is proposing to eliminate Rider SS and revise the demand charges of Rates TODS, TODP, RTS, and FLS to attempt to eliminate the possibility of having free riders. To accomplish this, the Company proposes for the Base Demand Period for each of the rates to make the demand charge the greatest of: (a) the maximum measured load in the current billing period, but not less than the minimum load required to take service under the rate schedule; (b) the highest measured load in the preceding eleven monthly billing periods; and (c) the contract capacity based on the maximum load expected on the system or on facilities specified by the customer. This approach will ensure that a customer that accurately informs the Company about the customer’s potential demand (contract capacity) will
pay appropriately to have that capacity available. Similarly, if a customer using the
Company for backup service actually makes use of the Company’s facilities for such
service and exceeds the contract capacity, the customer will pay a demand charge for
that increased amount of capacity for at least 12 months (assuming the customer does
not again equal or exceed that demand in the following 12 months). This approach
should help ensure customers pay for the service they are receiving without depending
on customers to self-report their desire for backup service from the Company. Further
details are discussed in the testimony of Mr. Seelye.

I. ELECTRIC RATES FOR SPECIAL CONTRACT CUSTOMER 1

Q. Why is the Company asking the Commission to terminate the Company’s existing
special contract with Special Contract Customer 1 in favor of having the customer
take service under standard Time-of-Day Primary (Rate TODP) rates?

A. The current special contract rates for Special Contract Customer 1 are inadequate to recover the Companies’ cost of serving the customer. As the Company’s
cost of service studies have repeatedly shown over the course of more than a decade,
the rate of return associated with the rates Special Contract Customer 1 has paid under
its special contract with the Company has been the lowest or among the lowest of the
rates of return the Company has earned from any of its rate classes. The Company
believes it is now appropriate for Special Contract Customer 1 to move to standard
tariff rates for the service it receives, namely the rates prescribed by Rate TODP due to

2 See, e.g., In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric
and Gas Rates, Case No. 2014-00372, Testimony of Dr. Martin Blake at 17 (Nov. 26, 2014); In the Matter of:
Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate
of Public Convenience and Necessity. Approval of Ownership of Gas Service Lines and Riders, and a Gas Line
Surcharge, Case No. 2012-00222, Testimony of Robert M. Conroy at 31 (June 29, 2012); In the Matter of: an
Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company, Case
the customer’s service characteristics. Therefore, because the contract is subject to the
jurisdiction of this Commission, the Company respectfully asks the Commission to
terminate the existing special contract between the Company and Special Contract
Customer 1, allowing the Company to serve Special Contract Customer 1 under the
standard rate schedule appropriate for its service characteristics, namely Rate TODP.
The revenue impact of this proposed rate change is incorporated in Schedule M-2.3-E.

J. OTHER STANDARD RATE SCHEDULES

Q. Please explain the changes shown on Sheet No. 10 concerning General Service (Rate GS).

A. In addition to the proposed increase to the Rate GS basic service charge and energy
charge to bring them more into line with the Company’s cost of service study, as well
as the splitting of the Rate GS energy charge on the tariff sheets as discussed above,
the Company proposes to add a section titled “Determination of Load,” which states
that Rate GS service will be metered except by agreement of the Company and the
customer. Such unmetered service will be billed on calculated consumption based on
the kind of equipment being served.

Q. Please explain the changes shown on Sheet No. 15 concerning Power Service (Rate
PS).

A. In addition to the proposed rate changes to bring them more into line with the
Company’s cost of service study, the Company proposes to add wording to the monthly
billing demand portion of the “Rate” section to clarify that, because not all Rate PS
customers take service under contracts, a “contract capacity” cannot be used in all cases
to help set monthly billing demand. The Company proposes also to change the term
“billing demand” to “measured load” in part (b) of the demand charge section to match
the “measured load” terminology used in part (a). This is solely a terminology change, not a substantive change.

Q. **Please explain the changes shown on Sheet Nos. 35 – 35.3 concerning Lighting Service (Rate LS).**

A. The Company proposes to add four energy-efficient LED lighting offerings to customers under Rate LS. The Company further proposes to move some of its current metal-halide light offerings (both overhead and similar underground offerings) to Restricted Lighting Service (Rate RLS) due to limited availability of new and replacement parts for such lights from their manufacturer.

Q. **Please explain the changes shown on Sheet Nos. 36 – 36.3 concerning Restricted Lighting Service (Rate RLS).**

A. Except for high-pressure sodium and metal-halide lights, the Company will no longer offer spot replacements for Rate RLS bulbs or fixtures due to lack of availability from manufacturers. The first proposed text change to the “Availability of Service” section of Sheet No. 36 reflects this changed policy.

The second proposed text addition to the Availability of Service section on Sheet No. 36 is identical to text in the Availability of Service section of Rate LS that precludes the Company from offering certain lighting options in residential neighborhoods except when requested by municipal authorities. The Company is adding this text to Rate RLS because it is moving certain metal-halide lights from Rate LS to Rate RLS, and those lights were subject to this restriction under Rate LS.

The other changes to Rate RLS reflect the Company’s proposal to move some of its current Rate LS metal-halide light offerings to Rate RLS.
Q. Please explain the changes shown on Sheet No. 38 concerning Traffic Energy Service (Rate TE).

A. The Company proposes to add text to the “Availability of Service” section to clarify that service under Rate TE is available for all manner of traffic-control devices, not only those specifically listed on Sheet No. 38.

K. CHANGES TO CABLE TELEVISION ATTACHMENT CHARGES (RATE CTAC), RENAMED POLE AND STRUCTURE ATTACHMENT CHARGES (RATE PSA)

Q. Is the Company proposing changes to the structure and rates of Rate CTAC?

A. Yes, the Company is proposing numerous changes to the existing CTAC rate schedule that broadens its scope to reflect the technological advancements in the facilities being attached to our poles. This overarching change is reflected in the proposed name of the tariff, which is now “Pole and Structure Attachment Charges,” Rate PSA. The Company has proposed to revise how “attachment” is defined to expressly include telecommunication wireline and wireless facilities, which are not included in the current rate schedule and are currently served under license agreements.

In addition, the Company is clarifying its terms of service with respect to the application and permit process, as well as construction and maintenance requirements and specifications. The revisions serve the dual purpose of improving the safety of the attachments with respect to the Company’s property and instituting additional measures to reduce the likelihood of electric reliability concerns resulting from a pole attachment. Moreover, the Company is including the terms and conditions of service in its rate schedule to apprise the Commission and interested parties of these requirements.

Q. Does the Company have a plan for how attachers not presently included in the rate schedule will begin taking service under the revised Rate PSA?
A. Yes. As I mentioned, the current CTAC rate schedule only applies to cable television attachments. As technology has evolved, parties providing different forms of wireline and wireless service have sought to attach on the Company’s poles. Because the Company does not have a tariff that addresses many of these services, it has executed license agreements with each of these entities. And because the license agreements were executed at different times, the license agreements have different expiration dates. Once a license agreement expires, if that customer seeks to continue attaching facilities to the Company’s poles and falls within the availability of service, it must then take service under the proposed new PSA rate schedule. The customer will then execute an agreement that incorporates the terms of service under the PSA rate schedule. Under this transition plan, virtually all entities that attach to the Company’s poles will take service under the PSA rate schedule within ten years, based on the remaining time periods on those contracts.

If approved by the Commission, customers currently receiving service under Rate CTAC and new customers falling within the availability of service that do not have a current contract will take service under the revised PSA rate schedule from the effective date forward.

Q. Are certain types of attachments excluded from the revised rate schedule?

A. Yes. As set forth in the availability of service on Sheet No. 40, the tariff applies to the facilities of cable television system operators and telecommunications carriers, except (1) facilities of incumbent local exchange carriers with joint use agreements with the Company; (2) facilities subject to a fiber exchange agreement; and (3) Macro Cell Facilities. These attachments are not included in the PSA rate schedule due to their
unique nature and pricing arrangements. As new agreements are made, these
attachments will be governed by special contracts that will be filed with the
Commission.

Q. Are there proposed changes to the attachment fees?

A. Yes. In the existing rate schedule, there is a single flat fee per attachment regardless of
the type of attachment. In the proposed rate schedule, there is a fee for each pole
attachment, a separate fee for each linear foot of duct utilized, and a fee for each
wireless facility. With respect to duct access fees, the proposed rate schedule expressly
disallows access to duct systems that support transmission lines due to safety and
reliability concerns.

The Company is proposing to maintain the current fee of $7.25 per year for
each pole attachment as contained in the current CTAC rate schedule. The Company
is proposing a charge of $0.81 per year for each linear foot of duct, and $84.00 per year
for each for each wireless facility. The Company has adhered to the formula prescribed
in the Commission’s Order in Administrative Case No. 251 in proposing the yearly
pole attachment fee. As required in the settlement agreement for the Company’s last
base rate case, the Companies met with the Kentucky Cable Telecommunication
Association (KCTA) to discuss methodological differences in the calculation of the
attachment rates. Although the Companies and KCTA were not able to reach a
complete agreement on methodology to be proposed in this base rate application, the
Companies have modified certain parts of its calculation to address the differences. A
discussion of these changes and the calculations of the proposed charges are discussed
in the testimony of Mr. Seelye.
Q. Does the revised rate schedule change the manner in which customers are billed?

A. Customers will continue to be billed semi-annually for the preceding six month period based on the type and number of a user’s attachments reflected in the Company’s records on December 1 and July 1. In addition, the Company is proposing that bills not paid within sixty days will incur a late fee of 3 percent, similar to what applies to the general service customer class. Presently, customers taking service under Rate CTAC are one of the only customer classes not paying a late fee on bills that are not paid by the due date. Also, the Company is proposing a ten-year term of service, with renewal options thereafter.

L. CHANGES TO ELECTRIC SPECIAL CHARGES

Q. Does the Company propose to change any of the Special Charges shown on Sheet No. 45 of its electric tariff?

A. The only existing Special Charge the Company proposes to change is its Meter Data Processing Charge, which the Company proposes to remove. Customers paying this charge have received from the Company paper reports concerning their usage profiles using data from the recorder metering equipment installed by the Company. The Company proposes to stop offering this service in favor of transitioning to having customers receive the same information at no cost via a portal on the Company’s web site, negating the need for the charge. Removing this charge will not have a material impact on the Company’s revenues; for the 12-months ending May 31, 2016, the Company received about $5,000 in revenue from this charge.

The Company further proposes to add an Unauthorized Reconnect Charge. This charge would allow the Company to recoup its cost of addressing theft of service in excess of back-billing customers for unauthorized service received. When a
customer reconnects to the Company’s service without authorization, the Company must incur costs to correct the customer’s unauthorized physical connection to the Company’s service and ensure the service stays disconnected until the Company makes an authorized reconnection. This charge is based on the Company’s experience with making such corrections in recent years, as well as the type of meter and damage at issue:

(1) A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

(2) A charge of $90.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter;

(3) A charge of $110.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading (AMR) meter;

(4) A charge of $174.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter System (AMS) meter; or

(5) A charge of $177.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a three-phase meter.

Mr. Seelye provides support for these charges in his testimony.

M. CHANGES TO OTHER RIDERS

Q. What changes does the Company propose to make to its Economic Development Rider (Rider EDR) at Sheet No. 71.1?

A. The Company proposes to revise one of the criteria for determining whether an existing customer is eligible for Rider EDR. Rider EDR currently requires an existing customer to contract for a minimum monthly billing load at least 1,000 kVA or kW above the
customer’s Existing Base Load, which is calculated by “averaging Customer’s previous three years’ monthly billing loads, subject to any mutually agreed upon adjustments thereto.” This creates challenges for customers who have not taken service for a full three years and invites possible disputes between the Company and an existing customer concerning reasonable adjustments to the customer’s three-year average demand. Moreover, a three-year average might not reflect accurately an existing customer’s current demand. To address these concerns, the Company proposes to revise the above-quoted text so the Existing Base Load is simply a 12-month rolling average of the customer’s measured demand; no adjustments will be permitted. This should minimize potential disputes between the Company and customers seeking to take part in Rider EDR, and should ensure the Existing Base Load accurately reflects each customer’s current level of demand.

Q. Please explain how the Company proposes to address its Solar Share Program Standard Rate Rider (“Rider SSP”).

A. On November 4, 2016, the Commission approved the Companies’ joint application for approval of its proposed Solar Share Program and its associated Rider SSP, and ordered the Companies to file Rider SSP tariff sheets within 20 days of the Commission’s order. Because Rider SSP was so recently approved and the tariff sheets were just filed, the Company is not proposing any changes to Rider SSP. But the Company recognizes that there may be revisions to the Solar Capacity Charge and Solar Energy Credit resulting from this case, and that those revised rates will become effective with

3 In the Matter of: Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of an Optional Solar Share Program Rider, Case No. 2016-00274, Order (Nov. 4, 2016).
the rest of the rates approved in this proceeding. Indeed, the Commission’s final order in the Solar Share Program case appears to contemplate this approach.¹

N. CHANGES TO ADJUSTMENT CLAUSES

Q. Please explain the text changes the Company proposes to make to Adjustment Clause ECR (Environmental Cost Recovery Surcharge) at Sheet No. 87.

A. The Company proposes to replace “CTAC” with “PSA” in the Availability of Service section to reflect the proposed change of that rate’s name. The Company further proposes to add Rates EVSE (Electric Vehicle Supply Equipment) and EVC (Electric Vehicle Charging Service) to Group 2 for ECR rate calculation purposes, which accords with the Commission’s final order approving electric vehicle rates in Case No. 2015-00355.⁵

Q. Please explain the text change the Company proposes to make to Adjustment Clause HEA (Home Energy Assistance) at Sheet No. 92.

A. The charge applies to residential customers only, and the current Rate section of Adjustment Clause HEA states that the rate is $0.25 per meter per month. In fact, some residential electric customers have more than one electric meter. The Company proposes to delete “per meter” to reflect that each residential electric customer pays only one HEA charge per month.

O. CHANGES TO CUSTOMER DEPOSITS

⁴ See, e.g., id. at 11-12.
⁵ In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Install and Operate Electric Charging Stations in their Certified Territories, for Approval of an Electric Vehicle Supply Equipment Rider, and Electric Vehicle Supply Equipment Rate, an Electric Vehicle Charging Rate, Depreciation Rate, and for a Deviation from the Requirements of Certain Commission Regulations, Case No. 2015-00355, Order (Apr. 11, 2016).
Q. Does the Company propose to increase customer deposits for Residential and General Service Rates?

A. No, the Company proposes to keep customer deposits at their current levels for Residential Rates RS, RTOD-Energy and RTOD-Demand ($160.00 for electric only customers and $260.00 for combined residential electric and gas customers) and General Service Rate GS ($240.00). The Commission’s regulations (807 KAR 5:006 Section 8(d)(2)) state that a utility may establish a deposit of an equal amount for each customer class based on the average bill of customers in that class, and that such a deposit cannot exceed two-twelfths of the average bill of customers in the class where bills are rendered monthly. Although Exhibit RMC-1 demonstrates the Company could support customer deposits as high as $221 for residential electric customers ($347 for combined residential electric and gas customers) and $673 for general service customers consistent with the Commission’s regulations, the Company believes its existing deposit levels are sufficient and strike the correct balance between protecting against uncollectible debts while minimizing burdens on customers paying deposits.

V. CHANGES TO ELECTRIC TERMS AND CONDITIONS

Q. Please explain the proposed text addition to the Customer Bill of Rights at Sheet No. 95.

A. The Company’s Customer Bill of Rights applies to service to residential customers. The relevant provision of the Company’s Customer Bill of Rights currently states, “You have the right to participate in equal, budget payment plans for your natural gas and electric service.” But since the Commission approved the Company’s electric tariff resulting from the Company’s 2014 base rate case, the Company’s tariff has contained two optional residential rates, Residential Time-of-Day Energy (RTOD-Energy) and
Residential Time-of-Day Demand (RTOD-Demand), explicitly stating that service under those rates is not eligible for the Company’s Budget Payment Plan. Offering a Budget Payment Plan to a customer under RTOD-Energy or RTOD-Demand would undermine the purpose of the rates, which is to provide time-differentiated price signals to customers to encourage reduced demand or consumption at different times of day. Allowing customers to participate in a Budget Payment Plan while taking service under those rates would reduce or eliminate the effectiveness of the pricing signal. The Commission apparently agreed with that view and approved the Company’s tariff containing the Budget Payment Plan restriction for RTOD-Energy and RTOD-Demand. Therefore, to ensure clarity and consistency across the Company’s tariff, it is proposing to revise the quoted portion of the Customer Bill of Rights to clarify that a customer has a right to participate in a Budget Payment Plan unless the standard rate schedule under which the customer takes service explicitly states otherwise.

Q. Please explain the text addition to the Company Terms and Conditions provision at Sheet No. 96.

A. The Company has added text to this provision to clarify how the Company already interprets and applies terms and conditions set out in specific rate schedules as compared to the terms and conditions set out at the end of the Company’s tariff, the latter of which are generally applicable. Consistent with basic contract and legal principles, the proposed text states that to the extent the specific terms and conditions of a particular rate schedule conflict with the tariff’s generally applicable terms and conditions, the specific terms and conditions will control.

Q. Please explain the new Customer Generation provision at Sheet No. 96.
A. The Company has added this provision to require customers to report to the Company all customer-installed generation designed to run in parallel with the Company’s service irrespective of the length of time the customer intends such generation to run. Having this information will aid the Company in ensuring safe and reliable grid operations, including helping ensure the Company is aware of generating units that might inadvertently deliver power to the distribution system during system restoration efforts and could affect the safety of the public and the Company’s restoration personnel.

Q. Please explain the changes to the Application for Service provision at Sheet No. 97.

A. The proposed revision is intended to clarify the kinds of information the Company may request when a person applies for service, and to clarify that the Company may refuse service to an applicant who refuses to provide requested information. The immediate cause of the proposed revision is a recent change in policy by the nation’s major credit reporting agencies requiring new accounts reported to them to include the applicant’s date of birth to help ensure the accuracy of the credit rating agencies’ credit tracking and reporting, as well as the date of birth of any authorized user added to an existing account. These credit-reporting-agency policy changes apply to accounts opened, or authorized users added, after September 15, 2017. The Company therefore seeks to have the proposed clarifying text added in this rate case to ensure it may request the needed information by the credit rating agencies’ September 15, 2017 deadline.

Q. Please explain the changes to the Contracted Demands provision at Sheet No. 97.
A. The proposed text changes describe how the Company will establish a monthly billing demand for a customer that takes service at a particular location under a rate with a demand charge, then stops taking service entirely at that location (for example, by leasing the facility to another entity), then later reestablishes service at the same location. The purpose of the text is to ensure that customers facing demand charges cannot take service and establish demand charges based on historical demand, leave the system, and then reestablish service at the same location in hopes of establishing new demand charges based on projected, rather than historical, demand. The proposed text permits the Company to set demand charges for a returning customer based on a contracted demand or load data sheet when the Company determines that the customer’s facilities, processes, or practices justify setting a different contract demand than the historical demand data might indicate.

Q. Please explain the changes to the Metering provision at Sheet No. 98.

A. The Company proposes to add a sentence to the Metering provision to clarify that the Company may install whatever metering equipment it deems necessary for a customer’s service. The Company believes this concept was already implicit in the Metering provision, but it is helpful to make this right explicit before the Company begins its proposed full deployment of AMS meters.

Q. Please explain the changes to the Firm Service provision at Sheet No. 98.1.

A. Because the Company has proposed to remove Rider SS (Standby or Supplemental Service), the Company proposes to delete the references to Rider SS from this provision.
Q. Please explain the changes to the Power Requirement provision of the Residential Rate Specific Terms and Conditions at Sheet No. 100.

A. The Company’s proposed text addition simply adds the two other residential rates (RTOD-Demand and RTOD-Energy) to the Power Requirement provision alongside Rate RS. The same Power Requirement provisions should apply to those two elective residential rates; nothing about serving customers under those rates would justify having different Power Requirement provisions.

Q. Please explain the changes to the Meter Readings and Bills provision at Sheet No. 101.

A. The proposed text addition clarifies that a “meter reading” for all tariff purposes includes usage data provided by automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to Company. Therefore, a physical, manual reading of a meter is not required to constitute a “meter reading.” This provision is intended to obviate the need for a deviation from the physical, manual meter-reading requirements of 807 KAR 5:006 Section 7, though the Company has requested one out of an abundance of caution as I discuss below.

Q. Please explain the changes to the Discontinuance of Service provision at Sheet No. 105.2.

A. Because the Company has proposed to add an Unauthorized Reconnect Charge to its Special Charges, it is appropriate to revise the Discontinuance of Service provision to replace the requirement that a fraudulent user pay “the cost to the Company incurred by reason of the fraudulent use” with “assessment of the charges under the
Unauthorized Reconnect Charge provision of Special Charges.” Whereas the Company previously had authority under its tariff to charge fraudulent users for costs incurred related to any damage caused by fraudulent use, the Company will now have a set of standard tariff rates to charge for such damage, if any, and it is appropriate to refer to those charges in this Discontinuance of Service provision.

VI. CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Q. Why is the Company seeking CPCNs for its proposed AMS and DA deployments?

A. The Commission stated in its final order in Case No. 2012-00428, which was its most recent case concerning smart-grid standards, “With regard to CPCNs, the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA [distribution automation], SCADA or volt/var resources.” Together, LG&E and KU are proposing to deploy AMS metering across their service territories (as Mr. Malloy describes in his testimony) and to conduct a significant DA deployment across their service territories (as Mr. Thompson describes in his testimony). Therefore, each of the Companies is requesting CPCNs for its part of the AMS and DA deployments based on the Commission’s final order noted above.

Q. Why should the Commission grant the CPCNs the Companies are requesting?

A. The Commission should grant the CPCNs the Companies are requesting because the proposed deployments meet all of the criteria for granting a CPCN. As Mr. Malloy explains in his testimony, the AMS deployment will provide numerous benefits to

---

customers and will provide net savings compared to continuing to operate the
Companies’ existing metering infrastructure of almost $470 million nominal dollars
($30.2 million net present value to 2016) through 2039. As documents attached to Mr.
Thompson’s testimony explain, the Companies’ proposed DA deployment will
significantly improve the performance of the distribution system, resulting in fewer
outages and faster restoration times for customers. Therefore, the Companies’
proposed AMS and DA will provide large benefits to customers and are entirely
consistent with the public convenience and necessity as required by 807 KAR 5:001
Sec. 15(2)(a).

Q. Will the Companies’ AMS and DA deployments require the issuance of any
permits or franchises by any public authority, and have the Companies attached
copies of such permits or franchises (if any) to their applications in these cases as
required by 807 KAR 5:001 Sec. 15(2)(b)?

A. No. There are no permits or franchises that need to be procured by the Companies to
deploy AMS or DA equipment.

Q. Have the Companies provided a full description of the proposed location, route,
or routes of the proposed AMS and DA deployments, including a description of
the manner of the construction, as well as the names of all public utilities,
corporations, or persons with whom the proposed deployments are likely to
compete, as required by 807 KAR 5:001 Sec. 15(2)(c)?

---

8 See Exhibit PWT-5, “LG&E and KU Electric Distribution Operations Distribution Reliability & Resiliency Improvement Program.” See also Exhibit PWT-7 concerning the costs and benefits of the proposed DA deployment.
A. Yes. The proposed full AMS deployment will occur across the entirety of the Companies’ Kentucky service territories, as it will eventually require replacing nearly all of the Companies’ existing electric meters, deploying related gas indices, and installing a variety of related support and communications systems. Exhibit JPM-1 to Mr. Malloy’s testimony more fully and precisely describes the proposed locations, timing, and sequencing of the full AMS deployment.

Similarly, the Companies’ proposed DA deployment will occur across the Companies’ Kentucky service territories: approximately 20% of the Companies’ distribution circuits and 50% of the Companies’ customers will be targeted for DA implementation. In addition to the description of the proposed DA deployment in Mr. Thompson’s testimony and the LG&E and KU Electric Distribution Operations Distribution Reliability & Resiliency Improvement Program document attached as Exhibit PWT-5 to his testimony, attached to Mr. Thompson’s testimony as Exhibit PWT-3 is a map showing the locations of the electronic reclosers the Companies will deploy as part of their proposed DA deployment.

Concerning the names of all public utilities, corporations, or persons with whom either deployment is likely to compete, there are no such public utilities, corporations, or persons; the deployments will occur entirely inside the Companies’ existing Kentucky electric service territories, and the gas-related equipment will be installed only at existing customers’ locations. Therefore, the proposed AMS and DA deployments necessarily will not compete with any other person or entity.

Q. Have the Companies provided the maps, plans, specifications, and drawings required by 807 KAR 5:001 Sec. 15(2)(d)(1) and (2)?
A. Yes. The required maps for the AMS deployment are included in Exhibit JPM-1, Section 8.1, Electric Meter and Gas Index Installations, an illustration of the planned AMS system architecture is included as Appendix A-2 to Exhibit JPM-1, and data sheets for various AMS system components are included as Appendices A-3.1 – 3.8 to Exhibit JPM-1. The required map for the DA deployment is included in Exhibit PWT-3, and drawings of various DA-related components are included in Exhibit PWT-4.

Q. As required by 807 KAR 5:001 Sec. 15(2)(e), how do the Companies plan to finance the proposed AMS and DA deployments?

A. The Companies expect to finance the costs of the AMS and DA deployments with a combination of new debt and equity. The mix of debt and equity used to finance the project will be determined so as to allow the Companies to maintain their strong investment-grade credit ratings.

Q. As required by 807 KAR 5:001, Section 15(2)(f), what are the estimated annual operating costs of the proposed AMS and DA deployments?

A. The estimated annual operating costs of the full AMS deployment are shown in the AMS Business Case (Mr. Malloy’s Exhibit JPM-1) at section 7.2. The estimated annual operating costs of the DA deployment are shown in Exhibit PWT-6 of Mr. Thompson’s testimony.

VII. REQUEST FOR DEVIATIONS FROM CERTAIN METER-RELATED COMMISSION REGULATIONS TO ACCOMMODATE THE COMPANY’S PROPOSED AMS DEPLOYMENT

Q. Why is the Company requesting deviations from certain meter-related Commission regulations?

A. The AMS equipment the Company proposes to deploy throughout its service territory will achieve the safety and reliability objectives that certain Commission regulations
pertaining to meter inspection and testing were intended to ensure, and will either
obviate the need for continued compliance with those regulations or, in certain cases,
render strict, literal compliance impracticable or impossible. The Company is therefore
asking the Commission to authorize a deviation from those regulations.

Q. **What is the Company requesting concerning 807 KAR 5:006 Section 7(5)?**

A. Section 7(5)(a) requires a utility to read each customer’s meter at least quarterly except
if prevented by reasons beyond its control and excepting customer-read meters subject
to Section 7(5)(b). In turn, Section 7(5)(b) requires that a meter be read manually at
least once during each calendar year. Commission Staff has previously opined that
solid-state metering systems that record meter readings at least daily and transmit such
meter readings directly to a utility’s central office comply with this regulation without
requiring a manual reading.\(^9\) The Company therefore requests an order confirming
that interpretation and declaring that the Company will be in compliance with 807 KAR
5:006 Section 7(5)(a) and (b) even if it does not physically read AMS electric meters
or gas meters with AMS indexes. In the alternative, the Company requests a permanent
deviation from this regulation because AMS metering equipment will transmit at least
daily the same information to the Company as it provides at a customer’s location,
eliminating the need to manually read AMS electric meters or gas meters with AMS
indexes.

Q. **What is the Company requesting concerning 807 KAR 5:006 Section 14(3)?**

A. Section 14(3) requires a utility to “inspect the condition of its meter and service
connections before making service connections to a new customer so that prior or

---

\(^9\) Letter from Beth O’Donnell, Executive Director, Kentucky Public Service Commission, to Ron Sheets, President, Kentucky Association of Electrical Cooperatives (Sept. 27, 2006).
fraudulent use of the facilities shall not be attributed to the new customer.” AMS electric meters are capable of sensing meter tampering and other defects, and can transmit that information to the Company. This capability renders physical inspections of meter and service connections unnecessary. Therefore, the Company requests a permanent deviation from 807 KAR 5:006 Section 14(3) for its AMS electric meters.

Q. What is the Company requesting concerning 807 KAR 5:006 Sections 26(4)(e) and 26(5)(a)(2)?

A. Section 26(4)(e) requires an electric utility to inspect its meters at least every two years. Section 26(5)(a)(2) requires a gas utility to inspect its meters at least every three years. An AMS electric meter provides information on its condition on a daily basis and has systems to promptly alert the utility of tampering or of malfunctions, allowing a utility to know when it should conduct a physical inspection; an AMS gas index provides similar data concerning the gas meter in which it is installed. This capability eliminates the need for biennial or triennial physical inspections. The Company estimates that the elimination of this requirement will result in annual savings of $1.2 million, which are in addition to the savings the Companies have projected as resulting from the full AMS deployment. Therefore, the Company requests a permanent deviation from the inspection requirements of 807 KAR 5:006 Sections 26(4)(e) and 26(5)(a)(2).

Q. What is the Company requesting concerning 807 KAR 5:041 Sections 15(3) and 16, as well as 807 KAR 5:006 Section 19?

A. 807 KAR 5:041 Sections 15(3) and 16 require that single-phase electric meters must be tested every eight years or in accordance with a Commission-approved sample-meter testing plan; the Company has such a testing plan, which the Commission
approved in Case No. 2005-00276. Because the Company proposes to replace all of its existing non-AMS single-phase meters within a two-year period with new AMS equipment, continued testing during this period appears unnecessary. The Company therefore requests a deviation from these regulations to suspend testing immediately and to resume testing in accordance with its existing Commission-approved testing plan after completion of AMS deployment. The Commission has permitted other electric utilities to suspend testing for similar deployments.

Similarly, Section 15(3) requires electric utilities to test metering equipment when removed from service. The Company intends during its AMS deployment to remove all of its existing non-AMS meters and immediately to dispose of the vast majority of the removed meters without testing them. Testing all of the removed meters would cost approximately $3.3 million and would likely serve little or no purpose, particularly because over the last six years more than 99% of the Companies’ electric meters tested have been within +/-2%, and of the <1% that were fast or slow, 82% were slow and 18% were fast, meaning that less than 0.18% of electric meters tested were fast. Granting this requested waiver would result in saving the $3.3 million that would be necessary to test all the removed meters, which savings are in addition to the savings

---


11 The Application of Big Sandy Rural Electric Cooperative Corporation for Deviation from the Provisions of 807 KAR 5:006, Section 6(5) and 807 KAR 5:041, Section 15(3), Case No. 2005-00048 (Ky. PSC Apr. 21, 2005) (approving a suspension of meter testing for four years while the AMR program was deployed); The Application of Owen Electric Cooperative, Inc. for a Deviation from Approved Meter Testing Program, Case No. 2006-00468 (Ky. PSC Dec. 13, 2006) (approving a deviation from its Sample Meter Testing Plan for a period of 3 years during the installation of solid-state meters); Request of Shelby Energy Cooperative, Inc. for a Temporary Deviation from its Sample Meter Testing Plan, Case No. 2010-00331 (Ky. PSC Aug. 3, 2011) (approving deviation from sample meter testing plan for two years during the installation of an AMI system).
the Companies have projected as resulting from the full AMS deployment. Therefore, the Company requests a deviation from Section 15(3) to permit the Company’s proposed meter-testing approach concerning the removed non-AMS meters, with the resumption of full compliance with Section 15(3) after the proposed AMS deployment has been completed.

Finally, the Company requests a deviation from 807 KAR 5:006 Section 19 to the extent it applies to the meters the Company will remove from service as part of its full AMS deployment. The regulation states, “A utility shall make a test of a meter upon written request of a customer if the request is not made more frequently than once each twelve (12) months.”12 On its face, this requirement would appear to apply only to meters still in service, not to meters already removed from service. But out of an abundance of caution, the Company asks the Commission to grant the Company a deviation from the entirety of 807 KAR 5:006 Section 19 with regard to all meters the Company removes—and only with regard to the meters it removes—as part of the full AMS deployment; the reasons for the deviation are the same as those given above for the Company’s requested deviation from 807 KAR 5:041 Section 15(3) concerning testing of meters removed from service.

VIII. GAS COST OF SERVICE STUDY, RATE DESIGN, AND ALLOCATION OF INCREASE

A. GAS COST OF SERVICE STUDY

Q. What methodology did LG&E use in its gas cost of service study?

A. In general, the methodology used followed the electric cost of service study; however, the gas cost of service study is not time differentiated. This methodology for the gas

---

12 807 KAR 5:006 Section 19(1).
cost of service is consistent with prior rate cases except that a refinement has been made in the way that transmission costs are allocated in the study. The details of that study are presented in the testimony of Mr. Seelye.

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

A. The following table (Table 2) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by LG&E:

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Actual Adjusted Rate of Return</th>
<th>Proposed Rate of Return</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential – Rate RGS</td>
<td>5.08%</td>
<td>6.32%</td>
</tr>
<tr>
<td>Commercial – Rate CGS</td>
<td>7.32%</td>
<td>8.48%</td>
</tr>
<tr>
<td>Industrial – Rate IGS</td>
<td>21.31%</td>
<td>21.29%</td>
</tr>
<tr>
<td>As-Available Service – Rate AAGS</td>
<td>30.69%</td>
<td>25.05%</td>
</tr>
<tr>
<td>Firm Transportation Service – Rate FT</td>
<td>11.00%</td>
<td>11.56%</td>
</tr>
<tr>
<td>Total System</td>
<td>6.00%</td>
<td>7.19%</td>
</tr>
</tbody>
</table>

The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect all pro forma adjustments. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base. Mr. Seelye discusses the actual adjusted and proposed rates of return in his testimony.

B. ALLOCATION OF GAS REVENUE INCREASE

Q. What revenue increase is LG&E proposing for gas operations?

A. As shown on Schedule M-2.1-G, LG&E is proposing an increase in gas forecasted test period revenues of $13,828,530, which is calculated by applying the proposed rates to
forecasted test period billing determinants. This increase is slightly lower than the revenue requirement increase of $13,828,546 shown in Schedule A for gas operations because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule.

Q. **How does the Company propose to allocate the gas revenue increase to the classes of service?**

A. As with LG&E’s electric rate classes, for the gas rate classes the Company proposes to recover larger relative portions of the overall revenue increase from rate classes with lower rates of return and smaller relative portions of the proposed revenue increase from rate classes with higher rates of return. The Company does not propose to eliminate all interclass subsidies in this proceeding. Given the higher rates of return for the Industrial Gas Sales class and the As-Available Gas Service noted in Table 2, the Company is proposing no increase for Rate IGS and a decrease for Rate AAGS. Mr. Seelye further discusses the details of his study in his testimony that supports this approach.

C. **RESIDENTIAL GAS SERVICE**

Q. **Does the Company propose to bring the rate components in residential gas rates more in line with the cost of service study?**

A. Yes. LG&E proposes to increase the monthly residential basic service charge from $13.50 to $24.00. As Mr. Seelye discusses further in his testimony, the cost of service study indicates that the customer-related cost for the residential class is $24.05 per customer per month. LG&E is therefore proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service. This cost is derived in Mr. Seelye’s Exhibit WSS-7. As I note below and as Mr. Seelye
discusses at greater length in his testimony, more than half of the proposed $10.50 increase in the residential basic service charge results from LG&E’s proposal to remove from the Gas Line Tracker mechanism (Adjustment Clause GLT) rate base all Gas Line Program projects prior to July 1, 2017 and to recover those costs through base rates, and in particular through basic service charges.

Q. What is the proposed rate of return for Rate RGS?

A. The proposed rate of return for Rate RGS is 6.32 percent, which is still under the overall rate of return of 7.19 percent.

Q. If the Commission approves the proposed base rates, what will be the percentage increase in monthly residential gas bills?

A. The average monthly residential gas bill increase due to the proposed gas base rates will be 5.0 percent, or approximately $2.99, for a residential customer using an average of 55 Ccf of gas. Typical bill calculations for various levels of gas consumption are shown in Schedule N for gas operations, which the Company is providing to satisfy the filing requirement of Section 16(8)(n).

Q. What other changes does LG&E propose to Rate RGS and its other rate schedules as well?

A. For Rate RGS, as well as Rates VFD (Volunteer Fire Department Service), CGS (Firm Commercial Gas Service), IGS (Firm Industrial Gas Service), AAGS (As-Available Gas Service), and DGGS (Distributed Generation Gas Service), the Company proposes to remove the Gas Supply Cost Component rate from the Rate section and add “Gas Supply Clause, Sheet No. 85” to the Adjustment Clauses section of each rate schedule. The purpose of the changes is to enhance administrative convenience by having only
one rate schedule, Adjustment Clause GSC (Gas Supply Clause), to update each time
the Company files updated gas costs with the Commission. This is comparable to the
approach the Company uses with other adjustment clauses with explicit charges stated
in the Company’s tariff, such as the Gas Line Tracker and the Home Energy Assistance
Program charge.

D. NEW STANDARD RATE FOR SUBSTITUTE GAS SALES SERVICE
(RATE SGSS)

Q. Please describe the Company’s proposed rate schedule for substitute gas sales
service.

A. LG&E has gas facilities in place to serve certain customers who also receive gas
supplies from sources other than LG&E. These customers are not gas transportation
customers who obtain gas supplies from third parties and then use LG&E’s facilities to
receive their gas. Unlike gas transportation customers, these customers receive gas
from other sources with which they are directly and physically connected (e.g., local
gas production or interstate pipelines). Despite having alternate physical supply
sources, these customers continue to desire to have LG&E provide firm gas sales
service if their alternate physical source of supply is either interrupted or inadequate to
meet their demand. Serving such customers under standard firm-service rates results
in inadequate cost recovery relative to the costs that such customers cause LG&E to
incur. This is the case because LG&E’s firm-service gas rate schedules recover
distribution-system costs on a volumetric basis. Such customers can be expected to
consume little, if any, gas on a regular basis, but still require LG&E to have facilities
available to serve the customer’s demand. Because LG&E’s rates recover costs on a
volumetric basis, LG&E will routinely under-recover distribution costs from these
kinds of customers. The result is that other customers subsidize the service provided to customers who use LG&E as a substitute source of gas supply.

To remedy this problem, LG&E is proposing Rate SGSS to ensure that customers seeking this kind of firm service from LG&E pay charges that provide adequate recovery of the costs such customers cause LG&E to incur. Rate SGSS accomplishes this recovery primarily through a demand charge, stated as a cost per Mcf of Monthly Billing Demand ($6.27 for commercial customers and $10.90 for industrial customers; Mr. Seelye’s testimony and exhibits address the derivation of all charges under Rate SGSS). A customer’s Monthly Billing Demand under Rate SGSS is the greater of the Maximum Daily Quantity (a contractually established daily maximum gas delivery) or the highest daily volume of gas LG&E delivered to the customer during that month or the previous eleven monthly billing periods. The minimum contract term under Rate SGSS is one year. Customers unwilling to receive gas sales service under Rate SGSS can request LG&E to remove its gas facilities and no further charges will be incurred by the customer.

Q. **Does the Company expect any customers will take service under Rate SGSS?**

A. Yes, at least one. If the Commission approves Rate SGSS, the Company will cease billing a customer under Rate CGS and begin billing it under Rate SGSS using the rates applicable to commercial customers. This change is appropriate because the customer takes gas service from sources other than LG&E (i.e., both locally produced gas and directly from an interstate pipeline), but has asked LG&E to keep its facilities in place and to be prepared to serve the customer’s full gas requirements as needed. Therefore, the customer will be served under Rate SGSS if the Commission approves the new rate
schedule. The revenue impact of this proposed rate change is incorporated in Schedule M-2.3-G.

E. NEW LOCAL GAS DELIVERY SERVICE (RATE LGDS)

Q. Please describe the Company’s proposed rate schedule for local gas delivery service.

A. Over the years, LG&E has received inquiries from entities potentially interested in using LG&E’s system to transport gas for local delivery, as well as to the interstate pipeline system. LG&E’s current gas transportation services are inadequate to provide such a service, and so LG&E has developed Rate LGDS to meet this need.

Service under Rate LGDS is available to any party who contracts with LG&E to provide firm transportation service of local gas (including landfill gas, bio-gas, synthetic gas, and locally produced natural gas). Under Rate LGDS a customer and LG&E would agree upon a point of receipt where LG&E would receive the gas on its system for transportation service to a pool operated under either Rider PS-FT or Rider PS-TS-2. LG&E may decline to initiate service if it could interfere with LG&E’s ability to operate its own facilities or deliver gas to its retail sales customers or end-use gas transportation customers. Importantly, Rate LGDS does not obligate LG&E to build any facilities to serve a customer taking service under Rate LGDS, and the customer taking service must pay for any facilities LG&E agrees to build to provide service under the rate. This helps ensure other gas customers will not subsidize facilities that by their nature could not be used to provide retail sales or end-use gas transportation service. Also important is the set of gas-quality standards incorporated in Rate LGDS. These gas quality standards are derived from interstate pipeline quality standards and are designed to ensure that prospective customers under Rate LGDS will
not deliver any gas into LG&E’s system that would be harmful to LG&E’s gas system or its customers.

The rate structure comprises an administrative charge of $550.00 per receipt point per month, a basic service charge of $1,310.00 per receipt point per month, a demand charge of $2.57 per Mcf of monthly billing demand, and a distribution charge of $0.0388 per Mcf of net nominated volumes at the delivery point. (Mr. Seelye’s testimony and exhibits address the derivation of all charges under Rate LGDS.) The monthly billing demand under Rate LGDS is the greater of the Maximum Daily Quantity (a contractually established daily maximum gas delivery) or the highest daily volume of gas LG&E delivered to the delivery point during that month or the previous eleven monthly billing periods. The other provisions of Rate LGDS (e.g., terms addressing nominations, delivery, and imbalances) are comparable to similar provisions in LG&E’s gas transportation services under Rider TS-2, Rider PS-TS-2, and Rate FT.

Q. Does the Company expect any customers will take service under Rate LGDS?
A. LG&E is not aware of any customers immediately interested in taking service under Rate LGDS. But as I noted above, LG&E has received inquiries about possibly using such a service. To be prepared to meet such customers’ needs, LG&E believes it is prudent to put in place the rate schedule now.

F. OTHER GAS RATE SCHEDULE CHANGES

Q. Please explain the text change to Volunteer Fire Department Service (Rate VFD) at Sheet No. 9.

A. LG&E is adding a paragraph to Rate VFD that is already included in the Rates RGS; not including it in Rate VFD previously was an inadvertent oversight. The paragraph
reiterates customers’ obligation (already stated in “Notice to Company of Changes in Customer’s Load”) to make LG&E aware of customer installations of equipment for gas-fired standby electric generation or personal vehicle fueling, and clarifies that service for such uses is subject to the availability of adequate capacity on LG&E’s system to provide the service without detriment to other customers.

Q. Please explain the text changes to Firm Transportation Service (Rate FT) and Gas Transportation Service / Firm Balancing Service (Rider TS-2) at Sheet Nos. 30.9 and 51.4, respectively.

A. LG&E is adding the same sentence to both rate schedules to clarify that, in addition to not having an obligation to deliver to a customer more than the Maximum Daily Quantity of gas, LG&E does not have an obligation to deliver more than 1/24 of the Maximum Daily Quantity in any single hour.

Also, as Lonnie E. Bellar describes in his testimony, because LG&E proposes to recover the cost of its planned Transmission Pipeline Modernization Program through LG&E’s Gas Line Tracker mechanism (Adjustment Clause GLT), LG&E proposes to add text to Rate FT to reflect the application of Adjustment Clause GLT to that tariff.

Q. Please explain the text changes to Rate FT, Rider TS-2, Pooling Service – Rider TS-2 (Rider PS-TS-2), and Pooling Service – Rate FT (Rider PS-FT) at Sheet Nos. 30.10, 51.5, 59.8, and 61.3, respectively.

A. LG&E is adding an essentially identical sentence to all four of the rate schedules listed above to require any gas transportation customer or their pool manager seeking to access LG&E’s telemetry data to enter into a Website Subscriber Agreement with
LG&E. This agreement is designed to ensure customers understand and agree to the terms for use of the website.

Q. Please explain the text changes to Riders PS-TS-2 and PS-FT at Sheet Nos. 59.7 and 61.2, respectively.

A. LG&E is deleting the same text—“a surety bond”—from both rate schedules because the Company no longer considers surety bonds adequate security for the performance of pool managers’ obligations. As the revised rate schedules reflect, irrevocable letters of credit remain an acceptable form of assurance.

Q. Please explain the text changes to Natural Gas Vehicle Service (Rider NGV) at Sheet Nos. 63 and 63.1.

A. On Sheet No. 63 LG&E proposes to delete two references to the compression of natural gas to clarify that LG&E does not provide gas-compression service or supply compressed gas. On Sheet No. 63.1 LG&E proposes to add a sentence making explicit that the customer, not LG&E, is solely responsible for reporting and paying all motor fuel taxes, if any, resulting from taking service under Rider NGV and using the gas so supplied for vehicle fuel.

G. CHANGES TO GAS SPECIAL CHARGES AND CUSTOMER DEPOSITS

Q. Does the Company propose to change any of the Special Charges shown on Sheet No. 45 of its gas tariff?

A. Yes, the Company proposes to add an Unauthorized Reconnect Charge for the same reasons I stated above concerning adding a similar charge to the Company’s electric tariff. This charge is based on the Company’s experience with making such corrections in recent years, as well as the type of meter and damage at issue:
(1) A charge of $70.00 for tampering or an unauthorized connection or reconnection that does not require the replacement of the meter;

(2) A charge of $132.00 for tampering or an unauthorized connection or reconnection that requires the replacement of a gas meter.

Mr. Seelye provides support for these charges in his testimony.

H. CHANGES TO ADJUSTMENT CLAUSES

Q. Please explain the changes LG&E proposes to Adjustment Clause GLT (Gas Line Tracker) at Sheet No. 84.

A. LG&E proposes a number of text changes to Sheet No. 84 to reflect the addition of GLT cost recovery for the Transmission Pipeline Modernization Project that Mr. Bellar describes in his testimony, as well as to reflect the addition of two new rate schedules to LG&E’s gas tariff, namely Rates SGSS and LGDS, both of which are subject to Adjustment Clause GLT. First, LG&E proposes to revise the applicability section to reflect that the GLT will now apply to Rates SGSS and LGDS, as well as to Rate FT, now that the GLT will be used to recover the costs of a gas transmission project. Second, LG&E proposes several text changes to the GLT Program Factors and Rates sections to reflect the added applicability of the GLT to Rates SGSS, LGDS, and FT, as well as to clarify that adjustments to the GLT following each annual GLT cost and balancing adjustment filing will become effective for services rendered on and after the first day of the following month after the effective date of such change. Finally, LG&E has removed from the GLT rate base all Gas Line Program projects prior to July 1, 2017 and to recover those costs through base rates; effectively resetting the GLT charges. Christopher M. Garrett discusses these and other filing changes requested for the GLT mechanism in his testimony.
Q. Please explain the changes LG&E proposes to Adjustment Clause DSM (Demand-Side Management Cost Recovery Mechanism) at Sheet Nos. 86 and following.

A. LG&E proposes small text changes to the Availability of Service and other sections to add new Rate SGSS to the rates to which Adjustment Clause DSM applies.

Q. Please explain the changes LG&E proposes to Adjustment Clause WNA (Weather Normalization Adjustment Clause) at Sheet No. 88.

A. LG&E proposes text changes to reflect the applicability of Adjustment Clause WNA to Rate VFD, the previous omission of which was an inadvertent oversight. LG&E further proposes minor text changes to clarify that WNA applies only to the Distribution Charges for Rates RGS, VFD, and CGS.

Q. Please explain the text change LG&E proposes to make to Adjustment Clause HEA (Home Energy Assistance) at Sheet No. 92.

A. As I discussed above concerning the HEA charge for LG&E’s electric customers, the charge applies to residential customers only, and the current Rate section of Adjustment Clause HEA states that the rate is $0.25 per meter per month. The Company proposes to delete “per meter” from the rate stated in Adjustment Clause HEA found in its gas tariff to be consistent with the same change it is proposing to its electric tariff, which I discussed above.

Q. Does the Company propose to increase customer deposits for Rate RGS?

A. No, LG&E proposes to keep its Rate RGS customer deposit at its current level ($100.00 for gas-service-only Rate RGS customers, and $260.00 for combined residential electric and gas customers). The Commission’s regulations (807 KAR 5:006 Section 8(d)(2)) state that a utility may establish a deposit of an equal amount for each customer
class based on the average bill of customers in that class, and that such a deposit cannot exceed two-twelfths of the average bill of customers in the class where bills are rendered monthly. Although Exhibit RMC-1 demonstrates the Company could support customer deposits as high as $126 for Rate RGS customers ($347 for combined residential electric and gas customers), LG&E believes its existing deposit levels are sufficient and strike the correct balance between protecting against uncollectible debts while minimizing burdens on customers paying deposits.

IX. **CHANGES TO GAS TERMS AND CONDITIONS**

Q. Please explain the proposed text addition to the Customer Bill of Rights at Sheet No. 95.

A. The Company’s Customer Bill of Rights applies to service to residential customers. The relevant provision of the Company’s Customer Bill of Rights currently states, “You have the right to participate in equal, budget payment plans for your natural gas and electric service.” As LG&E is proposing for its electric tariff and to ensure clarity and consistency across LG&E’s gas tariff, it is proposing to revise the quoted portion of the Customer Bill of Rights to clarify that a customer has a right to participate in a Budget Payment Plan unless the standard rate schedule under which the customer takes service explicitly states otherwise.

Q. Please explain the text addition to the Terms and Conditions provision at Sheet No. 96.

A. As LG&E is proposing for its electric tariff, it has added text to this provision to clarify how LG&E already interprets and applies terms and conditions set out in specific rate schedules as compared to the terms and conditions set out at the end of its tariff, the latter of which are generally applicable. Consistent with basic contract and legal
principles, the proposed text states that to the extent the specific terms and conditions
of a particular rate schedule conflict with the tariff’s generally applicable terms and
conditions, the specific terms and conditions will control.

Q. Please explain the proposed changes to the Exclusive Service on Installation
Connected provision at Sheet No. 97.2.

A. Because LG&E is proposing to add Rate SGSS to serve customers who have other
sources of gas supply with which they are physically connected, but who desire LG&E
to provide firm gas service, LG&E proposes to strike the sentence in this provision
stating LG&E will enter into a special contract with a customer to provide such service.
In place of that sentence, LG&E proposes to add a sentence specifying Rate SGSS as
applicable to any customer taking gas service from another gas provider as described
therein but who either desires LG&E to continue providing firm gas service or refuses
to allow LG&E to remove its facilities previously used to serve the customer. These
changes are necessary to harmonize this provision with Rate SGSS.

Q. Please explain the proposed changes to the Metering provision at Sheet No. 98.

A. LG&E proposes to add a sentence to the Metering provision to clarify that it may install
whatever metering equipment it deems necessary for a customer’s service. As I noted
above concerning the same change to LG&E’s electric terms and conditions, LG&E
believes this concept was already implicit in the Metering provision, but it is helpful to
make this right explicit before the Company begins its proposed full deployment of
AMS meters, which will include gas-meter-reading equipment.

Q. Please explain the proposed changes to the Special Rules provision under
Company Responsibilities at Sheet No. 98.2.
A. LG&E proposes to add Rates VFD and SGSS to the rate schedules governed by this provision concerning Special Rules for Customers Served from High Pressure Mains, Gas Transmission Mains, and Storage Gathering Lines. It is sensible that customers taking service under those rate schedules should be subject to the same rules regarding service from such facilities as are applicable to all other customers.

Q. Please explain the proposed changes to the Heating Value provision at Sheet No. 99.

A. LG&E proposes text changes to the Heating Value provision to accommodate gas received onto LG&E’s system from local suppliers under Rate LGDS. The changes will not have an impact on the quality of the gas LG&E might potentially receive into its system. The change is intended solely to accommodate the possible receipt into LG&E’s system of gas from sources other than interstate pipelines as a result of making Rate LGDS available.

Q. Please explain the changes to the Meter Readings and Bills provision at Sheet No. 101.

A. As LG&E is proposing for its electric tariff, the proposed text addition clarifies that a “meter reading” for all tariff purposes includes usage data provided by automated meter reading, automated meter infrastructure, advanced metering systems, and other electronic meter equipment or systems capable of delivering usage data to LG&E. Therefore, a physical, manual reading of a meter is not required to constitute a “meter reading.” This provision is intended to obviate the need for a deviation from the physical, manual meter-reading requirements of 807 KAR 5:006 Section 7, though the Company has requested one out of an abundance of caution as I discussed above.
Q. Please explain the changes to the General provision of the Deposits section at Sheet No. 102.

A. LG&E has deleted a reference to Standard Rate Rider PS-TS, which rider LG&E removed from its tariff several years ago. LG&E proposes also to add text to note that deposits for LGDS customers are subject to the creditworthiness provisions specific to that proposed rate schedule.

Q. Please explain the changes to the Discontinuance of Service provision at Sheet No. 105.1.

A. As LG&E is proposing for its electric tariff, because LG&E has proposed to add an Unauthorized Reconnect Charge to its Special Charges, it is appropriate to revise the Discontinuance of Service provision to replace the requirement that a fraudulent user pay “the cost to the Company incurred by reason of the fraudulent use” with “assessment of the charges under the Unauthorized Reconnect Charge provision of Special Charges.” Whereas LG&E previously had authority under its tariff to charge fraudulent users for costs incurred related to any damage caused by fraudulent use, it will now have a set of standard tariff rates to charge for such damage, if any, and it is appropriate to refer to those charges in this Discontinuance of Service provision.

Q. Please explain the changes to the Gas Service Restrictions and Curtailment Rules at Sheet Nos. 107 and following.

A. LG&E proposes to apply to Rate SGSS the same Gas Service Restrictions and Curtailment Rules that apply to similarly situated non-SGSS customers, which the proposed text changes reflect.

X. LOW-INCOME CUSTOMER ASSISTANCE

Q. Does the Company provide assistance to its low-income customers?
A. Yes. The Company is aware of its low-income customers’ needs through direct contact with such customers and through the Company’s relationships with a number of organizations engaged in community-assistance programs and efforts, including the Association of Community Ministries (“ACM”). Using forums and processes described in Mr. Malloy’s testimony, the Company meets and communicates with these groups on a regular basis to understand low-income customers’ needs, how community organizations are working to meet those needs, and how the Company can help.

The Company has used its experience and knowledge gained from these interactions as it has worked on its own and in conjunction with community groups to provide various forms of assistance to low-income customers over the years. For example, LG&E matches customer donations to the Winterhelp Energy Assistance Fund, which assists low-income customers with their utility bills during winter months. In the 2015-16 heating season alone, LG&E’s shareholders contributed $59,479 to Winterhelp. Since 2009, customer donations and matching funds from the Companies have raised nearly $3 million for Winterhelp and KU’s WinterCare. For the 2016-2017 heating season, LG&E’s shareholders will once again match $1.00 for every $1.00 donated by LG&E’s residential customers to Winterhelp. Moreover, LG&E has been a proud partner of Project Warm since its inception in 1982. Project Warm is a non-profit organization that provides weatherization assistance for the low-income elderly and disabled. Each November, LG&E’s employees work with Project Warm in the annual Project Warm Blitz, a program whereby hundreds of employees join volunteers and community organizations to weatherize the homes of low-income senior citizens and the disabled. LG&E provides the weatherization materials for Project Warm Blitz,
and in 2015, LG&E employees assisted in weatherizing approximately 268 homes through their participation and donations.

In addition, LG&E committed in its most recent base rate case (Case No. 2014-00372) to make annual shareholder contributions of $680,000 per year beginning in 2015 through the effective date of new base rates for LG&E. The $680,000 comprises a $500,000 contribution to ACM for its utility assistance programs and a $180,000 contribution to the HEA program. LG&E further agreed in that case to maintain its monthly residential charge for the HEA program of $0.25 through the effective date of new base rates for LG&E. Because LG&E’s shareholder-contribution commitments will continue only until the effective date of the new base rates proposed in this proceeding, they will cease thereafter absent a settlement extending the contributions.

Q. Does LG&E propose to continue the HEA charge?

A. Yes, although LG&E maintains discretion to discontinue or reduce the monthly residential HEA charge, LG&E proposes to continue its HEA charge at a level of $0.25 per customer per month.

Q. In addition to LG&E’s significant shareholder contributions and the support the HEA charge provides to low-income customers, has LG&E implemented any policy or tariff measures to assist fixed- and low-income customers?

A. Yes. LG&E provides all customers at least 22 calendar days to pay their bills after the issuance date, but goes even further to assist fixed- and low-income customers. First,

---

14 Id.
15 Id.
16 Id.
LG&E’s FLEX Program allows residential customers with limited incomes to pay their bill 28 days from issuance. This helps prevent the fixed- and low-income customers from incurring late payment charges, increases the time in which such customers may seek financial aid, and helps reduce the issuance of disconnection notices to these customers. The popularity of the FLEX Program indicates it is achieving its intended aims: since LG&E implemented the program in December 2009 through October 31, 2016, a total of 12,416 LG&E customers have used it.

Second, since October 1, 2010, an LG&E residential customer who has received a pledge or notice of low-income assistance from an authorized agency is not assessed or required to pay a late-payment charge for the bill for which the pledge or notice is received. Moreover, the customer will not be assessed or required to pay a late-payment charge in any of the 11 months following receipt of the pledge or notice. This waiver of the late-payment charge has provided significant benefits to low-income customers. From November 2015 through October 2016, LG&E waived approximately $401,000 in late-payment charges, helping to alleviate the financial burden LG&E’s fixed- and low-income customers are facing.

In addition, LG&E offers a DSM-EE program to assist low-income customers. Specifically, the Companies’ Low-Income Weatherization Program (“WeCare”) is an education and weatherization program designed to reduce the energy consumption of LG&E’s low-income customers. The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation

---

measures. A qualified low-income customer can receive—at no direct cost to the customer—energy conservation measures with a value of up to $2,100.\textsuperscript{18} WeCare is now KU and LG&E’s second largest DSM-EE program by budget: over $25.5 million total for both Companies for program years 2015-18, an average of over $6.35 million for both Companies for each program year for that period.\textsuperscript{19} In addition, LG&E offers DSM-EE programming for multi-family households, providing yet another opportunity for many low-income customers to participate in LG&E’s DSM-EE offerings. LG&E’s Residential Conservation / Home Energy Performance Program is available to multi-family properties, offering financial incentives to customers who implement energy-efficiency measures identified during on-site audits.\textsuperscript{20} Moreover, LG&E’s program includes a tier structure specifically for multi-family properties.\textsuperscript{21} In approving LG&E’s DSM-EE programming for 2015-18 the Commission noted its appreciation for “the Companies’ efforts in offering low-income programs for its customers” and that the record in the DSM-EE “proceeding reflects the Companies’ efforts to work with [community action agencies] and other interested parties to encourage participation by low-income customers in programs such as the WeCare and Residential Conservation/Home Energy Performance programs, which encourage EE and energy savings and aid in reducing the cost of customers' energy bills.”\textsuperscript{22}

In an effort to further increase low-income customers’ awareness of these efforts and DSM-EE offerings, LG&E conducts outreach specifically focused low-

\textsuperscript{18} Louisville Gas and Electric Company, P.S.C. Electric No. 10, Original Sheet No. 86.4 (LG&E’s electric tariff).
\textsuperscript{19} Case No. 2014-00003, Rebuttal Testimony of Michael E. Hornung at 13 (June 16, 2014).
\textsuperscript{20} Id. at 39-42.
\textsuperscript{21} Id.
\textsuperscript{22} Case No. 2014-00003, Order at 27 (Nov. 14, 2014).
income customers. This outreach includes advertisements on the interior and exterior of city buses in Louisville providing information on how to access these programs. In addition, the Company has held meetings with various community agencies and low-income advocates to further inform these representatives of the programs and discuss how these advocates can assist low-income customers with their participation in the programs.

All of these efforts demonstrate LG&E’s commitment to assisting its fixed- and low-income customers. Through the WeCare Program, LG&E works to weatherize the homes of low-income customers to decrease their monthly energy bills. LG&E’s FLEX program extends a low-income customers’ bill-due date to 28 days from bill issuance. To the extent further assistance is required, LG&E has generously increased giving to agencies that provide financial support, and LG&E waives the late payment charges for customers receiving assistance from such agencies. In short, LG&E provides a wide array of assistance to its fixed- and low-income customers, from before the time a customer uses energy until after LG&E issues a bill.

XI. **CONCLUSION**

Q. What are your conclusion and recommendation?

A. Based on the evidence provided above and in the Company’s application in this proceeding, I conclude the rates, revenue allocation, and proposed changes to the Company’s tariffs are reasonable and will aid the Company in continuing to provide safe, reliable, and economical service to its customers. I further conclude that the Company’s proposed AMS and DA deployments will serve the public convenience and necessity by providing significant benefits to customers, and that the Commission should grant the requested CPCNs for the deployments. Therefore, I recommend the
Commission approve the Company’s proposed rates, revenue allocation, changes to the
Company’s tariffs, the Company’s requested CPCNs, and the rest of the relief the
Company is requesting in this proceeding.

Q. **Does this conclude your testimony?**

A. Yes, it does.
VERIFICATION

COMMONWEALTH OF KENTUCKY )
COUNTY OF JEFFERSON )

The undersigned, Robert M. Conroy, being duly sworn, deposes and says that he is Vice President – State Regulation and 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 foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of November 2016.

JUDY SCHOOLER
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743
APPENDIX A

Robert M. Conroy
Vice President, State Regulation and Rates
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Previous Positions

Director, Rates          Feb 2008 – Feb 2016
Manager, Rates              April 2004 – Feb 2008
Manager, Generation Systems Planning       Feb. 2001 – April 2004

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995
Financial Research Institutes Advisory Board
Edison Electric Institute - Rates and Regulatory Affairs Committee
Southeastern Energy Exchange - Rates and Regulation Committee

Education

Essentials of Leadership, London Business School, 2004
Masters of Business Administration
Indiana University (Southeast campus), December 1998
Center for Creative Leadership, Foundations in Leadership program, 1998

Bachelor of Science in Electrical Engineering;
Rose Hulman Institute of Technology, May 1987
Exhibit RMC-1

Customer Deposit Requirements
## Residential Electric -- Rates RS, RTOD

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Forecasted Test Period Revenue (Schedule M-2.3 E, page 3/4)</td>
<td>$441,518,068</td>
</tr>
<tr>
<td>2</td>
<td>Proposed Increase (Schedule M-2.3 E, page 3/4)</td>
<td>$42,131,735</td>
</tr>
<tr>
<td>3</td>
<td>Total Revenues [(1) + (2)]</td>
<td>$483,649,803</td>
</tr>
<tr>
<td>4</td>
<td>Customer Months (Schedule M-2.3 E, page 3/4)</td>
<td>4,369,310</td>
</tr>
<tr>
<td>5</td>
<td>Average Bill [(3) / (4)]</td>
<td>111</td>
</tr>
<tr>
<td>6</td>
<td>Residential Electric Deposit Requirement [(5) * 2 months]</td>
<td>$221</td>
</tr>
<tr>
<td>7</td>
<td>Proposed Deposit Requirement</td>
<td>$160</td>
</tr>
</tbody>
</table>

## Residential Gas -- Rate RGS

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Forecasted Test Period Revenue (Schedule M-2.3 G, page 2)</td>
<td>$214,163,791</td>
</tr>
<tr>
<td>9</td>
<td>Proposed Increase (Schedule M-2.3 G, page 2)</td>
<td>$10,631,026</td>
</tr>
<tr>
<td>10</td>
<td>Total Revenues [(8) + (9)]</td>
<td>$224,794,817</td>
</tr>
<tr>
<td>11</td>
<td>Customer Months (Schedule M-2.3 G, page 2)</td>
<td>3,556,511</td>
</tr>
<tr>
<td>12</td>
<td>Average Bill [(10) / (11)]</td>
<td>63</td>
</tr>
<tr>
<td>13</td>
<td>Residential Gas Deposit Requirement [(12) * 2 months]</td>
<td>$126</td>
</tr>
<tr>
<td>14</td>
<td>Proposed Deposit Requirement</td>
<td>$100</td>
</tr>
</tbody>
</table>

## Combination Residential Gas and Electric

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>Proposed Deposit Requirement [(7) + (14)]</td>
<td>$260</td>
</tr>
</tbody>
</table>
**LOUISVILLE GAS AND ELECTRIC COMPANY**

Customer Deposit Requirements

### General Service -- Rate GS

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Forecasted Test Period Revenue (Schedule M-2.3 E, page 5)</td>
<td>$ 170,461,520</td>
</tr>
<tr>
<td>(2) Proposed Increase (Schedule M-2.3 E, page 5)</td>
<td>$ 12,180,705</td>
</tr>
<tr>
<td>(3) Total Revenues [(1) + (2)]</td>
<td>$ 182,642,225</td>
</tr>
<tr>
<td>(4) Customer Months (Schedule M-2.3 E, page 5)</td>
<td>542,844</td>
</tr>
<tr>
<td>(5) Average Bill [(3) / (4)]</td>
<td>336</td>
</tr>
<tr>
<td>(6) General Service Deposit Requirement [(5) * 2 months]</td>
<td>$ 673</td>
</tr>
<tr>
<td>(7) Proposed Deposit Requirement</td>
<td>$ 240</td>
</tr>
</tbody>
</table>