COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY	**)**	**CASE NO. 2018-00294**
FOR AN ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	**CASE NO. 2018-00295**
COMPANY FOR AN ADJUSTMENT	**)**	
OF ITS ELECTRIC AND GAS RATES	**)**	

DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE KENTUCKY

OFFICE OF THE ATTORNEY GENERAL

JANUARY 16, 2019

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia 23229.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 38-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have provided testimony relating to class cost of service and rate design before this Commission on numerous occasions including previous Kentucky Utilities ("KU") and Louisville Gas & Electric ("LG&E") rate cases (collectively, the "Companies").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates has been engaged by the Kentucky Office of the Attorney General ("OAG") to analyze the Companies' electric class cost of service studies as they relate to the allocation of generation plant and related costs. Specifically, I was asked to thoroughly examine the Companies' proposal to allocate generation-related costs solely on the basis of a methodology the Companies' refer to as Loss of Load Probability ("LOLP"). In addition, I was engaged to evaluate and respond to the Companies' proposed residential customer charges for both electric and gas operations. The purpose of my testimony, therefore, is to comment on KU's and LG&E's proposals on these issues and to present my findings and recommendations to the Commission.

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. With regard to the Companies' proposed allocation of generation-related costs based on its so-called LOLP method, I have concluded the Companies' studies: do not comport with the manner in which the Companies' generation resources were planned and built and therefore, do not reflect cost causation; do not comport with accepted industry practices as detailed in the NARUC Cost Allocation Manual; cannot be completely verified; and produce unreasonable, or anomalous results for numerous time periods. As a result, the Companies' proposed class cost of service studies cannot be reasonably used as a guide when determining the allocation of any overall potential rate increase across classes. With regard to residential customer charges, I have determined that the direct costs to serve residential customers is lower than the current fixed monthly charges. However, in the interest of rate continuity and other considerations, I recommend that the current residential customer charges for both electric and gas be maintained at their current levels.

Finally, I recommend that the Companies' proposals to restate the fixed monthly customer charge to a daily rate and their proposals to bifurcate energy charges on a customers' tariff between variable and fixed cost components be rejected.

II. ALLOCATION OF GENERATION-RELATED COSTS

A. General Concepts

Q. BEFORE YOU DISCUSS THE SPECIFICS OF THE COMPANIES' PROPOSED METHOD TO ALLOCATE GENERATION-RELATED COSTS, PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO THESE RESOURCES.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour ("KWH") would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that the Companies experience periods (hours) of higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system.

To further complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy (variable cost)/capacity (fixed cost) trade-off relating to production costs. That is, utilities design their mix of production facilities to minimize the total costs of variable energy and fixed capacity, while also ensuring there is enough available capacity to meet peak demand requirements. The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("KW") and the variable cost of producing a unit of output (KWH). Coal units require high capital expenditures resulting in large investments per KW of capacity, but operate very efficiently such that their variable running costs per KWH are very low. Conversely, combustion turbine units are relatively inexpensive to build per KW of capacity but are much less efficient and incur significantly higher variable running costs per KWH of output. Due to varying levels of demand placed on a utility's system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its total cost of service.

The investment (capacity) costs of generation facilities are fixed in nature and are considered sunk investment costs. At the same time, the energy cost of running generation plants tends to be almost all variable in nature such that base load units tend to have low variable running costs whereas peaking units tend to have much higher variable running costs per KWH. As a result, generation assets tend to be dispatched based upon the variable running costs of each unit wherein lower variable cost units are dispatched before higher cost units. As such, total system production costs vary each hour of the year.[1]

Q. DO KU AND LG&E ACKNOWLEDGE THE COST CAUSATION CONCEPT OF THE ENERGY/CAPACITY TRADEOFF THAT EXISTS AS IT RELATES TO THEIR PLANNING, DISPATCH, AND OPERATION OF THEIR VARIOUS GENERATING RESOURCES?

A. Yes. In their 2018 IRP Reserve Margin Analysis, which is provided as an Appendix to their 2018 Integrated Resource Plan,[2] the Companies' state as follows in the Executive Summary:

> The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. **In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy**, the ability to respond to unit outages

[1]A brief description of the most commonly used methods used to allocate generation-related costs along with each method's strengths and weaknesses are provided in my Schedule GAW-2.
[2] *See* Case No. 2018-00348.

> and follow load, and the ability to instantaneously produce power when customers want it. (page 3) [Emphasis added]

Q. CAN YOU PROVIDE EXAMPLES OF THE ENERGY/CAPACITY TRADEOFF SPECIFIC TO KU AND LG&E?

A. Yes. Consider Trimble Unit 2 which is a base load unit that has a capacity of 629 MW: this facility has a gross investment (capacity) cost of $1,795 per KW, yet, operates very efficiently with a forecasted fuel cost of 1.95¢ per KWH of output. At the other extreme, consider Zorn Unit 1 which is a peaker unit that has a capacity of only 18 MW: this facility has a gross investment (capacity) cost of $110.00/KW, yet, is much more expensive to run at 6.11¢ per KWH of output.[3]

B. KU and LG&E Combined Generation Assets and System Load Characteristics

Q. PLEASE SUMMARIZE THE COMPANIES' PORTFOLIO OF GENERATION ASSETS.

A. KU and LG&E jointly dispatch their generation assets such that the following is a summary of the combined portfolio of generation assets during the forecasted test year:

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[3] Calculated per LG&E responses to AG 1-145 and AG 1-149.

Summary of KU and LG&E Generation Portfolio[4]

Designation	Fuel Type	Capacity (MW)	Gross Investment 10/31/18
Base Load[5]	Coal	4,999	$6,972.3 million
Base Load[6]	Gas	808	$550.2 million
Total Base Load		5,807	$7,522.5 million
Intermediate[7]	Gas, Oil	875	$323.9 million
Intermediate[8]	Coal	464	$976.4 million
Total Intermediate		1,339	$1,300.3 million
Peaker[9]	Gas, Oil	1,603	$519.6 million
Other[10]	Solar/Hydro	146	$212.3 million
Total		8,895	$9,554.8 million

The details of the Companies' portfolio of generation assets along with capacities, variable fuel costs and investments are provided in my Schedule GAW-3.

Q. HOW DOES THIS OWNED CAPACITY COMPARE TO THE COMPANIES' SYSTEM PEAK LOAD DURING THE FORECASTED TEST YEAR?

A. The combined KU and LG&E system coincident peak ("CP") load during the forecasted test year is 6,360 MW.

[4] Source: LG&E response to AG 1-145.
[5] Includes: Trimble Units 1 and 2, Mill Creek Units 1, 2, 3, and 4, Ghent Units 1, 2, 3, and 4.
[6] Includes: Cane Run 7.
[7] Includes: Trimble Units 5 and 6 and Brown Units 5, 6, and 7.
[8] Includes: Brown 3.
[9] Includes: Brown Units 8, 9, 10, and 11, Trimble Units 7, 8, 9, and 10, Paddy's Run Units 11, 12, and 13, Zorn 1, Haefling Units 1 and 2, and Cane Run 11.
[10] Includes: Brown Solar, Dix Dam Units 1, 2, and 3, and Ohio Falls Units 1 through 8.

Q. BY COMPARING THE COMPANIES' FORECASTED PEAK LOAD OF 6,360 MW TO THEIR BASELOAD GENERATION NAMEPLATE CAPACITY OF 5,807 MW, IT WOULD APPEAR THAT THE COMPANIES CAN MEET ALMOST ALL OF THEIR LOAD REQUIREMENTS THROUGHOUT THE YEAR WITH JUST THEIR BASELOAD GENERATING FACILITIES. IS THIS A REASONABLE INFERENCE?

A. Not entirely. That is, and as will be explained later in my testimony, the Companies' joint loads for many hours of the year are at, or below, the rated, or nameplate capacity of its baseload generation units. However, all units have planned maintenance outages and experience unplanned forced outages. Therefore, one or more units may not be available each hour of the year. Furthermore, and due to the low cost of wholesale power (particularly during off-peak hours), it is sometimes cheaper for KU and LG&E to purchase blocks of power rather than dispatch certain generating units.

Q. THE ABOVE CAPACITY TO DEMAND RELATIONSHIP OF 8,895 MW TO 6,360 MW INDICATES A RESERVE MARGIN OF 39.9%. HOW DOES THIS COMPARE TO THE COMPANIES' TARGET RESERVE MARGIN?

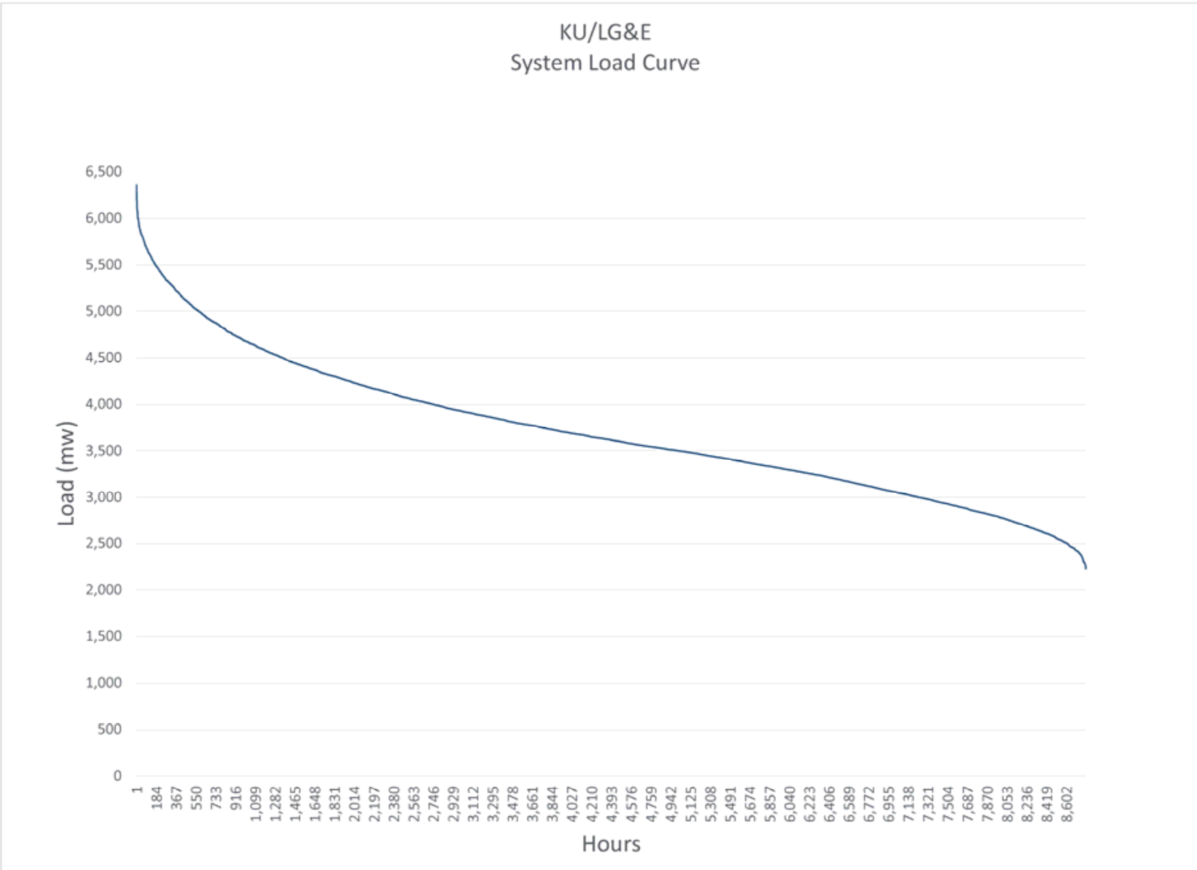
A. The Companies' 2018 IRP Reserve Margin Analysis states that the Companies' target reserve margin is in the range of 17% to 25%.

Q. HOW DO THESE RESERVE MARGINS COMPARE TO NEIGHBORING REGIONS?

A. As noted in the 2018 IRP Reserve Margin Analysis, MISO's target reserve margin is 17.1%, PJM's target reserve margin is 15.8% and TVA's target reserve margin is 15% (page 10).

Q. HAVE YOU EXAMINED THE COMPANIES' COMBINED SYSTEM LOAD REQUIREMENTS THROUGHOUT THE FORECASTED TEST YEAR?

A. Yes. In LG&E response to AG 1-141, the Companies provided their forecast of system loads for every hour of the test year (8,784 hours due to the test year being a leap year). As a result, I was able to develop the Companies' actual load duration curve. A graph of the Companies' system load duration curve is provided below:



Q. PLEASE EXPLAIN WHAT A LOAD DURATION CURVE REPRESENTS.

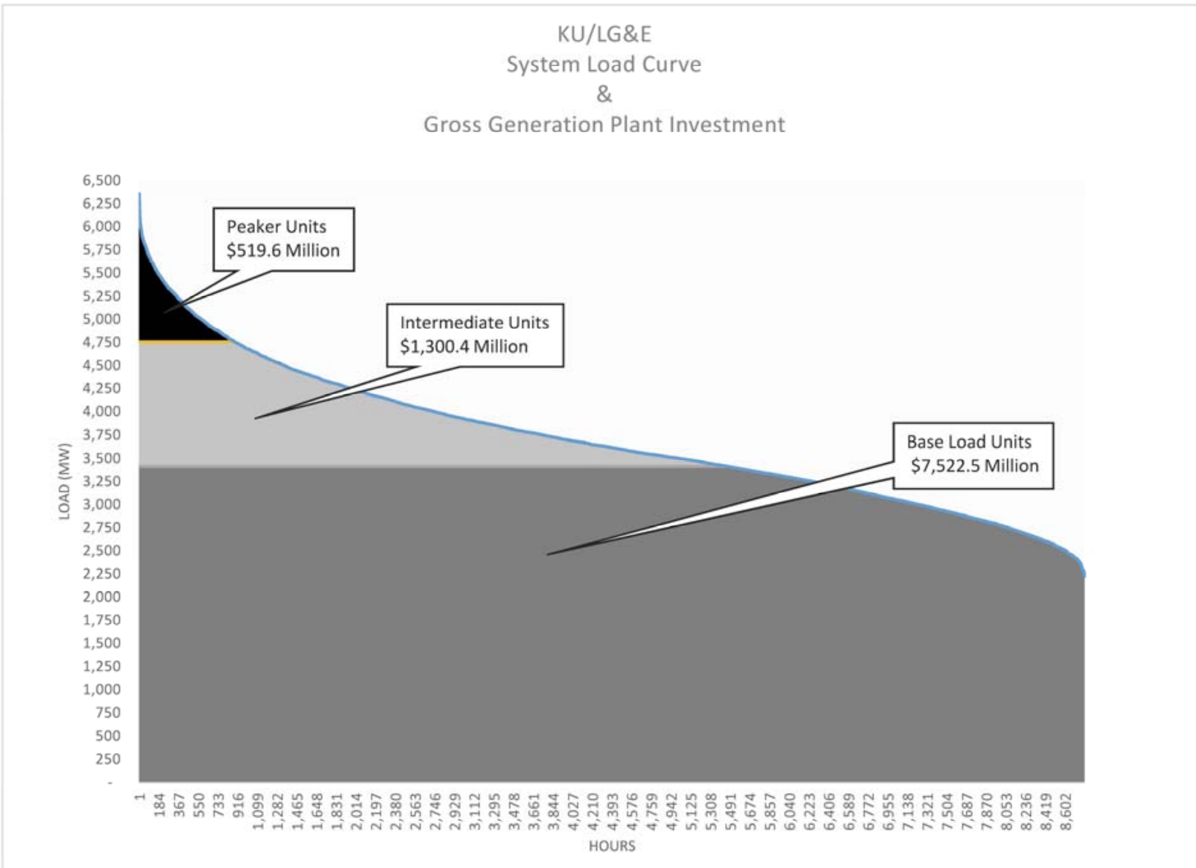
A. A load duration curve shows the demand by hour for an entire year such that the first hour on the graph represents the annual system peak while the last hour shows the lowest hourly demand for the test year. In other words, it is a curve that is sorted from highest hourly demand to lowest hourly demand. The area under the curve represents the total energy required during a year and most importantly, shows the incidence and duration of load requirements.

Q. EARLIER YOU INDICATED THAT THE COST CAUSATION FOR GENERATION COSTS RELATES TO THE ENERGY/CAPACITY TRADEOFF BETWEEN VARIOUS GENERATION RESOURCES. HOW SHOULD THIS COST CAUSATION PRINCIPLE BE REFLECTED WITHIN CLASS COST ALLOCATION STUDIES?

A. As noted earlier, and acknowledged by KU and LG&E, baseload units provide low cost energy throughout the year such that they are planned to be dispatched first within the entire portfolio of generation assets. As a result, these baseload units operate and provide benefits to all customers during most hours of the year. Therefore, the assignment of costs associated with baseload units should be commensurate with how customers utilize energy throughout the year. At the other extreme, peaker units are planned and designed to operate for only a few hours of the year during peak load requirements. As such, these peaker units should be allocated to classes based on their respective loads during these peak periods. Finally, intermediate plants are just that – those units that are planned and operate during intermediate load periods wherein these costs should be allocated to classes based on their respective loads during shoulder or intermediate system load periods.

Q. CAN YOU GRAPHICALLY SHOW THE RELATIONSHIP BETWEEN THE COMPANIES' GENERATION GROSS INVESTMENT TO ITS SYSTEM LOAD DURATION CURVE?

A. Yes. The following graph provides the Companies' forecasted test year system load duration curve along with the capacity associated with its base-load, intermediate, and peaker units. In developing this graph, I defined the peak period under the load duration curve based on the capacity of the Companies' peaker units (1,603 MW). The intermediate period was defined as the capacity of the Companies' intermediate generation capacity (1,339 MW). Finally, the base-load of 3,428 MW are those hours below the combined peak and intermediate periods. As shown in this graph, the area under the base-load portion of the load duration curve serves all customers' load requirements for the plurality of the year and represents the majority of the Companies' total investment in generation plant ($7,522 million). The area under the intermediate portion of the load duration curve serves customers' load requirements for a smaller portion of the year with a smaller gross investment ($1,300 million) while the area under the peak portion of the load duration curve serves customer load requirements for only a few hours of the year with a relatively minimal level of gross investment ($520 million).[11]



Q. DOES THE ABOVE GRAPH CONCEPTUALLY SHOW HOW GENERATION INVESTMENT COSTS ARE INCURRED AND HOW THEY SHOULD BE ALLOCATED ACROSS CLASSES?

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[11] Note: the capacity and costs associated with solar and hydro are not included in this graph due to their inability to serve load every hour of the year and are therefore, not considered as truly base-load, intermediate, or peaking units.

A. Yes. The investment costs associated with each of the three periods should be allocated to individual rate classes commensurate with the loads they place on the system during these periods. This is most important because from a cost causation perspective we see that the majority of generation investment is related to base-load units that serve all customers throughout the year, while the peak period investment costs are significantly less and should be allocated to customer classes based on their loads during peak periods.

In practice, this is most important because certain classes such as large industrials tend to use energy more uniformly throughout the year (i.e., have higher load factors) while other customers and classes tend to "drive the peak" in that these classes are responsible for a much larger percentage of load during peak periods than high load factor customers. As a result of these realities, residential and small commercial customers should be assigned relatively more responsibility to peak periods than base-load periods. At the same time, large industrial customers should be assigned relatively more responsibility to base-load costs as their relative use and loads during base-load periods are greater than during peak periods. In short, class cost responsibility should coincide with the loads they place on the system at various times and load levels along with the specific investment costs required to serve these loads during the same time periods.

C. KU and LG&E's Proposed LOLP Allocation Method

Q. PLEASE EXPLAIN HOW COMPANY WITNESS SEELYE ALLOCATED GENERATION PLANT COSTS TO INDIVIDUAL RATE CLASSES.

A. Mr. Seelye relied upon Company-calculated system loss of load probabilities for each hour of the test year. At the same time, the Company (or Mr. Seelye) estimated every class' load for each hour of the forecasted test year. Then for each hour, Mr. Seelye multiplied the weighted LOLP by each class' contribution to load. These weighted class allocation factors are then summed for all hours that had any probability of loss of load to develop his ultimate generation allocation factor. To further explain, consider the following hypothetical example that shows the methodology utilized by Mr. Seelye to develop his generation allocation factor:

Seelye Generation Allocation Factor Method
(Hypothetical Example)

Hour	Hourly System Load	Hourly LOLP	Hourly LOLP Weight	Load (MW) Resid.	Load (MW) Comm.	Load (MW) Industrial
A	6,350	0.5200%	53.89%	3,175	635	2,540
B	6,325	0.3600%	37.31%	3,158	632	2,535
C	6,310	0.0800%	8.29%	3,154	631	2,525
D	6,305	0.0050%	0.52%	3,150	630	2,525
All Other Hours		0.0000%	0.00%	Varies in Descending Order		
Total		0.9650%	100.00%			

Hour	Percent of Total Load Resid.	Percent of Total Load Comm.	Percent of Total Load Industrial	Hourly Allocation Weight Resid.	Hourly Allocation Weight Comm.	Hourly Allocation Weight Industrial	Hourly Allocation Weight Total
A	50.00%	10.00%	40.00%	26.94%	5.39%	21.55%	53.89%
B	49.93%	9.99%	40.08%	18.63%	3.73%	14.95%	37.31%
C	49.99%	10.00%	40.02%	4.14%	0.83%	3.32%	8.29%
D	49.96%	9.99%	40.05%	0.26%	0.05%	0.21%	0.52%
All Other Hours				0.00%	0.00%	0.00%	0.00%
Total				49.97%	9.99%	40.03%	100.00%

In the above hypothetical example, there are only four hours in which there is a calculated LOLP greater than zero; i.e., the other 8,756 hours of the year have a zero probability of not meeting system load.[12] The sum of all hours' LOLPs is 0.965%. Therefore, the weighted LOLP in Hour A is 53.89% of all LOLP hours (0.52% ÷ 0.965%). Each class's relative load in Hour A is then multiplied by 53.89%. For example, the residential load in Hour A is 3,175, which is 50% of the system load. This 50% residential contribution in Hour A is then multiplied by the LOLP weight of 53.89% to arrive at a residential weight for Hour A of 26.94%. These weighted class contributions are then summed for all hours with an LOLP greater than zero to arrive at the ultimate allocation factors of 49.97% for residential, 9.99% for commercial, and 40.03% for industrial.[13]

[12] Assuming a non-leap year.
[13] Note: Printed amounts do not sum to exactly 100% due to rounding in the printed example.

Once Mr. Seelye's class generation allocation factors are developed, these percentages are then multiplied by KU and LG&E's <u>total</u> investment in generation plant (base-load plus intermediate plus peaker units on a combined basis).

Q. BEFORE YOU DISCUSS THE DETAILS AND IMPLICATIONS OF MR. SEELYE'S APPROACH TO ALLOCATE GENERATION-RELATED COSTS, PLEASE BRIEFLY EXPLAIN THE CONCEPT OF LOLP.

A. In the most basic sense, LOLP is a statistical evaluation of the probability of a utility not being able to meet its load obligations at any point in time given its forecasted load requirement (demand) and available sources of supply (supply). To the extent that demand exceeds supply, there is a positive loss of load probability. Similarly, to the extent there is enough supply relative to demand, the LOLP is equal to zero. In developing supply availability, the LOLP considers not only the rated capacity of generation resources but also reflects scheduled and forced outage rates of particular units as well as other supply-side constraints and resources. The specifics of KU and LG&E's LOLP modeling and estimation procedures will be discussed later in my testimony.

Q. EARLIER YOU SHOWED THAT ON A SYSTEM BASIS, KU AND LG&E HAVE INSTALLED GENERATION CAPACITY OF 8,895 MW AS COMPARED TO ITS FORECASTED SYSTEM PEAK LOAD OF 6,360 MW. GIVEN THE FACT THAT THE INSTALLED GENERATION CAPACITY GREATLY EXCEEDS THE COMPANIES' FORECASTED PEAK DEMAND, HOW IS IT POSSIBLE TO HAVE ANY HOURS WITH A LOLP GREATER THAN ZERO?

A. While I understand and recognize that all generation capacity may not be available each and every hour of the year due to outages, I also recognize and understand that the Companies have curtailable load available through their Curtailable Service Rider ("CSR") as well as purchased power options available. In these regards, the Companies' representations of how hourly LOLPs are calculated (or what they represent) are conflicting. To illustrate, Mr. Seelye's direct testimony at page 74 states "LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour." This statement appears to ignore other supply/demand-side resources available such as the ability to purchase power and demand-side management programs such as curtailable service. Yet, in LG&E's response to AG 1-140, the Company states "in addition to the Companies' firm supply-side capacity resources, the [LOLP] analysis assumed that the Companies could purchase up to 558 MW of energy in an hour and could curtail up to 141 MW of CSR-related load."[14]

Assuming that the Companies' LOLP modeling did in fact reflect an additional supply resource of 558 MW and a CSR availability of 141 MW, this brings the total potential supply availability to 9,594 MW, which is 3,234 MW more than their peak load; i.e., total potential supply is 51% greater than peak demand.

While there is no doubt that some sources of supply will be unavailable during certain hours of the year, I see no plausible potential or probability that the Companies cannot (or will not) meet their demand obligations each and every hour of the year considering the multitude of resources available and the fact that the potential supply-side resources exceed its maximum demand by more than 50%. In other words, there is no reasonable probability that the Companies will be unable to meet their load requirements such that there is a realistic LOLP of zero percent for each and every hour of the year.

Q. HAVE THE COMPANIES OR MR. SEELYE BEEN ABLE TO DOCUMENT OR SHOW HOW THE SPECIFIC LOLPs WERE CALCULATED?

A. No. Through numerous attempts in discovery in this case as well as the last rate cases,[15] the Companies were requested to provide all workpapers, calculations, etc. utilized to develop hourly LOLPs. The Companies were unable to do so and simply claimed that the hourly LOLPs are the result of a black box answer generated by a proprietary software package called PROSYM. With these responses, the Attorney General then requested in AG 2-12 for the Company (LG&E) to simply provide all calculations, tables, etc. showing the development of the system LOLPs for only four hours. The Company's response was as follows:

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[14] See also LG&E response to Staff DR 3-23 wherein Mr. Sinclair states, "The LOLP analysis recognizes that a potential loss of load scenario would require the Companies to attempt to purchase power from other utilities. The Companies include the purchases as a resource that can be called upon to avoid a loss of load."
[15] Case Nos. 2016-00371 and 2016-00372.

> The Companies do not have access to PROSYM's calculation of LOLP and EUE, as it is a proprietary calculation that is performed internally in the software. PROSYM does not show the calculations and tables that lead to LOLP and EUE results.[16]

In short, I do not fully understand and cannot verify, replicate, or validate the Companies' reported LOLPs. Significantly, it is apparent that the Companies are unable to do so as well.

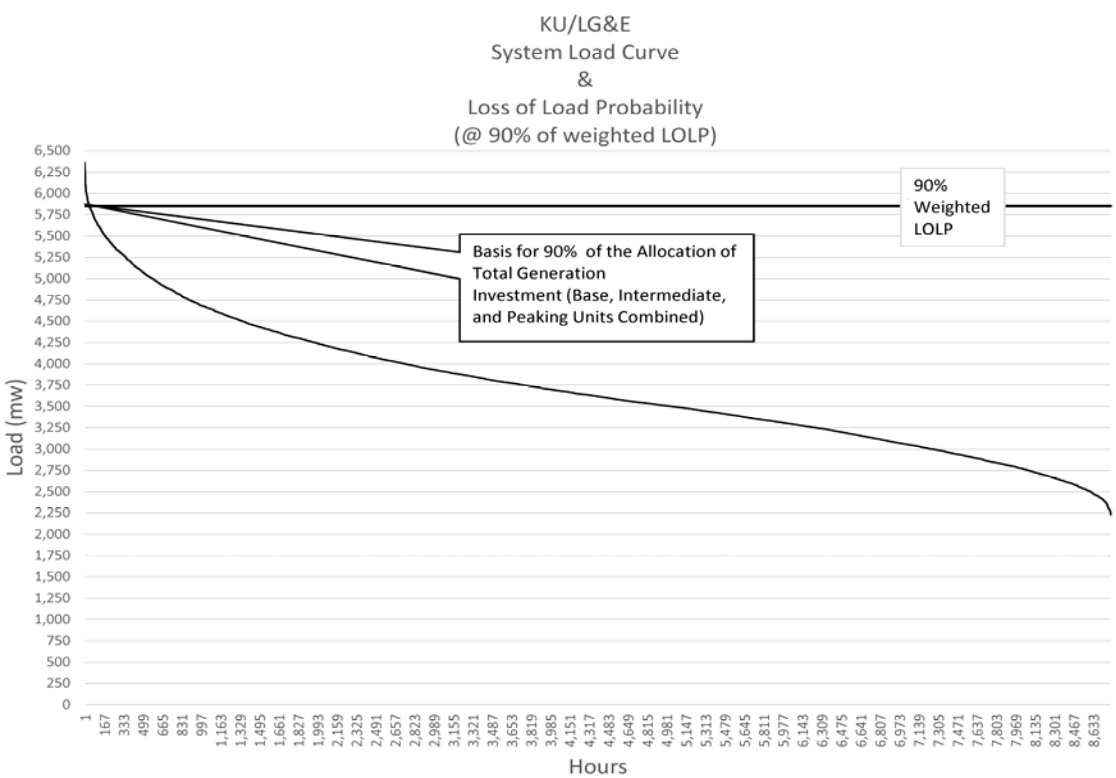
Q. ALTHOUGH IT IS YOUR OPINION THERE IS NO REALISTIC POSSIBILITY THAT THE COMPANIES WILL BE UNABLE TO MEET THEIR LOAD REQUIREMENTS DURING THE FORECASTED TEST YEAR, WHAT ARE THE COMPANIES' CALCULATED PROBABILITIES THAT THEY WILL NOT BE ABLE TO MEET THEIR LOAD REQUIREMENTS? IN OTHER WORDS, WHAT IS THE RANGE OF THE COMPANIES' CALCULATED LOLPs?

A. The vast majority of the calculated hourly LOLPs are effectively zero [less than one one-hundredth of one percent (0.0001)]. The highest loss of load probability is slightly more than one-half of one percent (0.005035). These hourly LOLPs decrease as the forecasted system load declines during the forecast period. However, and as explained earlier in my hypothetical example of how Mr. Seelye developed his generation allocation factors, it is not the absolute level of hourly LOLPs that is important, but rather, the relative amounts. To further illustrate, suppose there were only two hours (out of 8,784 hours in a leap year) in which there was an LOLP greater than zero and these LOLPs were 0.4% (hour 1) and 0.1% (hour 2). Under Mr. Seelye's weighting mechanism, the class contributions during hour 1 would receive 80% weight within the development of the allocation factor [0.4% ÷ (0.4% + 0.1%)] with class contributions in hour 2 receiving 20% weighting. All other hourly loads would be ignored.

[16] EUE means Expected Unserved Energy for a given LOLP time period. Because the Companies' LOLPs are calculated on an hourly basis, the unserved energy (MWH) in a given hour is equal to the expected unserved load (MW) in that hour.

Q. WITH THESE UNDERSTANDINGS, CAN YOU SHOW HOW MR. SEELYE HAS ALLOCATED ALL OF THE BASE, INTERMEDIATE, AND PEAKER GENERATION-RELATED COSTS?

A. Yes. As noted earlier, the vast majority of hours in the test year have calculated LOLPs of essentially zero. The hours that do have a calculated positive LOLP are few in number and represent those highest annual system peak loads. The following graph shows that 90% of Mr. Seelye's generation allocation factors only consider loads during the highest peak periods even though it has been established that the vast majority of the Companies' investment in generation facilities is ascribed to base-load units that were planned, designed and are utilized to serve customers' loads throughout the year.



So that it is clear, 90% of Mr. Seelye's allocation factor is based on a few peak hours of the year wherein class contributions to these few peak hours are then used to allocate all generation-related costs.

Q. IS MR. SEELYE'S APPROACH APPROPRIATE FOR KU AND LG&E?

A. No. As discussed and shown above, Mr. Seelye's method to assign generation-related costs to individual classes gives no consideration to the manner in which the Companies' combined generation resources were planned, designed, or installed. As a result, his analysis does not reasonably reflect the manner in which the Companies' generation costs are incurred. In turn, Mr. Seelye's approach over-assigns costs to those classes that contribute relatively more to a few peak hours of the year than they do during other periods of the year.

Q. DOES THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC") RECOGNIZE LOLP AS A METHOD FOR ALLOCATING GENERATION-RELATED COSTS WITHIN CLASS COST ALLOCATION STUDIES?

A. Yes. The NARUC Electric Utility Cost Allocation Manual does include the LOLP as a recognized method to allocate generation costs across classes.

Q. DO MR. SEELYE'S LOLP APPROACH AND STUDIES COMPORT WITH THE LOLP METHODOLOGY SET FORTH IN THE NARUC MANUAL?

A. No. Mr. Seelye's approach is far from complying with the methodology set forth in the NARUC Manual. The NARUC Manual states that the LOLP method should be conducted as follows:

> Using the LOLP production cost method, **hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values**. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occuring in each. **Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above.** This method requires detailed analysis of

> hourly LOLP values and a significant data manupulation effort. (page 62) [Emphasis added]

With regard to assigning costs to the three rating periods, the NARUC Manual explains the prescribed approach under the Base-Intermediate-Peak ("BIP") method as follows:

> **The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components**. **In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only**.
>
> There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period. (pp. 60-61) [Emphasis added]

As described above, the NARUC-prescribed LOLP method is based on the cost causation principles discussed earlier wherein proper consideration is given to investment costs devoted to serving base, intermediate, and peak load requirements. This is in <u>stark contrast</u> to Mr. Seelye's approach wherein he has effectively allocated virtually all of the Companies' total generation costs simply on peak period demands.

Q. WITH THE EXCEPTION OF KU AND LG&E, HAVE YOU EVER SEEN THE LOLP USED FOR CLASS COST ALLOCATION PURPOSES?

A. In my 38 years of experience that has involved hundreds of embedded class cost allocation studies, I have encountered only one instance in which a class cost allocation study was employed using the LOLP methodology. This one instance was a 1986 rate case involving Houston Light & Power that was ultimately settled.

Q. WITH THE EXCEPTION OF HIS OWN STUDY IN THE LAST KU AND LG&E RATE CASE, IS MR. SEELYE AWARE OF THE LOLP METHODOLOGY EVER BEING USED FOR CLASS COST ALLOCATION PURPOSES?

A. No. In LG&E's response to KIUC 1-15, Mr. Seelye acknowledged that he is not aware of any regulatory jurisdiction that has adopted the LOLP cost of service method used in this case nor is he aware of any electric utility that supported the LOLP method (other than himself).

Q. NOTWITHSTANDING THE FACTS THAT THE COMPANIES HAVE NOT BEEN ABLE TO EXPLAIN OR SHOW HOW HOURLY LOLPs WERE CALCULATED AND THE COMPANIES' REPRESENTATIONS AS TO WHAT RESOURCES ARE, AND ARE NOT, INCLUDED IN THE DETERMINATION OF ITS HOURLY LOLPs, HAVE YOU OBSERVED SEVERAL APPARENT ANOMALIES ASSOCIATED WITHIN THEIR LOLP ANALYSIS?

A. Yes. In LG&E's response to AG 1-139, the Company indicated that "the LOLP study is a statistical calculation of hourly LOLP based on the Companies' forecasted resource characteristics and load at an hourly level, however, it does not involve developing an hourly dispatch model." Nonetheless, in response to various data requests, the Companies provided forecasted hourly system loads, hourly system LOLPs and hourly production by individual generating unit as well as the amount of purchased power and curtailable load through CSR.[17] My Schedule GAW-4 shows the highest forecasted system loads for several hours, the hourly LOLP, the amount of unserved load, and source of supply by individual generating unit, CSR and purchased power.

Consider the hour with the highest annual load of 6,360 MW. As shown on the first line of Schedule GAW-4, the Companies' LOLP estimates that slighly more than 1 MW of power will not be served (1.06 MW). Although this is a miniscule amount, consider that during this hour, the Companies utilize only 93 MW of the 141 available MW of CSR, they forecast purchases of only 512 MW out of an apparent available amount of 558 MW and that there is 1,926 MW of undispatched owned generation which

[17] Specifically, hourly system loads and hourly system LOLPs were provided in response to LG&E AG 1-141 and hourly production by individual source of supply was provided in response to LG&E AG 2-13.

includes Brown 3 (464 MW), Ghent 3 (557 MW), Mill Creek 3 (463 MW), Brown 5 (123 MW), Brown 10 (126 MW), Brown 11 (126 MW), Cane Run 11 (16 MW), Paddy's Run 12 (33 MW), and Zorn 1 (18 MW). Clearly, there are numerous supply resources available to the Company during this hour to accommodate the miniscule 1 MW of unserved load.

Similarly, consider the observation in which the forecasted load is 6,247 MW (4^{th} row in Schedule GAW-4). The Companies' LOLP analysis projects an unserved load of 0.61 MW, yet the Company is not utilizing any of its available CSR and has 1,785 MW of owned generation capacity that is not dispatched. These unrealistic results are contained throughout my Schedule GAW-4.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. SEELYE'S PROPOSED CLASS COST OF SERVICE STUDY IN THIS CASE?

A. Mr. Seelye's cost of service study should be rejected in its entirety. His proposed LOLP method does not comport with the NARUC <u>Electric Utility Cost Allocation Manual</u> in which recognition is to be given to how generation resources are utilized during all periods of the year, is contrary to cost causation generally and how costs are specifically incurred by KU and LG&E. Furthermore, the Companies' hourly LOLPs cannot be verified or replicated. Indeed, the Companies' calculated hourly LOLPs are illogical for several hours considering their supply resources relative to the system load.

Q. HAVE YOU CONDUCTED YOUR OWN INDEPENDENT CLASS COST OF SERVICE STUDY FOR THESE CASES?

A. No. My engagement is limited to a thorough review of the Companies' proposed class cost of service study as it relates to the allocation of generation-related costs. I was not engaged to conduct an independent or alternative class cost of service study.

Q. IN THE ABSENCE OF REASONABLE CLASS COST ALLOCATION STUDIES, HOW SHOULD ANY OVERALL REVENUE INCREASE AUTHORIZED IN THIS CASE BE ASSIGNED TO INDIVIDUAL RATE CLASSES AND RATE SCHEDULES?

A. The OAG has advised me that in the absence of a reasonable and appropriate class cost allocation study, this Commission's long-standing practice is to distribute any overall revenue increase to individual classes on an equal percentage basis.[18] As such, I recommend that any overall revenue increase (or decrease) granted in this case be assigned to individual rate classes and schedules on an equal percentage basis. I believe this is a reasonable alternative in light of the fact that the Companies' single cost-of-service study is unusable for the purposes of guiding the Commission in allocating any base rate change in these matters.

III. RESIDENTIAL RATE DESIGN

A. Customer Charges

Q. DO THE COMPANIES PROPOSE SIGNIFICANT INCREASES TO THEIR FIXED RESIDENTIAL CUSTOMER CHARGES?

A. Yes. Witnesses Robert Conroy and William Seelye propose the following increases to residential customer charges:

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[18] *See* In Re. An Investigation Of The Multi-Family Master-Metered Residential Service Tariffs Proposed By Louisville Gas And Electric Company And Kentucky Utilities Company, Case No. 2002-00419, Order at 2 (Ky. PSC Mar. 19, 2003) ("When rates are adjusted in the absence of a cost-of-service study, the Commission has historically allocated revenue increases or decreases on a proportionate share to maintain each customers class's (i.e., residential, commercial, and industrial) relative contribution."); *See also* In Re. Electronic Application of U.S. 60 Water District of Shelby And Franklin Counties for an Alternative Rate Adjustment, Case No. 2017-00338, Order (Ky. PSC Mar. 21, 2018); In Re. Application of North McLean County Water District for Alternative Rate Adjustment, Case No. 2018-00260, Order (Ky. PSC Dec. 20, 2018); In Re. Application for Rate Adjustment of Nebo Water District, Case No. 2016-00435, Order (Ky. PSC Jun. 5, 2017); In Re. Application of North Hopkins Water District for Rate Adjustment for Small Utilities Pursuant to 807 KAR 5:076, Case No. 2018-00118, Order, (Ky. PSC Aug. 16, 2018); In Re. Application of North McLean County Water District for Alternative Rate Adjustment, Case No. 2017-00253, Order (Ky. PSC Jan. 5, 2017); In Re. Electronic Application of West Carroll Water District for Rate Adjustment, Case No. 2017-00244, Order (Ky. PSC Apr. 24, 2018); In Re. Alternative Rate Adjustment Filing of South Hopkins Water District, Case No. 2013-00428, Order, (Ky. PSC Jun. 12, 2014); In Re. West Carroll Water District for an Adjustment in Rates Pursuant to the Alternative Rate Filing Procedure for Small Utilities, Case No. 2012-00433, Order at 5 (Ky. PSC Apr. 19, 2013) ("In the absence of a cost-of-service study to allocate costs, the most equitable means to establish rates to produce the revenue requirement is to allocate the required revenue increase evenly.")

Company		Current Rate	Proposed Rate	$ Increase	% Increase
KU	Electric	$12.25	$16.13	$3.88	31.7%
LG&E	Electric	$12.25	$16.13	$3.88	31.7%
LG&E	Gas	$16.35	$19.78	$3.43	21.0%

Q. MR. WATKINS, HAVE YOU IDENTIFIED A COMMON OBJECTIVE IN THE COMPANIES' CUSTOMER CHARGE PROPOSALS?

A. Yes. It is clear from the testimonies of Messrs. Conroy and Seelye that the primary objective of the Companies' residential rate design is to guarantee revenue collection and profitability associated with fixed monthly customer charges.

Q. WHY DO THE COMPANIES DESIRE MORE RESIDENTIAL REVENUE COLLECTED FROM FIXED CHARGES?

A. Fixed monthly customer charges represent guaranteed revenue to the Companies. These guarantees of revenue obviously reduce the risks of operations and provide much more assurance of net income available to shareholders.

Q. HOW DO THE COMPANIES SUPPORT THESE LARGE INCREASES IN FIXED RESIDENTIAL CUSTOMER CHARGES?

A. Messrs. Conroy and Seelye offer three rationale for high customer charges. First, Mr. Conroy observes that a residential rate design that recovers a larger portion of revenue from fixed charges will stabilize customers' monthly bills. Second, Messrs. Conroy and Seelye are of the opinion that because the majority of the Companies' total costs of providing service are "fixed" in nature, a large portion of revenue should be collected from fixed charges. Third, Mr. Seelye claims that higher fixed charges will help eliminate intra-class subsidies within the residential class.

Q. IS MR. CONROY CORRECT IN HIS ASSERTION THAT THE COLLECTION OF A HIGHER PROPORTION OF TOTAL REVENUES FROM FIXED CHARGES WILL TEND TO STABILIZE CUSTOMERS' MONTHLY BILLS?

A. Mathematically, Mr. Conroy is absolutely correct. However, this certainly is not an objective of proper economic rate design or accepted public policy. If a rate structure is reconfigured such that a larger proportion of customers' bills are comprised of non-avoidable fixed charges and a smaller proportion of customers' bills are comprised of volumetrically-based (energy) charges, customers' abilities to make rational economic decisions are reduced. In other words, the ability of individuals to control their total electric bill is diminished with rate structures that are comprised largely of fixed charges. This reduced ability to control bills leads to uneconomic decisions relating to the consumption of electricity and clearly hampers incentives to conserve energy. Additionally, those customers seeking bill stability between months have the right and ability to participate in the budget billing plan in which those customers will pay equal amounts each month during the payment plan.

Q. ARE MESSRS. CONROY'S AND SEELYE'S ASSERTIONS THAT FIXED COSTS SHOULD BE COLLECTED FROM FIXED CHARGES IN ACCORDANCE WITH SOUND ECONOMIC PRINCIPLES OR ACCEPTED PRICING PRACTICES?

A. No. These witnesses have a profound misunderstanding of sound economic principles, and their assertions are contrary to accepted pricing practices. First, I will discuss the theoretical aspects of sound economic pricing principles and then I will discuss accepted pricing practices in our economy.

The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[19] As such, the pricing policy for a regulated

[19] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

public utility should mirror those of competitive firms to the greatest extent practical.

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[20] It is well known that all costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

[20] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS KU AND LG&E.

A. Due to the Companies' investments in system infrastructure, there is no debate that many of their short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity and natural gas usage, i.e., the level of KWH or CCF consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. ARE THE ELECTRIC AND NATURAL GAS UTILITY INDUSTRIES UNIQUE IN THEIR COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing, agricultural, and transportation industries are comprised of cost structures predominated with "fixed" costs. Obvious examples of these industries include: automobile and truck manufacturing; petroleum production; farming; airline; rail transportation; and shipping transportation. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated.

Accordingly, Company witnesses Messrs. Conroy and Seelye's positions that their fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Companies' long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Companies' products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. Yes. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[21] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[22] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

[21] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.
[22] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[23]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[24]

Recently, some public utilities have begun to advocate SFV residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. ARE CONSERVATION AND EFFICIENCY GAINS A NEW RISK TO PUBLIC UTILITIES?

A. No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average residential electric and natural gas usage per appliance has been declining, utilities have remained financially healthy and have continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

[23] *Id.* p. 8 (alteration in original).
[24] *Id.* pp. 128-129.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status (and regulator approval). In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. PLEASE RESPOND TO MR. SEELYE'S CONCERN THAT FIXED COSTS TYPICALLY WILL NOT CHANGE IF A CUSTOMER USES MORE ENERGY OR IF A CUSTOMER USES LESS ENERGY.

A. First, it should be remembered that the concept of "fixed" costs are an accounting concept. These so-called fixed costs are more properly referred to as sunk costs in that these are costs that are required to provide service to customers for the purchase and use of energy. As discussed earlier, there are numerous industries with a high degree of sunk costs required to provide their products and services to customers. Second, Mr. Seelye's concern appears to also relate to the Companies' desire for revenue stability and any risk associated with not collecting revenues due to lower than requested fixed customer charges. In LG&E's and KU's responses to KIUC 1-8, the Companies provided weather normalized usage and number of customers for the residential class for each of the last three years. The following table provides the average usage per customer (on a weather normalized basis) for each of the last three years:

Average Electric Use per Customer
(Weather Normalized)

LG&E Electric

Year	MWH	Avg. Cust.	Avg. Use KWH	Variance from Avg.
2015	4,099,225	357,122	11,479	1.08%
2016	4,052,621	360,099	11,254	-0.89%
2017	4,117,743	363,331	11,333	-0.19%
	Average		11,355	

KU

Year	MWH	Avg. Cust.	Avg. Use KWH	Variance from Avg.
2015	6,034,195	422,871	14,270	2.87%
2016	5,820,433	425,366	13,683	-1.35%
2017	5,855,239	428,637	13,660	-1.52%
	Average		13,871	

Considering that the Companies have rate cases every two to three years and that the rate application in this case is based on a weather normalized forecasted test year, the above table demonstrates there is little chance that the Companies will not collect its revenues from residential customers absent higher fixed customer charges.

Q. PLEASE RESPOND TO MR. SEELYE'S CONCERN THAT IF COSTS ARE RECOVERED THROUGH VOLUMETRIC CHARGES, IT IS "PARTICULARLY PROBLEMATIC IF A CUSTOMER REDUCES ENERGY CONSUMPTION BY INSTALLING DISTRIBUTED GENERATION TECHNOLOGY."

A. First, Mr. Seelye's rationale is little more than an argument to throw the baby out with the bath water. That is, the vast majority of the Companies' residential customers do not have, nor will they ever have in the foreseeable future, a significant level of distributed generation. While there are a few customers that will install solar panels and perhaps even a windmill, this group of customers is and will represent a small percentage of the Companies' total residential class. For the few customers that do install distributed generation, they tend to be upper income and high energy usage households. Mr. Seelye's rationale would punish the low usage customer that has no ability or desire to install distributed generation.

Second, in AG 1-175, the Companies were requested to provide the cost of service impact of existing distributed generation discussed by witness Sinclair. The Companies responded that they have not performed an analysis of the cost of service impact of distributed generation.

Q. PLEASE RESPOND TO MR. SEELYE'S ASSERTION THAT HIGHER FIXED CUSTOMER CHARGES HELP REDUCE INTRA-CLASS SUBSIDIES.

A. Although I have already explained why the notion that fixed costs should be recovered from fixed charges does not comport with accepted economic theory and practice, the genesis of Mr. Seelye's rationale relating to intra-class subsidies rests on the premise that the revenue derived from small volume customers does not sufficiently recover the total costs to provide service, such that the revenue generated from large volume customers subsidize the small volume customers. Mr. Seelye's rationale and opinion is incorrect and fails to consider two important aspects of cost causation and ratemaking principles and practices.

First, one must compare the "cost causation" of "small volume and large volume" customers within a particular rate class particularly as it relates to residential customers. Based on the seasonal nature of the demand for electricity, residential customers use much more electricity in the winter and summer months than during the spring and fall months due to the use of electricity for heating and air conditioning. Some residential customers do not use electricity for space heating purposes and may not have air conditioning (or use in a limited fashion). As such, these annual small volume customers use electricity at a much more constant rate throughout the year than do residential large volume customers; i.e., small volume customer's usage is more constant throughout the year.

To illustrate, on a weather normalized basis, KU's average residential customer uses about 1,591 KWH during the winter months of January and February and about 1,263 KWH during the summer months of July and August. However, during the spring and fall months of April, May, October, and November, the average residential customer uses only about 861 KWH.[25] As a result, the load factor of small volume (non-heating/air conditioning customers) tends to be much higher than that for large volume (heating/air conditioning customers). As a matter of cost causation, the Companies must plan and install relatively more capacity for heating/air conditioning customers than for small volume customers. This additional capacity obviously comes at a cost such that the cost to serve a high load factor (low annual volume) customer is significantly less than that for a low load factor (high annual volume) customer.

The second aspect concerns the pricing structure of goods and services generally, and public utility rates specifically. That is, taken to the extreme, it could be argued that every consumer of a good or service (whether competitive or regulated) imposes a different cost upon the good or service provided such that a different price could theoretically be calculated for every individual customer. This of course is not done in practice as it is not practical or reasonable. For example, if two customers purchase gasoline from a gas station at the same time, one driving a very large vehicle with a large fuel tank and the other driving a very small car with a small fuel tank, the customer purchasing a small amount of gasoline does not pay more per gallon than the customer purchasing significantly more gasoline. This is true even though the ultimate delivered price of gasoline includes a significant level of "fixed" costs such as the cost of the store, gas pumps, labor, etc.

[25] Per KU response to KIUC data request 1-8.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH THE COMPANIES' RESIDENTIAL ELECTRIC AND NATURAL GAS CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (KWH) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO KU'S AND LG&E'S ELECTRIC RESIDENTIAL CLASSES?

A. Yes. I conducted a direct customer cost analyses for KU's and LG&E's electric residential classes separately. The details of these analyses are provided in my Schedule GAW-5 (two pages). As indicated in this Schedule, the residential direct customer cost is at most $6.55 per month for KU and $4.20 per month for LG&E. It should be noted that my customer cost analyses is based on the Companies' proposed return on equity of 10.42%. If a lower cost of equity is used, the resulting customer costs are somewhat reduced.

Q. HAVE YOU ALSO CONDUCTED A CUSTOMER COST ANALYSIS APPLICABLE TO LG&E'S NATURAL GAS RESIDENTIAL SERVICE?

A. Yes. I also conducted a direct customer cost analysis for LG&E's natural gas residential class. The details of this analysis is provided in my Schedule GAW-6. As indicated in this Schedule, the residential direct customer cost is at most $12.14 per month.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all utilities, the Companies are in the business of providing electricity and natural gas to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to the Companies' services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric charges.

Q. MR. SEELYE CLAIMS THAT HIS "COST-BASED" ELECTRIC RESIDENTIAL CUSTOMER CHARGE IS $23.89 PER MONTH FOR KU AND $20.34 PER MONTH FOR LG&E. PLEASE EXPLAIN HOW MR. SEELYE ARRIVED AT THESE LEVELS.

A. Mr. Seelye's figures include a portion of distribution plant investment costs associated with poles, overhead lines, underground conductors, conduit, and transformers. In addition, his calculated residential customer costs includes an assignment of intangible plant and general plant. With regard to O&M expenses, Mr. Seelye has included a large portion of administrative and general expenses as well as other overhead expenses. Finally, Mr. Seelye's customer cost analysis includes the entire amount of uncollectible expenses. These costs should not be reflected within the determination of an appropriate fixed customer charge.

Q. IN TERMS OF MAGNITUDE, WHAT LEVEL OF COSTS HAS MR. SEELYE CLASSIFIED AS "CUSTOMER-RELATED" AND INCLUDED WITHIN HIS ELECTRIC CUSTOMER COST DETERMINATION?

A. On a total Company basis, Mr. Seelye has included the following electric costs in his customer analyses:

Seelye Inappropriate Costs Included in "Customer Costs"
($ Millions)

	KU	LG&E - Electric
Rate Base:		
Intangible Plant	$13.872	$0
OH Lines & Poles	$492.988	$365.576
UG Lines	$169.968	$240.900
Transformers	$146.755	$65.060
General Plant	$31.377	$2.691
Cash Working Capital	$12.606	$13.190
Materials & Supplies	$8.493	$6.665
Prepayments	$2.363	$2.201
Total Rate Base	$878.422	$696.283
O&M Expenses:		
OH Lines-Operations	$3.409	$5.008
Misc. Distribution Expenses	$4.414	$2.978
Maintenance of OH Lines	$18.836	$11.208
Maintenance of UG Lines	$0.515	$0.899
Maintenance of Transformers	$0.051	$0.065
Uncollectible Expense	$20.079	$2.034
Customer Service Expenses	$4.623	$2.783
Administrative & General	$31.002	$19.176
Total O&M Expenses	$82.929	$44.151

Q. IN TERMS OF MAGNITUDE, WHAT LEVEL OF COSTS HAS MR. SEELYE CLASSIFIED AS "CUSTOMER-RELATED" AND INCLUDED WITHIN HIS GAS CUSTOMER COST DETERMINATION?

A. On a total Company basis, Mr. Seelye has included the following gas costs in his customer analyses:

Seelye Inappropriate Costs
Included in "Customer Costs"
($ Millions)

	LG&E - Gas
Rate Base:	
Intangible Plant	$0
Mains	$281.549
Other Equipment	$0.626
General Plant	$9.523
Common Utility Plant	$52.272
Cash Working Capital	$10.736
Materials & Supplies	$0.488
Prepayments	$2.019
Total Rate Base	$357.213
O&M Expenses:	
Mains/Services Expenses	$4.441
Other Distribution Expenses	$3.620
Maintenance of Mains	$8.332
Maintenance of Other Equip.	$0.336
Uncollectible Expense	$0.376
Customer Service Expenses	$0.961
Administrative & General	$13.252
Total O&M Expenses	$31.318

Q. WHY IS IT INAPPROPRIATE TO INCLUDE A PORTION OF ELECTRIC DISTRIBUTION OVERHEAD LINES, UNDERGROUND LINES, AND TRANSFORMER COSTS, AS WELL AS NATURAL GAS DISTRIBUTION MAINS IN THE DETERMINATION OF REASONABLE FIXED CUSTOMER CHARGES?

A. Every electric utility's investment in distribution lines and transformers reflects the backbone of the company's distribution system and indeed, serves as the infrastructure supporting the company's entire existence. In other words, distribution lines and transformers are the conduit to move electricity from the transmission system to individual customers. Similarly, distribution gas mains serve in a similar function. Residential customers do not subscribe to the Companies' service simply to be "connected," rather, they rely upon the Companies to distribute their energy requirements throughout the year.

Q. MR. SEELYE ASSERTS THAT THE COSTS ASSOCIATED WITH THE MINIMUM SYSTEM ARE APPROPRIATE IN THE DETERMINATION OF CUSTOMER CHARGES. PLEASE RESPOND TO THIS ASSERTION.

A. On page 22 of his direct testimony, Mr. Seelye states:

> A cost of service study is performed for the purpose of allocating costs as accurately as possible based on cost causation. In a cost of service study, it is important to distinguish the distribution system costs related to demand from the distribution system costs that are related to the minimum system that are not related to demand, as discussed in the NARUC *Electric Cost Allocation Manual*.

In this regard, Mr. Seelye is confusing the manner in which joint costs are allocated to classes as compared to how rates should be designed and collected from customers. The reason that some distribution costs are reasonably allocated to various customer classes has nothing to do with cost causation per se, but rather, due to differences in densities across customer classes.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT DISTRIBUTION POLES, LINES, AND TRANSFORMERS SHOULD NOT BE CONSIDERED AS "CUSTOMER-RELATED" COSTS FOR PURPOSES OF DETERMINING THE REASONABLENESS OF FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. In his well-known treatise Principles of Public Utility Rates, Professor James C. Bonbright states:

> . . . if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customers costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories. (Second Edition, page 492)

Q. EARLIER YOU NOTED THAT MR. SEELYE CONFUSES THE CONCEPT OF COST ALLOCATION WITH RATE DESIGN. IN THERE A NARUC PUBLICATION THAT DISCUSSES THE DETERMINATION OF RESIDENTIAL CUSTOMER CHARGES FOR RATE DESIGN PURPOSES?

A. Yes. In a NARUC Publication entitled Charging for Distribution Utility Services: Issues in Rate Design, the authors found as follows as it relates to the determination of fixed monthly customer charges:

> As one moves along the continuum of rate designs from usage-based to fixed, the benefits of the former give way more and more to the difficulties of the latter. This is the kind of trade-off that commissions are often faced with balancing: our analysis concludes that the balance strongly favors a rate structure that allows consumers to avoid charges, when there cost-effective alternatives that they value more highly. Usage-based rates fit this bill; so do hook-up fees (page 46).

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR KU AND LG&E'S RESIDENTIAL CUSTOMERS?

A. Although my customer cost analysis indicates that electric residential customer charges of no more than $6.55 per month for KU and $4.20 for LG&E are warranted, I recommend that the current electric residential customer charge for both KU and LG&E of $12.25 per month be maintained. Furthermore, my customer cost analysis for LG&E's gas operations indicates a cost-based charge of no more $12.14 per month as compared to the current customer charge of $16.35 per month. I also recommend that LG&E's residential natural gas customer charge be maintained at the current rate.

Maintaining the current customer charges will promote rate continuity as well as promoting conservation as any increase authorized in this case will be collected from residential energy charges, thereby sending a more appropriate price signal for customers to conserve and use energy more efficiently. Furthermore, by maintaining the current electric customer charge of $12.25, this leaves at least $6.00 for the recovery of non-direct customer-related costs including overhead and other costs for KU and $8.05 for LG&E's electric operations. Similarly, by maintaining the current residential natural gas customer charge of $16.35 leaves at least $4.21 for the recovery of non-direct customer-related costs including overhead and other costs.

B. Residential Rate Structure

Q. DO THE COMPANIES PROPOSE ANY STRUCTURAL CHANGES TO THE MANNER IN WHICH CHARGES ARE PRESENTED TO CUSTOMERS?

A. Yes. The Companies propose two changes to the way they charge residential customers. First, the Companies propose that the customer charge be expressed on customers' bills as a daily charge instead of a monthly charge. Second, the Companies proposed that the residential energy charge be bifurcated on certain tariffs between a variable component and a fixed component.

Q. DO YOU SUPPORT THE COMPANIES' PROPOSAL TO CHANGE ITS CUSTOMER CHARGE FROM A MONTHLY TO DAILY CHARGE?

A. No. The Companies' proposal has no reasonable merit and should be rejected. Indeed, the Companies' proposal to change the residential fixed charge from a monthly to daily rate obfuscates its proposed high fixed customer charges with the illusion of a low "daily" rate of $0.53 per day (electric) and $0.65 per day (gas) compared to the reality of its proposed $16.13 per month electric fixed charge and $19.78 per month gas fixed charge. The accepted industry practice and one in which virtually all public utility ratepayers are used to, is to price customer charges on a monthly basis. This monthly-based customer charge reflects that customers receive a bill on a monthly basis and they can then easily see that the fixed charge is a certain amount per month. The Companies propose to abandon this long-standing and industry-wide accepted practice by claiming the fixed charge is priced on a daily basis such that when a customer receives his monthly bill, he or she must multiply that daily rate by the number of days in a particular billing cycle. In fact, the Companies developed their proposed customer charges based on a monthly basis and then converted these proposed monthly charges to a daily rate.

Q. HAVE THE COMPANIES EXPRESSED ANY REASONS AS TO WHY THEY PROPOSE TO RESTRUCTURE THE CUSTOMER CHARGE FROM A MONTHLY TO DAILY RATE?

A. Yes. Mr. Conroy claims that converting to a daily service charge will permit more accurate cost recovery for each billing period since all billing periods do not have the same number of days and will avoid any need to prorate service for any customers who begin or end service mid-billing period. Mr. Seelye repeats Mr. Conroy's reasoning and adds that "a daily customer charge could also create future optionality for new programs such as electric vehicle rates and prepaid metering, which may need to be billed on a daily basis."[26]

While there is no doubt that some customers initiate or terminate service in between billing cycles, there is no evidence that such a change will make it easier for a consumer to understand the billing for a partial month of service. The proration of monthly charges is well known to consumers and is a common practice not only in the regulated utility business but also other types of industries such as cable television, wireless telecommunications, mortgage and loan payments, health and fitness centers, etc.

With regard to Mr. Seelye's assertion that a daily charge could create future optionality for new programs, these future programs can, and should be, addressed if and when they are proposed based on the specifics of the particular programs. There is no need to change the tried and true traditional residential rate structure for potential new programs that may or may not be proposed in the future.

Q. DO YOU SUPPORT THE PROPOSED BIFURCATION OF ENERGY CHARGES ON THE RESIDENTIAL TARIFF?

A. No. First, even for those customers that understand the concepts of fixed versus variable costs, they could care less about the cost structure for ratemaking purposes

[26] Case Nos. 2018-00295 & 2018-00294, Direct Testimony of William Steven Seelye at 14 (Ky. PSC Sep. 28, 2018).

within their energy charges.[27] What the customer is interested in is what those variable charges are in total. As an analogy, when consumers purchase gasoline, they could care less how much of the total cost per gallon is associated with the fixed cost of producing, transporting, and delivering that gallon of gasoline versus the variable cost of gasoline at the wellhead. Second, in my practice throughout the United States, I have not seen such a proposal, let alone such a bifurcation of rates between "fixed" and "variable" costs. This could lead to additional customer confusion as they may not understand the distinction between "fixed" and "variable" costs, and perhaps more importantly, may disagree with the Companies determination of what is and what is not a fixed cost. The point of this is that such a distinction is unnecessary, will not assist consumers in their efficient utilization of electricity, nor assist in making decisions on how to control their electricity bills. Indeed, it is clear that this proposal is nothing more than a campaign by the Companies to advocate the collection of so-called "fixed" costs from non-avoidable charges.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A, Yes.

[27] Upon review of the Companies' responses to AG DR 1-168 and Staff DR 1-27, of the approximate 1,262,380 customers taking service under at least one gas or electric tariff, there were only 9,845 unique views over a 20+-month period to the Companies' webpage that contains the Companies' tariffs.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	))))	CASE NO. 2018-00294

-and-

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	CASE NO. 2018-00295

AFFIDAVIT OF Glenn Watkins

Commonwealth of Virginia)
)
)

Glenn Watkins, being first duly sworn, states the following:
The prepared Pre-Filed Direct Testimony and Schedules attached thereto constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief his statements made are true and correct. Further affiant saith naught.

Glenn Watkins

SUBSCRIBED AND SWORN to before me this 15th day of January, 2019.

NOTARY PUBLIC

My Commission Expires: 03/31/2022

SUSAN W. CREW
NOTARY PUBLIC
REG # 270986
MY COMMISSION EXPIRES 3/31/2022
COMMONWEALTH OF VIRGINIA

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

PRESIDENT/SENIOR ECONOMIST

TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers' compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

BRIEF DESCRIPTION AND STRENGTHS AND WEAKNESSES OF MOST COMMON METHODS USED TO ALLOCATE GENERATION COSTS

Single Coincident Peak ("1-CP")

The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning one hundred percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as KU had a peak load of 6,500 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 6,500 mW for 1 hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a "free ride" on the assignment of generation costs that this class requires.

4-CP

The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

<u>Summer and Winter Coincident Peak ("S/W Peak")</u>

The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is no more reasonable than the 1-CP method.

<u>12-CP</u>

Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities than does the 1-CP or 4-CP methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

<u>Peak and Average ("P&A")</u>

The various P&A methodologies rest on the premise that a utility's generation facilities are designed and placed into service to meet peak load <u>and</u> serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on some arbitrary factor such as system coincident load factor.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

Average and Excess (“A&E”)

The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a “free-ride” under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak (“BIP”)

The BIP method is also known as a production stacking method that explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility’s resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors tend to run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods.

Finally, wind and solar generating facilities may only produce energy when environmental conditions are present; i.e., wind or sunshine. As a result, their reliability factors are such that they may not be relied upon to meet peak loads at all times. For example, many utilities experience peak demands in the early morning and evening hours when there is either no sunlight present or minimal sunlight available for solar generation. As such, wind and solar generating units are classified as energy-related.

Probability of Dispatch

The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year (8,760 hours). Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only those few peak hours. The hourly capacity costs for each generating asset are summed to develop hourly investment cost responsibilities. These hourly investments are then assigned to individual rate classes based on class contributions to system load for each hour of the year. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

Equivalent Peaker ("EP")

The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant level of assumptions regarding the current (or future) costs of various generating alternatives.

Conclusions

In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

KU and LG&E Generating Unit Characteristics

Generating Unit (a)	Designation	Order of Dispatch 1/	Forecasted Fuel Cost/MWH 2/	KU/LG&E Capacity 3/	Capacity Factor	Gross Investment 10/31/18 ($000) 4/	Fuels 3/	Net Generation in Forecasted Test Year 3/
Trimble County 2	Base	3	$ 19.50	629	46.80%	$ 1,128,924.8	Coal	3,445,250,000
Cane Run 7	Base	4	$ 19.90	808	66.79%	$ 550,214.7	Gas	4,740,180,000
Ghent 2	Base	5	$ 20.20	556	58.65%	$ 434,348.3	Coal	2,866,140,000
Trimble County 1	Base	7	$ 20.90	425	46.62%	$ 648,331.0	Coal	2,318,340,000
Mill Creek 4	Base	6	$ 21.50	544	63.25%	$ 865,072.4	Coal	3,020,190,000
Ghent 1	Base	12	$ 21.70	557	54.41%	$ 702,479.6	Coal	2,661,540,000
Ghent 4	Base	13	$ 21.70	556	49.77%	$ 1,238,207.2	Coal	2,431,550,000
Mill Creek 1	Base	8	$ 22.00	356	58.11%	$ 320,319.5	Coal	1,814,490,000
Mill Creek 2	Base	9	$ 22.10	356	52.92%	$ 388,271.4	Coal	1,652,540,000
Mill Creek 3	Base	10	$ 22.30	463	49.78%	$ 547,177.4	Coal	2,022,930,000
Ghent 3	Base	15	$ 22.60	557	46.14%	$ 699,121.0	Coal	2,255,570,000
	Total Base			**5,807**		**$ 7,522,467.3**		
Brown 6	Intermediate	26	$ 29.60	177	10.26%	$ 66,454.8	Gas, Oil	159,530,000
Brown 7	Intermediate	27	$ 29.80	177	4.39%	$ 62,219.0	Gas, Oil	68,220,000
Brown 5	Intermediate	28	$ 37.30	123	14.97%	$ 55,080.1	Gas	161,770,000
Trimble County 5	Intermediate	18	$ 38.00	199	22.84%	$ 73,841.6	Gas	399,070,000
Brown 3	Intermediate	16	$ 40.00	464	16.44%	$ 976,435.3	Coal	669,990,000
Trimble County 6	Intermediate	19	$ 40.70	199	17.53%	$ 66,354.4	Gas	306,320,000
	Total Intermediate			**1,339**		**$ 1,300,385.2**		
Brown 8	Peak	31	$ 42.20	126	2.04%	$ 37,790.5	Gas, Oil	22,600,000
Brown 9	Peak	29	$ 42.30	126	2.29%	$ 56,667.4	Gas, Oil	25,370,000
Brown 11	Peak	32	$ 43.00	126	1.52%	$ 46,676.1	Gas, Oil	16,820,000
Brown 10	Peak	30	$ 43.70	126	3.24%	$ 36,732.0	Gas, Oil	35,890,000
Trimble County 7	Peak	20	$ 45.40	199	12.53%	$ 57,011.8	Gas	218,900,000
Paddys Run 13	Peak	24	$ 45.70	178	9.55%	$ 84,764.4	Gas	149,490,000
Zorn 1	Peak	36	$ 61.10	18	0.34%	$ 1,974.7	Gas	540,000
Trimble County 8	Peak	21	$ 64.70	199	5.68%	$ 56,457.7	Gas	99,300,000
Trimble County 9	Peak	22	$ 86.90	199	3.49%	$ 56,793.9	Gas	61,010,000
Haefling 1	Peak	37	$ 138.60	21	0.39%	$ 4,374.1	Gas, Oil	710,000
Haefling 2	Peak	37	$ 138.60	21	0.00%		Gas, Oil	
Trimble County 10	Peak	23	$ 152.40	199	1.64%	$ 70,160.8	Gas	28,660,000
Cane Run 11	Peak	33	$ 465.20	16	0.51%	$ 3,726.4	Gas, Oil	730,000
Paddy's Run 11	Peak	34	$ 1,026.30	16	0.22%	$ 2,151.1	Gas	310,000
Paddy's Run 12	Peak	35	$ 1,151.80	33	0.22%	$ 4,339.2	Gas	620,000
	Total Peak			**1,603**		**$ 519,620.1**		
Brown Solar	Solar & Hydro	1		10	20.95%	$ 25,492.4	Solar	18,400,000
Dix Dam 1 (1)	Solar & Hydro	2		11	83.13%	$ 43,422.8	Hydro	81,780,000
Dix Dam 2	Solar & Hydro	2		11	0.00%		Hydro	
Dix Dam 3	Solar & Hydro	2		11	0.00%		Hydro	
Ohio Falls 1 (1)	Solar & Hydro	2		13	263.03%	$ 143,394.8	Hydro	300,360,000
Ohio Falls 2	Solar & Hydro	2		13	0.00%		Hydro	
Ohio Falls 3	Solar & Hydro	2		13	0.00%		Hydro	
Ohio Falls 4	Solar & Hydro	2		13	0.00%		Hydro	
Ohio Falls 5	Solar & Hydro	2		13	0.00%		Hydro	
Ohio Falls 6	Solar & Hydro	2		13	0.00%		Hydro	
Ohio Falls 7	Solar & Hydro	2		13	0.00%		Hydro	
Ohio Falls 8	Solar & Hydro	2		13	0.00%		Hydro	
	Total Solar & Hydro			**146**		**$ 212,310.0**		
Business Solar						85	Solar	

1/ Per response to LG&E 1-147.
2/ Per response to LG&E 1-149.
3/ Per response to LG&E 1-146.
4/ Per response to LG&E 1-145.

Year	Month	Day	Hour	LOLP	System Load (MW)	CSR	Purchases	Total Owned Generation	Total Supply	Capacity Not Dispatched	Unserved Load (MW)
2019	8	28	16	0.50351%	6,360	93	512	5,756	6,360	1,926	1.06
2019	8	28	15	0.41836%	6,321	109	505	5,707	6,321	1,926	0.87
2019	8	28	14	0.34877%	6,282	69	470	5,742	6,281		0.71
2019	8	29	15	0.29895%	6,247	-	658	5,403	6,061	1,785	0.61
2019	8	28	17	0.22836%	6,186	-	446	5,740	6,186		0.46
2019	8	30	15	0.15467%	6,110	-	-	6,109	6,109	1,582	0.30
2019	8	30	16	0.14941%	6,100	-	-	6,101	6,101		0.29
2019	8	27	15	0.14727%	6,100	-	73	6,026	6,099	1,132	0.29
2019	8	29	16	0.13804%	6,084	-	658	5,386	6,044		0.27
2019	8	29	14	0.13331%	6,079	-	658	5,421	6,079		0.26
2019	8	30	14	0.12077%	6,059	-	-	6,060	6,060		0.23
2019	8	28	13	0.10266%	6,027	-	259	5,768	6,027		0.20
2019	7	17	13	0.10115%	6,017	63	-	5,954	6,017	1,100	0.19
2019	8	27	14	0.09431%	6,010	-	26	5,984	6,010		0.18
2019	7	17	14	0.09670%	6,007	81	-	5,926	6,007		0.18
2019	8	29	13	0.08967%	5,998	-	658	5,330	5,988		0.17
2019	8	27	16	0.08695%	5,991	-	25	5,966	5,991		0.16
2019	7	17	15	0.08784%	5,989	62	-	5,926	5,988		0.17
2019	8	29	17	0.08305%	5,980	-	658	5,322	5,980		0.16
2020	1	7	8	0.01679%	5,972	-	-	5,972	5,972		0.03
2019	8	28	18	0.07851%	5,968	-	202	5,765	5,967		0.15
2019	8	30	17	0.07538%	5,961	-	-	5,961	5,961		0.14
2019	8	30	13	0.07057%	5,953	-	-	5,953	5,953		0.13
2019	7	17	12	0.06949%	5,944	48	-	5,896	5,944		0.13
2019	8	27	13	0.06077%	5,925	-	-	5,925	5,925		0.11
2019	8	28	19	0.06070%	5,916	-	91	5,825	5,916		0.11
2019	7	17	16	0.06043%	5,914	16	-	5,898	5,914		0.11
2020	1	24	7	0.01165%	5,905	-	-	5,905	5,905		0.02
2019	7	16	14	0.05512%	5,899	-	508	5,391	5,899		0.10
2019	7	16	15	0.05371%	5,893	-	559	5,334	5,893		0.10
2019	8	22	15	0.05154%	5,892	-	-	5,891	5,891		0.10
2019	7	10	12	0.05343%	5,891	-	-	5,892	5,892		0.10
2019	8	29	12	0.04845%	5,880	-	658	5,211	5,869		0.09
2019	8	27	17	0.04817%	5,874	-	81	5,793	5,874		0.09
2019	7	9	14	0.04796%	5,871	-	-	5,871	5,871		0.09

Year	Month	Day	Hour	LOLP	System Load (MW)	Brown 3	Ghent 1	Ghent 2	Ghent 3	Ghent 4	Mill Creek 1	Mill Creek 2	Mill Creek 3	Mill Creek 4	OVEC	Trimble 1	Trimble 2	Brown 5	Brown 6	Brown 7
Unit Capacity						464	557	556	557	556	356	356	463	544		425	629	123	177	177
2019	8	28	16	0.50351%	6,360	-	474	484	-	477	299	296	-	476	152	340	546	-	146	146
2019	8	28	15	0.41836%	6,321	-	474	484	-	422	299	256	-	476	152	340	546	-	146	146
2019	8	28	14	0.34877%	6,282	-	474	484	-	443	299	266	-	476	152	340	546	-	146	146
2019	8	29	15	0.29895%	6,247	415	474	484	189	-	-	207	330	476	152	368	510	30	146	146
2019	8	28	17	0.22836%	6,186	70	464	484	-	407	299	256	-	476	152	340	546	-	146	146
2019	8	30	15	0.15467%	6,110	205	474	484	441	461	-	287	390	476	152	368	546	88	146	146
2019	8	30	16	0.14941%	6,100	195	474	484	441	473	-	286	390	476	152	368	546	86	146	146
2019	8	27	15	0.14727%	6,100	236	474	484	480	288	76	296	390	476	152	368	540	97	146	146
2019	8	29	16	0.13804%	6,084	415	474	484	252	-	-	207	363	296	152	368	510	108	146	146
2019	8	29	14	0.13331%	6,079	313	474	484	126	-	-	207	297	476	152	368	510	108	146	146
2019	8	30	14	0.12077%	6,059	185	474	484	441	438	-	286	390	476	152	368	546	92	146	146
2019	8	28	13	0.10266%	6,027	-	474	484	-	427	299	261	-	476	152	340	546	-	146	146
2019	7	17	13	0.10115%	6,017	324	42	484	480	477	299	207	390	476	152	368	546	30	146	146
2019	8	27	14	0.09431%	6,010	235	474	484	480	288	38	296	390	476	152	368	540	98	146	146
2019	7	17	14	0.09670%	6,007	285	84	484	480	477	299	207	390	476	152	368	546	-	146	146
2019	8	29	13	0.08967%	5,998	415	474	484	63	-	-	207	264	476	152	368	510	108	146	146
2019	8	27	16	0.08695%	5,991	209	474	484	480	288	114	296	390	476	152	368	540	88	146	146
2019	7	17	15	0.08784%	5,989	183	126	484	480	467	299	277	390	476	152	368	546	-	146	146
2019	8	29	17	0.08305%	5,980	307	474	484	315	-	-	207	390	296	152	368	510	108	146	146
2020	1	7	8	0.01679%	5,972	140	218	485	450	477	299	207	393	485	158	368	567	90	151	-
2019	8	28	18	0.07851%	5,968	140	464	484	-	407	299	256	-	476	152	340	546	-	146	146
2019	8	30	17	0.07538%	5,961	183	474	484	441	458	-	279	390	476	152	368	546	88	146	146
2019	8	30	13	0.07057%	5,953	145	474	484	441	438	-	266	390	476	152	368	546	88	146	146
2019	7	17	12	0.06949%	5,944	159	-	484	470	447	299	207	390	476	152	368	546	88	146	146
2019	8	27	13	0.06077%	5,925	175	474	484	480	457	-	276	390	476	152	368	540	88	146	146
2019	8	28	19	0.06070%	5,916	140	474	484	-	437	299	266	-	476	152	340	546	-	146	146
2019	7	17	16	0.06043%	5,914	167	168	484	470	454	299	276	390	476	152	368	546	-	146	146
2020	1	24	7	0.01165%	5,905	218	478	485	475	-	299	264	359	415	158	368	567	100	-	171
2019	7	16	14	0.05512%	5,899	272	-	484	480	-	251	296	-	476	152	368	546	98	146	146
2019	7	16	15	0.05371%	5,893	222	-	484	480	-	299	207	-	476	152	368	546	98	146	146
2019	8	22	15	0.05154%	5,892	170	474	484	480	457	299	-	390	476	152	368	546	30	146	-
2019	7	10	12	0.05343%	5,891	156	474	484	470	447	299	276	390	476	152	368	546	88	-	-
2019	8	29	12	0.04845%	5,880	415	474	484	-	-	-	207	231	476	152	368	510	108	146	146
2019	8	27	17	0.04817%	5,874	-	474	484	460	288	150	266	390	476	152	368	540	88	146	146
2019	7	9	14	0.04796%	5,871	154	474	484	460	447	299	266	390	476	152	368	546	88	-	-

Year	Month	Day	Hour	LOLP	System Load (MW)	Brown 8	Brown 9	Brown 10	Brown 11	Cane Run 11	Haefling	Paddys Run 11	Paddys Run 12	Paddys Run 13	Trimble 5	Trimble 6	Trimble 7	Trimble 8	Trimble 9	Trimble 10	Zorn 1	Cane Run 7	Dix Dam	Ohio Falls	Brown Solar
Unit Capacity						126	126	126	126	16	42	16	33	178	199	199	199	199	199	199	18	808	33	104	10
2019	8	28	16	0.50351%	6,360	27	27	-	-	-	12	12	-	147	159	159	159	159	159	159	-	662	32	40	6
2019	8	28	15	0.41836%	6,321	50	50	-	-	-	12	12	-	147	159	159	159	159	159	159	-	662	32	40	7
2019	8	28	14	0.34877%	6,282	52	52	-	-	-	12	12	-	147	159	159	159	159	159	159	-	662	32	40	8
2019	8	29	15	0.29895%	6,247	102	102	27	27	-	24	-	-	147	159	159	159	159	159	159	14	-	32	40	7
2019	8	28	17	0.22836%	6,186	50	50	-	-	-	12	12	-	147	159	159	159	157	149	149	14	662	32	40	3
2019	8	30	15	0.15467%	6,110	-	80	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	32	40	7
2019	8	30	16	0.14941%	6,100	-	74	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	32	40	6
2019	8	27	15	0.14727%	6,100	90	92	92	82	-	-	-	-	147	159	159	-	159	159	159	-	-	32	40	8
2019	8	29	16	0.13804%	6,084	102	102	102	102	-	24	-	-	147	159	159	159	159	159	-	14	-	32	40	6
2019	8	29	14	0.13331%	6,079	102	102	102	102	-	12	-	-	147	159	159	159	159	159	159	14	-	32	40	7
2019	8	30	14	0.12077%	6,059	-	70	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	32	40	8
2019	8	28	13	0.10266%	6,027	50	50	-	50	-	12	12	-	147	159	159	159	159	159	159	-	662	32	40	8
2019	7	17	13	0.10115%	6,017	-	-	-	27	-	-	-	-	147	159	159	159	-	-	-	-	662	32	34	8
2019	8	27	14	0.09431%	6,010	87	92	90	82	-	-	-	-	147	159	159	-	159	159	159	-	-	32	40	8
2019	7	17	14	0.09670%	6,007	-	-	27	-	-	-	-	-	147	159	159	159	-	-	-	-	662	32	34	7
2019	8	29	13	0.08967%	5,998	102	102	102	-	-	24	-	-	147	159	159	159	159	159	159	14	-	25	40	8
2019	8	27	16	0.08695%	5,991	72	79	78	80	-	-	-	-	147	159	159	-	159	159	159	-	-	18	40	6
2019	7	17	15	0.08784%	5,989	-	27	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	32	34	6
2019	8	29	17	0.08305%	5,980	102	102	102	102	-	12	-	-	147	159	159	159	159	159	-	14	-	-	40	3
2020	1	7	8	0.01679%	5,972	53	56	58	-	-	-	-	-	175	179	179	179	179	179	179	-	-	32	36	0
2019	8	28	18	0.07851%	5,968	50	50	-	-	-	12	12	-	147	159	159	156	149	149	149	14	662	-	40	1
2019	8	30	17	0.07538%	5,961	-	-	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	-	40	3
2019	8	30	13	0.07057%	5,953	-	58	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	-	40	9
2019	7	17	12	0.06949%	5,944	-	-	-	-	-	-	-	-	147	159	159	159	159	-	-	-	662	32	34	8
2019	8	27	13	0.06077%	5,925	71	70	72	69	-	-	-	-	147	159	159	-	159	159	159	-	-	-	40	9
2019	8	28	19	0.06070%	5,916	52	52	-	-	-	12	-	-	147	159	159	159	159	159	159	-	662	-	40	(0)
2019	7	17	16	0.06043%	5,914	-	-	-	-	-	-	-	-	147	159	159	159	-	-	-	-	662	32	34	5
2020	1	24	7	0.01165%	5,905	-	-	88	88	-	-	-	-	175	149	149	149	-	-	-	-	683	32	36	(0)
2019	7	16	14	0.05512%	5,899	27	-	-	102	14	-	-	-	147	159	-	159	159	159	-	14	662	32	34	9
2019	7	16	15	0.05371%	5,893	82	-	-	82	14	-	-	-	147	159	-	159	159	159	-	14	662	32	34	8
2019	8	22	15	0.05154%	5,892	27	-	-	27	-	-	-	-	147	159	159	159	-	-	-	-	662	32	40	7
2019	7	10	12	0.05343%	5,891	27	-	27	-	-	-	-	-	-	159	159	159	-	-	-	-	662	32	34	7
2019	8	29	12	0.04845%	5,880	102	102	102	-	-	24	-	-	147	159	159	159	159	159	159	14	-	-	40	8
2019	8	27	17	0.04817%	5,874	57	60	52	52	-	-	-	-	147	159	159	159	159	159	159	-	-	-	40	3
2019	7	9	14	0.04796%	5,871	-	27	-	27	-	-	-	-	-	159	159	159	-	-	-	-	662	32	34	8

KENTUCKY UTILITIES COMPANY

Residential Customer Cost Analysis

		Total Company	Allocation Factor	Residential
Gross Plant				
369	Services	$108,672,088	70.1693%	$76,254,411
370	Meters	$77,500,987	61.5794%	$47,724,643
	Total Gross Plant	**$186,173,075**		**$123,979,054**
Depreciation Reserve				
	Services	$38,258,338	70.1693%	$26,845,596
	Meters	$27,336,849	61.5794%	$16,833,868
	Total Depreciation Reserve	**$65,595,187**		**$43,679,464**
Total Net Plant		**$120,577,888**		**$80,299,590**
Operation & Maintenance Expenses				
586	Dist Oper - Meter	$8,624,080	61.5794%	$5,310,657
597	Maintenance-Meters	$0		$0
902	Meter Reading	$8,696,616	64.2520%	$5,587,750
903	Records & Collections	$20,079,309	64.2520%	$12,901,358
	Total O & M Expenses	**$37,400,005**		**$23,799,764**
Depreciation Expense				
	Services	$2,609,877	70.1693%	$1,831,332
	Meters	$1,864,844	61.5794%	$1,148,360
	Total Depreciation Expense	$4,474,721		$2,979,691
Revenue Requirement				
	Interest			$1,646,142
	Equity return			$4,421,238
	State Income Taxes @ 5.00%			$294,553
	Federal Income Tax @21.00%			$1,175,266
	Revenue For Return			$7,537,198
	O & M Expenses			$23,799,764
	Depreciation Expense			$2,979,691
	Subtotal Customer Revenue Requirement			$34,316,653
	Total Revenue Requirement			**$34,316,653**
	Number of Customers			436,423
	Number of Bills			5,237,076
	TOTAL MONTHLY CUSTOMER COST			$6.55

LOUISVILLE GAS & ELECTRIC COMPANY - ELECTRIC OPERATIONS

Residential Customer Cost Analysis

		Total Company	Allocation Factor	Residential
Gross Plant				
369	Services	$37,740,878	76.6650%	$28,934,044
370	Meters	$42,039,099	69.2460%	$29,110,394
	Total Gross Plant	**$79,779,977**		**$58,044,439**
Depreciation Reserve				
	Services	$13,463,418	76.6650%	$10,321,729
	Meters	$15,052,577	69.2460%	$10,423,307
	Total Depreciation Reserve	**$28,515,995**		**$20,745,037**
Total Net Plant		**$51,263,982**		**$37,299,402**
Operation & Maintenance Expenses				
586	Dist Oper - Meter	$8,418,826	69.2460%	$5,829,700
597	Maintenance-Meters	$0		$0
902	Meter Reading	$3,447,792	73.7260%	$2,541,919
903	Records & Collections	$7,045,716	73.7260%	$5,194,525
	Total O & M Expenses	**$18,912,334**		**$13,566,144**
Depreciation Expense				
	Services	$1,032,087	76.6650%	$791,249
	Meters	$1,153,909	69.2460%	$799,036
	Total Depreciation Expense	$2,185,996		$1,590,285
Revenue Requirement				
	Interest			$787,017
	Equity return			$2,053,678
	State Income Taxes @ 5.00%			$136,821
	Federal Income Tax @21.00%			$545,914
	Revenue For Return			$3,523,431
	O & M Expenses			$13,566,144
	Depreciation Expense			$1,590,285
	Subtotal Customer Revenue Requirement			$18,679,860
	Total Revenue Requirement			**$18,679,860**
	Number of Customers			370,580
	Number of Bills			4,446,960
	TOTAL MONTHLY CUSTOMER COST			$4.20

LOUISVILLE GAS & ELECTRIC - GAS OPERATIONS

Gas Residential Customer Cost Analysis

		Total Company	Allocation Factor	Residential
Gross Plant				
380	Services	$390,754,787	73.9926%	$289,129,688
381	Meters	$64,986,993	66.0003%	$42,891,586
383	House Regulators	$26,848,132	66.0003%	$17,719,838
	Total Gross Plant	**$482,589,912**		**$349,741,111**
Depreciation Reserve				
	Services	$117,005,313	73.9926%	$86,575,292
	Meters	$24,334,111	66.0003%	$16,060,577
	House Regulators	Included in Meters		Included in Meters
	Total Depreciation Reserve	**$141,339,424**		**$102,635,869**
Total Net Plant		**$341,250,488**		**$247,105,242**
Operation & Maintenance Expenses				
878	Meter & House Regulator Expense	$2,193,210	66.0003%	$1,447,524
879	Customer Installations	$179,575	73.9926%	$132,872
892	Maintenance of Services	$784,684	73.9926%	$580,608
893	Maintenance of Meters & House Regulators	$0		$0
902	Meter Reading	$2,708,980	85.3197%	$2,311,295
903	Records & Collections	$5,535,920	85.3197%	$4,723,233
	Total O & M Expenses	**$11,402,369**		**$9,195,532**
Depreciation Expense				
	Services	$12,660,955	73.9926%	$9,368,172
	Meters	$2,488,624	66.0003%	$1,642,498
	House Regulators	Included in Meters		Included in Meters
	Total Depreciation Expense	$15,149,579		$11,010,670
Revenue Requirement				
	Interest			$5,213,921
	Equity return			$13,605,437
	State Income Taxes @ 5.00%			$906,425
	Federal Income Tax @21.00%			$3,616,635
	Revenue For Return			$23,342,417
	O & M Expenses			$9,195,532
	Depreciation Expense			$11,010,670
	Subtotal Customer Revenue Requirement			$43,548,620
	Total Revenue Requirement			**$43,548,620**
	Number of Customers			298,980
	Number of Bills			3,587,760
	TOTAL MONTHLY CUSTOMER COST			$12.14