COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

CASE NO. 2016-00370

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

DIRECT TESTIMONY OF
DENNIS W. GOINS, PH.D.
ON BEHALF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

March 3, 2017

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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. Following graduate school I worked as a staff economist at the North Carolina Utilities Commission (NCUC), where I testified in numerous cases involving electric, gas, and telephone utilities. Since leaving the NCUC, I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on policy, planning, and pricing issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing issues; prepared analyses related to utility mergers, transmission access and pricing, and the development of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts.

I have submitted testimony and affidavits and provided technical assistance in more than 200 proceedings before state and federal agencies as an expert in cost of service, rate design, competitive market issues, regulatory policy, and utility planning and operating practices. These agencies include the Federal Energy Regulatory Commission (FERC), the Government Accountability Office, state courts in Iowa, Montana, and West Virginia, and regulatory agencies in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Wyoming, and the District of Columbia.[1]

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I previously filed testimony in Case Nos. 2009-00548, 2009-00549, 2012-00221, and 2012-00222.

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[1] *See* Exhibit DWG-1.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Kentucky Industrial Utility Customers, Inc. (KIUC). Two KIUC members are served by Kentucky Utilities Company (KU) under its curtailable service Rider CSR.[2] One of these members is also served under KU's Rate FLS.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to review KU's base rate filing, focusing on KU's proposals regarding curtailable rate options[3] that it offers. In particular, I was asked to determine whether KU's proposals are reasonable, and, if necessary, suggest recommended changes.

Q. WHAT INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed KU's filing, testimony, exhibits, and responses to requests for information.[4] I also reviewed testimony and Commission orders in prior KU rate and integrated resource planning (IRP) cases. Finally, I reviewed information found on web sites operated by LG&E and KU, PPL Corporation, PJM—a regional transmission organization, FERC, and the Commission.

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[2] Two additional KIUC members are served under curtailable rate options offered by Louisville Gas and Electric Company (LG&E), KU's sister operating company. One of the KIUC members has four different business divisions counted as separate CSR customers by KU. As a result, seven of the CSR customers served by LG&E and KU are represented by KIUC.

[3] KU uses *curtailable* in designating its current and proposed nonfirm rate options for large industrial customers. Curtailable or interruptible load is generally associated with a customer's agreement either to reduce load to zero or no more than the customer's firm contract demand, or to provide a contractually stated reduction in demand when requested by the host utility. In my testimony, I use *curtailable* and *interruptible* interchangeably except when referring to specific KU nonfirm rate options that are designated *curtailable*.

[4] Selected responses related to KU's Rider CSR are presented in Exhibit DWG-2.

CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. KU currently offers curtailable service under Rider CSR, which includes administratively set credits (differentiated by service voltage) paid to customers for their curtailable load measured during specified periods. The current CSR rider includes both physical and economic curtailments, a 60-minutes notice before a curtailment begins, maximum annual hours of physical (100 hours) and economic (275 hours) curtailments permitted,[5] and, as noted, credits differentiated by a customer's service voltage. In addition, a CSR customer may choose either of two types of load reduction (Option A or Option B).[6]
2. In this case, KU has proposed four significant changes to Rider CSR—two of which unreasonably increase the cost of interruptible service to large manufacturers. (Some of these CSR customers have invested millions of dollars in production processes designed to operate efficiently using nonfirm electric service.) More specifically, KU has proposed:
   - Closing Rider CSR to new curtailable load that was not under contract at the end of 2016.
   - Changing the analytical method used to set CSR credits. In this case, KU abandoned the avoided cost approach to set CSR credits—an approach that has been used by KU and approved by this Commission in numerous prior cases. In this case, KU

[5] During a physical curtailment, a CSR customer must reduce load either to or below the customer's firm contract demand (Option A) or by a specified amount (Option B). During a physical curtailment, a CSR customer does not have the option to buy curtailable energy during the curtailment. During an economic curtailment, a CSR customer may either buy curtailable energy at the Automatic Buy-Through Price—a formula-based price specified in Rider CSR, or reduce load according to the terms of contract Option A or Option B.

[6] KU's affiliated operating company (LG&E) offers the same curtailable rate options.

switched to an arcane embedded cost approach that has no sound economic or engineering basis.

- Reducing CSR credits by 50 percent.[7] Most of KU's applications for base rate adjustments in the past 10 years have included proposals to slash CSR credits and/or impose more onerous CSR service conditions relative to the CSR rider in effect at the time of each rate case. This current case is no different. KU's proposed reduction in the CSR credits—combined with its proposed increases in applicable firm service rates used in conjunction with the CSR rider—dramatically increases the total cost of electric service for CSR customers. Despite these severe rate impacts, KU did not present or discuss its proposed changes to Rider CSR with interruptible customers prior to filing this case, nor did KU evaluate the potential customer impacts of its proposed CSR changes.[8]
- Changing the designated gas price index used to set economic buy-through prices in the Automatic Buy-Through Price formula. The current formula defines the designated gas price as the mid-point natural gas price for the buy-through day posted in *Platt's Gas Daily* for Dominion South Point delivery. KU wants to change the designated gas price to the most recently posted cash price for Henry Hub gas posted in the *Wall Street Journal* at least one day preceding the buy-through (Henry Hub daily spot price).

3. In its testimony and data responses in this case, KU has raised some important CSR issues—for example, the current limitation on physical curtailments and its inability to use CSR load as operating reserve because of the 60-minutes notice requirement before a

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[7] Under KU's proposal, the CSR credits per kVA of curtailable load decrease from $6.50 (primary) and $6.40 (transmission) to $3.31 (primary) and $3.20 (transmission).
[8] *See* KU's responses to KIUC 1-49(b)-(d) in Exhibit DWG-2.

curtailment begins.[9] These issues are not addressed in KU's proposed changes to Rider CSR. Moreover, as I noted earlier, most of KU's recent base rate applications include a common theme—unilateral proposals that cut the value of interruptible service to CSR customers.

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Reject KU's proposed embedded cost method for determining the CSR credits. This embedded cost method arbitrarily biases the estimated value of curtailable load downward dramatically relative to the avoided cost approach that has been vetted and approved in prior cases. Instead of KU's embedded cost approach, I recommend that the Commission require KU to continue using an avoided cost approach as the basis for setting CSR credits. KU uses the avoided (or marginal) cost approach to evaluate load management and energy efficiency programs offered to customers and in developing its integrated resource plans (IRPs). KU should not be allowed to single out Rider CSR and use a completely different cost method to evaluate its interruptible rate option for industrial customers.
2. Reject KU's proposed reduction in the CSR credits. Instead, the Commission should require KU to leave the credits unchanged. KU has provided no compelling evidence to justify arbitrarily reducing (by nearly half) CSR credits that were set just two years ago. KU's proposed CSR reductions contribute to unreasonably high rate increases for CSR customers, reduce the competitiveness of CSR manufacturers in Kentucky, and dramatically decrease the

[9] *See* KU's response to KIUC 1-56(c)-(e) in Exhibit DWG-2.

attractiveness of interruptible service. KU's CSR credits should not be changed.

3. Approve KU's proposed change in the designated gas price used in pricing buy-through energy purchased during economic curtailments under Rider CSR. The proposed change addresses market issues that could artificially depress the price of buy-through energy. Switching to the Henry Hub daily spot price is a reasonable way to address the problem.
4. Establish a post-rate case process in which stakeholders can work together to resolve recurring CSR-related issues. In my opinion, a collaborative approach to address and resolve CSR issues would be more reasonable and productive compared to the unilateral approach KU usually takes in rate cases. I recommend that the Commission establish a post-rate case process led by the Commission Staff and open to interested stakeholders in which the parties can identify, address, and try to reach consensus on ways to improve industrial interruptible rate options that will benefit firm as well as interruptible customers. The Commission should require a stakeholder report detailing the group's conclusions and recommendations regarding potential changes and improvements in KU's industrial interruptible rate options, including Rider CSR. This report could then be used as the framework for addressing CSR and other interruptible issues in KU's next base rate case.

BACKGROUND: INTERRUPTIBLE SERVICE

Q. HOW DOES INTERRUPTIBLE SERVICE DIFFER FROM FIRM SERVICE?

A. Interruptible service and firm service are separate utility products, with availability of the interruptible product dependent on the demand for the firm product being less than available supply. On a daily basis, utilities serve interruptible loads using available generating resources that are not required to serve firm load. That is, the available supply of interruptible service depends on the relationship between available power supply resources and firm service demands at a point in time. From a long-term planning perspective, utilities are able to avoid building or acquiring new supply resources to serve interruptible load.[10]

Unlike customers buying firm service, interruptible customers agree to interrupt or curtail all or part of their loads under terms specified in applicable interruptible rates and/or contracts with their supplier. Service interruptions are normally required when reliability to firm service customers is threatened—for example, when firm demand exceeds available electric supply. At other times, when available generating resources are not required to serve firm load, service interruptions are unnecessary since the supplier has excess capacity available to serve firm load.[11] The price for interruptible service is less than firm service because it is a different, lower quality product. In addition, interruptible customers typically face significant financial penalties if they do not interrupt load when required.[12]

Q. DO FIRM CUSTOMERS AS WELL AS THE UTILITY SUPPLIER BENEFIT FROM INTERRUPTIBLE LOAD?

A. Yes. In general, interruptible load enables a supplier to maximize the value of existing capacity resources and to avoid acquiring new capacity resources. Utilities can also use interruptible load, if permitted, for high-value off-system sales or to mitigate high incremental fuel costs paid by

[10] In some wholesale markets, interruptible load is treated as a supply-side resource that can be bid into capacity resource auctions.

[11] Some interruptible rates and service agreements (including Rider CSR) permit curtailments for economic reasons even when capacity is available.

[12] In Rider CSR, the penalty for failing to comply with a curtailment request (Noncompliance Charge) is $16 per kVA of noncompliant load.

firm customers. Interruptible load creates environmental benefits by helping suppliers avoid the impacts of constructing and operating fossil generation, expands the range of resources available to meet contingencies, and can substitute, in certain cases, for spinning and operating reserves. Interruptible load can even be used to mitigate wholesale price volatility and curb potential market power problems. In addition, the availability of cost-based interruptible service options helps states promote economic development and the retention of manufacturing jobs.

Q. IS THERE A RECOGNIZED APPROACH FOR EVALUATING THE CAPACITY VALUE OF INTERRUPTIBLE LOAD?

A. Yes. The long-term avoided cost of peaking generation capacity--for example, the cost of a new combustion turbine (CT) -capacity)--is often the starting point. In addition to the marginal or avoided cost of CT capacity, measures of the economic value of interruptible load should reflect the cost of reserve capacity that would have been required if the interruptible load was firm, as well as the cost of transmission losses. That is, an interruptible capacity credit should reflect the utility's avoided cost of reserve capacity and losses.

Q. HOW DOES KU TREAT INTERRUPTIBLE CSR LOAD IN ITS CAPACITY PLANNING?

A. KU treats interruptible load as a capacity resource in its long-range capacity plans.[13] Simply stated, KU does not plan to build or acquire capacity to serve interruptible load.

[13] *See* KU's response to KIUC 1-56(a)-(b) in Exhibit DWG-2.

Q. WHY DO CUSTOMERS, PARTICULARLY LARGE MANUFACTURERS, BUY INTERRUPTIBLE INSTEAD OF FIRM SERVICE?

A. Manufacturers with flexible, electricity-intensive production processes often find it economically essential to use nonfirm electric service to control production costs and maintain or improve their competitive position in national and global markets. These manufacturers do not require firm service to make their products. Instead, they need reasonable and fairly priced interruptible rate options that provide mutual benefits to them, their supplier, and firm customers.

Q. IS THERE A FUNDAMENTAL PRINCIPLE UNDERLYING HOW INTERRUPTIBLE SERVICE SHOULD BE PRICED?

A. Yes. As I noted earlier, interruptible load does not drive a utility's need for capacity. A utility neither builds nor acquires capacity to serve interruptible load. As a result, the price of interruptible service should exclude fixed costs (both generation and bulk transmission) incurred to serve firm load. For utilities with rates reflecting their marginal cost of capacity (for example, the avoided cost of peaking capacity), applying this principle is fairly straightforward—interruptible service should be priced at or close to the utility's short-run marginal cost. However, most utilities (including LG&E and KU) have rates that reflect their embedded cost of capacity. For these utilities, interruptible service is typically priced at a discount to firm service prices using credits or discounts that reflect avoided cost savings and reduced costs of service. To the extent possible, the discount should reflect the utility's long-run avoided cost of peaking generation (CT) capacity, including the utility's avoided cost of reserve capacity and losses.

Q. WHY SHOULD CSR CREDITS BE BASED ON LONG-RUN AVOIDED COSTS INSTEAD OF THE EMBEDDED COST OF CT CAPACITY OR SHORT-TERM CAPACITY PRICES IN WHOLESALE MARKETS?

A. The embedded cost of CT capacity has no relationship to KU's cost of providing nonfirm service. Short-run market prices fluctuate to reflect current market conditions for existing generating capacity, while long-run avoided costs reflect the cost of adding new capacity to meet demand growth. Long-run—not short-run—capacity costs more accurately reflect avoided cost savings attributable to interruptible service. Neither embedded costs nor short-run prices are reasonable measures of KU's cost of capacity to serve future peak demands. Interruptible credits that reflect the long-run avoided cost of adding capacity—not a short-term value that reflects current capacity surpluses or shortages—should be the basis for setting CSR credits.

Setting administratively determined curtailable credits to reflect embedded CT costs or short-run market conditions is a short-sighted and improper approach that ignores the long-term contractual and/or operational commitment that interruptible customers make in choosing nonfirm service. Moreover, a short-run focus in setting interruptible credits is akin to asking a utility to base its test-year revenue requirement to reflect current market conditions instead of costs incurred to make long-lived investments in generation, transmission, and distribution plant and equipment. A utility might like that option when capacity is constrained and prices are high, but would abhor it when market conditions drive capacity prices down temporarily.

Q. SHOULD INTERRUPTIBLE RATES RECOVER ANY FIXED PRODUCTION COSTS?

A. No, although most interruptible rates include at least some recovery of demand-related fixed production costs. My conclusion is supported by Professor James C. Bonbright, a recognized pricing authority, who advocated pricing interruptible service to reflect no capacity-related cost of service:

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer-connected spur lines and substations) and energy costs (e.g., fuel and incremental maintenance cost) actually incurred and ***no capacity pricing cost should be included in pricing interruptible service***.
>
> While some feel that it is an impropriety to treat interruptible customers as if they were firm customers, they still opine that it would be fair and reasonable to obtain a small contribution from them for capacity costs. This is debatable.[14]

Q. WOULD EXCLUDING DEMAND-RELATED PRODUCTION COSTS FROM INTERRUPTIBLE PRICES RESULT IN INTERRUPTIBLE CUSTOMERS BECOMING FREE RIDERS?

A. No. Under an efficient pricing scheme, customers should only pay for costs attributable to their demands. Since a utility is not required to build or acquire generating capacity to serve interruptible load, only firm service customers should pay for the demand-related costs of this capacity. If interruptible rates recover part of the fixed costs of capacity built to serve only firm loads, then interruptible customers cannot be free riders.

[14] James C. Bonbright, *et al.*, *Principles of Public Utility Rates*, (Arlington, Virginia: Public Utilities Reports, Inc., 1988), at 502 (emphasis added).

Q. SHOULD CSR CREDITS BE SET WELL BELOW LONG-RUN AVOIDED CT COSTS SINCE A CT MAY OPERATE MORE HOURS THAN ARE AVAILABLE FOR CURTAILMENT UNDER RIDER CSR?

A. No. This argument for low CSR credits confuses the nonfirm CSR product that KU sells with the CT generating capacity that it builds or buys. They are not the same. If KU avoids building or buying capacity because it serves interruptible load, then the standalone price for this nonfirm service should reflect only variable operating costs and exclude all production capacity charges. KU has chosen not to price CSR interruptible service this way. Instead, KU links the nonfirm CSR price to an otherwise applicable firm service rate using a credit against the demand charge(s) in the firm rate. The appropriate CSR credit in this case is one that approaches the annualized cost of peaking (CT) capacity, adjusted upward for reserves and losses.

KU'S RIDER CSR

Q. WHAT ARE SOME KEY DESIGN ELEMENTS IN KU'S CURRENT RIDER CSR?

A. Nine KU customers are served under the current CSR Rider, which includes a 60-minutes curtailment notice, 375 hours of allowed curtailments—of which 100 hours may be physical curtailments and 275 hours may be economic curtailments, and credits of $6.50 per kVA (primary) and $6.40 per kVA (transmission). (See Table 1 below.)

Table 1. KU/ LG&E: Current Rider CSR

Notice (minutes)	60
Curtailment Hours	
Physical	100
Economis	275
Total	375
Credit ($/kVA-mo)	
Primary	$6.50
Transmission	$6.40
Customers	
KU	9
LG&E	3
Total	12

The rider also includes a penalty of $16 per kVA for failing to comply with a physical curtailment notice.

Q. ARE KU'S CURRENT CSR CREDITS IN LINE WITH INTERRUPTIBLE CREDITS OFFERED BY SOME NEARBY UTILITIES?

A. Yes. For example, I reviewed retail interruptible rate credits offered by several utilities with service areas reasonably close to LG&E and KU.[15] The monthly credits in their interruptible rate options range from $3.68 per kW to $8.61 per kW—a range that includes KU's current CSR credits.

Q. HAS KU PROPOSED ANY SIGNIFICANT CHANGES FOR RIDER CSR?

A. Yes. As I noted, KU has recommended:

- Closing Rider CSR to new load.
- Switching to an approach for setting CSR credits based on the embedded cost of selected CT generating units.
- Reducing the CSR credits by about half.

[15] These companies include Kentucky Power, East Kentucky Power Cooperative, AEP Ohio, and the First Energy-Ohio companies. Interruptible options for Kentucky Power and AEP Ohio include only physical interruptions for system emergencies (no economic interruptions).

- Changing the designated gas price index used to price economic curtailment buy-through energy.

While each of these proposed changes is important, my testimony focuses on the changes related to CSR credits and the gas price index.

Q. DID KU CONSULT CURRENT CURTAILABLE CUSTOMERS BEFORE DECIDING ON ITS PROPOSED CHANGES TO RIDER CSR?

A. No. Moreover, it appears that KU did not assess the potential bill impacts of its proposals.[16] KU's failure to conduct even a cursory examination of customers impacts of its CSR proposals is disturbing.

Q. WHAT TYPE OF COSTING METHOD HAS KU TRADITIONALLY USED IN DEVELOPING CSR CREDITS?

A. KU has traditionally used an avoided cost approach based on the marginal cost of combustion turbine capacity.[17] As I noted earlier, the avoided cost approach is widely used in evaluating resource options, including demand response (DR) options such as Rider CSR. Moreover, most utilities with which I am familiar—including LG&E and KU—use the avoided cost method to evaluate both DR and energy efficiency resource options considered in their IRPs. In other words, using avoided cost as the basis for evaluating resource options is widely recognized and accepted by regulators, utilities, and stakeholders.

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[16] *See* KU's responses to KIUC 1-49 through 1-51 and 2-25 in Exhibit DWG-2.
[17] *See* the direct testimony of William Steven Seelye (Seelye Direct) at 51:9-14.

Q. IS THE EMBEDDED COST APPROACH KU HAS PROPOSED IN THIS CASE SIGNIFICANTLY DIFFERENT FROM THE AVOIDED COST APPROACH IT HAS TRADITIONALLY USED?

A. Yes. The two approaches are fundamentally different in concept, and produce dramatically different results. While the avoided cost approach looks at the expected cost of new CT capacity that can be avoided using CSR load, KU's embedded cost method looks at the embedded cost of a select group of CTs jointly owned by LG&E and KU.[18] KU's embedded CT cost approach produced estimated unit costs of the selected CT capacity of $3.20 per kVA-month (transmission) and $3.31 per kVA-month (primary).[19] KU set its proposed CSR credits equal to these estimated CT unit costs. In contrast, the joint LG&E/KU avoided cost from their most recent DSM (Case No. 2014-00003) and IRP (Case No. 2014-00131) filings was $99.92 per kW-year, or about $8.33 per kW-month.[20] This estimate is a reasonable benchmark for evaluating the reasonableness of KU's CSR credits. As can be seen from these embedded and avoided cost estimates, KU's proposed CSR credits are less than half the avoided cost used in its IRP and DSM cases.

Q. WHAT IS THE CLAIMED BASIS FOR KU'S SWITCH TO THE EMBEDDED CT COST METHOD?

A. According to KU witness David S. Sinclair:

> …[T]he circumstances when the Companies are allowed to call a physical CSR curtailment will likely be at peak times when the primary CTs would be expected to operate. Thus, the CSR customer would not be getting to utilize energy from the primary CTs during peak events, so it is reasonable to base the

[18] *See* Seelye Direct at 51-53 and Exhibit WSS-3.
[19] *See* Seelye Direct at Exhibit WSS-3.
[20] *See* KU's response to Attorney General 1-76 in Exhibit DWG-2.

> credit on the cost of the capacity CSR customers are agreeing not to use.[21]

Q. DO YOU AGREE WITH KU?

A. No. KU's rationale simply states the obvious—curtailments are most likely under peak load conditions. But electrons are not color-coded by type of generation. A CSR customer that is curtailed cannot know and does not care whether its unserved energy during the curtailment was produced by a CT, a combined cycle gas unit, or a baseload coal unit. KU's rationale actually supports using a slice of KU's total embedded generating capacity costs, not simply the embedded cost of primary CTs, to set CSR credits.

Q. WOULD APPLYING KU'S RATIONALE TO FIRM ENERGY PRODUCTS SOLD TO NON-CSR CUSTOMERS PRODUCE PERVERSE RESULTS?

A. Yes. For example, the rationale KU used to justify switching to the embedded CT cost method also implies that rates for off-peak users should primarily reflect demand-related baseload capacity costs since expensive baseload capacity is typically used to serve off-peak loads. Such an outcome runs counter to basic economic pricing principles that suggest assigning no (or at least minimal) capacity cost responsibility to off-peak sales. Off-peak rates (even those based on embedded costs) are set below peak rates for a simple reason—off-peak demands do not drive a utility's need for capacity and should bear little if any of demand-related cost responsibility.

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[21] *See* the direct testimony of David S. Sinclair (Sinclair Direct) at 26:10-15.

Q. DOES KU'S EMBEDDED CT COST ANALYSIS YIELD RESULTS CONSISTENT WITH AN EMBEDDED COST APPROACH BASED ON ITS BIP COST ALLOCATION METHOD?

A. No. I used KU's BIP cost allocation method and an analytical approach similar to that presented in Witness Seelye's Exhibit WSS-3 to develop voltage-differentiated unit costs for the peak capacity category of demand-related production costs for LG&E, KU, and the joint LG&E/KU system. As shown in Exhibit DWG-3, the voltage-differentiated BIP peak capacity unit costs for the joint LG&E/KU system exceed $9.00 per kVA-month—around 2.75 times KU's selected CT unit costs. I am not endorsing a BIP peak capacity cost approach for setting CSR credits. The results shown in Exhibit DWG-3 simply demonstrate the unit costs derived in KU's CT cost analysis are far below the results derived using the BIP method.

Q. DID KU PROPOSE USING ITS EMBEDDED CT APPROACH IN ITS IRP AND DSM ANALYSES?

A. No. Such an approach would significantly reduce the estimated benefits of DSM programs, and also contradict accepted practices for evaluating these resource options. Instead, KU has chosen to single out CSR customers, and significantly understate the value of their interruptible load by using an untested and unaccepted embedded CT cost method. In my opinion, KU's singular focus on CSR load (while ignoring other demand response program options) is discriminatory and unjust. If KU's embedded CT approach is appropriate for evaluating CSR load, it is also appropriate for evaluating KU's other load management programs.

Q. ARE KU'S PROPOSED CSR CREDIT REDUCTIONS SIGNIFICANT?

A. Yes. As shown in Table 2 below, KU has proposed around a 50-percent reduction in its CSR credits.

Table 2. KU: Present and Proposed CSR Credits

	Credit ($/kVA-mo)		
Voltage	**Pres**	**Prop**	**Chng**
Primary	6.50	3.31	-49%
Transmission	6.40	3.20	-50%

Q. DO THE PROPOSED CSR CREDIT REDUCTIONS HAVE A MAJOR IMPACT ON ELECTRICITY COSTS FOR CSR CUSTOMERS?

A. Yes. I have not conducted—and neither has KU—a bill impact assessment for all CSR customers. However, I did look at potential bill impacts on KIUC's CSR customers. This analysis indicates that the CSR credit reductions—combined with KU's proposed increases in firm rates—result in total bill increases up to 3.5 times KU's proposed 6.5 percent system average increase. I would expect similar results for any CSR customer whose nonfirm CSR load is large relative to its total load.

Q. ARE SUCH LARGE RATE INCREASES REASONABLE?

A. No—particularly when they are premised on KU's arcane embedded CT cost method. Moreover, KU's failure to consider the impacts of its CSR bill increases implies a callous disregard for the potential harmful effects of its proposals on business development and job retention in Kentucky. As I noted earlier, low-cost nonfirm service is often critical in helping electricity-intensive manufacturers be competitive in product markets.

Q. HOW DID KU JUSTIFY ITS PROPOSED CSR CREDIT REDUCTIONS?

A. KU witness Seelye stated:

> …KU has no need for additional generation capacity for the next decade or so. The Companies have not issued any curtailments under Rider CSR since January 2015. Because the current generation mix was planned to take into account CSR capacity and its use in avoiding combustion turbine capacity, the Companies believe that it is appropriate to provide *current* CSR customers a credit based on the actual fixed cost of the most recent combustion turbines that were installed by the Companies.[22]

Q. IS IT SURPRISING THAT KU HAS NO NEED FOR CAPACITY "FOR THE NEXT DECADE OR SO?"

A. No. It is not surprising given KU's recent 4-year (May 2015 – April 2019), 165-MW capacity purchase and tolling arrangement with Bluegrass Generation,[23] as well as the April 2014 announcement that effective May 2019, municipal customers with 325 MW of wholesale load currently served by KU would leave the LG&E/KU system. However, KU's current capacity situation does not justify forcing CSR customers to suffer financially simply because LG&E and KU filled a 4-year capacity need with the Bluegrass purchase, and also still have to face the financial consequences of losing 325 MW of wholesale load in May 2019.

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[22] *See* Seelye Direct at 54:20 – 55:4.

[23] *See* the joint response of LG&E/KU to Commission Staff 1-2 in Case No. 2014-00321. This response indicates that the capacity charge plus fixed O&M cost for the Bluegrass purchase in 2017-2018 is around $4..90 per kW-month, or about 1.5 times the proposed CSR credits.

Q. WHEN THE COMMISSION ISSUED ITS JUNE 2015 ORDER APPROVING THE CURRENT CSR CREDITS IN KU'S LAST RATE CASE, WAS INFORMATION AVAILABLE ABOUT THE 4-YEAR BLUEGRASS PURCHASE, KU'S LONG-TERM CAPACITY NEEDS, AND THE PENDING LOSS OF MUNICIPAL LOAD?

A. Yes. By June 2015 when the Commission issued its order approving rates in Case No. 2014-00370 (which included approval of KU's current CSR credits), KU knew or should have known about each of these items. The Bluegrass purchase had already begun. KU's 2014 IRP indicated no long-term need for capacity until at least after 2020. And the pending loss of municipal load in 2019 had been announced in 2014. In the current case, the Bluegrass tolling arrangement continues, KU says it has no need for additional capacity in the near-term, and the municipal load is still leaving in 2019. Yet, in this case, KU has proposed slashing CSR credits that were set less than 2 years ago based on essentially the same market conditions that existed in 2015.

Q. DID KU PROPOSE CHANGING THE GAS PRICE INDEX USED TO PRICE BUY-THROUGH ENERGY DURING ECONOMIC CURTAILMENTS?

A. Yes. As I noted earlier, KU proposed changing the designated gas price in the Automatic Buy-Through Price formula from the Dominion South Point index to the Henry Hub spot price. Market imbalances at Dominion South Point have created artificially depressed and fluctuating gas prices that could make the cost of buy-through energy less than KU's cost of operating its natural gas generation. This result would be inconsistent with the intent of the buy-through formula. Using Henry Hub spot prices is less likely to cause this problem.

Q. DO YOU AGREE WITH KU'S PROPOSED CHANGE?

A. Yes. KU's proposal is a reasonable solution to this pricing problem.

Q. HAS KU RAISED CONCERNS ABOUT ELEMENTS OF RIDER CSR THAT IT IS NOT PROPOSING TO CHANGE IN THIS CASE?

A. Yes. KU has raised several concerns in testimony and responses to data requests related to the use and value of CSR load. These concerns include:

- Limitations on physical interruptions. Under terms of Rider CSR, KU can only call a physical interruption after all generating units have been dispatched and all off-system sales curtailed.[24]
- Curtailment notice. Although KU did not criticize the 60-minutes advance notice requirement, it pointed out how the notice requirement limited its ability to use CSR load as operating reserve capacity. According to KU, capacity resources must be available for service within 15 minutes to qualify as operating reserve capacity. The 60-minutes curtailment notice requirement in Rider CSR precludes CSR load as operating reserve.
- Limited hours of physical interruptions. Rider CSR limits physical interruptions to 100 hours annually.

Q. DOES ANY OTHER NON-CSR INDUSTRIAL RATE ALLOW KU TO EXERCISE CURTAILMENTS WITH SHORT NOTICE?

A. Yes. Under Rate FLS (which is available to customers with at least 20 MVA of load), KU can *electronically* interrupt up to 95 percent of the customer's load with 5-minutes notice for up to 10 minutes per interruption and 20 interruptions per month. More specifically, Rate FLS says in part:

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[24] *See* KU responses to KIUC 1-62 and 1-63 in Exhibit DWG-2.

> Company reserves the right to interrupt up to 95% of Customer's load to ***facilitate Company compliance with system contingencies and with industry performance criteria***. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours if any, under the CURTAILABLE SERVICE RIDER CSR. ***Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates*** of LG&E and KU Energy LLC System ("LKE System") owned or purchased generation ***or when Automatic Reserve Sharing is invoked***. LKE System, as used herein, shall consist of LG&E and KU… (Emphasis added).

Q. DOES KU CONSIDER FLS LOAD AS OPERATING RESERVE CAPACITY GIVEN ITS ABILITY TO CURTAIL ANY FLS CUSTOMER WITH 5-MINUTES NOTICE?

A. No.[25] However, it is clear that the rate's short curtailment notice provision and utility-controlled curtailments make FLS load a valuable capacity resource for meeting system contingencies, industry performance criteria, unplanned outages and de-rates, and critical system events requiring automatic reserve sharing.

Q. DOES KU CURRENTLY SERVE ANY FLS CUSTOMERS?

A. Yes. One of KU's largest industrial loads and a KIUC member is currently served under Rate FLS. In the past two years, KU has ***physically curtailed*** that customer's FLS load on numerous occasions under the 5-minutes interruption notice provision of Rate FLS—43 times in 2015 and 26 times in 2016.

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[25] *See* KU's response to KIUC 2.26(b) in Exhibit DWG-2.

Q. DO YOU RECOMMEND ANY SPECIFIC CHANGES TO RIDER CSR OTHER THAN THOSE INCLUDED IN KU'S PROPOSALS?

A. No. The concerns that KU raised are a rate design problem that can be solved without gutting the CSR program or imposing unilateral changes without customer input. KIUC's members with CSR and FLS load would welcome the opportunity to work with KU (and LG&E) in evaluating options to improve interruptible rate options for large industrial customers. In my opinion, the most efficient and productive way to address issues related to Rider CSR (as well as Rate FLS) would be a Commission-ordered, post-rate-case collaborative of stakeholders.

Q. HOW WOULD THIS POST-RATE-CASE COLLABORATIVE WORK?

A. The collaborative, led by the Commission Staff, would allow interested stakeholders to identify, address, and try to reach consensus on ways to improve industrial interruptible programs for the benefit of all customers—both firm and nonfirm. For example, one issue that could be addressed is whether KU should once again offer an interruptible service product with a 10-minutes curtailment notice provision. The Commission should require a stakeholder report detailing the group's conclusions and recommendations regarding potential changes and improvements. This report would provide the Commission with valuable information that would help frame CSR issues in KU's next base rate case.

Q. SHOULD THE COLLABORATIVE INCLUDE RATE FLS IN ADDRESSING WAYS TO IMPROVE KU'S INTERRUPTIBLE SERVICE OPTIONS?

A. Yes. Any examination of issues regarding large nonfirm industrial loads served under Rider CSR—particularly an examination looking at ways to improve the rider—should also include an examination of Rate FLS. Both CSR and FLS loads provide valuable capacity and reliability benefits for KU and its firm customers. Ways to improve these interruptible rate options should be examined jointly.

Q. SHOULD THE CSR CREDITS BE REDUCED AS KU RECOMMENDS?

A. No. In my opinion, KU's proposed CSR credit reductions are unjustified, unreasonable, and discriminatory. Moreover, adopting KU's CSR credits will make CSR customers less competitive and make Kentucky a less attractive business environment. I recommend leaving the current CSR credits unchanged.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

Commonwealth of Virginia)
County of Fairfax) SS

Before me this day appeared DENNIS W. GOINS of Potomac Management Group, who stated under oath that the foregoing testimony was prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said testimony; and that such matters are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to me this 27th day of February 2017.

Dennis W. Goins

Notary Public

REYNA MARIBEL VANEGAS
Notary Public
Commonwealth of Virginia
320413
My Commission Expires Jan 31, 2018

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

CASE NO. 2016-00370

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

EXHIBITS TO THE
DIRECT TESTIMONY OF
DENNIS W. GOINS, PH.D.
ON BEHALF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

March 3, 2017

EXHIBIT DWG-1

QUALIFICATIONS OF DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, VA

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC
- Principal, Resource Consulting Group, Inc., Cambridge, MA
- Senior Associate, Resource Planning Associates, Inc., Cambridge, MA
- Economist, North Carolina Utilities Commission, Raleigh, NC

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in developing product pricing strategies, setting rates for energy-related products and services, negotiating power supply and natural gas contracts for private and public entities, evaluating competitive market conditions, and analyzing power and fuel requirements, prices, market operations, and transactions. He has participated in more than 200 cases as an expert on cost of service, rate design, competitive market issues, utility restructuring, power market planning and operations, utility mergers, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office (now the Government Accountability Office), the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, the Linn County District Court of Iowa, and regulatory commissions in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Wyoming, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding electricity pricing and contract issues in a case before the United States Court of Federal Claims.

DENNIS W. GOINS

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1139 (2016), on behalf of the General Services Administration, re cost of service and retail rate design.
2. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 532 (2016), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
3. Washington Gas Light Company, before the District of Columbia Public Service Commission, Formal Case No. 1137 (2016), on behalf of the General Services Administration, re cost of service and retail rate design.
4. Baltimore Gas and Electric Company, before the Maryland Public Service Commission, Case No. 9406 (2016), on behalf of the Department of Defense and all other Federal Executive Agencies, re Baltimore City conduit tax and retail rate design.
5. PECO Energy Company, before the Pennsylvania Public Utility Commission, Docket No. R-2015-2468981 (2015), on behalf of the General Services Administration, re retail distribution standby electric service.
6. Consolidated Edison of New York, Inc., before the New York Public Service Commission, Case No. 15-E-0050 (2015), on behalf of the General Services Administration, re retail delivery service cost recovery.
7. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER15-623-000 (2015), on behalf of the Department of Defense/Federal Executive Agencies, re RPM market design and capacity performance resources.
8. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 14-1297-EL-SSO, (2014), on behalf of Nucor Steel Marion, Inc., re standard service offer and demand response.
9. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1121 (2014), on behalf of the General Services Administration, re infrastructure cost allocation and surcharge design.
10. Consolidated Edison of New York, Inc., *et al*., before the New York Public Service Commission, Case No. 14-M-0101 (2014), on behalf of the General Services Administration, re *Reforming the Energy Vision* issues.
11. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1116 (2014), on behalf of the General Services Administration, re infrastructure cost allocation and surcharge design.
12. Potomac Electric Power Company *et al.*, before the Maryland Public Service Commission, Case No. 9361 (2014), on behalf of the General Services Administration, re Exelon-PHI merger issues.

13. Potomac Electric Power Company *et al*., before the District of Columbia Public Service Commission, Formal Case No. 1119 (2014), on behalf of the General Services Administration, re Exelon-PHI merger issues.
14. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1114 *et al*. (2014), on behalf of the General Services Administration, re retail dynamic pricing.
15. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 41791 (2013), on behalf of Texas Cities, re cost of service and retail rate design.
16. Entergy Gulf States Louisiana, before the Louisiana Public Service Commission, Docket No. U-32707 (2013), on behalf of the Department of Energy, re retail cost recovery.
17. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 40979 (2013), on behalf of Texas Cities, re analysis of JSP PPA termination.
18. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1103 (2013), on behalf of the General Services Administration, re retail delivery service cost recovery.
19. Consolidated Edison of New York, Inc., before the New York Public Service Commission, Case No. 13-E-0030 (2013), on behalf of the General Services Administration, re retail delivery service cost recovery.
20. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 11-5201-EL-RDR *et al*., (2013), on behalf of the Ohio Energy Group and Nucor Steel Marion, Inc., re alternative energy rider.
21. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9311 (2013), on behalf of the General Services Administration, re retail cost recovery.
22. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 12-2190-EL-POR *et al*., (2012), on behalf of the Ohio Energy Group and Nucor Steel Marion, Inc., re energy efficiency and peak demand reduction portfolios.
23. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 485 (2012), on behalf of Nucor Steel-Hertford, re fuel rate adjustment.
24. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2012-00221 (2012), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
25. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2012-00222 (2012), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.

26. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 479 (2012), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
27. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2012-0174 (2012), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
28. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9286 (2012), on behalf of the General Services Administration, re retail cost recovery.
29. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 44075 (2012), on behalf of Steel Dynamics, Inc., re retail cost-of-service and fuel and purchased power cost recovery.
30. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 39896 (2012), on behalf of Texas Cities, re cost of service and retail rate design.
31. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1087 (2012), on behalf of the General Services Administration, re retail cost recovery.
32. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 474 (2011), on behalf of Nucor Steel-Hertford, re fuel rate adjustments.
33. Mid-Kansas Electric Company, before the Kansas Corporation Commission, Docket No. 11-GIME-597-GIE (2011), on behalf of Kansas Electric Power Cooperative, Inc., re local delivery service and operating agreements.
34. Duke Energy Corporation *et al*., before the Federal Energy Regulatory Commission, Docket No. EC11-60-000 (2011), on behalf of the North Carolina Electric Membership Corporation, re merger-related market power issues.
35. Resale Power Group of Iowa *et al*., before the Linn County District Court of Iowa, Case No. LACV 054271 (2011), on behalf of Central Iowa Power Cooperative, re compensation for unauthorized transmission access.
36. Columbus Southern Power Company *et al*., before the Public Utilities Commission of Ohio, Case No. 11-346-EL-SSO *et al*., (2011), on behalf of the OMA Energy Group., re standard service offer electric security plan rate design issues.
37. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 11-0274-E-GI (2011), on behalf of Steel of West Virginia, Inc., re expanded net energy cost rate issues.

38. Rocky Mountain Power Company, before the Wyoming Public Service Commission, Docket No. 20000-384-ER-10 (2011), on behalf of Cimarex Energy Company, QEP Field Services Company, and Kinder Morgan Interstate Gas Transmission, re utility rates, cost-of-service, and resource acquisition issues.
39. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43955 (2011), on behalf of Nucor Steel and Steel Dynamics, Inc., re utility-sponsored energy efficiency programs.
40. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2010-0355 (2010), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
41. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 10-0699-E-42T (2010), on behalf of Steel of West Virginia, Inc., re cost-of-service and rate design issues.
42. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 10-010-U (2010), on behalf of Arkansas Electric Energy Consumers, Inc., re industrial opt out of utility-sponsored energy efficiency programs.
43. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 62-S1 (2010), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
44. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 459 (2010), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
45. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 461 (2010), on behalf of Nucor Steel-Hertford, re fuel rate adjustments.
46. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 37744 (2010), on behalf of Texas Cities, re cost of service and retail rate design.
47. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2009-00548 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
48. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2009-00549 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
49. Ohio Edison *et al.*, before the Public Utilities Commission of Ohio, Case No. 09-1948-EL-POR *et al.*, (2010), on behalf of Nucor Steel Marion, Inc., re energy efficiency and peak demand reduction portfolios.

50. Kauai Island Utility Cooperative, before the Hawaii Public Utilities Commission, Docket No. 2009-0050 (2010), on behalf of Kauai Marriott Resort & Beach Club, re retail cost allocation and rate design issues.
51. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 09-024-U (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re power plant environmental retrofit.
52. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00030 (2009), on behalf of Steel Dynamics, Inc., re retail cost allocation and rate design issues.
53. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 09-906-EL-SSO (2009), on behalf of Nucor Steel Marion, Inc., re market rate offer.
54. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 456 (2009), on behalf of Nucor Steel-Hertford, re fuel cost adjustment.
55. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00068 (2009), on behalf of Steel Dynamics, Inc., re demand response programs.
56. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 43750 (2009), on behalf of Steel Dynamics, Inc., re wind power purchased power agreement.
57. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 07-085-TF (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re energy efficiency cost recovery.
58. CenterPoint Energy Arkansas Gas, before the Arkansas Public Service Commission, Docket No. 07-081-TF (2009), on behalf of Arkansas Gas Consumers, Inc., re energy efficiency cost recovery.
59. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2009-261-E (2009), on behalf of CMC Steel-SC, re DSM cost recovery surcharge.
60. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 38707 FAC81 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
61. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1076 (2009), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
62. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00039 (2009), on behalf of Steel Dynamics, Inc., re environmental and reliability cost recovery.

63. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 63 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
64. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-302-00038 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
65. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-302-E (2008), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
66. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-196-E (2008), on behalf of CMC Steel-SC, re base load review order for a nuclear facility.
67. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO *et al*. (2008), on behalf of Nucor Steel Marion, Inc., re standard service offer via an electric security plan.
68. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 08-936-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re market rate offer via a competitive bidding process.
69. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2008), on behalf of CMC Steel Alabama, Nucor Steel Birmingham, Inc., and Nucor Steel Tuscaloosa, Inc., re energy cost recovery.
70. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 35269 (2008), on behalf of Texas Cities, re jurisdictional allocation of system agreement payments.
71. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43374 (2008), on behalf of Nucor Steel and Steel Dynamics, Inc., re alternative regulatory plan.
72. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 34800 (2008), on behalf of Texas Cities, re affiliate transactions.
73. Commonwealth Edison Company, before the Illinois Commerce Commission, Docket No. 07-0566 (2008), on behalf of Nucor Steel Kankakee, Inc., re cost-of-service and rate design issues.
74. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 07-0551-EL-AIR *et al*. (2008), on behalf of Nucor Steel Marion, Inc., re cost-of-service and rate design issues.
75. Appalachian Power Company dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 06-0033-E-CN (2007), on behalf of Steel of West Virginia, Inc., re power plant cost recovery mechanism.

76. Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership, before the Public Utilities Commission of Texas, PUC Docket No. 34077 (2007), on behalf of Nucor Steel - Texas, re acquisition of TXU Corp. by Texas Energy Future Holdings Limited Partnership.
77. Arkansas Oklahoma Gas Company, before the Arkansas Public Service Commission, Docket No. 07-026-U (2007), on behalf of West Central Arkansas Gas Consumers, re gas cost-of-service and rate design issues.
78. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-07-08 (2007), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
79. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1056 (2007), on behalf of the General Services Administration, re demand-side management and advanced metering programs.
80. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2007-229-E (2007), on behalf of CMC Steel-SC, re cost-of-service and rate design issues.
81. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9092 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
82. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1053 (2007), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
83. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32907 (2006), on behalf of Texas Cities, re hurricane cost recovery.
84. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 32710/ SOAH Docket No. 473-06-2307 (2006), on behalf of Texas Cities, re reconciliation of fuel and purchased power costs.
85. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 060001-EI (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and purchased power cost recovery.
86. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-05-0816 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
87. PacifiCorp (dba Rocky Mountain Power), before the Utah Public Service Commission, Docket No. 06-035-21 (2006), on behalf of the U.S. Air Force (Federal Executive Agencies), re rate design issues.

88. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2006-2-E (2006), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.
89. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31544/ SOAH Docket No. 473-06-0092 (2006), on behalf of Texas Cities, re transition to competition rider.
90. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-05-28 (2006), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
91. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2005), on behalf of SMI Steel-Alabama, re energy cost recovery.
92. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050001-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re fuel and capacity cost recovery.
93. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 31315/ SOAH Docket No. 473-05-8446 (2005), on behalf of Texas Cities, re incremental purchased capacity cost rider.
94. Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 050045-EI (2005), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
95. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 05-042-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re power plant purchase.
96. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 04-141-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re cost-of-service and rate design issues.
97. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 412 (2005), on behalf of Nucor Steel-Hertford, re cost-of-service and interruptible rate issues.
98. Public Service Company of Colorado, before the Colorado Public Utilities Commission, Docket No. 04S-164E (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re cost-of-service and interruptible rate issues.
99. CenterPoint Energy Houston Electric, LLC, *et al.*, before the Public Utility Commission of Texas, PUC Docket No. 29526 (2004), on behalf of the Coalition of Commercial Ratepayers, re stranded cost true-up balances.
100. PacifiCorp, before the Utah Public Service Commission, Docket No. 04-035-11 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re time-of-day rate design issues.

101. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-03-0347 (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
102. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-03-13 (2004), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re retail cost allocation and rate design issues.
103. PacifiCorp, before the Utah Public Service Commission, Docket No. 03-2035-02 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re retail cost allocation and rate design issues.
104. Dominion Virginia Power, before the Virginia State Corporation Commission, Case No. PUE-2000-00285 (2003), on behalf of Chaparral (Virginia) Inc., re recovery of fuel costs.
105. Jersey Central Power & Light Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02080506, OAL Docket No. PUC-7894-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.
106. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02050303, OAL Docket No. PUC-5744-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.
107. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2002-223-E (2002), on behalf of SMI Steel-SC, re retail cost allocation and rate design issues.
108. Montana Power Company, before the First Judicial District Court of Montana, *Great Falls Tribune et al. v. the Montana Public Service Commission*, Cause No. CDV2001-208 (2002), on behalf of a media consortium (*Great Falls Tribun*e, *Billings Gazett*e, *Montana Standar*d, *Helena Independent Recor*d, *Missoulia*n, Big Sky Publishing, Inc. dba *Bozeman Daily Chronicl*e, the Montana Newspaper Association, *Miles City Sta*r, *Livingston Enterpris*e, Yellowstone Public Radio, the Associated Press, Inc., and the Montana Broadcasters Association), re public disclosure of allegedly proprietary contract information.
109. Louisville Gas & Electric *et al*., before the Kentucky Public Service Commission, Administrative Case No. 387 (2001), on behalf of Gallatin Steel Company, re adequacy of generation and transmission capacity in Kentucky.
110. PacifiCorp, before the Utah Public Service Commission, Docket No. 01-035-01 (2001), on behalf of Nucor Steel, re retail cost allocation and rate design issues.
111. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 23640/ SOAH Docket No. 473-01-1922 (2001), on behalf of Nucor Steel, re fuel cost recovery.

112. FPL Group *et al*., before the Federal Energy Regulatory Commission, Docket No. EC01-33-000 (2001), on behalf of Arkansas Electric Cooperative Corporation, Inc., re merger-related market power issues.
113. Entergy Mississippi, Inc., *et al*., before the Mississippi Public Service Commission, Docket No. 2000-UA-925 (2001), on behalf of Birmingham Steel-Mississippi, re appropriate regulatory conditions for merger approval.
114. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 22350/ SOAH Docket No. 473-00-1015 (2000), on behalf of Nucor Steel, re unbundled cost of service and rates.
115. PacifiCorp, before the Utah Public Service Commission, Docket No. 99-035-10 (2000), on behalf of Nucor Steel, re using system benefit charges to fund demand-side resource investments.
116. Entergy Arkansas, Inc. *et al*., before the Arkansas Public Service Commission, Docket No. 00-190-U (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re the development of competitive electric power markets in Arkansas.
117. Entergy Arkansas, Inc. *et al*., before the Arkansas Public Service Commission, Docket No. 00-048-R (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re generic filing requirements and guidelines for market power analyses.
118. ScottishPower and PacifiCorp, before the Utah Public Service Commission, Docket No. 98-2035-04 (1999), on behalf of Nucor Steel, re merger conditions to protect the public interest.
119. Dominion Resources, Inc. and Consolidated Natural Gas Company, before the Virginia State Corporation Commission, Case No. PUA990020 (1999), on behalf of the City of Richmond, re market power and merger conditions to protect the public interest.
120. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 18465 (1998) on behalf of the Texas Commercial Customers, re excess earnings and stranded-cost recovery and mitigation.
121. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER98-1384 (1998) on behalf of Wellsboro Electric Company, re pricing low-voltage distribution services.
122. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, re market power in relevant markets.
123. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070458 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

124. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070459 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.
125. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070461 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.
126. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070462 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.
127. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, Allegheny Electric Cooperative, Inc., and Selected Municipalities, re market power in relevant markets.
128. CSW Power Marketing, Inc., before the Federal Energy Regulatory Commission, Docket No.ER97-1238-000 (1997) on behalf of the Transmission Dependent Utility Systems, re market power in relevant markets.
129. Central Hudson Gas & Electric Corporation *et al*., before the New York Public Service Commission, Case Nos. 96-E-0891, 96-E-0897, 96-E-0898, 96-E-0900, 96-E-0909 (1997), on behalf of the Retail Council of New York, re stranded-cost recovery.
130. Central Hudson Gas & Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0909 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
131. Consolidated Edison Company of New York, Inc., supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0897 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
132. New York State Electric & Gas Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0891 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
133. Rochester Gas and Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0898 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
134. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 15015 (1996), on behalf of Nucor Steel-Texas, re real-time electricity pricing.
135. Central Power and Light Company, before the Public Utility Commission of Texas, Docket No. 14965 (1996), on behalf of the Texas Retailers Association, re cost of service and rate design.

136. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 95-1076-E (1996), on behalf of Nucor Steel-Darlington, re integrated resource planning.
137. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13575 (1995), on behalf of Nucor Steel-Texas, re integrated resource planning, DSM options, and real-time pricing.
138. Arkansas Power & Light Company, *et al*., Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
139. Arkansas Power & Light Company, *et al*., Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
140. Arkansas Power & Light Company, *et al*., Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-U (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
141. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 94-202-G (1995), on behalf of Nucor Steel, re integrated resource planning and rate caps.
142. Gulf States Utilities Company, before the United States Court of Federal Claims, *Gulf States Utilities Company v. the United States*, Docket No. 91-1118C (1994, 1995), on behalf of the United States, re electricity rate and contract dispute litigation.
143. American Electric Power Corporation, before the Federal Energy Regulatory Commission, Docket No. ER93-540-000 (1994), on behalf of DC Tie, Inc., re costing and pricing electricity transmission services.
144. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13100 (1994), on behalf of Nucor Steel-Texas, re real-time electricity pricing.
145. Carolina Power & Light Company, *et al*., Proposed Regulation Governing the Recovery of Fuel Costs by Electric Utilities, before the South Carolina Public Service Commission, Docket No. 93-238-E (1994), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
146. Southern Natural Gas Company, before the Federal Energy Regulatory Commission, Docket No. RP93-15-000 (1993-1995), on behalf of Nucor Steel-Darlington, re costing and pricing natural gas transportation services.

147. West Penn Power Company, *et al*., v. State Tax Department of West Virginia, *et al*., Civil Action No. 89-C-3056 (1993), before the Circuit Court of Kanawha County, West Virginia, on behalf of the West Virginia Department of Tax and Revenue, re electricity generation tax.

148. Carolina Power & Light Company, *et al*., Proceeding Regarding Consideration of Certain Standards Pertaining to Wholesale Power Purchases Pursuant to Section 712 of the 1992 Energy Policy Act, before the South Carolina Public Service Commission, Docket No. 92-231-E (1993), on behalf of Nucor Steel-Darlington, re Section 712 regulations.

149. Mountain Fuel Supply Company, before the Public Service Commission of Utah, Docket No. 93-057-01 (1993), on behalf of Nucor Steel-Utah, re costing and pricing retail natural gas firm, interruptible, and transportation services.

150. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 11735 (1993), on behalf of the Texas Retailers Association, re retail cost-of-service and rate design.

151. Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE920041 (1993), on behalf of Philip Morris USA, re cost of service and retail rate design.

152. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.

153. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Rate Design (1992), on behalf of the Department of Energy, Strategic Petroleum Reserve.

154. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.

155. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.

156. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.

157. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 91-4-E, 1991 Fall Hearing, on behalf of Nucor Steel-Darlington.

158. Sonat, Inc., and North Carolina Natural Gas Corporation, before the North Carolina Utilities Commission, Docket No. G-21, Sub 291 (1991), on behalf of Nucor Corporation, Inc.

159. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.

160. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase IV-Rate Design (1991), on behalf of the Department of Energy, Strategic Petroleum Reserve.

161. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 9850 (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve.

162. General Services Administration, before the United States General Accounting Office, Contract Award Protest (1990), Solicitation No. GS-00P-AC87-91, Contract No. GS-00D-89-B5D-0032, on behalf of Satilla Rural Electric Membership Corporation, re cost of service and rate design.

163. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 90-4-E (1990 Fall Hearing), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

164. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve, re cost of service and rate design.

165. Atlanta Gas Light Company, before the Georgia Public Service Commission, Docket No. 3923-U (1990), on behalf of Herbert G. Burris and Oglethorpe Power Corporation, re anticompetitive pricing schemes.

166. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 89-1001-EL-AIR (1990), on behalf of North Star Steel-Ohio, re cost of service and rate design.

167. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Cost of Service/Revenue Spread (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

168. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-89-865 (1989), on behalf of North Star Steel-Minnesota.

169. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

170. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 89-039-10 (1989), on behalf of Nucor Steel-Utah and Vulcraft, a division of Nucor Steel.

171. Soyland Power Cooperative, Inc. v. Central Illinois Public Service Company, Docket No. EL89-30-000 (1989), before the Federal Energy Regulatory Commission, on behalf of Soyland Power Cooperative, Inc., re wholesale contract pricing provisions

172. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 8702 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

173. Houston Lighting and Power Company, before the Public Utility Commission of Texas, Docket No. 8425 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.
174. Northern Illinois Gas Company, before the Illinois Commerce Commission, Docket No. 88-0277 (1989), on behalf of the Coalition for Fair and Equitable Transportation, re retail gas transportation rates.
175. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 79-7-E, 1988 Fall Hearing, on behalf of Nucor Steel-Darlington, re fuel-cost recovery.
176. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 869 (1988), on behalf of Peoples Drug Stores, Inc., re cost of service and rate design.
177. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 88-11-E (1988), on behalf of Nucor Steel-Darlington.
178. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GR-87-670 (1988), on behalf of the Metalcasters of Minnesota.
179. Ohio Edison Company, before the Ohio Public Utilities Commission, Case No. 87-689-EL-AIR (1987), on behalf of North Star Steel-Ohio.
180. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 87-7-E (1987), on behalf of Nucor Steel-Darlington.
181. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase I (1987), on behalf of the Strategic Petroleum Reserve.
182. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 7195 (1987), on behalf of the Strategic Petroleum Reserve.
183. Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. ER86-558-006 (1987), on behalf of Sam Rayburn G&T Cooperative.
184. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 85-035-06 (1986), on behalf of the U.S. Air Force.
185. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 6765 (1986), on behalf of the Strategic Petroleum Reserve.
186. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 85-212 (1986), on behalf of the U.S. Air Force.
187. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket Nos. 6477 and 6525 (1985), on behalf of North Star Steel-Texas.
188. Ohio Edison Company, before the Ohio Public Utilities Commission, Docket No. 84-1359-EL-AIR (1985), on behalf of North Star Steel-Ohio.

189. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 84-035-01 (1985), on behalf of the U.S. Air Force.
190. Central Vermont Public Service Corporation, before the Vermont Public Service Board, Docket No. 4782 (1984), on behalf of Central Vermont Public Service Corporation.
191. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-15641 (1983), on behalf of the Strategic Petroleum Reserve.
192. Southwestern Power Administration, before the Federal Energy Regulatory Commission, Rate Order SWPA-9 (1982), on behalf of the Department of Defense.
193. Public Service Company of Oklahoma, before the Federal Energy Regulatory Commission, Docket Nos. ER82-80-000 and ER82-389-000 (1982), on behalf of the Department of Defense.
194. Central Maine Power Company, before the Maine Public Utilities Commission, Docket No. 80-66 (1981), on behalf of the Commission Staff.
195. Bangor Hydro-Electric Company, before the Maine Public Utilities Commission, Docket No. 80-108 (1981), on behalf of the Commission Staff.
196. Oklahoma Gas & Electric, before the Oklahoma Corporation Commission, Docket No. 27275 (1981), on behalf of the Commission Staff.
197. Green Mountain Power, before the Vermont Public Service Board, Docket No. 4418 (1980), on behalf of the PSB Staff.
198. Williams Pipe Line, before the Federal Energy Regulatory Commission, Docket No. OR79-1 (1979), on behalf of Mapco, Inc.
199. Boston Edison Company, before the Massachusetts Department of Public Utilities, Docket No. 19494 (1978), on behalf of Boston Edison Company.
200. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 173, on behalf of the Commission Staff.
201. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-100, Sub 32, on behalf of the Commission Staff.
202. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 203, on behalf of the Commission Staff.
203. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 170, on behalf of the Commission Staff.
204. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.
205. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.

206. Natural Gas Ratemaking, before the North Carolina Utilities Commission, Docket No. G-100, Sub 29, on behalf of the Commission Staff.
207. General Telephone Company of the Southeast, before the North Carolina Utilities Commission, Docket No. P-19, Sub 163, on behalf of the Commission Staff.
208. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 264, on behalf of the Commission Staff.
209. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 297, on behalf of the Commission Staff.
210. Duke Power Company, *et al*., Investigation of Peak-Load Pricing, before the North Carolina Utilities Commission, Docket No. E-100, Sub 21, on behalf of the Commission Staff.
211. Investigation of Intrastate Long Distance Rates, before the North Carolina Utilities Commission, Docket No. P-100, Sub 45, on behalf of the Commission Staff.

EXHIBIT DWG-2

KU'S RESPONSES TO SELECTED REQUESTS FOR INFORMATION

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 49

Responding Witness: David S. Sinclair / William S. Seelye / John P. Malloy / Robert M. Conroy / Counsel

Q.1-49. Referring to the proposed Curtailable Service Rider:

a. Please provide in native format all workpapers, studies, analyses, and documents (all Excel worksheets with working formulas and intact links) supporting and/or underlying the development of the proposed rider.

b. Provide all studies and/or analyses that Kentucky Utilities Company (KU) conducted concerning expected customer acceptance of and willingness to receive service under the proposed rider.

c. Identify and provide all documents provided to and correspondence with existing interruptible customers related to the development, implementation, and operation of the proposed CSR rider.

d. Provide all documents relating to any customer comments and/or feedback that KU received regarding the proposed reductions in rate credits under the CSR rider prior to KU's deciding to include the reduced credits in the proposed CSR rider.

e. Identify and provide all alternative rate credits for the CSR rider that KU considered but rejected, and describe in detail the reasons for rejecting the considered alternative(s).

A.1-49.

a. See attached. Responsive documents subject to attorney-client privilege or attorney work product protection are not being produced, and are noted in the Company's privilege log being filed in this proceeding. Also see the response to PSC 1-54.

b. The Company performed no surveys, analysis or studies concerning expected customer acceptance of or willingness to receive service under the proposed rider.

c. Beginning November 1, 2016 and thereafter, following the press release issued by the Company of a rate adjustment filing, Major Accounts Representatives communicated by email and/or telephone to inform their assigned customers of the filing. This proactive outreach is part of the role these employees serve with the company's key and largest customers. Then on November 16, 2016 and thereafter, the Major Accounts Representatives communicated with customers that the proposed rates had been filed. Numerous communications between Major Accounts Representatives and their assigned customers have occurred since then and continue to occur. If requested by the customer, in-person meetings are being scheduled to discuss the proposed changes and spreadsheets forecasting the calculations of the proposed rates are being provided. Attached is a template email document used to communicate with customers including those served under the Curtailable Service Rider.

   Across the Companies, two customers being served under Curtailable Service Rider requested and were provided a rate comparison used during an in-person meeting to discuss the proposed rates. Those rate comparisons are being provided with all customer-identifying information replaced with generic identifiers.

d. There are no such documents.

e. See the Company's objection filed on January 20, 2017.

Sebourn, Michael

From:	Sauer, Bruce
Sent:	Tuesday, October 11, 2016 4:25 PM
To:	Sebourn, Michael
Subject:	Comparison of Henry Hub, TGT Mainline, and Dominion South gas prices
Attachments:	Comparison of Henry Hub_TGT_Mainline_Dominion_South_Gas_Prices_10_11_16 _MSebourn.xlsx

Mike,

The attached workbook summarizes the comparison between Henry Hub, TGT Mainline, and Dominion South daily average prices. There is relatively little difference between Henry Hub and TGT Mainline, with TGT Mainline averaging $0.07/mmBtu lower than Henry Hub. Dominion South is considerably weaker, averaging $1.06/mmBtu lower than the Henry Hub. I've asked PIRA for an explanation.

For the last 12 months, the average prices are as follows:

Henry Hub	$2.25/mmBtu
TGT Mainline	$2.18/mmBtu
Dominion South	$1.29/mmBtu

Bruce

Attachment 2 is being provided in a separate file in Excel format.

Rate Case to be Submitted Initial Communication

Good morning.

As you may have seen or heard earlier this morning, Kentucky Utilities Company and Louisville Gas and Electric Company announced today that they are investing $2.2 billion in their electric and natural gas system to improve safety, reduce outage times and enhance service to customers. To recover some of the costs associated with these investments, Kentucky Utilities and Louisville Gas and Electric plan to request approval from the Kentucky Public Service Commission to adjust customer rates accordingly.

A press release was made this morning at 7am, and I have attached it for your reference. You will see there is some mention of the cost increases for the residential rate class. At this time, I do not have the respective information on the increases for Commercial or Industrial customer classes.

Next steps
As the filings are made public they will be posted to our website (https://lge-ku.com/our-company/regulatory), and I plan to forward you a copy at that time. I would be happy to meet with you and your management team in November and December to discuss the specific impacts to your business operations. The filing will request that the rate adjustments be effective in July 2017.

Please discuss this information within your organization and let me know if you have any questions or concerns.

Thanks,

Rate Case to be Submitted Follow-up Communication

Kentucky Utilities Company and Louisville Gas and Electric Company published paperwork with the Kentucky Public Service Commission for base rate adjustments. They are KPSC case numbers 2016-00370 and 2016-00371, respectively.

Additionally, the following legal notices will begin appearing in customer's bills and various newspapers around the state:

KU Current and Proposed Electric Rates
LG&E Current and Proposed Electric & Gas Rates

In these links you will find the proposed rate changes. Because every commercial and industrial customer has a different load factor, the impact to your facility will vary. The filing will request that the rate adjustments be effective in July 2017.

I would be happy to meet with you and look at a "side by side" comparison of current and proposed rates based upon the historical usage of your facility. Furthermore, if you have any questions or concerns about the proposed increases, please give me a call.

In the meantime, I hope you have a happy thanksgiving with your friends and family.

Kind regards,

LG&E RTS Comparison of Current and Proposed Rates

CA: XXXXXXX
Customer Name: Customer 1
Service Address: 138kV Service

Contract Capacity: 46,000 kVA
CSR Firm: 4,500 kVA

Existing Tariff

Basic Service Charge:	$ 1,000	
Energy Charge:	$ 0.03711	/kWh
Peak Demand Charge:	$ 4.85	/kVA
Interm. Demand Charge:	$ 3.30	/kVA
Base Demand Charge:	$ 3.05	/kVA
CSR Credit:	$ (6.40)	/kVA

Proposed Tariff

Basic Service Charge:	$ 1,400	
Energy Charge:	$ 0.03711	/kWh
Peak Demand Charge:	$ 6.98	/kVA
Interm. Demand Charge:	$ 5.12	/kVA
Base Demand Charge:	$ 1.52	/kVA
CSR Credit:	$ (3.56)	/kVA

24 Month Historical Information

Test Month Bill Date	Energy kWH	Measured On Peak kVA Demand	Measured Interm. kVA Demand	Measured Base kVA Demand
11/29/2016	20,866,200	39,457.90	39,457.90	39,457.90
10/27/2016	22,695,658	37,574.50	37,574.50	37,574.50
09/28/2016	10,167,500	30,283.90	30,283.90	30,283.90
08/30/2016	19,653,427	29,916.20	30,118.00	31,046.20
07/28/2016	19,701,487	30,145.20	30,297.90	30,693.30
06/29/2016	19,121,954	30,257.00	30,257.00	30,344.00
05/27/2016	20,231,205	29,911.80	30,132.70	30,759.60
04/28/2016	19,894,530	32,525.80	33,303.40	33,935.40
03/30/2016	23,418,925	37,498.80	37,498.80	37,498.80
02/29/2016	19,315,577	33,520.80	33,879.60	34,198.10
01/29/2016	17,920,385	30,421.80	31,006.60	31,079.60
12/30/2015	17,342,125	30,586.80	31,197.30	31,197.30
11/30/2015	17,293,286	32,056.10	32,056.10	32,056.10
10/28/2015	23,563,889	38,390.90	38,390.90	38,390.90
09/29/2015	20,333,344	38,030.50	38,030.50	38,070.30
08/28/2015	17,870,039	30,456.90	30,456.90	30,694.80
07/28/2015	14,837,000	30,550.80	30,694.80	30,694.80
06/29/2015	19,702,763	33,361.30	34,833.60	34,833.60
05/28/2015	23,808,903	40,645.60	40,645.60	42,453.10
04/29/2015	23,519,560	42,030.70	42,659.60	42,744.50
03/30/2015	25,060,943	40,141.30	40,141.30	40,141.30
02/27/2015	25,449,855	46,192.60	46,192.60	49,986.60
01/29/2015	24,244,068	40,222.30	40,512.90	46,175.80
12/30/2014	22,798,615	40,167.40	40,472.70	40,472.70

Existing Rates

Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 1,000	$ 774,345	$ 441,928	$ (223,731)	$ 993,543
$ 1,000	$ 842,236	$ 420,834	$ (211,677)	$ 1,052,393
$ 1,000	$ 377,316	$ 352,039	$ (165,017)	$ 565,338
$ 1,000	$ 729,339	$ 349,708	$ (163,955)	$ 916,091
$ 1,000	$ 731,122	$ 351,412	$ (165,107)	$ 918,428
$ 1,000	$ 709,616	$ 351,820	$ (164,845)	$ 897,590
$ 1,000	$ 750,780	$ 349,735	$ (164,049)	$ 937,466
$ 1,000	$ 738,286	$ 372,876	$ (184,342)	$ 927,821
$ 1,000	$ 869,076	$ 419,987	$ (211,192)	$ 1,078,871
$ 1,000	$ 716,801	$ 379,604	$ (188,029)	$ 909,375
$ 1,000	$ 665,025	$ 364,212	$ (169,642)	$ 860,595
$ 1,000	$ 643,566	$ 365,641	$ (170,863)	$ 839,345
				$ 10,896,856

Proposed Rates

Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 1,400	$ 774,345	$ 547,361	$ (124,450)	$ 1,198,655
$ 1,400	$ 842,236	$ 524,571	$ (117,745)	$ 1,250,462
$ 1,400	$ 377,316	$ 436,355	$ (91,791)	$ 723,280
$ 1,400	$ 729,339	$ 432,939	$ (91,200)	$ 1,072,478
$ 1,400	$ 731,122	$ 435,459	$ (91,841)	$ 1,076,140
$ 1,400	$ 709,616	$ 436,030	$ (91,695)	$ 1,055,350
$ 1,400	$ 750,780	$ 432,984	$ (91,252)	$ 1,093,911
$ 1,400	$ 738,286	$ 467,463	$ (102,540)	$ 1,104,609
$ 1,400	$ 869,076	$ 523,655	$ (117,476)	$ 1,276,656
$ 1,400	$ 716,801	$ 477,359	$ (104,591)	$ 1,090,968
$ 1,400	$ 665,025	$ 447,078	$ (94,363)	$ 1,019,140
$ 1,400	$ 643,566	$ 449,206	$ (95,042)	$ 999,130
				$ 12,960,781
			Change:	$ 2,063,925
				18.9%

LG&E RTS Comparison of Current and Proposed Rates

CA: XXXXXXX
Customer Name: Customer 1
Service Address: 138kV Service

Contract Capacity: 46,000 kVA
CSR Firm: 4,500 kVA

Existing Tariff

Basic Service Charge:	$	1,000	
Energy Charge:	$	0.03711	/kWh
Peak Demand Charge:	$	4.85	/kVA
Interm. Demand Charge:	$	3.30	/kVA
Base Demand Charge:	$	3.05	/kVA
CSR Credit:	$	-	/kVA

Proposed Tariff

Basic Service Charge:	$	1,400	
Energy Charge:	$	0.03711	/kWh
Peak Demand Charge:	$	6.98	/kVA
Interm. Demand Charge:	$	5.12	/kVA
Base Demand Charge:	$	1.52	/kVA
CSR Credit:	$	-	/kVA

24 Month Historical Information

Test Month Bill Date	Energy kWH	Measured On Peak kVA Demand	Measured Interm. kVA Demand	Measured Base kVA Demand
11/29/2016	20,866,200	39,457.90	39,457.90	39,457.90
10/27/2016	22,695,658	37,574.50	37,574.50	37,574.50
09/28/2016	10,167,500	30,283.90	30,283.90	30,283.90
08/30/2016	19,653,427	29,916.20	30,118.00	31,046.20
07/28/2016	19,701,487	30,145.20	30,297.90	30,693.30
06/29/2016	19,121,954	30,257.00	30,257.00	30,344.00
05/27/2016	20,231,205	29,911.80	30,132.70	30,759.60
04/28/2016	19,894,530	32,525.80	33,303.40	33,935.40
03/30/2016	23,418,925	37,498.80	37,498.80	37,498.80
02/29/2016	19,315,577	33,520.80	33,879.60	34,198.10
01/29/2016	17,920,385	30,421.80	31,006.60	31,079.60
12/30/2015	17,342,125	30,586.80	31,197.30	31,197.30
11/30/2015	17,293,286	32,056.10	32,056.10	32,056.10
10/28/2015	23,563,889	38,390.90	38,390.90	38,390.90
09/29/2015	20,333,344	38,030.50	38,030.50	38,070.30
08/28/2015	17,870,039	30,456.90	30,456.90	30,694.80
07/28/2015	14,837,000	30,550.80	30,694.80	30,694.80
06/29/2015	19,702,763	33,361.30	34,833.60	34,833.60
05/28/2015	23,808,903	40,645.60	40,645.60	42,453.10
04/29/2015	23,519,560	42,030.70	42,659.60	42,744.50
03/30/2015	25,060,943	40,141.30	40,141.30	40,141.30
02/27/2015	25,449,855	46,192.60	46,192.60	49,986.60
01/29/2015	24,244,068	40,222.30	40,512.90	46,175.80
12/30/2014	22,798,615	40,167.40	40,472.70	40,472.70

Existing Rates

Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 1,000	$ 774,345	$ 441,928	$ -	$ 1,217,273
$ 1,000	$ 842,236	$ 420,834	$ -	$ 1,264,070
$ 1,000	$ 377,316	$ 352,039	$ -	$ 730,355
$ 1,000	$ 729,339	$ 349,708	$ -	$ 1,080,047
$ 1,000	$ 731,122	$ 351,412	$ -	$ 1,083,534
$ 1,000	$ 709,616	$ 351,820	$ -	$ 1,062,435
$ 1,000	$ 750,780	$ 349,735	$ -	$ 1,101,515
$ 1,000	$ 738,286	$ 372,876	$ -	$ 1,112,162
$ 1,000	$ 869,076	$ 419,987	$ -	$ 1,290,063
$ 1,000	$ 716,801	$ 379,604	$ -	$ 1,097,405
$ 1,000	$ 665,025	$ 364,212	$ -	$ 1,030,237
$ 1,000	$ 643,566	$ 365,641	$ -	$ 1,010,208
				$ 13,079,305

Proposed Rates

Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 1,400	$ 774,345	$ 547,361	$ -	$ 1,323,105
$ 1,400	$ 842,236	$ 524,571	$ -	$ 1,368,207
$ 1,400	$ 377,316	$ 436,355	$ -	$ 815,071
$ 1,400	$ 729,339	$ 432,939	$ -	$ 1,163,678
$ 1,400	$ 731,122	$ 435,459	$ -	$ 1,167,981
$ 1,400	$ 709,616	$ 436,030	$ -	$ 1,147,045
$ 1,400	$ 750,780	$ 432,984	$ -	$ 1,185,164
$ 1,400	$ 738,286	$ 467,463	$ -	$ 1,207,150
$ 1,400	$ 869,076	$ 523,655	$ -	$ 1,394,132
$ 1,400	$ 716,801	$ 477,359	$ -	$ 1,195,560
$ 1,400	$ 665,025	$ 447,078	$ -	$ 1,113,503
$ 1,400	$ 643,566	$ 449,206	$ -	$ 1,094,172
				$ 14,174,768
			Change:	$ 1,095,463
				8.4%

KU TODP Comparison of Current and Proposed Rates

CA: XXXXXX
Customer Name: Customer 2
Service Address: XXXXXXX

Contract Capacity: 10,722 kVA
CSR Firm: 4,000 kVA

Existing Tariff

Basic Service Charge:	$ 300	
Energy Charge:	$ 0.03432	/kWh
Peak Demand Charge:	$ 5.89	/kVA
Interm. Demand Charge:	$ 4.39	/kVA
Base Demand Charge:	$ 3.34	/kVA
CSR Credit:	$ (6.50)	/kVA

Proposed Tariff

Basic Service Charge:	$ 330	
Energy Charge:	$ 0.03433	/kWh
Peak Demand Charge:	$ 6.83	/kVA
Interm. Demand Charge:	$ 5.34	/kVA
Base Demand Charge:	$ 2.92	/kVA
CSR Credit:	$ (3.67)	/kVA

24 Month Historical Information				
Test Month Bill Date	Energy kWH	Measured On Peak kVA Demand	Measured Interm. kVA Demand	Measured Base kVA Demand
12/21/2016	5,092,800	10,014.60	10,025.80	10,025.80
11/21/2016	5,721,600	11,171.40	11,171.40	11,171.40
10/21/2016	5,596,800	10,643.00	10,643.00	10,643.00
09/22/2016	5,798,400	10,483.40	10,483.40	10,483.40
08/23/2016	6,110,400	10,471.00	10,705.30	10,705.30
07/22/2016	4,435,200	9,876.60	9,898.60	9,984.40
06/22/2016	5,198,400	9,372.90	9,419.00	9,609.60
05/20/2016	4,752,000	8,816.50	8,964.60	8,964.60
04/21/2016	5,347,200	10,256.90	10,337.40	10,337.40
03/22/2016	5,059,200	10,091.70	10,091.70	10,091.70
02/23/2016	5,078,400	9,899.40	10,099.30	10,259.10
01/25/2016	5,424,000	9,551.20	10,059.90	10,059.90
12/22/2015	5,361,600	9,649.60	9,649.60	9,906.80
11/20/2015	5,203,200	10,377.40	10,469.50	10,533.50
10/22/2015	5,318,400	10,461.10	10,555.10	10,704.60
09/23/2015	6,028,800	10,678.60	10,678.60	10,678.60
08/21/2015	6,326,400	10,336.60	10,336.60	10,683.90
07/22/2015	4,833,600	9,848.70	9,873.80	9,873.80
06/23/2015	5,784,000	9,747.90	9,780.60	9,780.60
05/21/2015	4,848,000	9,395.60	9,455.70	9,575.80
04/23/2015	5,668,800	9,934.20	9,934.20	10,049.50
03/24/2015	5,179,200	9,786.10	9,805.40	9,805.40
02/23/2015	5,462,400	9,834.20	9,834.20	9,834.20
01/23/2015	5,212,800	9,522.00	9,881.30	9,881.30

Existing Rates				
Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 300	$ 174,785	$ 136,485	$ (39,168)	$ 272,403
$ 300	$ 196,365	$ 152,154	$ (46,614)	$ 302,206
$ 300	$ 192,082	$ 144,958	$ (43,180)	$ 294,160
$ 300	$ 199,001	$ 142,784	$ (42,142)	$ 299,943
$ 300	$ 209,709	$ 144,426	$ (43,584)	$ 310,851
$ 300	$ 152,216	$ 134,976	$ (38,341)	$ 249,151
$ 300	$ 178,409	$ 128,652	$ (35,224)	$ 272,137
$ 300	$ 163,089	$ 121,226	$ (32,270)	$ 252,344
$ 300	$ 183,516	$ 140,321	$ (41,193)	$ 282,944
$ 300	$ 173,632	$ 137,449	$ (39,596)	$ 271,785
$ 300	$ 174,291	$ 136,909	$ (39,645)	$ 271,854
$ 300	$ 186,152	$ 134,020	$ (39,389)	$ 281,082
				$ 3,360,860

Proposed Rates				
Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 330	$ 174,836	$ 154,558	$ (22,115)	$ 307,609
$ 330	$ 196,423	$ 168,576	$ (26,319)	$ 339,010
$ 330	$ 192,138	$ 160,834	$ (24,380)	$ 328,922
$ 330	$ 199,059	$ 158,891	$ (23,794)	$ 334,486
$ 330	$ 209,770	$ 159,991	$ (24,608)	$ 345,483
$ 330	$ 152,260	$ 151,624	$ (21,648)	$ 282,566
$ 330	$ 178,461	$ 145,623	$ (19,888)	$ 304,526
$ 330	$ 163,136	$ 139,396	$ (18,220)	$ 284,642
$ 330	$ 183,569	$ 156,565	$ (23,258)	$ 317,206
$ 330	$ 173,682	$ 154,124	$ (22,357)	$ 305,780
$ 330	$ 174,341	$ 152,851	$ (22,384)	$ 305,138
$ 330	$ 186,206	$ 150,263	$ (22,240)	$ 314,559
				$ 3,769,928
			Change:	$ 409,068
				12.2%

KU TODP Comparison of Current and Proposed Rates

CA: XXXXXX
Customer Name: Customer 2
Service Address: XXXXXXX

Contract Capacity: 10,722 kVA
CSR Firm: 4,000 kVA

Existing Tariff

Basic Service Charge:	$	300	
Energy Charge:	$	0.03432	/kWh
Peak Demand Charge:	$	5.89	/kVA
Interm. Demand Charge:	$	4.39	/kVA
Base Demand Charge:	$	3.34	/kVA
CSR Credit:	$	-	/kVA

Proposed Tariff

Basic Service Charge:	$	330	
Energy Charge:	$	0.03433	/kWh
Peak Demand Charge:	$	6.83	/kVA
Interm. Demand Charge:	$	5.34	/kVA
Base Demand Charge:	$	2.92	/kVA
CSR Credit:	$	-	/kVA

24 Month Historical Information				
Test Month Bill Date	Energy kWH	Measured On Peak kVA Demand	Measured Interm. kVA Demand	Measured Base kVA Demand
12/21/2016	5,092,800	10,014.60	10,025.80	10,025.80
11/21/2016	5,721,600	11,171.40	11,171.40	11,171.40
10/21/2016	5,596,800	10,643.00	10,643.00	10,643.00
09/22/2016	5,798,400	10,483.40	10,483.40	10,483.40
08/23/2016	6,110,400	10,471.00	10,705.30	10,705.30
07/22/2016	4,435,200	9,876.60	9,898.60	9,984.40
06/22/2016	5,198,400	9,372.90	9,419.00	9,609.60
05/20/2016	4,752,000	8,816.50	8,964.60	8,964.60
04/21/2016	5,347,200	10,256.90	10,337.40	10,337.40
03/22/2016	5,059,200	10,091.70	10,091.70	10,091.70
02/23/2016	5,078,400	9,899.40	10,099.30	10,259.10
01/25/2016	5,424,000	9,551.20	10,059.90	10,059.90
12/22/2015	5,361,600	9,649.60	9,649.60	9,906.80
11/20/2015	5,203,200	10,377.40	10,469.50	10,533.50
10/22/2015	5,318,400	10,461.10	10,555.10	10,704.60
09/23/2015	6,028,800	10,678.60	10,678.60	10,678.60
08/21/2015	6,326,400	10,336.60	10,336.60	10,683.90
07/22/2015	4,833,600	9,848.70	9,873.80	9,873.80
06/23/2015	5,784,000	9,747.90	9,780.60	9,780.60
05/21/2015	4,848,000	9,395.60	9,455.70	9,575.80
04/23/2015	5,668,800	9,934.20	9,934.20	10,049.50
03/24/2015	5,179,200	9,786.10	9,805.40	9,805.40
02/23/2015	5,462,400	9,834.20	9,834.20	9,834.20
01/23/2015	5,212,800	9,522.00	9,881.30	9,881.30

Existing Rates				
Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 300	$ 174,785	$ 136,485	$ -	$ 311,570
$ 300	$ 196,365	$ 152,154	$ -	$ 348,820
$ 300	$ 192,082	$ 144,958	$ -	$ 337,340
$ 300	$ 199,001	$ 142,784	$ -	$ 342,085
$ 300	$ 209,709	$ 144,426	$ -	$ 354,435
$ 300	$ 152,216	$ 134,976	$ -	$ 287,492
$ 300	$ 178,409	$ 128,652	$ -	$ 307,361
$ 300	$ 163,089	$ 121,226	$ -	$ 284,614
$ 300	$ 183,516	$ 140,321	$ -	$ 324,137
$ 300	$ 173,632	$ 137,449	$ -	$ 311,381
$ 300	$ 174,291	$ 136,909	$ -	$ 311,499
$ 300	$ 186,152	$ 134,020	$ -	$ 320,471
				$ 3,841,206

Proposed Rates				
Customer Charge	Energy Charge	Demand Charge	CSR Credit	Total
$ 330	$ 174,836	$ 154,558	$ -	$ 329,724
$ 330	$ 196,423	$ 168,576	$ -	$ 365,329
$ 330	$ 192,138	$ 160,834	$ -	$ 353,302
$ 330	$ 199,059	$ 158,891	$ -	$ 358,280
$ 330	$ 209,770	$ 159,991	$ -	$ 370,092
$ 330	$ 152,260	$ 151,624	$ -	$ 304,214
$ 330	$ 178,461	$ 145,623	$ -	$ 324,414
$ 330	$ 163,136	$ 139,396	$ -	$ 302,862
$ 330	$ 183,569	$ 156,565	$ -	$ 340,464
$ 330	$ 173,682	$ 154,124	$ -	$ 328,137
$ 330	$ 174,341	$ 152,851	$ -	$ 327,523
$ 330	$ 186,206	$ 150,263	$ -	$ 336,799
				$ 4,041,138
			Change:	$ 199,933
				5.2%

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 50

Responding Witness: William S. Seelye / David S. Sinclair

Q.1-50. Identify and provide all workpapers, studies, analyses, and documents related to any analyses conducted by or on behalf of KU concerning the potential customer-specific and service-area economic impacts of reducing the existing CSR credits.

A.1-50. There are no workpapers, studies, analyses, and documents related to any analyses conducted by or on behalf of KU concerning the potential customer-specific and service-area economic impacts of reducing the existing CSR credits.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 51

Responding Witness: Christopher M. Garrett

Q.1-51. For each existing CSR customer (identified only by reference number), please provide the estimated annual dollar impact of KU's proposed reductions in the CSR credit. Provide all workpapers supporting the estimated annual dollar impacts.

A.1-51. No such estimate was made. The Company does not forecast the annual dollar impact of the proposed reductions in the CSR credit by customer; therefore, the requested information is not available. Refer to Tab 66 of the Filing Requirements for present and proposed rates.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 52

Responding Witness: David S. Sinclair

Q.1-52. Referring to existing Rider CSR:

a. For each customer (identified only by reference number) served under the rider, identify the total MW of curtailable/interruptible load under contract. Please indicate if the requested information is the same as information provided in the direct testimony of witness David S. Sinclair at 24: Table 6. This instruction applies to each subpart of this request.

b. State the number of months in which each customer in subpart (a) above has been continuously served under the existing rider or its predecessor.

c. For each customer identified in the subpart (a) above, provide the customer's firm contract demand if applicable under Option A.

d. For each customer identified in the subpart (a) above, provide the customer's Designated Curtailable Load if applicable under Option 3.

A.1-52.

a. See attached.

b. See the response to part a.

c. See the response to part a.

d. See the response to part a.

Utility	Company	CSR Date	Units	Contract Capacity	Reducible To (Firm Contract Demand Option A)	Contract Capacity Minus Firm Load	Continuous Months Served
KU	4	4-Jul	kVA	195,000	2,000	193,000	150
KU	5	14-May	kVA	9,000	3,500	5,500	32
KU	6	13-Jan	kVA	7,000	3,000	4,000	48
KU	7	14-Jan	kVA	10,722	4,000	6,722	36
KU	8	14-Jun	kVA	12,000	6,500	5,500	31
KU	9	16-Jul	kVA	31,600	9,000	22,600	6
KU	10	16-Jul	kVA	9,950	2,250	7,700	6
KU	11	16-Jul	kVA	12,750	3,500	9,250	6
KU	12	16-Jul	kVA	15,450	10,500	4,950	6

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 53

Responding Witness: David S. Sinclair

Q.1-53. Referring to existing Rider CSR and its predecessors:

a. For each customer (identified only by reference number) served under the rider, identify the date, time, and duration of each curtailment called by KU in the past 60 months?

b. For each curtailment referenced in the response to subpart (a) above, specify whether the curtailment was a system reliability event or a buy-through event, identify the MW of load curtailment requested, and identify the MW of load that failed to comply with the curtailment request.

c. For each buy-through curtailment identified in the response to subpart (b) above, specify whether the customer bought through the curtailment, the amount of buy-through energy purchased, the price paid for such buy-through energy, and the source (system supply or market) of the buy-through price.

A.1-53. a. CSR Curtailments 01/01/2012 through 01/13/2017:

Customer	*Start Date/Time*	*End Date/Time*	*Hours*	*Type*	*Contract/CSR Firm or CSR Reduction*	*Load Not Compliant (kVA)*
3	10/17/2012 08:55	10/17/2012 09:25	0.50	Physical Curtailment	150 MVA contract; 4,000 kW firm	0
3	01/06/2014 18:30	01/06/2014 19:41	1.18	Physical Curtailment	150 MVA contract; 4,000 kW firm	0
3	01/07/2014 07:14	01/07/2014 10:00	2.77	Physical Curtailment	150 MVA contract; 4,000 kW firm	0
4	01/07/2014 07:20	01/07/2014 10:00	2.67	Physical Curtailment	5,000 kVA contract; 3,500 kW firm	5,129.8
5	01/07/2014 07:40	01/07/2014 10:00	2.33	Physical Curtailment	2,000 kVA reduction	0
3	01/30/2014 07:36	01/30/2014 08:06	0.50	Physical Curtailment	150 MVA contract; 4,000 kW firm	39,184.8
4	01/30/2014 07:37	01/30/2014 08:07	0.50	Physical Curtailment	5,000 kVA contract; 3,500 kW firm	5,157.5

b. See the response to part a.

c. No curtailments were buy-through curtailments.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated January 11, 2017

Question No. 54

Responding Witness: David S. Sinclair

Q.1-54. Please provide a timeline for the last 10 years showing by year each curtailable/interruptible rate or rider offered by KU, the number of customers served under each rate/rider, and the total MW of interruptible or curtailable load served under each curtailable/interruptible rate/rider.

A.1-54. See attached.

CSR Offered

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CSR1	x	x	x							
CSR2	x	x	x							
CSR3	x	x	x							
CSR10				x	x	x	x	x		
CSR30				x	x	x	x	x		
CSR									x	x

Customers on each rider

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CSR1										
CSR2										
CSR3	1	1	1							
CSR10				1	2	2	2	2		
CSR30							1	3		
CSR									5	9

Maximum Curtailable(MW)

	2010	2011	2012	2013	2014	2015	2016
CSR10	146.0	153.8	153.8	153.8	196.5		
CSR30				2.0	14.5		
CSR						214.7	259.2

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 55

Responding Witness: David S. Sinclair / John P. Malloy

Q.1-55. Please identify all reports, studies, and/or analyses conducted by on behalf of KU or its parent company in the past 5 years related in total or in part to retail interruptible or curtailable electric service in Kentucky.

A.1-55. Each year, the Companies estimate the hourly integrated load reduction associated with curtailable customers that are treated as a capacity resource. The table below shows forecasted curtailable capacity for both LG&E and KU in MW by year, up to the current year, from the previous ten business plans.

Hourly Integrated Curtailable Capacity

Year	2008 Plan	2009 Plan	2010 Plan	2011 Plan	2012 Plan	2013 Plan	2014 Plan	2015 Plan	2016 Plan	2017 Plan
2008	121									
2009	121	93								
2010	121	93	93							
2011	121	93	93	93						
2012	121	93	93	93	93					
2013	121	93	93	93	98	119				
2014	121	93	93	93	100	122	122			
2015	121	93	93	93	102	125	125	133		
2016	121	93	93	93	102	125	125	133	136	
2017	121	93	93	93	102	125	125	133	136	130

Also, see the Companies' Industrial DSM Potential Assessment filed with the Commission in Case No. 2014-00003, particularly the section concerning load control beginning at page 59. The assessment is available at: http://psc.ky.gov/pscecf/2014-00003/rick.lovekamp@lge-ku.com/05262016071923/Closed/LGE_KU_Ind_DSM_Potential_Study_2014-00003_05-26-16.pdf

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 56

Responding Witness: David S. Sinclair

Q.1-56. Please explain in detail how KU (acting alone or in conjunction with affiliates) treats interruptible/curtailable load in:

a. Developing its long-run load forecast.

b. Determining its long-run need for future supply-side resources.

c. Determining its need for operating reserve capacity.

d. Providing ancillary services.

e. Determining whether such load qualifies as spinning reserve.

A.1-56.

a. The Company considers interruptible/curtailable load as a capacity resource.

b. See response to (a). The Company considers CSR as a capacity resource available to meet planning reserve margin requirements in resource planning decisions. CSR capacity is assumed to remain at the current level through the analysis period.

c. CSR capacity does not affect operating reserves, which consist of spinning reserves and non-spinning (supplemental) reserves. Both spinning and supplemental reserves must be available to serve load within a 15 minute period. For curtailable load to qualify as operating reserves, the curtailable load must be fully removable from system load within a 15 minute period. The execution of a CSR event requires a 60 minute notice. Therefore, CSR does not qualify as an operating reserve and is not considered when determining the need for operating reserve capacity.

d. As noted in part c., CSR capacity cannot be used for spinning and supplemental operating reserves. Similar limitations also exist for considering CSR capacity for contingency and regulating reserves. Contingency reserves must be available within 15 minutes and regulating reserves must be immediately reactive to Automatic Generation Control to provide normal regulating margin.

e. See the response to part c.

KENTUCKY UTILITIES COMPANY

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Response to First Set of Data Requests of
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Question No. 57

Responding Witness: Robert M. Conroy

Q.1-57. Given existing laws and regulations in Kentucky, please identify and describe in detail each non-KU market option and/or mechanism under which an existing CSR customer could have its curtailable load served.

A.1-57. KU is not aware of any such market option or mechanism.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 58

Responding Witness: Robert M. Conroy

Q.1-58. Given existing laws and regulations in Kentucky, please identify and describe in detail each non-KU market option and/or mechanism through which an existing CSR customer could sell its interruptible load as a demand response resource.

A.1-58. KU is not aware of any such market option or mechanism.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 59

Responding Witness: Christopher M. Garrett

Q.1-59. Please explain in detail how KU treats curtailment buy-though revenues in setting base rates and/or modifying its Fuel Adjustment Clause.

A.1-59. The last time KU had curtailment buy-through revenues was in September 2011 and there are no curtailable buy-through revenues included in this case. If a curtailment buy-through would occur, the buy-through revenues (fuel cost) would be deducted from the power purchase fuel cost for the month in the Fuel Adjustment Clause calculation.

Total FAC recoverable fuel cost = generation fuel + (power purchase fuel – curtailment buy-through revenues/fuel) – off system sales fuel.

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Response to First Set of Data Requests of
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Dated January 11, 2017

Question No. 60

Responding Witness: William S. Seelye

Q.1-60. Please identify and explain in detail how KU treats test-year curtailment buy-though revenue in the electric cost-of-service study filed in this case. This request refers to the methodology that KU would use even if it received no test-year CSR buy-through revenue.

A.1-60. There are no buy-through revenues included in the test-year.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 61

Responding Witness: William S. Seelye

Q.1-61. Please identify and explain in detail how KU treats test-year curtailment credits paid to CSR customers in the electric cost-of-service study filed in this case. This request refers to the methodology used by KU, and not to any specific amount of test-year CSR credits.

A.1-61. CSR credits are treated as miscellaneous credits. In the cost of service study, as with other miscellaneous revenues and credits, CSR credits are allocated to all customer classes.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 62

Responding Witness: David S. Sinclair

Q.1-62. Please identify and explain in detail all situations other than a system reliability event in which KU would need or want to physically curtail load under the CSR rider.

A.1-62. With no restriction requiring all generating units to be committed prior to curtailing load under the CSR rider, the CSR reduction would be used as an economic resource to save fuel costs up to the amount of hours specified in the tariff.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
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Dated January 11, 2017

Question No. 63

Responding Witness: David S. Sinclair

Q.1-63. Referring to the direct testimony of David S. Sinclair at 24:11 — 25:3:

a. Confirm that the key condition discussed at 24:16-18 refers only to physical curtailments under Rider CSR.

b. Since Rider CSR (or its predecessors) was first approved by the Commission, please identify each instance in which KU would have issued a physical curtailment request but was prevented from doing so by the key condition restriction discussed at 24:16-18.

A.1-63. a. The key condition referenced in Mr. Sinclair's testimony that requires all system generating units be dispatched or in the process of being dispatched before curtailments applies to physical curtailment events.

b. Prior to August 1, 2010, the Rider CSR did not require that all generating units be dispatched before issuing a curtailment request. While the Company is not able to identify the specific hours for additional physical curtailment, it is likely that CSR would be implemented consistent with the response in Question 62 in the absence of the key condition restriction.

KENTUCKY UTILITIES COMPANY

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Response to First Set of Data Requests of
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Question No. 64

Responding Witness: David S. Sinclair

Q.1-64. Referring to the direct testimony of David S. Sinclair at 25:4-9:

a. Please provide the Annual Generation Forecast.

b. For each of the eight forecast CSR curtailment events, identify and explain in detail the underlying load and system conditions driving KU's expected need for physical curtailment.

A.1-64.

a. See "Section 7 – Generation Forecast" on pages 20-22 of Mr. Sinclair's testimony and the "2017 Business Plan Generation & OSS Forecast" attached at Tab 16, Section 16(7)(c), Item H of the Companies' Applications.

b. Of the eight forecasted curtailment events, two pertained only to a curtailable customer served in the Old Dominion Power service territory in Virginia, which is governed by different rules with regard to curtailment. The Companies' underlying load and system conditions for the peak hour of each of the remaining six events are summarized in the table below. Also see the response to PSC 2-55.

Curtailment Event Date	Event Time	Total Generation Capacity (MW)	Peak Hourly Load During Event (MW)	Generation Unavailable – Planned Outage (MW)	Generation Unavailable – Other (MW)	Spinning Reserves (MW)	Purchases (MW)
7/18/2017	Hours 13-15	8,136	6,406	6	1,317	406	0
7/19/2017	Hours 13-16	8,136	6,411	6	1,039	679	0
8/9/2017	Hours 14-16	8,136	6,807	6	1,628	232	538
3/12/2018	Hour 8	8,261	4,025	1,498	2,286	452	0
3/14/2018	Hour 7-8	8,261	4,095	1,498	2,330	338	0
3/15/2018	Hour 10	8,261	4,030	1,498	2,436	297	0

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Response to First Set of Data Requests of
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Dated January 11, 2017

Question No. 65

Responding Witness: John P. Malloy

Q.1-65. Please identify each existing DSM and/or energy efficiency program that KU proposes to either close to new customers or limit incremental program participation by existing participants during the Forecasted Test Period.

A.1-65. In the Forecasted Test Period, the Companies are not planning to end any of the current DSM programs or limit incremental program participation. The Companies' current DSM programs are approved through December 2018. The Companies will complete their re-evaluation of the programs by the end of 2017.

KENTUCKY UTILITIES COMPANY

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Response to First Set of Data Requests of
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Dated January 11, 2017

Question No. 66

Responding Witness: David S. Sinclair

Q.1-66. Referring to the direct testimony of David S. Sinclair at 26:5 — 27:3:

a. Please define primary' as used in the phrase prima,) combustion turbines.

b. Please define (and if possible, quantify) meaningful as used in the phrase meaningful annual load growth.

c. For each of the past 10 years, please provide KU's annual load growth.

d. Please provide KU's forecast of annual load growth for each of the next 10 years.

A.1-66.

a. See the response to PSC 2-56(a).

b. Meaningful load growth in this context is load growth that would require resource additions in the next three to five years, and would therefore require actions in the near term to begin developing these resources.

c. See attached.

d. See attached.

66c

	Actual Volumes (GWh)	Actual Sales Growth*	WN Volumes (GWh)	WN Sales Growth	Peak Hour (MW)	Peak Growth
2007	21,643	4.69%	21,439	2.35%	4,344	3.26%
2008	21,191	-2.09%	21,079	-1.68%	4,476	3.04%
2009	20,260	-4.39%	20,398	-3.23%	4,640	3.66%
2010	21,938	8.28%	21,234	4.10%	4,517	-2.65%
2011	21,163	-3.53%	21,133	-0.48%	4,292	-4.98%
2012	20,955	-0.98%	21,216	0.39%	4,138	-3.59%
2013	21,269	1.50%	21,262	0.22%	4,193	1.33%
2014	21,610	1.60%	21,253	-0.04%	5,068	20.87%
2015	20,902	-3.28%	20,792	-2.17%	5,112	0.87%
2016	20,757	-0.69%	20,603	-0.91%	4,415	-13.63%

*relative to prior year

66d

	Forecasted Volumes (GWh)	Forecasted Sales Growth**	Forecasted Volumes (GWh)	Forecasted WN Sales Growth	Peak Hour (MW)	Peak Growth
2017	20,160	-2.88%	20,160	-2.15%	4,337	-1.77%
2018	20,167	0.04%	20,167	0.04%	4,333	-0.09%
2019	19,238	-4.61%	19,238	-4.61%	4,319	-0.32%
2020	18,763	-2.47%	18,763	-2.47%	4,155	-3.81%
2021	18,772	0.05%	18,772	0.05%	4,135	-0.48%
2022	18,780	0.04%	18,780	0.04%	4,145	0.24%
2023	18,801	0.11%	18,801	0.11%	4,148	0.09%
2024	18,826	0.13%	18,826	0.13%	4,160	0.29%
2025	18,826	0.00%	18,826	0.00%	4,167	0.16%
2026	18,819	-0.04%	18,819	-0.04%	4,167	-0.01%

**2017 compared to both 2016 actual and 2016 WN; others relative to prior year

KENTUCKY UTILITIES COMPANY

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Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 67

Responding Witness: David S. Sinclair

Q.1-67. Please provide KU's current estimated cost in current dollars of an installed combustion turbine. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this estimate.

A.1-67. The Companies' current estimated combustion turbine capital cost is $624/kW in 2016 dollars. See the Companies' 2014 Integrated Resource Plan ("IRP"), Volume III, "2014 Reserve Margin Study" and "2014 Resource Assessment" reports. The Companies' estimated cost data for a simple-cycle combustion turbine in 2013 dollars can be found in Section 4.4.1, Table 5, on page 15 of the "2014 Reserve Margin Study." The 2014 IRP value in 2013 dollars was escalated at 2 percent per year to 2016 dollars.

See also the response to AG 1-279.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 68

Responding Witness: David S. Sinclair

Q.1-68. Please provide a levelized fixed charge rate for a new combustion turbine using KU's cost of capital and tax rates. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this response.

A.1-68. The levelized fixed charge rate for a new combustion turbine is 8.13%. See attached.

Generation Planning & Analysis
Revenue Requirement Model
For Fixed Charge Rate & Levelized Cost Factor

Assumptions

Book Basis	$100
Tax Basis	$100
Book Life - Years	30
Tax Life - Years	15
Months in First Year	12
Base Property Tax Rate	0.150%
Property Tax Rate Escalation	0.00%
O&M Escalation Rate	2.000%
O&M Base	$1
Discount Rate	10.62%
Cost of Capital	6.49%
Income Tax Rate	38.900%
Insurance Rate	0.085%
Insurance Escalation Rate	0.00%
Tax Equivalent Rate	0.00%

Fixed Charge Rate	**0.0813**
Levelized Cost Factc	**0.73**

CAPITAL STRUCTURE

Debt	47.00%	4.13%
Common	53.00%	10.0%

Tax Depreciation Schedule	macrs									
		1	1	1	1	1	1	1	1	1
	Year	1	2	3	4	5	6	7	8	9
	Months	12	12	12	12	12	12	12	12	12
Deferred Taxes										
Tax Depreciation		5.00	9.50	8.55	7.70	6.93	6.23	5.90	5.90	5.90
Book Depreciation		1.67	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33
Deferred Tax		1.30	2.40	2.03	1.70	1.40	1.13	1.00	1.00	1.00
Rate Base	Constr Period									
Beginning Balance	100	100	97	91	86	81	76	72	67	63
Less: Book Depreciation		(1.67)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)
Less: Deferred Taxes	-	(1.30)	(2.40)	(2.03)	(1.70)	(1.40)	(1.13)	(1.00)	(1.00)	(1.00)
Ending Balance	100	97	91	86	81	76	72	67	63	59
EndYear Rate Base		97	91	86	81	76	72	67	63	59
Debt Return (Interest)		1.88	1.77	1.67	1.57	1.48	1.39	1.31	1.22	1.14
Preferred Stock Return		-	-	-	-	-	-	-	-	-
Common Equity Return		5.14	4.84	4.55	4.29	4.04	3.80	3.57	3.34	3.11
Property Tax		0.075	0.148	0.143	0.138	0.133	0.128	0.123	0.118	0.113
A&G		0.042	0.085	0.085	0.085	0.085	0.085	0.085	0.085	0.085
Revenue Requirements (non-equity)		3.67	5.34	5.23	5.13	5.03	4.94	4.85	4.76	4.67
Revenue Requirements (equity)		8.42	7.92	7.45	7.02	6.61	6.22	5.85	5.47	5.09
Discount Rate		1.00	0.94	0.88	0.83	0.78	0.73	0.69	0.64	0.60
Present Value	$128.00	12.08	12.45	11.19	10.06	9.05	8.15	7.33	6.59	5.91
Fixed Charge Rate		8.13%								
O&M		1	1	1	1	1	1	1	1	1
Present Value		0.90	0.83	0.77	0.71	0.65	0.60	0.56	0.51	0.47
Levelized Cost Factor		0.73								
		$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13
	$128.00	$8.13	$7.63	$7.17	$6.73	$6.32	$5.93	$5.57	$5.23	$4.92

Generation Planning & Analysis
Revenue Requirement Model
For Fixed Charge Rate & Levelized Cost Factor

Assumptions

Book Basis	$100
Tax Basis	$100
Book Life - Years	30
Tax Life - Years	15
Months in First Year	12
Base Property Tax Rate	0.150%
Property Tax Rate Escalation	0.00%
O&M Escalation Rate	2.000%
O&M Base	$1
Discount Rate	10.62%
Cost of Capital	6.49%
Income Tax Rate	38.900%
Insurance Rate	0.085%
Insurance Escalation Rate	0.00%
Tax Equivalent Rate	0.00%

Tax Depreciation Schedule	macrs									
		1	1	1	1	1	1	1	1	1
	Year	10	11	12	13	14	15	16	17	18
	Months	12	12	12	12	12	12	12	12	12
Deferred Taxes										
Tax Depreciation		5.90	5.90	5.90	5.90	5.90	5.90	2.95	-	-
Book Depreciation		3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33
Deferred Tax		1.00	1.00	1.00	1.00	1.00	1.00	(0.15)	(1.30)	(1.30)
Rate Base	Constr Period									
Beginning Balance	100	59	54	50	46	41	37	33	30	28
Less: Book Depreciation		(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)
Less: Deferred Taxes	-	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	0.15	1.30	1.30
Ending Balance	100	54	50	46	41	37	33	30	28	25
EndYear Rate Base		54	50	46	41	37	33	30	28	25
Debt Return (Interest)		1.06	0.97	0.89	0.80	0.72	0.64	0.57	1	0
Preferred Stock Return		-	-	-	-	-	-	-	-	-
Common Equity Return		2.88	2.65	2.42	2.19	1.96	1.73	1.57	1.46	1.35
Property Tax		0.108	0.103	0.098	0.093	0.088	0.083	0.078	0.073	0.068
A&G		0.085	0.085	0.085	0.085	0.085	0.085	0.085	0.085	0.085
Revenue Requirements (non-equity)		4.58	4.49	4.40	4.31	4.22	4.14	4.07	4.02	3.98
Revenue Requirements (equity)		4.72	4.34	3.97	3.59	3.21	2.84	2.56	2.39	2.21
Discount Rate		0.57	0.53	0.50	0.47	0.44	0.41	0.39	0.37	0.34
Present Value	$128.00	5.28	4.71	4.19	3.72	3.29	2.89	2.58	2.35	2.13
Fixed Charge Rate										
O&M		1	1	1	1	1	1	1	1	1
Present Value		0.44	0.40	0.37	0.34	0.32	0.29	0.27	0.25	0.23
Levelized Cost Factor										
		$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13
	$128.00	$4.62	$4.33	$4.07	$3.82	$3.59	$3.37	$3.17	$2.97	$2.79

Generation Planning & Analysis
Revenue Requirement Model
For Fixed Charge Rate & Levelized Cost Factor

Assumptions

Book Basis	$100
Tax Basis	$100
Book Life - Years	30
Tax Life - Years	15
Months in First Year	12
Base Property Tax Rate	0.150%
Property Tax Rate Escalation	0.00%
O&M Escalation Rate	2.000%
O&M Base	$1
Discount Rate	10.62%
Cost of Capital	6.49%
Income Tax Rate	38.900%
Insurance Rate	0.085%
Insurance Escalation Rate	0.00%
Tax Equivalent Rate	0.00%

Tax Depreciation Schedule	macrs									
		1	1	1	1	1	1	1	1	1
	Year	19	20	21	22	23	24	25	26	27
	Months	12	12	12	12	12	12	12	12	12
Deferred Taxes										
Tax Depreciation		-	-	-	-	-	-	-	-	-
Book Depreciation		3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33
Deferred Tax		(1.30)	(1.30)	(1.30)	(1.30)	(1.30)	(1.30)	(1.30)	(1.30)	(1.30)
Rate Base	Constr Period									
Beginning Balance	100	25	23	21	19	17	15	13	11	9
Less: Book Depreciation		(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)	(3.33)
Less: Deferred Taxes	-	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Ending Balance	100	23	21	19	17	15	13	11	9	7
EndYear Rate Base		23	21	19	17	15	13	11	9	7
Debt Return (Interest)		0	0	0	0	0	0	0	0	0
Preferred Stock Return		-	-	-	-	-	-	-	-	-
Common Equity Return		1.24	1.13	1.03	0.92	0.81	0.70	0.59	0.49	0
Property Tax		0.063	0.058	0.053	0.048	0.043	0.038	0.033	0.028	0.023
A&G		0.085	0.085	0.085	0.085	0.085	0.085	0.085	0.085	0.085
Revenue Requirements (non-equity)		3.94	3.89	3.85	3.80	3.76	3.71	3.67	3.62	3.58
Revenue Requirements (equity)		2.03	1.86	1.68	1.50	1.33	1.15	0.97	0.80	0.62
Discount Rate		0.32	0.30	0.28	0.27	0.25	0.24	0.22	0.21	0.20
Present Value	$128.00	1.93	1.74	1.57	1.42	1.28	1.15	1.03	0.92	0.82
Fixed Charge Rate										
O&M		1	1	1	2	2	2	2	2	2
Present Value		0.21	0.19	0.18	0.16	0.15	0.14	0.13	0.12	0.11
Levelized Cost Factor										
		$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13	$8.13
	$128.00	$2.62	$2.46	$2.31	$2.17	$2.04	$1.91	$1.80	$1.69	$1.59

Generation Planning & Analysis
Revenue Requirement Model
For Fixed Charge Rate & Levelized Cost Factor

Assumptions

Book Basis	$100
Tax Basis	$100
Book Life - Years	30
Tax Life - Years	15
Months in First Year	12
Base Property Tax Rate	0.150%
Property Tax Rate Escalation	0.00%
O&M Escalation Rate	2.000%
O&M Base	$1
Discount Rate	10.62%
Cost of Capital	6.49%
Income Tax Rate	38.900%
Insurance Rate	0.085%
Insurance Escalation Rate	0.00%
Tax Equivalent Rate	0.00%

Tax Depreciation Schedule	macrs				
		1	1	1	0
	Year	28	29	30	31
	Months	12	12	12	12
Deferred Taxes					
Tax Depreciation		-	-	-	-
Book Depreciation		3.33	3.33	3.33	1.67
Deferred Tax		(1.30)	(1.30)	(1.30)	(0.65)
Rate Base	Constr Period				
Beginning Balance	100	7	5	3	1
Less: Book Depreciation		(3.33)	(3.33)	(3.33)	(1.67)
Less: Deferred Taxes	-	1.30	1.30	1.30	0.65
Ending Balance	100	5	3	1	0
EndYear Rate Base		5	3	1	0
Debt Return (Interest)		0	0	0	0
Preferred Stock Return		-	-	-	-
Common Equity Return		0	0	0	0
Property Tax		0.018	0.013	0.008	0.000
A&G		0.085	0.085	0.085	0.042
Revenue Requirements (non-equity)		3.53	3.49	3.45	1.71
Revenue Requirements (equity)		0.44	0.27	0.09	0.00
Discount Rate		0.18	0.17	0.16	0.15
Present Value	$128.00	0.73	0.65	0.57	0.26
Fixed Charge Rate					
O&M		2	2	2	2
Present Value		0.10	0.09	0.09	0.08
Levelized Cost Factor					
		$8.13	$8.13	$8.13	$8.13
	$128.00	$1.49	$1.40	$1.31	$1.23

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 69

Responding Witness: David S. Sinclair

Q.1-69. Please provide the estimated fixed O&M for a new combustion turbine in current dollars. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this response.

A.1-69. The Companies' current estimated combustion turbine fixed O&M cost is $29.7/kW-yr in 2016 dollars, which comprises $21.9/kW-yr for firm gas transport and $7.7/kW-yr for other fixed O&M. See the response to Question No. 67. The 2014 IRP values in 2013 dollars were escalated at 2 percent per year to 2016 dollars.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 70

Responding Witness: David S. Sinclair

Q.1-70. Please provide KU's required reserve margin for capacity planning. Provide all workpapers, studies, analyses, and documents supporting and/or underlying this response.

A.1-70. The Companies target a 16% minimum planning reserve margin. See the Companies' 2014 Integrated Resource Plan ("IRP"), Volume III, "2014 Reserve Margin Study." See also the response to AG 1-279.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 71

Responding Witness: Robert M. Conroy

Q.1-71. Please provide a copy of KU's most recent integrated resource plan.

A.1-71. See the response to AG 1-279.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 72

Responding Witness: David S. Sinclair

Q.1-72. Please provide all workpapers, studies, analyses, and documents underlying and supporting KU's proposed change in the natural gas price index used to determine the automatic buy-through price in Rider CSR.

A.1-72. See the response to Question No. 49(a).

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 73

Responding Witness: Robert M. Conroy

Q.1-73. Referring to the direct testimony of Robert M. Conroy at 16:20-24:

a. Explain in detail the conditions under which KU would no longer "continue to allow the current customers under the CSR service schedule to remain CSR customers for an indefinite period of time...."

b. Explain in detail why "the Company is not proposing to remove CSR from its tariff at this time."

A.1-73.

a. KU has not established such a set of conditions.

b. KU is not proposing the remove CSR from its tariff at this time because existing CSR customers' curtailable load is included as a resource in existing plans and could help KU meet its reserve margin requirements in the future.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated February 7, 2017

Question No. 25

Responding Witness: Robert M. Conroy

Q.2-25. Referring to KU's response to KIUC 1-49(c), Attachment 1:

a. Did KU conduct similar rate comparisons for CSR customers that did not request such comparisons?

b. If the answer to the preceding request is yes, please provide such comparisons in native format with working formulas and all links intact.

A.2-25.

a. No, KU did not conduct similar rate comparisons for CSR customers that did not request such comparisons.

b. Not applicable.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 7, 2017

Question No. 26

Responding Witness: David S. Sinclair

Q.2-26. Referring to KU's responses to KIUC 1-56(c)-(e):

a. Please explain in detail whether CSR load subject to a 10-minute notice of interruption would qualify as operating reserve as defined in the response to KIUC 1-56(c).

b. Explain in detail how KU treats load subject to the interruption provisions of Rate FLS (System Contingencies and Industry Performance Criteria section) in meeting system operating reserve requirements.

A.2-26.

a. As indicated in the response to KIUC 1-56(c), for curtailable load to qualify as operating reserves, the curtailable load must be fully removable from system load within a 15 minute period. Therefore, the load must first be in place on the system (the Company cannot be assured that the curtailable customer has load to reduce) and second, must be removable within a 15 minute period. Thus, if a CSR load was subject to a 10-minute notice, the load must first be occurring on the system and second must be removed within 5 minutes after the 10-minute notice period expired. Furthermore, for interruptible load to qualify as operating reserve, no restrictions on the number or frequency of requests could be in place.

b. KU does not consider FLS load in meeting its operating reserve requirements, which consist of spinning reserves and non-spinning (supplemental) reserves. Both spinning and supplemental reserves must be available to serve load within a 15 minute period. For curtailable load to qualify as operating reserves, the curtailable load must be fully removable from system load within a 15 minute period. The execution of a FLS interruption requires a 5 minute notice, can last no longer than ten minutes, and may not be fully removable from the system. Therefore, FLS does not qualify as an operating reserve and is not considered when determining the need for operating reserve capacity.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 7, 2017

Question No. 27

Responding Witness: David S. Sinclair

Q.2-27. Referring to KU's response to KIUC 1-63(b):

a. Please describe and explain in detail the justification for the August 2010 change in Rider CSR that restricted interruption requests to periods in which all generating units were dispatched.

b. Please identify each occasion and the exigent circumstances under which KU would have invoked a physical curtailment of CSR load since January 2014 to the present if the interruption restriction noted in the preceding request had not been in place.

A.2-27.

a. Prior to August 2010, the CSR tariff effective February 6, 2009 allowed for curtailments for any reason for a limited number of hours annually.

Effective February 6, 2009, the CSR1 tariff stated:

> "Customer may, at Customer's option, contract with Company to curtail service upon notification by Company. Requests for curtailment shall not exceed two hundred (200) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with no more than two (2) requests for curtailment per calendar day within these parameters. Company may request or cancel a curtailment at any time during an hour, but shall give no less than twenty (20) minutes notice when either requesting or canceling a curtailment."

Effective August 1, 2010, the CSR10 tariff stated:

> "Company may request at its sole discretion up to 100 hours of physical curtailment per year without a buy-through option during system reliability events. For the purposes of this rider, a system reliability event

is any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing ("ARS") at some point during the event."

This new language was agreed to as part of the settlement in the June 7, 2010 Stipulation and Recommendation (pages 111 and 114) between the Companies and several parties (including the Kentucky Industrial Utility Customers, Inc.) in the rate proceedings in Case No. 2009-00548. The Stipulation and Recommendation can be found at: http://psc.ky.gov/PSCSCF/2009%20cases/2009-00548/20100608_KU_and_LGE_Stipulation_and_Recommendation.PDF.

Note, the new language did not explicitly restrict "interruption requests to periods in which all generating units were dispatched" although as a practical matter, the circumstances described in the tariff would likely result in all available units being committed.

b. See the response to KIUC 1-63b. As stated, the Company is not able to identify the specific hours for additional physical curtailment. Also see the Company's response to KIUC 1-62.

KENTUCKY UTILITIES COMPANY

CASE NO. 2016-00370

Response to the Attorney General's Supplemental Data Requests
Dated February 7, 2017

Question No. 76

Responding Witness: John P. Malloy / David S. Sinclair

Q-76. Provide:

a. The cost per avoided MW used for the cost-benefit tests in the Companies' most recent DSM application (2014-00003).

b. The cost per (avoided) MW used in the Companies' most recent Integrated Resource Plan (2014-00131).

A-76.

a. The cost per avoided MW used in DSM application 2014-00003 was \$99.92/kW-year.

b. The cost per avoided MW used in the Companies' 2014 Integrated Resource Plan was \$99.92/kW-year.

EXHIBIT DWG-3

BIP ANALYSIS OF CSR CREDITS

Kentucky Utilities Company and Louisvillle Gas & Electric Company
Production Costs functionalized to Peak
Based on 12 Months Ended June 30, 2018

Description			KU BIP Peak Unadjusted	LGE BIP Peak Unadjusted	Combined BIP Peak Unadjusted
Plant			$ 1,270,954,484	$ 741,780,593	$ 2,012,735,077
Accumulated Depreciation			$ 506,456,928	$ 286,222,757	$ 792,679,685
Net Plant			$ 764,497,556	$ 455,557,836	$ 1,220,055,392
Total Working Capital			28,600,478	22,043,175	$ 50,643,653
Accumulated Deferred Income Taxes			156,281,533	90,683,035	$ 246,964,568
Accumulated Deferred Investment Tax Credit			24,034,541	-	$ 24,034,541
Net Cost Rate Base			$ 612,781,961	$ 386,917,976	$ 999,699,937
Rate of Return			7.29%	7.23%	
Return			$ 44,671,045	$ 27,975,999	$ 72,647,044
Depreciation Expenses			$ 45,505,094	$ 24,484,475	$ 69,989,569
Non-Burdened Non-Fuel Operation and Maintenance Expenses			$ 33,774,624	$ 23,807,553	$ 57,582,177
Burdened Non-Fuel Operation and Maintenance Expenses					
Income Taxes	0.3856	0.3864	$ 20,951,836	$ 13,307,334	$ 34,382,845
Property Taxes (& Other for LGE)			$ 4,462,862	$ 5,416,077	$ 9,878,939
Other Taxes (KU)			$ 2,317,433		$ 2,317,433
Amortization of ITC (LGE)				$ (166,921)	$ (166,921)
Revenue Requirement			$ 151,682,894	$ 94,824,518	$ 246,631,087
Nameplate Capacity					
Cost per kW per Month (Nameplate Capacity)					
Net Peak Demand on Plant (Form 7, Pages 402-403, line 6)			1,492,399	827,855	2,320,253
Cost per kW per Month (Net Peak Demand on Plant)			$ 8.47	$ 9.55	$ 8.86
Loss Factor (Transmission)			0.0281	0.0281	0.0281
Cost per kW per Month (Transmission)			$ 8.71	$ 9.82	$ 9.11
Loss Factor (Primary)			0.0613	0.0613	0.0613
Cost per kW per Month (Primary)			$ 9.02	$ 10.17	$ 9.44

	KU	LGE	Combined
Thompson Summer Peak Capacity	5,041,120	2,796,380	7,837,500
BIP Peak Functionalization Factor	29.60%	29.60%	
Summer Peak Capacity Functionalized to BIP Peak	1,492,399	827,855	2,320,253