COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application of Kentucky Power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief

CASE No. 2017-00179

DIRECT TESTIMONY OF DAVID E. DISMUKES, PH.D.

On Behalf of
Office of the Kentucky Attorney General

October 3, 2017
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I. INTRODUCTION AND QUALIFICATIONS

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?
A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?
A. I am a Consulting Economist with the Acadian Consulting Group, LLC (“ACG”) a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?
A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University (“LSU”). I am also a full Professor in the Department of Environmental Sciences and the Director of the Coastal Marine Institute in the College of the Coast and Environment at LSU. I also serve as an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), and I am a member of the graduate research faculty at LSU.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. I have been retained by the Kentucky Attorney General’s Office of Rate Intervention (“Attorney General”) to provide an expert analysis and opinion regarding several rate design proposals offered by Kentucky Power Company (“KPCo” or the “Company”) in this proceeding. Specifically, I was asked to evaluate the proposed rate design in the context of the economic hardships present in the Company’s eastern Kentucky service territory. I have
also reviewed the Company’s proposal to increase its monthly Kentucky Economic
Development Surcharge (“KEDS”) used to support the Company’s economic development
initiatives.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The balance of testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Overview of the Eastern Kentucky Economy
- Section IV: Revenue Distribution and Rate Design
- Section V: The Company’s Economic Development Programs and Surcharge Proposal
- Section VI: Conceptual Issues with the K-PEGG Program
- Section VII: Proposed K-PEGG Expansion and the Eastern Kentucky Economy
- Section VIII: Conclusions and Recommendations

Q. HAVE YOU PREPARED ANY EXHIBITS SUPPORTING YOUR DIRECT TESTIMONY?

A. Yes. Attachment A to my testimony provides my academic vita that includes a full
listing of my publications, presentations, pre-filed expert witness testimony, expert reports,
expert legislative testimony, and affidavits. In addition, I have prepared nine (9) exhibits in
support of my testimony.

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING THE ECONOMIC IMPACTS ASSOCIATED WITH THE COMPANY’S OVERALL RATE INCREASE PROPOSAL?
A. This increase comes at a very inopportune time for Eastern Kentucky ratepayers. These ratepayers have experienced considerable economic hardships dating back to the last economic recession and, in many instances, are still feeling the lingering impacts of this economic downtown and the change in public policy prejudicing the use of coal as a primary fuel. While there is some evidence that the Eastern Kentucky economy is starting to turn around, this potential economic turn-around does not support laddering the region with additional electric utility rate increases; affordability is still a real and important issue for many households in this region. Further, these ratepayers have seen considerable cumulative rate increases over the past several years and the addition of yet another additional rate increase will likely be overly-burdensome to many households, particularly many working and lower-income families. Lastly, the Company’s rates are already relatively high, as compared with other regional peer utilities. As I will show later in my testimony, the Company’s customer and energy charges are some of the highest in the region: this rate increase will, at best, maintain what are already high and unattractive electricity service rates, and, at worst, will exacerbate what is already a bad situation. Thus, I am recommending that the Commission limit any revenue increase in this matter. This recommendation is based on a number of considerations that I discuss further in my testimony but include: (a) a finding by other Attorney General witnesses that the merits and cost information upon which this rate request are based are questionable; (b) KPCo’s customers are unable to afford any rate increase, and (c) a large rate increase to the extent the Company proposes at this time would set the entire economy of Eastern Kentucky back, counteracting any economic expansion that is on the horizon.
Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY’S PROPOSED RATE DESIGN?

A. I recommend that the Commission reject the Company’s proposal to increase customer charges for any customer class. Residential customers, in particular, have seen significant increases to electric rates in recent years, and a noticeable shift towards fixed cost recovery.¹ Increases in fixed charges for these customers disproportionately hurt low-income customers in a region that has seen significant hardship in recent years. The Company has ultimately not provided sufficient evidence to justify its proposal. In fact, as I will show later, all of the Company’s customer-related costs are already recovered in its fixed customer charge, undermining its purported cost-based justification for considerably higher residential monthly customer charges.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY’S PROPOSED INCREASE IN ITS KEDS?

A. I recommend that the Commission reject the Company’s proposal to increase its KEDS. Furthermore, I recommend that the Commission eliminate the Company’s KEDS, and its associated K-PEGG program since it (1) is not an economically efficient use of ratepayer dollars and (2) the current program suffers from a large number of accountability deficiencies that shift a large amount of the program’s economic development performance risk away from the Company and onto ratepayers.

III. OVERVIEW OF THE ECONOMY OF EASTERN KENTUCKY

¹ By law, KPCo has for many years been allowed to recover fuel and environmental costs via separate monthly surcharges. In addition, in KPCo’s last base rate case, Case No. 2014-00396, the Commission approved several new tracking mechanisms, including: (a) the BS1OR, which has authorized the company to collect operating costs of its Big Sandy 1 generating unit; and (b) the Big Sandy Retirement Rider, through which the company collects costs of the retirement of Big Sandy Unit 2 and so much of Big Sandy 1 that involved its then coal-firing.
A. Eastern Kentucky Economy post Economic Recession

Q. HAVE YOU EXAMINED HISTORIC KENTUCKY EMPLOYMENT TRENDS?

A. Yes. Exhibit DED-1 presents historic quarterly employment for the Eastern Kentucky region and the state overall. This analysis covers the period starting with the second quarter of 2001 and ending with the second quarter of 2016. In general, Kentucky has seen significant employment declines since the economic recession starting in 2008. Indeed, employment in the state peaked in the fourth quarter of 2007, before declining and ultimately stagnating for years. Kentucky employment did not return to those late 2007 levels again until the fourth quarter, 2014, a full seven years later. Employment in Eastern Kentucky has suffered even greater than the state as a whole over the past decade. Eastern Kentucky employment peaked in the second quarter of 2006, over a decade ago, with a reported employment level of 124,381 jobs and to this date, has not recovered to those levels. The current Eastern Kentucky employment is over 19,000 jobs, or 15.5 percent, lower than levels reported a decade earlier.

Q. HAVE YOU EXAMINED THE HISTORIC MONTHLY EARNINGS ACROSS KENTUCKY?

A. Yes. Exhibit DED-2 presents historic monthly average earnings for both the state and Eastern Kentucky. This analysis shows that while the State was impacted hard during the recent economic recession, average monthly earnings have remained stable, growing consistently even in the face of a weakening labor market. The same earnings trends, however, cannot be said for Eastern Kentucky.
Q. **HOW HAVE EASTERN KENTUCKY WORKERS FAIRED RELATIVE TO WORKERS ELSEWHERE IN THE STATE?**

A. Eastern Kentucky has historically reported average earnings that are between 10 to 20 percent lower than the state-wide average. Over the past decade, Eastern Kentucky’s average wages have tended to stagnate while those elsewhere in the state have increased by moderate amounts (at least, post-recession). There was a time, more recently, where this differential was starting to close to around the 10 percent, rather than 20 percent boundary of this range. However, over the past several years, the progress in closing that relative wage differential has contracted, and wages in Eastern Kentucky are now back up to a level that is 20 percent lower than the statewide average.

Q. **WHAT DOES THIS MEAN FOR THE EASTERN KENTUCKY ECONOMY?**

A. Eastern Kentucky has been economically depressed for the past decade. Whereas Kentucky as a whole mostly weathered the recent economic recession, Eastern Kentucky suffered immensely. The Commission should take the economic conditions of the region into consideration in evaluating the Company’s overall rate and rate design proposals particularly as they relate to important public policy issues such as affordability and rate continuity.

Q. **HAS THE COMPANY PROVIDED ANY INFORMATION THAT SUPPORTS THE CONTENTION THAT CUSTOMERS IN ITS SERVICE TERRITORY ARE STRUGGLING FINANCIALLY?**

A. Yes. In response to discovery, the Company has separately provided information on (1) the number of customers within its service territory that have made at least one late payment since August 2014,² and (2) the numbers of customers during the same time period.

² Company’s Response to Data Request AG 2-003.
that have experienced service disconnections due to delinquencies. The Company’s analysis shows that for the period August 2014 through July 2015, 457,559 late payments were made by residential customers. This amount has only grown in recent years, with the period August 2016 through July 2017 seeing 473,760 late payments, a growth of over 3.5 percent.

Q. WHAT DOES THE COMPANY’S DISCONNECTED SERVICE INFORMATION SHOW?

A. The Company’s data shows that for accounts receiving multiple disconnects for nonpayment it disconnected 1,386 accounts on more than one occasion in 2015 due to nonpayment with an increase to 1,469 customers receiving multiple disconnects for nonpayment in 2016. Customer disconnection information is only available for the first seven months of 2017, January through July. However, in these seven months, the Company has disconnected 933 accounts, an average rate of more than 133 customers per month. If the rate of disconnections continues through the remainder of the year, the Company will have disconnected nearly 1,600 customers by the end of 2017. This would amount to an 8.2 percent increase year-over-year.

Q. PLEASE DISCUSS THE COMPANY’S HISTORIC RATE INCREASES.

A. Exhibit DED-3 examines the Company’s historic rates for residential customers from March 2006 (decided in Case No. 2005-00341) through the Company’s current filing. The analysis shows that the Company’s residential rates have been increasing rapidly in the past few years. From the Company’s 2005 rate case, through its 2014 rate case in Case No. 2014-00396, the Company has increased its customer charge to residential customers by 87.71 percent, or an average annual increase of 9.48 percent per year over a roughly nine-year period.

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3 Company’s Response to Data Request AG 2-004.
period. Likewise, the Company increased its variable energy charge to residential customers by 48.45 percent over the same period, or an average annual increase of 5.24 percent per year.

Q. **WHAT HAVE THESE HISTORIC RATE INCREASES MEANED FOR THE COMPANY’S AVERAGE RESIDENTIAL CUSTOMER?**

A. Exhibit DED-3 also shows the impact that these historic rate increases have meant for average customers. This analysis is developed from the Company’s 2016 annual report filed with the Federal Energy Regulatory Commission (“FERC”), commonly referred to as a FERC Form 1. That annual report lists 2016 average residential customer use as being 1,295 kWh per month. In 2006, a customer using this amount of electricity would see a non-fuel electric bill of $83.59 per month. By 2015, after Case No. 2014-00396, this same customer would have seen a non-fuel electric bill of $126.38 per month. This is an increase of 51.2 percent over a roughly nine year period, or approximately 5.54 percent in annual electric bills. This annualized level of increase is greater than both the national average,⁴ as well as the average rate of inflation in the economy over a comparable period of time.

Q. **DO THE COMPANY’S PROPOSED RESIDENTIAL RATES IN THE CURRENT PROCEEDING EXACERBATE THE ALREADY HIGH RATE INCREASES SEEN IN RECENT YEARS?**

A. Yes. Exhibit DED-3 shows that the Company’s proposed rate increase to residential customers will increase what is already a very heavy burden for electric service. If the Company’s current proposal is allowed, residential customers will have seen a 198.63 percent increase in fixed customer charges since 2006. This represents a nearly threefold increase in residential customers’ fixed charges over a roughly 11-year period, or approximately 17.53

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⁴ See, U.S. Bureau of Labor Statistics, Consumer Price Index (“CPI”) for All Urban Consumers; the average inflation rate for U.S. urban consumers has been 2.0 percent over the last decade (January 2007 through January 2017).
percent per year. Likewise, energy charges for residential customers will have increased by
80.82 percent since 2006 or by 7.13 percent on an annualized basis. Again, these represent
annual average increases that exceed the U.S. electric utility average as well as the overall
rates of inflation seen in the economy over a comparable time period.

Q. HOW WILL THE COMPANY’S PROPOSED INCREASE IMPACT THE
AVERAGE MONTHLY ELECTRIC BILL OF A TYPICAL RESIDENTIAL
CUSTOMER?

A. Exhibit DED-3 shows the impact that the Company’s proposed rate increase will have
on an average monthly bill for a standard residential customer using 1,295 kWh per month.
These typical customers will likely see their bills increase to $158.05 per month, which is
more than a 25 percent increase to the current typical monthly bill of $126.38. However,
when placed in context of the Company’s historic rate increases, the average residential
customer using 1,295 kWh per month has seen an increase in his/her monthly utility bill of
89.08 percent (nearly double) since 2006. This means that over a roughly 11 year period,
residential customers have seen an increase in their base electric bills of approximately 7.86
percent per year.

Q. IS IT LIKELY THAT THE COMPANY’S RATE INCREASES HAVE
ADVERSELY IMPACTED LOW-USE CUSTOMERS?

A. Yes. While the Company’s historic and proposed rate increases have significantly
impacted all of its residential customers, these historically high rate increases have likely
impacted lower use customers proportionally more than those exhibiting higher levels of use.
Exhibit DED-3 shows that residential customers using one-half the residential average
(discussed above) have seen total base utility rates increase by 53.59 percent for the period
2006 through 2015, or an average of 5.79 percent per year. A customer using 150 percent of
the system average per month has seen rates increase by 50.33 percent over the same period,
or approximately 5.44 percent per year.

Q. DOES THE COMPANY’S CURRENT PROPOSED RATE DESIGN
EXACERBATE THIS LOW-USE/HIGH-USE BILL DIFFERENTIAL?
A. Yes. Under the Company’s proposed residential rates, a customer using half of the
residential monthly average will see rates that are 96.25 percent greater than in 2006, just 11
years ago. This is an increase of approximately 8.49 percent per year. Likewise, a customer
using 150 percent of residential average, while seeing significant increases to electric rates,
sees a lower percent increase than a low-use customer. Specifically, a customer using 150
percent of the residential average will have seen electric rates that are 86.46 percent greater
than those in 2006 if the Company’s proposed rates are approved. This is an average increase
of 7.63 percent per year for these customers.

Q. HAVE YOU EXAMINED THE IMPACT OF THE COMPANY’S PROPOSED
RATE INCREASE ON THE ABILITY OF EASTERN KENTUCKY CUSTOMERS TO
PAY FOR THEIR ELECTRICAL SERVICE?
A. Yes. As noted earlier, Eastern Kentucky has seen significant economic hardship over
the last few years, this while seeing increasing electrical rates from KPCo. Over the 12 month
period stretching from the 3rd quarter 2015 through the 2nd quarter of 2016, the Eastern
Kentucky region saw average monthly household wages of approximately $3,097. This
implies that the current typical KPCo monthly bill of $126.38 represents approximately 4.08
percent of the average Eastern Kentucky worker’s total monthly earnings. The Company’s
proposed increase of typical residential utility bills to $158.05 per month increases this
percentage of average monthly earnings to 5.10 percent. In other words, under the Company’s proposed increase in residential rates, the average Eastern Kentucky citizen will be devoting over 1/20 of their month earnings, or approximately one-half of one day of a bi-weekly pay cycle, towards paying their rate obligation. This is just for the average worker in Eastern Kentucky, and lower income customers will see a higher relative burden.

Q. ARE YOU CONCERNED WITH THE IMPACT ANY INCREASE IN ELECTRICITY RATES MAY HAVE ON CUSTOMER ENERGY USAGE?

A. Yes. It is well-known in economics that there exists an inverse relationship between electric usage and price. This relationship is referred to as the price elasticity of demand. While the price elasticity of demand for electricity is low, it is not zero. In practical terms, this means that, holding other factors constant, any proposed increase in electricity rates will be accompanied by a reduction in customer usage. This is simply the natural reaction of demand whenever costs are increased. As demand decreases in reaction to price increases, this has the potential to create a revenue requirement shortfall in the future, leading to future rate increases.

Q. IN WHAT OTHER WAYS COULD RATEPAYERS REACT TO CASCADING RATE INCREASES?

A. Ratepayers of all rate classes could move to other electric utilities’ service territories. In many states, industrial customers that are very sensitive to any utility price increase have already chosen that option. The Company has already provided data that shows that the total number of customers is steadily decreasing in its territory, and increases in electricity will likely exacerbate this phenomenon.
Q. ARE THERE OTHER NEGATIVE IMPACTS ASSOCIATED WITH INCREASING ELECTRICITY RATES?

A. Yes. As noted later in this testimony, increasing electric rates reduces customers’ disposable income, and the ability of customers to purchase other goods and services. In this manner increasing electricity rates customers pay causes a negative ripple-effect through the economy and impacts overall economic growth. The Company’s proposed increase in electric utility rates runs the risk of harming the economic development of the region it has devoted much effort to improving.

B. Company’s Historic Rates

Q. HAVE YOU REVIEWED THE COMPANY’S RATES AGAINST OTHER REGIONAL UTILITIES?

A. Yes, and this analysis is presented in Direct Exhibit DED-4. For this analysis, I collected and utilized information submitted in the FERC Form 1 for regional peer utilities. I have presented an estimated base rate for residential, commercial, and industrial customers in overall rate terms, as well as a rank ordering (from lowest to highest rate) for each regional utility for the years 2007 through 2016.

Q. WHAT DOES THIS COMPARISON OF PEER UTILITY AVERAGE RESIDENTIAL RATES SHOW?

A. The Company’s 2016 average residential rate is estimated to be 6.18 percent lower than the peer average rate per customer. However, the Company’s 2016 residential rates are nearly 31.1 percent higher than its rates in 2015. Prior to 2016, the Company had one of the lowest base residential rates in the region, however, by 2016 it had fallen to 5th position out of 13 peer utilities.
Q. HAS THE COMPANY PREPARED ANY INTERNAL COMPARISONS OF ITS RATES TO OTHER PEER UTILITIES?

A. No. While the Company states that it uses semi-annual rate comparison of the Edison Electric Institute (“EEI”) to compare its residential and industrial rates to other utilities, the Company has not conducted any analyses to evaluate the competitiveness of its rates nor has it made any such comparisons available to intervenors, including the Attorney General, in this proceeding.⁵

IV. REVENUE DISTRIBUTION AND RATE DESIGN

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE DISTRIBUTION PROCESS IN SETTING RATES.

A. The revenue distribution process allocates a utility’s overall revenue deficiency across customer classes, which in turn, is used to establish a new set of retail rates to be applied prospectively. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class’ billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

⁵ Company’s Response to AG_1_384.
A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis could result in a very significant and adverse rate impact for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a set of broad ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. There are several generally-accepted rate making principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the principles I mentioned above. However, any principle’s relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universally-accepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. HAS THE COMMISSION COME TO SIMILAR RATE DESIGN CONCLUSIONS?
A. Yes, the Commission has a long standing precedent of using gradualism when setting rates.  

A. Revenue Distribution

Q. WHAT IS THE COMMISSION’S GENERAL POLICY ON REVENUE DISTRIBUTION?

A. The Commission has generally used the cost of service study as a guide when allocating the revenue requirement among the rate classes. However, in the instance that the Commission finds the cost of service study to be insufficient or unreasonable the Commission has used total revenue when assigning the revenue increase or decrease to each rate class. Thus, the Commission has found that holding slavishly to strict CCOSS results can be counterproductive under certain circumstances.

Q. PLEASE EXPLAIN HOW THE COMPANY HAS PROPOSED TO DISTRIBUTE ITS CLASS REVENUE REQUIREMENTS.

A. The Company states that, consistent with the Commission’s long-standing policy of gradualism, its application makes small movement towards an equalized rate of return across all customer classes. As a result the Company is proposing to reduce the residential class

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9 Direct Testimony of Ranie K. Wohnhas, 8:19-22.
“subsidy” by five percent. The Company has proposed to allocate the revenue requirement in proportion to each customer class’s rate base.

B. Rate Design

Q. WHAT ARE THE COMPANY’S RATE DESIGN GOALS?

A. The Company does not outline its specific rate design goals but does state that its underlying approach is to design rates and rate components in a manner that reflects the costs to provide service to each of its customer classes.

Q. PLEASE EXPLAIN HOW RATES WERE DETERMINED IN THE COMPANY’S LAST RATE CASE.

A. The revenue distribution in the Company’s last rate case, Case No. 2014-00396 was the result of a non-unanimous Settlement Agreement that the Commission approved. As a result of the settlement, the Residential class received a 9.89 percent increase, while the remaining classes received increases between 5.13 percent and 8.86 percent.

Q. DOES THE COMPANY PROPOSE CHANGING ANY OF ITS CURRENT RATE STRUCTURES IN THE CURRENT PROCEEDING?

A. Yes. The Company proposes to “refine” its rate design for residential customers, creating a new optional pilot residential demand metering tariff. The Company also

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10 Id., 8:22-23.
11 Company’s response to AG 1 285, Attachment KPCO_R_KPSC 1 73_Attachment 35_KPCO_CCOS_ - Test_Year_2017__DRB__FINAL__KPSC_DR_1-73.xlsx.
12 Direct Testimony of Alex E. Vaughan, 9:6-8.
14 Id., Order, June 22, 2015, Settlement Agreement, Exhibit 1, April 30, 2015.
15 Direct Testimony of Alex E. Vaughan, 9:22 to 10:2.
proposes to combine small and medium general service customers into a newly designed rate structure under a new general service tariff.\textsuperscript{16}

Q. **HOW SHOULD POLICY BALANCE RATE DESIGN GOALS BETWEEN SETTING APPROPRIATE CUSTOMER CHARGES AND VOLUMETRIC RATES?**

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a “two-part tariff,” sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weights of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. **WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?**

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (\textit{i.e.}, fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the “fixed charge-equals-fixed cost” philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

\textsuperscript{16} Id.
C. Customer Charges

Q. DISCUSS THE COMPANY’S RESIDENTIAL CUSTOMER CHARGE PROPOSALS.

A. The Company proposes to increase the fixed basic service or customer charge to $17.50 per month from the current $11.00 per customer per month.17 The Company states that the reason behind its proposed increased in residential customer charges is to “more accurately reflect the actual fixed cost of providing service to those customers.”18 Specifically, the Company argues that the rate structures for customer classes that utilize demand charges are better aligned with cost causation principles than those that do not because fixed costs are generally recovered through a demand charge.19 The Company notes that the current low basic service charge creates intra-class subsidies between customers, specifically disadvantaging higher usage customers including electric heating customers.20

Q. HAS THE COMPANY PROVIDED ANY ESTIMATED TYPICAL BILL IMPACTS?

A. To an extent. The Company provides an analysis of what it characterizes as a demonstration of the intra-class subsidies present in its current residential service schedule.21 The Company states that a Kentucky family using 2,200 kWh on average per month, which the Company represents as being typical of a customer using electric heat, will on average over contribute $290 in intra-class subsidies. The Company also maintains that smaller use customers like a customer using only 1,000 kWh per month or 400 kWh per month will receive subsidies of $58 and $232 per year, respectively.

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17 Id., 10:5-6.
18 Id., 10:10.
21 Id., 11:9.
Q. PLEASE EXPLAIN HOW THE COMPANY DEVELOPED ITS PROPOSED RESIDENTIAL CUSTOMER CHARGE.

A. The Company states that it calculated a fixed monthly customer charge at full cost of service rates to be approximately $38 per month. In other words, $38 was calculated by the Company as representing the fixed portion of the distribution system used to serve the residential class. No specific reason is given to support the Company’s proposed $17.50 basic service charge position, besides that it is consistent with the principle of gradualism when considered against the potential for a customer charge of $38 per month.22

Q. HOW DID THE COMPANY ARRIVE AT ITS ESTIMATED MONTHLY FIXED COSTS FOR DISTRIBUTION SERVICE OF $38 PER MONTH?

A. The Company uses its CCOSS as a starting point. From there, the Company assigned 100 percent of the customer portion of the revenue requirement assigned to residential customers to customer-related costs that would be included in the proposed customer charge.23 Equally important is the fact that the Company also assigned a portion of the remaining distribution revenue requirements, specifically primary and secondary voltage distribution systems, to these costs. These primary/secondary distribution system costs, in turn, were developed using the results of a study that compares each distribution plant account’s cost components to what the total cost would be if all components of these distribution plant components were the typical or average size installed by the Company when connecting the average distribution level customer.24 The Company’s study found that 77 percent of secondary-voltage systems and 78 percent of primary-voltage systems were

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22 Id., 14:3-5.
23 Id., 14:13-16.
24 Id., 14:21 through 15:3.
associated with serving customer demands, or represented fixed utility costs.\textsuperscript{25} The total cumulative fixed costs found in each cost category: customer-related, secondary-voltage, and primary-voltage distribution system, was then divided by the average number of residential customers during the test year to reach the estimated fixed monthly cost of $37.88 per customer.

Q. **DO YOU AGREE WITH THE COMPANY’S ANALYSIS?**

A. No. The Company analysis of “fixed” costs is flawed. Specifically, the Company assigns demand-related costs as being essentially the equivalent of customer-related costs, and thus fixed. *This is fundamentally incorrect.* Demand-related costs are not the equivalent of customer-related costs, and are variable, particularly over time, with respect to customer usage patterns, namely a customer’s load profile.

Q. **CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?**

A. Yes. Demand-related costs are associated with meeting maximum energy demands. Electric substations and line transformers are designed, in part, to meet the maximum demand requirement for the portion of the overall distribution system with which they are associated. The most common demand allocation factors used in a COSS are those related to system coincident peaks (“CP”) or non-coincident customer class peaks (“NCP”).

Q. **HOW ARE ENERGY-RELATED COSTS DEFINED?**

A. Energy-related costs are defined as those that tend to change with the amount of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. **WHAT ABOUT CUSTOMER-RELATED COSTS?**

\textsuperscript{25} Id., Exhibit AEV-2.
A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. HAVE OTHER UTILITIES ARGUED THAT A PORTION OF PRIMARY AND SECONDARY DISTRIBUTION FACILITIES SHOULD BE ASSIGNED TO CUSTOMERS AS BEING “FIXED” IN NATURE?

A. Yes. The Company’s arguments are strikingly similar to COSS arguments advanced by some utilities that there exists a definable portion of primary and secondary distribution facilities associated with serving customers rather than serving the utility load. Such analyses utilize one of two methods, either what is called a Minimum System Study (“MSS”) or what is called a Zero-Intercept Study. A MSS estimates the hypothetical minimum costs of developing a system that only provides customers with connection to the company’s electric system, but not a system sufficient to actually serve the customer’s electrical needs. A Zero-Intercept Study, on the other hand, uses statistical relationships revealed through regression analyses to estimate the minimum system costs per customer associated with different distribution systems serving no electrical load.

Q. ARE THERE ANY THEORETICAL SHORTCOMINGS ASSOCIATED WITH MSS AND ZERO-INTERCEPT STUDIES?

A. Yes. These analyses deal in hypotheticals that often do not exist in the real world, including the assumption that somehow there is an electric distribution system out there in the

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world that could be plausibly built to serve customers but not load. In this the Company makes the same fallacy by assigning a portion of its primary and secondary-voltage distribution systems as being fixed relative to the number of customers taking service off of its system. The underlying assumption and modeling of such an analysis are difficult, if not impossible, to verify due to the simple fact that there exists no electrical system designed only to provide customer connections and not serve their electric loads. Thus, while the Company’s study is not a true minimum-system or zero-intercept study, and instead can be thought of as an average system study, it still suffers from some of the same methodological shortcomings as either a minimum system study or a zero-intercept study. As such, the Company’s analysis should be dismissed as somehow justifying its customer charge proposals in this proceeding.

Q. HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE ASSIGNING OF DEMAND-RELATED COSTS AS FIXED RELATIVE TO THE NUMBER OF CUSTOMERS TAKING ELECTRICAL SERVICE?

A. Yes. Dr. James Bonbright, in his seminal work on public utility rates, raised a number of questions about the use of such methodologies in developing CCOSS and rate design.\(^\text{30}\) Bonbright’s primary concern was the lack of empirical support in the academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental costs of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the

costs to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, a fact inherently ignored by arbitrarily assigning these costs as fixed customer costs as the Company has done in its analysis:

…the annual costs of this phantom, minimum-sized distribution system are related as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum distribution costs] inclusion among the customer costs is defended on that, since they vary directly with the area of the distribution system (or else with the length of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the “zero-intercept” method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customer per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company’s entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.31

Q. IS THERE INFORMATION FROM THE COMPANY’S CCOS WHICH CAN BE APPROPRIATELY USED TO JUDGE THE REASONABLENESS OF THE COMPANY’S CURRENT CUSTOMER CHARGES?

A. Yes. While, as stated previously, there is no requirement that a rate class’ customer charge should recover all or even most of the customer-related costs, this metric is commonly

used to judge the reasonableness of a utility’s customer charge and the ability of the revenues
generated from these charges to cover customer-related costs.

Q. **DID YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH CUSTOMER CHARGES?**

A. Yes, and that has been provided on Schedule DED-5. “Customer-related” expense
accounts are those typically allocated on the basis of customers and can include: installation
of meters and service drops; meter maintenance; meter reading expense; customer records and
collections; customer billing and accounting; customer service and information; and sales
expense. These costs can also include the depreciation expense associated with the meter and
service drop plant accounts and property taxes as well as the carrying charges (at the
Company’s requested rate of return).

Q. **HOW DO THE COMPANY’S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE CUSTOMER-RELATED RESULTS OF ITS CCOSS?**

A. Exhibit DED-5 presents a comparison of the results of the Company’s CCOSS with
respect to customer-related costs. The analysis confirms that the Company’s stated
presentation that strictly customer-related costs for the residential customer class account for
only $7.47 per customer per month.

Q. **HOW DO THE COMPANY’S SMALL AND LARGE COMMERCIAL CUSTOMER CHARGES COMPARE WITH THE RESULTS OF ITS CCOSS?**

A. The results of the Company’s non-residential classes’ revenues are also shown in
DED-5. The Company’s customer charge revenues for the Small General Service (“SGS”)
and the Company’s secondary Medium General Service (“MGS”) are each 146 percent of
their class cost responsibility. Likewise, the customer charge revenues for the Large General Service (“LGS”) secondary class recovers 254 percent of its cost of service responsibilities.

Q. WHAT DO THE RESULTS OF YOUR ANALYSIS SHOW?

A. The results of my analysis show that the Company’s existing customer charge for the residential customer class recovers over 147 percent of the customer-related costs required to serve that class. Likewise most small, medium, and large general service customers are significantly over recovering their customer related costs. This analysis shows that the Company’s existing customer charges are more than adequate to recover the Company’s associated customer-related cost of service.

Q. HAVE YOU COMPARED THE COMPANY’S RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Exhibit DED-6. This analysis shows that the Company’s current residential customer charge of $11.00 per month is noticeably greater than the regional average of $9.60 per month, by nearly 14.6 percent. This exhibit surveys current residential and small commercial customer charges for major vertically-integrated electric utilities operating in Kentucky and the surrounding region. There are only five electric utilities in the survey with residential customer charges more than the Company’s current residential customer charge of $11.00, and 11 utilities less than the Company’s current residential customer charge. If the Company’s proposal of $17.50 per customer per month is approved, the Company would become the least competitive investor owned utility in the survey with respect to monthly customer charges.

Q. HAVE YOU COMPARED THE COMPANY’S SMALL COMMERCIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?
A. Yes. The Company’s current small commercial customer charge of $17.50 per month is greater than the average small commercial customer charge of $16.38 for other regional utilities. Furthermore, out of 16 electric distribution companies in the survey, nine utilities have a customer charge for small commercial customers that is lower than the Company’s current customer charge. This means that the Company currently has the seventh highest customer charge for small commercial customers in the region.

Q. IS THE COMPANY’S PROPOSED RATE DESIGN INCONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?

A. Yes, for the simple reason that it places more costs into the fixed component of rates than in the variable component. This reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable.

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT INCREASED FIXED CHARGES HAVE ON ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission (“MPSC”) recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

Even though this issue was virtually uncontested by the parties, we find we must reject Staff’s proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company’s proposal to achieve the entire revenue requirement increase through volumetric and demand
charges. This approach also is consistent with and supports our EmPOWER Maryland goals.\textsuperscript{32}

Q. IS THE MPSC ALONE IN ITS BELIEF THAT HIGH FIXED CHARGES DISCOURAGES EFFICIENT USE OF ENERGY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners (“NARUC”) found decoupling as one of three major approaches to delink utility revenues from sales. One alternative listed was Straight-Fixed Variable (“SFV”) rate design, which as a proposal places all fixed-related costs to fixed charges while relegating only variable charges to volumetric rates. The NARUC research noted this type of rate design to be problematic because of its effects on customer incentives to conserve energy:

\textbf{Straight-Fixed Variable Rate Design.} This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility’s revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers’ bills. This approach has been criticized for having the unintended effect of reducing customers’ incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.\textsuperscript{33}

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?


\textsuperscript{33} “Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)” (September 2007), Grants & Research Department, National Association of Regulatory Utility Commissioners, p. 5. (Emphasis added).
NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer’s utility bill, such as SFV for strictly distribution services:

Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers’ efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility’s costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.  

Q. DOES THE COMPANY MAKE ANY OTHER ARGUMENTS CONCERNING ITS PROPOSAL TO INCREASE CUSTOMER CHARGES FOR RESIDENTIAL CUSTOMERS?

A. Yes. The Company argues that increased customer charges will reduce customer bill volatility, particularly in high usage months and for the Company’s electric heating customers who tend to experience very high usage during winter heating months. Likewise, the Company argues that its proposed rate design change will help lower income customers.

A higher basic service charge will help lower income customers who, because they often do not have the resources to invest in weatherization and energy efficient appliances, have higher than average usage.  

Q. DO YOU AGREE WITH THE COMPANY’S ARGUMENT THAT AN INCREASE IN RESIDENTIAL CUSTOMER CHARGES WILL ASSIST LOW INCOME CUSTOMERS?

A. No. The Company’s argument is fundamentally flawed since higher customer charges make it increasingly more difficult for lower income households to reduce their electricity bills as a share of their relatively limited income. This is simply regressive and will have deleterious impacts on lower-income households, not positive impacts. Lower income customers are not benefited by reduced price volatility as much as they are by the ability to control their usage and actually reduce their monthly electric bill.

Q. DO YOU AGREE WITH THE COMPANY’S ASSERTION THAT THERE IS NOT A DIRECT CORRELATION BETWEEN LOWER INCOME HOUSEHOLDS AND LOWER ELECTRICITY USE?

A. No. The Company argues that low income households have higher than average electric use because these customers do not have the resources to invest in weatherization or energy efficient appliances. While the Company’s general statement about the availability of weatherization and energy efficiency appliances for low income households may be true, the Company’s assertion requires one to assume that low income households are not necessarily or even generally related to lower electrical use households. The suggestion that electric usage falls as income rises is contrary to basic economic theory that says that the demand for a “normal” good or service increases as income increases. In fact, there are

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numerous studies in the academic literature supporting the hypothesis that electricity is a “normal good.”³⁷

Q. HAVE YOU CONDUCTED ANY ANALYSES EXAMINING THE RELATIONSHIP OF ELECTRICITY USAGE AND INCOME?
A. Yes. Page 1 of Schedule DED-7 provides the results of an analysis I have performed using data from the 2009 Residential Electricity Consumption Survey (“RECS”) produced by the United States Energy Information Administration (“EIA”) and household data from the Census division in which Kentucky is located.³⁸ The results show a positive relationship between electricity consumption (in kWh terms) and income. This clearly shows that as income increases electricity consumption increases, and vice versa: as income decreases, electricity usage decreases. Thus asserting, as the Company does, that electricity usage for low income households is actually equal or higher than higher income households is simply incorrect.

Q. DO THE RESULTS OF YOUR ANALYSIS CHANGE IF YOU CONTROL FOR THE NUMBER OF INDIVIDUALS IN A RESPECTIVE HOUSEHOLD TYPE OR BY PHYSICAL HOUSEHOLD SIZE?
A. No, the results of my earlier analysis hold even if differences between the number of people in a household and household square feet are included. Page 2 of Schedule DED-7

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³⁸ This census division includes the states of Alabama, Kentucky, Mississippi, and Tennessee. This is the most detailed level of aggregation available in the RECS.
provides the results of a regression-based approach that estimates the relationship between electricity consumption (in kWh terms), using income, the number of members in a household, and the heated square footage in the household as independent variables. The results clearly show that electricity usage increases as both the number of members in a household and the square footage of the household increases.

Q. DO LOWER INCOME HOUSEHOLDS SPEND PROPORTIONATELY MORE IN ELECTRICITY THAN HIGHER INCOME HOUSEHOLDS?

A. Yes. Lower income households spend a larger share of their income on electricity than higher income households. Put another way, while households consume more electricity as income increases, the share of their income they spend on electricity decreases as their income increases. Schedule DED-8 clearly shows this relationship. Consumers with income of less than $10,000 per year spend approximately 16 percent of their income on electricity, while a family that makes between $50,000 and $60,000 per year only spends approximately three percent of their income on electricity. As income increases further, this percentage continues to decline.

Q. WHAT DO THESE FINDINGS MEAN FOR LOWER-INCOME HOUSEHOLDS UNDER THE COMPANY’S RATE DESIGN PROPOSALS?

A. Lower-income households will likely be impacted negatively and in a fashion disproportionate to higher income households. As I noted earlier, electricity use increases as income increases, meaning that contrary to the Company’s assertions, lower-income households will likely use less, rather than more electricity than their upper income counterparts. The Company’s residential class revenue requirement, however, is set with an average monthly fixed customer charge across the entire class, meaning that lower than
average use customers (like low-income customers) will be harmed more by these rate proposals than upper-income households. This proposal will be additionally harmful when considering the fact that lower-income households will have to give up a proportionately larger share of their disposable income to effectively support the customer charge set by the Company under its fixed customer charge rate design proposals.

V. OVERVIEW OF THE COMPANY’S ECONOMIC DEVELOPMENT PROGRAMS AND SURCHARGE PROPOSAL

Q. PLEASE DESCRIBE THE COMPANY’S HISTORIC ECONOMIC DEVELOPMENT ACTIVITIES.

A. The Company states that it re-initiated its economic development efforts in 2012\(^\text{39}\) and began offering monetary incentives for economic development in 2014 through the “Kentucky Power Economic Advancement Program” (“KEAP”), a program that offered economic development grant assistance to Lawrence County and its contiguous Kentucky counties.\(^\text{40}\) The Company also notes that in 2014 it began partnering with several community banks in what is referred to as a Local Bank Financing Program which provides investment-grade lending opportunities for local banks aiding in the diversification of local bank loan portfolios.\(^\text{41}\)

Q. PLEASE EXPLAIN THE BACKGROUND OF THE KEAP PROGRAM.

A. The KEAP program was created in the Non-Unanimous Stipulation and Settlement Agreement resolving some of the issues associated with the Company’s 2012 application seeking a Certificate of Public Convenience and Necessity (“CPCN”) for a proposed transfer from a Company affiliate, Ohio Power Company, of 50 percent of the full interest in the

\(^{39}\) Direct Testimony of Brad Hall, 6:19-20.  
\(^{40}\) Direct Testimony of Brad Hall, 7:4-6.  
\(^{41}\) Direct Testimony of Brad Hall, 7:6-13.
Mitchell Generating Station located in Moundsville, West Virginia (the “Mitchell Transfer Case”). The CPCN proceeding required the Company to conduct in-depth analyses of reasonable portfolio alternatives in lieu of expensive retrofits needed for the Company’s Big Sandy Unit 2 generating station to continue operating under the expanded requirements. The Company noted in this CPCN proceeding that the Mitchell units would be compliant and effective resource alternatives since these units were already equipped with flue gas desulfurization (“FGD”) and selective catalytic reduction (“SCR”) systems. In the CPCN preceding the Company also requested the authority to accumulate and defer for review and recovery approximately $28 million in other costs associated with its analytic efforts to meet environmental requirements at its Big Sandy Unit 2.

Q. WHY WAS THE KEAP PROGRAM CREATED AS PART OF THE CPCN SETTLEMENT?

A. The CPCN proceeding generated significant interest from the public, especially those in the region most affected by the Company’s decision to abandon consideration of the installation of pollution control systems at Big Sandy Unit 2, and instead retire the existing unit. This public interest included the Kentucky House Majority Floor Leader and the Lawrence County Attorney. Of particular concern was the direct loss of the plant’s 150 jobs

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42 In the Matter of: Application of Kentucky Power Company for (1) a Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company’s Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) All Other Required Approvals and Relief; Case No. 2012-00578; Order dated October 7, 2013; p. 1.

43 Id., Verified Application; ¶1.

44 Id., Verified Application; ¶2.


as well as losses in franchise tax revenues to local government.\textsuperscript{48} The Company entered into a partial stipulation with some parties (but not the Attorney General) in which the Company agreed to a series of commitments designed to mitigate the negative economic impacts of the plant’s closure.\textsuperscript{49} These commitments included a shareholder contribution of $100,000 annually for five years towards economic development and job training in the Lawrence county and the contiguous Kentucky counties impacted by the closure of Big Sandy Unit 2. The Commission increased this commitment to $200,000 for economic development and $33,000 annually for job training after finding that the initial commitment was insufficient to mitigate the significant negative economic impact caused by the closure of Big Sandy Unit 2.\textsuperscript{50}

\textbf{Q. HOW DOES THE COMPANY FUND ITS KEAP PROGRAM?}

\textbf{A.} The KEAP program has been funded from shareholder funds since 2014 by an annual amount of up to $200,000. The Company notes that in 2016, it only received grant applicants for $177,500.\textsuperscript{51} To make up this shortfall, the Company issued a total of $222,000 in KEAP grants in 2017.\textsuperscript{52} The Company’s financial commitment will end with the program’s termination in 2018.\textsuperscript{53}

\textbf{Q. DID THE COMPANY CREATE ANY OTHER ECONOMIC DEVELOPMENT INCENTIVES IN 2014?}

\textbf{A.} Yes. The Company’s Economic Development Rider (“EDR”) tariff was submitted and approved in 2014, in accordance with Commission directives in a 1990 Commission

\begin{itemize}
\item[\textsuperscript{48}] Id., Order dated October 7, 2013; p. 25.
\item[\textsuperscript{49}] Id., Order dated October 7, 2013; p. 2.
\item[\textsuperscript{50}] Id., Order dated October 7, 2013; pp. 36-37.
\item[\textsuperscript{51}] Direct Testimony of Brad Hall, 24:21 to 25:1.
\item[\textsuperscript{52}] Direct Testimony of Brad Hall, 25:1-2.
\item[\textsuperscript{53}] Direct Testimony of Brad Hall, 25:4-7 and 25:10-11.
\end{itemize}
Order in Administrative Case No. 327. The EDR tariff is available to new and existing customers looking to locate or expand facilities in the Company’s service territory. EDR-eligible companies are required to have or increase their current monthly base maximum billing demand by at least 500 kW, and are eligible to take service under the Company’s Large General Service (“LGS”) or Industrial General Service (“IGS”) tariff schedules. Under the terms of the EDR tariff, eligible customers are offered an Incremental Billing Demand Discount (“IBDD”) that reduces monthly billing demand charges by 50 percent for the first year of service, a discount that decreases by 10 percent for each subsequent year available until full tariff rates after the end of the fifth year. Likewise, eligible customers are offered a Supplemental Billing Demand Discount (“SBDD”) that further reduces monthly billing demand charges by five percent for the first year if the customer demonstrates the creation of at least 50 jobs, or 2.5 percent for the first year if the customer demonstrates the creation of at least 25 jobs. In both cases, the SBDD’s discount decreases by one-half of one percent each year as available, until being completely removed after the fifth year of service.

Q. DOES THE EDR TARIFF HAVE ANY OTHER SERVICE RESTRICTIONS?

A. Yes. The EDR requires customers to demonstrate, to the Company’s satisfaction, that absent the availability of the discounted rate, the qualifying new or increased electrical demand would either not be placed in service or would have been located outside of the

54 In the Matter of: Application of Kentucky Power Company for (1) Approval of an Economic Development Rider; (2) for any Required Deviation from the Commission’s Order in Administrative Case No. 327; and (3) All Other Required Approvals and Relief; Case No. 2014-00336; Order dated March 4, 2015.

55 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.

56 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.

57 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.
Company’s service territory. Also, customers taking service under the EDR tariff must contract with the Company for a term of service that is twice the agreed-to discount period. Therefore the full five year terms of the IBDD and SBDD presented earlier are for customers who enter into contracts of at least 10 years; only four years of discounts are available for customers who enter into eight year service contracts, etc. Furthermore, all service under the EDR tariff is classified by the Company as a “Special Contract,” and thus subject to Commission approval prior to implementation of the discounted rate. Lastly, the entire EDR tariff is not available for additional subscription once a total of 250 MW of new load has been added to the Company’s system under the tariff.

Q. HAS THE COMPANY EXPANDED ITS OFFERING OF DIRECT ECONOMIC DEVELOPMENT INCENTIVES SINCE 2014?

A. Yes. In 2016, the Company implemented the Kentucky Power Economic Growth Grants (“K-PEGG”). Through the K-PEGG program, the Company issues economic grants throughout the entirety of the Company’s service territory, as opposed to the KEAP program that provides grant assistance only to entities in Lawrence County and its contiguous Kentucky counties. Unlike the KEAP program, K-PEGG is funded through the Kentucky Economic Development Surcharge (“KEDS”).

Q. PLEASE EXPLAIN THE KEDS.

58 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.
59 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.
60 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.
61 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.
62 Direct Testimony of Brad Hall, 7:16-17.
63 Id. at 7:16-17.
64 Id., 7:17-20.
A. The KEDS was proposed by the Company in its prior rate case, Case No. 2014-00396. Specifically, the Company proposed in that proceeding to establish a surcharge equal to $0.15 per meter per month for all customers in its service territory. All revenues derived from the ratepayer surcharge would be matched equally by the Company with shareholder funds. The combined funding streams were expected to generate a total of $615,014 annually, which would be used by the Company to fund economic development initiatives.

Q. IS THE COMPANY REQUESTING AN INCREASE TO THE KEDS?
A. Yes. The Company is requesting to increase the KEDS by $0.10 per meter per month. If approved, this would raise the current $0.15 charge per meter to $0.25 per meter per month, resulting in a $3.00 per meter per year ratepayer charge.

Q. WHAT SUPPORT DOES THE COMPANY PROVIDE FOR ITS KEDS PROPOSAL?
A. The Company provides its “InSite Economic Development Gap Analysis” to identify areas within its service territory where economic development activities are needed. This “gap analysis” was one of the first activities performed by the Company after it re-initiated its economic development efforts in 2012. The gap analysis focuses on such topics as: a lack of functional and properly trained local or regional economic development organizations; limited competitive and marketable industrial parks and buildings; insufficient marketing.

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65 Id., Order dated June 22, 2015.
66 Id., Order dated June 22, 2015; p. 49.
67 Id., Order dated June 22, 2015; p. 49.
68 Id., Order dated June 22, 2015; p. 49.
70 Id. at 17:15-16.
71 Direct Testimony of Brad N. Hall, 8:16-20.
72 Direct Testimony of Brad N. Hall, 6:19 to 7:3.
infrastructure for available opportunities; and insufficient workforce development and training.\textsuperscript{73}

Q.  How much has the company collected under the KEDS?

A. The Company states that as of February 28, 2017, it has collected $493,529 through its surcharge and when coupled with the 50 percent match, leads to a total of $987,058 that has been allocated to the K-PEGG program.\textsuperscript{74}

Q.  How does the company select the organizations or entities receiving K-PEGG grants?

A. The Company has a review team made up of the Company leaders who represent various departments and geographical areas of Kentucky Power’s service territory, as well as representatives from the Kentucky Association for Economic Development and the Kentucky Cabinet for Economic Development.\textsuperscript{75} The Company states that the “review team was selected to provide a breadth of insight and knowledge to evaluate each application’s merit with regard to the program’s mission of economic advancement.”\textsuperscript{76}

Q.  Did ratepayers or stakeholders have any input on the team selected to evaluate K-PEGG grant recipients?

A. No, the Company did not consult ratepayers when considering the selection team.\textsuperscript{77} The Company stated that it “selected the team based on experience and understanding of community and economic development as well as availability to participate in the process confidentially, frequently, and reliably. Economic development and community development

\textsuperscript{73} Id., 9:1-7.
\textsuperscript{74} Company’s response to AG_1_033.
\textsuperscript{75} Company’s response to AG_1_395.
\textsuperscript{76} Id.
\textsuperscript{77} Company’s response to AG_1_395.
VI. CONCEPTUAL ISSUES WITH THE K-PEGG PROGRAM

A. The Company has failed to demonstrate the need for the K-PEGG program.

Q. WHAT RATIONALE DOES THE COMPANY PROVIDE FOR ITS K-PEGG PROGRAM?

A. The Company notes that its service territory has suffered from a significant economic downturn, primarily driven by decreases in coal and steel production, since 2008. For instance, coal mining employment has fallen from a 2008 level of 14,373 miners to a 2016 figure of 3,833 miners. Additionally, the Company notes the decreased international demand for steel that has caused some steel blast furnace operations to shut down including the AK Steel plant in Ashland, Kentucky in December 2015, resulting in a loss of over 600 jobs. The Company states that these economic trends have resulted in declining customer counts and retail sales. The Company notes that it has lost 6,931 customers from 2008-2016, and seen retail sales fall from approximately 7.24 GWh to 5.80 GWh over the same period.

Q. DOES THE COMPANY PROVIDE ANY FURTHER JUSTIFICATION FOR ITS K-PEGG PROGRAM?

A. No. The Company states the region’s economic experiences since 2008 underscore the dangers of an undiversified economic base. Because of this, the Company feels that

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78 Company’s response to AG 1 395.
79 Direct Testimony of Brad Hall, 4:17-19.
80 Direct Testimony of Brad Hall, 5:1-4.
81 Direct Testimony of Brad Hall, 5:9-11.
82 Direct Testimony of Brad Hall, 5:15-19.
83 Direct Testimony of Brad Hall, 5:22 to 6:1.
promoting greater industrial diversity, through the K-PEGG program, will increase economic
growth opportunities and would take advantage of the myriad of talents found within the
communities Kentucky Power serves.\footnote{Direct Testimony of Brad Hall, 6:3-8.} No other justification has been provided for
continuing this program, nor increasing the surcharge that supports its activities.

Q. HAVE YOU EXAMINED THE TRENDS IN COMPANY CUSTOMER
COUNTS AND ELECTRICITY SALES?

A. Yes. Exhibit DED-9 shows the Company historic customer counts for the years 2006
through 2016. This analysis shows that the number of customers on the Company’s system
has decreased from a maximum of 175,705 in 2007, to 168,848 in 2016. This loss of 6,857
customers represents a customer count decrease of 3.9 percent, a decrease of 0.4 percent on an
annual average basis. Exhibit DED-9 likewise shows the historic trend in Company electric
sales. This analysis shows that electric sales have decreased from a maximum of 7,349 GWh
in 2010 to 5,863 GWh in 2016. This loss of 1,486 GWh represents a decrease of 20.2 percent,
or 2.9 percent per year on an average annual basis over the last seven years.

Q. HAS THE COMPANY EXPERIENCED SIMILAR DOWNWARD TRENDS IN
ITS ELECTRIC SALES REVENUES?

A. No. The Company has been able to maintain its electric sales revenues even while
facing declining billing determinates. For instance, the Company has actually increased its
revenues by over $166.7 million since 2007, the last year of positive customer growth. This
represents a 41.0 percent revenue increase, or an increase in revenues of approximately 4.1
percent annually. The Commission should note that while the Company has lost nearly 7,000
customers since 2007, rate increases to its remaining customers have actually increased the
Company’s revenue position, contrary to the Company’s assertions.
Q. DOES THE CURRENT STATE OF THE REGIONAL ECONOMY OF EASTERN KENTUCKY JUSTIFY THE COMPANY’S K-PEGG PROGRAM?

A. No. Despite the Company’s good intentions, it is asking to take money away from ratepayers and redistribute it within the Eastern Kentucky economy. The Commission should not approve a re-distributive program of this nature without ensuring that the K-PEGG’s program leads to known and measurable benefits that are greater than the cost imposed on ratepayers in the form of higher rates.

Q. HAS THE COMPANY PROVIDED ANY MEANINGFUL QUANTITATIVE ANALYSES SUPPORTING THE CONTINUATION OF THE K-PEGG PROGRAM OR ITS PROPOSED EXPANSION?

A. No. The Company has failed to provide any meaningful quantitative evidence that the K-PEGG program has successfully encouraged commercial and industrial customers to locate or remain in the Company’s service territory, nor has the Company provided meaningful quantitative evidence supporting the proposed expansion of the program. What little evidence the Company has provided on these subjects does not provide a complete picture of “success” of its K-PEGG offerings.

Q. WHAT EVIDENCE HAS THE COMPANY OFFERED AS AN INDICATOR OF K-PEGG PROGRAM SUCCESS?

A. The Company simply states that it has approved a total of 17 K-PEGG grants out of 23 grant requests since the introduction of the program in January of 2016. About half of the approved grant requests (12) totaling $652,500, were made in 2016, while five grant requests,

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85 See, Company’s Response to AG_1_362.
86 Direct Testimony of Brad Hall, 15:9-11.
totaling $178,700, were made in the month of April, 2017. In total, the Company has provided economic development grants of $831,200 in the first 18 months of the program’s operations.

Q. EXPLAIN THE COMPANY’S ESTIMATES OF THE JOBS THAT HAVE BEEN CREATED BY THE K-PEGG PROGRAM.

A. While the Company references four projects as “early success stories” of its K-PEGG program, it is unclear what impact, if any, the K-PEGG program has had in creating known and measurable employment gains. In fact, the Company explicitly notes that “many of the projects funded through the K-PEGG Program are not designed to result in direct job creation.” To this point, it should be recognized that all K-PEGG grants have been provided to regional third party entities not directly associated with job creation. For example, the two largest grants provided through the K-PEGG program have been to the Big Sandy Regional Industrial Development Authority to acquire property owned in Martin County and to the Floyd County Fiscal Court for the purposes of providing bridge financing for a proposed gas to liquids projects being developed. In both cases, the K-PEGG funding appears to have at most expedited existing development. Specifically, the acquisition of property in Martin County allowed the prior owner to relocate operations to a larger facility in Magoffin County without needing to take the time to find a buyer of its existing facility. Likewise, the bridge funding alleviated the need for the gas to liquids project developer to obtain outside loans.

87 Direct Testimony of Brad Hall, pp. 15-16.
88 Direct Testimony of Brad Hall, pp. 15-16.
89 Direct Testimony of Brad Hall, 17:16.
90 Direct Testimony of Brad Hall, 17:16-18.
91 Direct Testimony of Brad Hall, p. 16.
92 Direct Testimony of Brad Hall, 18:2-10.
93 Direct Testimony of Brad Hall, p. 16.
Q. WHAT EVIDENCE HAS THE COMPANY PROVIDED AS INDICATION OF
THE NEED TO EXPAND THE K-PEGG PROGRAM?

A. The Company states that the early results of the K-PEGG Program show promise, but
that additional work is necessary to make the region’s economic development efforts more
competitive.\textsuperscript{94} The Company states that its proposed expansion will allow it to support more
economic development projects and allow the Company more flexibility to respond to
economic development opportunities as they arise.\textsuperscript{95} The Company notes, as an example, that
what it believes is a current funding deficiency for the program forced it to delay its review of
two 2016 applications.\textsuperscript{96}

Q. DO YOU BELIEVE THAT THE COMPANY HAS PROVIDED SUFFICIENT
EVIDENCE TO SUPPORT ITS PROPOSED K-PEGG EXPANSION?

A. No. The Company’s proposed K-PEGG expansion appears to be based in no small
part on the fact that the Company had insufficient funds to handle all requests for grant money
in 2016 and in that year alone. The Commission should recognize two items associated with
the Company’s argument. First, 2016 represents the first year of the K-PEGG Program.
Early interest in the K-PEGG program grants may not be indicative of future needs as early
program grants could represent stalled or back-logged projects that have accumulated for a
number of years. Furthermore, the Commission should recognize that the supporting
rationale for its K-PEGG program is partially contradictory to the position it takes in other
parts of its testimony that its service territory is continuing to contract.

Q. PLEASE EXPLAIN HOW THE COMPANY’S REQUEST IS
CONTRADICTORY.

\textsuperscript{94} Direct Testimony of Brad Hall, 19:16-18.
\textsuperscript{95} Direct Testimony of Brad Hall, 20:6-10.
\textsuperscript{96} Direct Testimony of Brad Hall, 20:13-15.
A. The Company’s primary rationale for its proposed K-PEGG expansion is that it had insufficient funds to process two 2016 applications.\textsuperscript{97} However, the Company also reports, in the same year (2016), that its KEAP grant applications (its original economic development program approved as part of its prior Mitchell CPNC) only received grant applicants accounting for 89 percent of its 2016 financial allotment (applications of $177,500 relative to the $200,000 annual commitment).\textsuperscript{98} The fact that one economic development program is oversubscribed while the other is significantly undersubscribed, is contradictory.

Q. **COULD THE DIFFERENCES IN THE NATURE OF THE TWO PROGRAMS BE IMPACTING THIS APPARENT INCONSISTENCY?**

A. Yes. As noted previously, the KEAP program was created to provide economic development funding to the counties directly affected by the Company’s closure of one of its Big Sandy generating units. In this, the KEAP program was narrowly focused on counties seeing an immediate negative economic impact from the Company’s closed facility. The K-PEGG program on the other hand is noticeably unfocused in either regional scope or purpose.

Q. **HAS THE COMPANY PROVEN THAT THE K-PEGG IS MORE EFFECTIVE THAN KEAP?**

A. No. The Company has not shown how the K-PEGG program is superior to KEAP or any other potential ways in which it could stimulate economic development, such as through changing/modifying its economic development rate or special contracts.

Q. **DOES THE COMPANY CURRENTLY HAVE AN ECONOMIC DEVELOPMENT RATE?**

\textsuperscript{97} Direct Testimony of Brad Hall, 20:13-15.
\textsuperscript{98} Direct Testimony of Brad Hall, 24:21 to 25:2.
A. Yes, as previously discussed, the Company offers an EDR tariff to its eligible LGS and IGS customers. The EDR tariff is comprised of a declining demand charge for new and existing customers that meet certain load requirements as a means of incentivizing large customers to locate or expand in the Company’s service territory. In this manner, the EDR tariff supplements the functionality of the KEAP program since both are tied to a specific economic development-based outcomes: more jobs or more load. The K-PEGG program, on the other hand, is not, and is simply a request by local economic developers for more funds to support their economic development activities. Further, the Company has not identified any current deficiency in either its KEAP program or its EDR that make either inferior to the K-PEGG.

Q. ARE THERE OTHER REASONS TO BELIEVE THAT THE EDR TARIFF IS SUPERIOR TO THE K-PEGG PROGRAM?

A. Yes, since, as explained in greater detail earlier, the EDR includes accountability measures designed to ensure that rate discounts are provided in return for jobs or expanded usage that benefit local communities and ultimately all of the Company’s ratepayers.

B. The Company’s K-PEGG Program Shifts Performance Risks onto Ratepayers

Q. IS THERE A GENERAL CONCEPTUAL PROBLEM WITH THE COMPANY’S K-PEGG PROGRAM?

A. Yes. At its core, the K-PEGG program is a grant program, providing economic development grants to third-party organizations operating within the Company’s service territory that engage in activities designed to market local communities to large commercial

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99 Rates-Charges-Rules-Regulations for Furnishing Electric Service in the Kentucky Territory Served by Kentucky Power Company (June 30, 2015); P.S.C. KY. No. 10; Sheet No. 37-1 through 37-6, Tariff E.D.R.
and industrial businesses looking to locate or expand existing operations. The program does not directly create jobs, but instead, offers funds to organizations whose primary purposes is to recruit business and industries. Thus, there is no direct, known and measurable dollar-for-dollar tie between K-PEGG funds and jobs, economic output, or increased electricity sales. The “hope” is that these dollars ultimately lead to jobs, but there is no link or requirement in the K-PEGG that they do so. Thus, at least half of the performance risk of the K-PEGG program (i.e., the risk that it will create known and measurable economic benefits) falls upon ratepayers.

Q. HAS THE COMPANY PROVIDED ANY ESTIMATES OF THE NUMBER OF JOBS CREATED THROUGH ITS ECONOMIC DEVELOPMENT PROGRAMS?

A. No. The Company has not provided any quantifiable, known and measurable employment data associated with its K-PEGG program: it has also failed to provide any known and measurable quantitative information on any increases in local tax revenues, economic output, or increases in electricity customers or sales.\(^{100}\) Instead, the Company references many “early success stories” as the primary benefits that have arisen from its K-PEGG program. This should come as no surprise since the Company itself does not require (as a tariff condition or grant condition) any of the participating economic development organizations to provide post-grant award information verifying employment creation, tax revenue creation, or increased electricity customers/sales: \(^{101}\) this is simply not a pre-condition for the K-PEGG program.

\(^{100}\) See, Company’s Response to AG_1_372.

\(^{101}\) Company’s Response to AG_1_358, AG_1_387, and AG_2_024.
Q. DO THE FINANCIAL INCENTIVE AND TAX CREDIT PROGRAMS OFFERED BY THE STATE OF KENTUCKY HAVE ANY MINIMUM EMPLOYMENT OR EMPLOYMENT CERTIFICATION REQUIREMENTS?
A. Yes. For instance, the Kentucky Business Incentive (“KBI”) program\textsuperscript{102} offered by the Kentucky Cabinet for Economic Development provides income tax credits equal to up to 100 percent of the entity’s corporate income or limited tax liability from the project. Applicants are required to meet minimum investment levels of at least $100,000, and create a minimum of 10 new full-time jobs and maintain an annual average of 10 new full-time jobs.\textsuperscript{103}

Q. IS THE KBI PROGRAM THE ONLY PROGRAM OFFERED BY THE KENTUCKY CABINET FOR ECONOMIC DEVELOPMENT?
A. No, the Cabinet for Economic Development offers at least 27 different tax credit and financial incentive programs in a number of categories including expanding industries, job retention, energy and environment, technology, agriculture, job training, and tourism.\textsuperscript{104} Many of these programs have output-contingent requirements such as Kentucky Economic Development Finance Authority (“KEDFA”) Direct Loans, which provides reduced loan rates for a portion of fixed asset costs, depending on total capital investment.\textsuperscript{105} Further, many of the programs offered by the Cabinet for Economic Development appear to be duplicative to the intent of the K-PEGG program such as the Kentucky Business Investment (“KBI”) Program. The KBI Program provides up to 10 years of tax credits for companies looking to locate or expand in Kentucky. The KBI Program provides and an additional 5 years of tax

\textsuperscript{102} See, KBI Fact Sheet, available at thinkkentucky.com.
\textsuperscript{103} See, KBI Fact Sheet, available at thinkkentucky.com.
credits and up to 5 percent of employee gross wages incentives for companies looking to locate to a county designated as ‘enhanced incentive’ eligible.\textsuperscript{106} Finally, the KBI Program, unlike the Company’s economic development initiatives, requires eligible projects to meet minimum investment, minimum employment, and minimum employee wage and benefits requirements.\textsuperscript{107}

Q. DOES THE COMPANY REQUIRE POTENTIAL GRANT RECIPIENTS SEEKING FUNDING THROUGH THE ECONOMIC DEVELOPMENT SURCHARGE TO COMMIT TO A MINIMUM LEVEL OF CAPITAL INVESTMENT AS A CONDITION OF ELIGIBILITY?

A. No. The Company does not require prospective customers or third party entities to either commit to a minimum level of capital investment, or achieve an actual threshold level of capital investment.\textsuperscript{108}

Q. DOES THE COMPANY REQUIRE COMPANIES TO PAY BACK ANY GRANT FUNDING AMOUNTS IF THEY LEAVE THE COMPANY’S SERVICE TERRITORY?

A. No. The Company does not require customers or third party entities to repay the discounts provided to them in the case of a customer ceasing operations in the Company’s service territory.\textsuperscript{109}

Q. DOES THE COMPANY’S ECONOMIC DEVELOPMENT RIDER REQUIRE ANY MINIMUM USAGE OR JOB CREATION?

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\textsuperscript{106} See, KBI Fact Sheet, available at thinkkentucky.com.
\textsuperscript{108} Company’s Response to AG_1_372.
\textsuperscript{109} Company’s Response to AG_1_371 and AG_1_377.
A. Yes. The Company’s Tariff EDR requires that a new customer have at least a monthly maximum billing demand of 500 kW and an existing customer must increase its monthly billing demand by at least 500 kW. The Company’s Tariff EDR also requires that the customer create and sustain at least 25 full-time permanent jobs over the term of the contract.  

C. The Company’s Proposal is Likely to Shift Costs onto Captive Ratepayers

Q. DO ECONOMIC DEVELOPMENT RIDERS SUCH AS THE COMPANY’S K-PEGG PROGRAM PROVIDE OTHER BENEFITS BESIDES JOBS AND ECONOMIC DEVELOPMENT?

A. As explained previously, the main objective of economic development tariffs is to encourage job creation in the local economy. However, economic development riders are often touted as a means to increase a utility’s revenue base by adding large consuming customers with relatively low capacity needs compared to smaller customers, thus allowing a utility to more effectively utilize system assets to maximize revenues. In this manner, economic development riders are thought to potentially lower future rate increases for all customers by increasing the utility’s revenue stream without increasing the utility’s fixed cost overhead. Indeed, in proposing the K-PEGG and associated KEDS, the Company noted this very purpose of the surcharge, characterizing the increase in revenue streams as an objective of the program.  

The Company, by strengthening communities’ ability to grow the service territory economy will grow its load and its

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customer base. Everything else being equal, this will allow the Company to spread its costs over a greater number of kilowatt hours and customers and keep the cost to individual customers as low as possible.\textsuperscript{112}

Q. HAS THE COMPANY ESTIMATED THE EFFECT ITS ECONOMIC DEVELOPMENT EFFORTS HAS HAD ON THE COMPANY’S REVENUES?

A. No, the Company has not provided any analysis of the effect the Company’s economic development efforts have had on net revenues.\textsuperscript{113} Although the Company did provide data on its revenues associated with new customer’s electricity use, the Company states that it “is unable to separately identify increases in revenue associated with expansions arising from the Company’s economic development efforts. There is no way from the Company’s records to determine whether the cause of a change in a customer’s electricity usage is attributable to an expansion or other variables.”\textsuperscript{114} Furthermore, the Company has not identified incremental revenues generated through its economic development efforts either historically or into the future, as its records do not permit this type of analysis.\textsuperscript{115} Because of this, it is impossible to even independently assess the cost effectiveness of the economic surcharge to the Company’s ratepayers.

Q. DO YOU BELIEVE THE FAILURE TO JUSTIFY THE COST EFFECTIVENESS OF THE COMPANY’S ECONOMIC DEVELOPMENT EFFORTS REPRESENTS AN INEFFICIENCY OF THE SURCHARGE TARIFF?

\textsuperscript{112} Id. at 19:21 – 20:2.
\textsuperscript{113} Company’s Response to AG 1_387.
\textsuperscript{114} Id.
\textsuperscript{115} Id.
A. Yes. As noted earlier, the Company identified an objective of the K-PEGG Program when it was proposed was to keep the costs to individual customers as low as possible. In other words, the program was meant to assist all ratepayers by incentivizing businesses, such as large commercial and industrial customers to relocate or expand in Kentucky, providing a net positive revenue stream to the Company, revenues that would be used to offset rate increases in the future. However, the Company states that it does not maintain records of incremental revenues generated through its economic development programs, nor does it produce forecasts of future revenue growth or decay through the program going into the future.  

VII. PROPOSED K-PEGG EXPANSION AND THE EASTERN KENTUCKY ECONOMY

Q. PLEASE DESCRIBE THE COMPANY’S RATIONALE FOR THE CREATION OF THE K-PEGG PROGRAM AND ITS PROPOSED EXPANSION.

A. The Company correctly notes that the eastern Kentucky region has seen an economic downturn dating back to 2008. The Company references sharp decreases in coal mining jobs in eastern Kentucky, and the closure, in December 2015, of the AK Steel facility that employed over 600 people. The Company also notes that these events resulted in a direct customer loss of 6,931 customers between 2008 and 2016, and a corresponding annual sales decrease from around 7.24 GWh to 5.80 GWh (a decrease of 1.44 GWh).

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117 Company’s Response to AG_1_387.
118 Direct Testimony of Brad Hall, 4:17-18.
119 Direct Testimony of Brad Hall, 5:1-4.
120 Direct Testimony of Brad Hall, 5:9-11.
121 Direct Testimony of Brad Hall, 5:15-19.
Q. **IS IT TRUE THAT EASTERN KENTUCKY HAS SUFFERED ECONOMIC LOSSES?**

A. Yes. However, most of these decreases have arisen in the past, and these past economic trends may not necessarily be indicative of the potential future regional economic performance. Baring negative impacts potentially caused by the Company’s proposed rate increase, there are plenty of indicators that show that the previous economic hardship miring eastern Kentucky has subsided, and that the region may even be seeing some moderate growth potential.

Q. **ARE THE DATA SHOWING A POTENTIAL TURN AROUND IN THIS PAST ECONOMIC DOWNTURN?**

A. Yes. The Company itself also notes many new large industrial customers are expressing an interest in moving into the Company’s service territory. For instance, the Company notes that Braidy Industries Inc. announced plans, on April 26, 2017, to construct an aluminum mill near South Shore in Greenup County that will ultimately provide approximately 550 advanced manufacturing and administrative jobs. The Company also notes that a chemical manufacturing company looking to expand its operations in the region has indicated plans to create 100 new jobs at a facility located on the site of a former plant. Likewise, the Company notes that a local economic development organization has marketed the former Big Sandy site to a company needing rail access and that, if developed, this target company’s development could lead to the creation of 1,000 jobs.

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122 Direct Testimony of Matthew J. Satterwhite, 11:7-14.
123 Direct Testimony of Brad Hall, 27:19-22.
124 Direct Testimony of Brad Hall, 27:22 to 28:2.
Q. HAS THE COMPANY PROVIDED ADDITIONAL DETAILS ON THE ANNOUNCEMENT BY BRAIDY INDUSTRIES TO CONSTRUCT AN ALUMINUM MILL NEAR SOUTH SHORE?

A. Yes. The Company states that the proposed mill will comprise a 2.5 million square foot facility that will cost approximately $1.3 billion to construct.\footnote{Direct Testimony of Matthew J. Satterwhite, 11:7-14.} Once opened in 2020, the mill will produce Series 5000, 6000, and 7000 aluminum sheet and plate products for use in the automotive and aerospace industry, and employ approximately 550 advanced manufacturing and administrative jobs.\footnote{Direct Testimony of Matthew J. Satterwhite, 11:8-10.} The Company notes that the project, during its construction phase, anticipates supporting up to 1,000 construction jobs.\footnote{Direct Testimony of Matthew J. Satterwhite, 11:14-15.} The Company also notes that the mill, once developed, may support on-site research and development activities designed to advance the science and technology of molten-metal manufacturing.\footnote{Direct Testimony of Matthew J. Satterwhite, 11:10-12.}

Q. HAS THE COMPANY IDENTIFIED THE EFFECT THE ANNOUNCED BRAIDY INDUSTRIES ALUMINUM MILL WILL HAVE ON THE UTILIZATION OF THE COMPANY’S ELECTRICAL SYSTEM?

A. To an extent. The Company states that its preliminary estimated load for the proposed mill is 55 MW when it becomes fully operational in 2020.\footnote{Company’s Response to Data Request KPSC_2_007.} Assuming a modest load factor of 80 percent, this is equivalent to 386 GWh per year in sales. As stated earlier, the Company has lost approximately 1,486 GWh in retail sales since 2010, when the Company’s sales last peaked. This means that Braidy Industries, as a single new customer, will if the plant is constructed as proposed, reverse nearly 26 percent, or over a quarter, of all of the Company’s lost electric sales seen over a six year period since 2010.
Q. IS THERE REASON TO BELIEVE THAT THE NEW ALUMINUM MILL WILL CREATE ADDITIONAL ECONOMIC OPPORTUNITIES IN EASTERN KENTUCKY?

A. Yes. Economic theory states that there are multiplier effects to economic “shocks” such as the creation of a large new employer like Braidy Industries. New employees with additional disposable income seek the services of retail and service sector businesses, such as retail shopping centers and coffee shops.\textsuperscript{130} In this manner a shock such as this ‘induces’ new economic growth. Likewise, the new employer itself seeks the services of third party suppliers, some of which may be locally sourced.

Q. HAS THE COMPANY INDICATED A BELIEF THAT LOCATION OF THE BRAIDY INDUSTRIES ALUMINUM MILL WILL SPUR ADDITIONAL ECONOMIC DEVELOPMENT IN EASTERN KENTUCKY?

A. Yes. In a joint announcement with Governor Bevin, Mr. Satterwhite indicated a belief that the new industrial customer will set off an “economic cascade”\textsuperscript{131} in the region. With this game-changing project in Greenup County, Braidy Industries will positively affect all of Eastern Kentucky, both directly and by attracting other automotive and aerospace-related manufacturers. (…) I’m enthusiastic about the future of our region and will be working alongside Braidy Industries as an economic development partner to ensure its success. Get ready Eastern Kentucky, Braidy Industries is just the first company moving in for what is the best kept secret in the country – the skilled available workforce in our region.\textsuperscript{132}

\textsuperscript{130} See, for example, Company’s Response to Data Request KIUC_1_060.
Q. IS THE IMPACT OF THE NEW ALUMINUM MILL INCLUDED WITH THE COMPANY’S TEST YEAR?

A. No. The Company states that its test year is for the twelve months ended February 28, 2017, and that the aluminum mill was not announced until April 26, 2017. The Commission should therefore recognize that all future electricity sales and associated revenue associated with Braidy Industries is not included within the Company’s requested pro-forma rates.

Q. DID THE COMPANY’S K-PEGG PROGRAM INCENTIVIZE THE LOCATING OF BRAIDY INDUSTRIES TO THE COMPANY’S SERVICE TERRITORY?

A. The Company has not provided any compelling evidence that the K-PEGG grants played any direct role in incentivizing Braidy Industries to locate to Eastern Kentucky. It could just as easily be the case that the Company’s willingness to negotiate a special rate contract with the Braidy Industries may be playing just as important, if not a more important role than the K-PEGG grants. The Company notes that it is in the process of negotiating the terms of a special contract with Braidy Industries that will be filed with the Commission for approval. Although KPCo has responded in the record that any potential special contract with Braidy would mark the first time in over a decade that the Company has sought approval for a special contract with one of its customers, prospective or otherwise, nonetheless KPCo has in fact applied for two special contracts in 2017, one with Deane Mining LLC, and the other with McCoy Elkhorn Mining.

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133 Company’s Response to KIUC_1_011.
134 See, Company’s Response to KPSC_2_007.
135 Company’s Response to KIUC_1_011.
136 Company’s Response to AG_1_385.
Q. HAS THE COMPANY IDENTIFIED ANY OTHER INDUSTRIES THAT
HAVE EXPRESSED AN INTEREST IN LOCATING OR EXPANDING IN ITS
SERVICE TERRITORY?

A. Yes. As noted earlier, the Company references two large customers that have
expressed interest, or are being courted to develop on the site of the Company’s previous Big
Sandy 2 electric generation unit. Specifically, the Company notes that One East Kentucky, a
regional economic development partner, has been in discussions with a large chemical
manufacturing company looking to expand its operations.\(^{137}\) Likewise, the Kentucky Cabinet
for Economic Development, another economic development partner, has marketed the site to
a company interested in the site due to its preexisting rail access.\(^{138}\)

Q. HAS THE COMPANY PROVIDED ADDITIONAL DETAILS ON EITHER OF
THE TWO POTENTIAL CUSTOMERS IN QUESTION?

A. The Company declines to provide detailed information on either of the two
prospective customers, noting that:

> It (...) is in the interests of customers and Company alike not to
jeopardize economic developments by prematurely disclosing
the identity of companies seeking to locate in Kentucky Power’s
service territory.\(^{139}\)

The only information the Company has provided is that the potential chemical
manufacturing company indicates that its development could lead to 100 new jobs\(^{140}\) while
the other customer (needing pre-existing rail access) could create 1,000 jobs.\(^{141}\) If these two
additional projects are developed, it could positively contribute to the utilization of the

\(^{137}\) Direct Testimony of Brad N. Hall, 27:19-22.
\(^{138}\) Direct Testimony of Brad N. Hall, 27:22 to 28:2.
\(^{139}\) Company’s Response to KIUC_1_061.
\(^{140}\) Direct Testimony of Brad N. Hall, 27:19-22.
\(^{141}\) Direct Testimony of Brad N. Hall, 27:22 to 28:2.
Company’s system, potentially at levels comparable to those referenced earlier for the Braidy Industries aluminum mill.

Q. **IS THE CREATION OF NEW INDUSTRIAL ACTIVITY IMPORTANT TO THE COMPANY?**

A. Yes. While the Company notes its loss in customers over the past few years, the vast majority of its lost energy sales have been due to a substantial loss in industrial sales base. Specifically, the Company states that its weather-normalized total sales to ultimate customers in 2011 was 7,016 GWh, a number that fell to 5,836 GWh in 2016. This results in a decrease of 1,180 GWh in sales from 2011 to 2016, of which losses to industrial customers accounted for 842 GWh, or over 71 percent.\(^{142}\)

Q. **DOES THE COMPANY FORECAST CONTINUAL DECREASES IN INDUSTRIAL ELECTRICAL SALES IN THE FUTURE?**

A. No. The Company forecasts that its 2017 internal energy requirement for industrial customers will remain virtually unchanged through 2021.\(^{143}\) In fact, the Company estimates a slight increase in internal energy requirements for industrial customers. This likewise corresponds to a similar increase in total internal energy requirements for its entire system, 2017 to 2021.\(^{144}\) Notably, the Company’s load forecast process has not changed since its Integrated Resource Plan (“IRP”) filed December 20, 2016.\(^{145}\) Therefore, these forecasts presumably do not include additional electrical load associated with the new Braidy Industries aluminum mill, or potential new customers for the Big Sandy site.

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\(^{142}\) Company’s Response to AG_1_347.

\(^{143}\) Company’s Response to AG_1_348.

\(^{144}\) Company’s Response to AG_1_380.

Q. **IS THERE OTHER EVIDENCE OF POTENTIAL ECONOMIC GROWTH IN EASTERN KENTUCKY?**

A. Yes. AEPSC’s Economic Forecasting group monitors various economic indicators of historic performance and projections for Kentucky Power’s service territory as part of the Company’s annual load forecast development and review process. According to the Company, AEPSC’s Economic Forecasting group’s work is based on information provided by Moody’s Analytics. The Company’s upper management was provided with this economic outlook on May 18, 2016, and May 12, 2017. In the 2016 presentation, employment was estimated to decrease by 0.1 percent over the decade 2017 through 2027, resulting in a forecast retail sales decrease of 0.3 percent over the same time period. However, in the more recent 2017 presentation, the Company estimates employment to increase by 0.1 percent over the decade 2018 through 2028, thereby reducing its anticipated retail sales decline from 0.3 percent to 0.1 percent.

Q. **WHAT SHOULD THE COMMISSION TAKE-AWAY FROM THESE RECENT INDUSTRIAL DEVELOPMENT ANNOUNCEMENTS AND SALES FORECASTS?**

A. The Company’s service territory has suffered considerably over the past decade. However, some of the data discussed above, and the Company’s own internal analyses, tends to show that perhaps the worst of this economic downturn is over, at least for commercial and industrial customers. While the K-PEGG program may seem to have merit, it lacks important accountability provisions and appears to shift economic development program performance...
risk away from the Company and onto ratepayers. While having the Company being a partner in economic development is important, this should not come at any cost, particularly a cost that re-distributes resources from residential customers and applies those valuable economic resources to third parties, that have little to no performance accountability to the ratepayers making these funding contributions. This is an ill-advised and poorly constructed economic development program that deviates considerably from best practices in utility economic development programs, and should be discontinued.

Q. **CAN THE COMPANY’S PROPOSED RATE INCREASE NEGATIVELY HURT ANY POTENTIAL ECONOMIC GAINS EASTERN KENTUCKY CUSTOMERS MAY SEE IN THE UPCOMING YEARS?**

A. Yes. Just as the creation of a large new employer creates a ripple effect through the economy from multiplier effects, negative economic shocks likewise cause contractionary effects throughout the economy. The proposed increase in customer electrical rates will reduce the disposable income for customers living in the Company’s service territory, lowering the amount of money these customers are able to spend in the retail and service sectors. This in turn lowers the earnings margins for these businesses, potentially causing them to reduce worker hours and even job positions to meet expense obligations. In this manner a negative shock such as the increase in customer electric rates ‘induces’ further contractions in the local economy. The Company’s proposed increase in electric utility rates runs the risk of harming the economic development of the region it has devoted much effort to improving.

VIII. **CONCLUSIONS AND RECOMMENDATIONS**
Q. WHAT ARE YOUR OVERALL CONCLUSIONS REGARDING THE ECONOMIC IMPACTS ASSOCIATED WITH THE COMPANY’S OVERALL RATE INCREASE PROPOSAL?

A. The timing of KPCo’s proposed rate increase poses a major hardship for Eastern Kentucky ratepayers. These ratepayers have experienced considerable economic hardships dating back to the last economic recession and, in many instances, are still reeling from the lingering impacts of this economic downtown and decreasing coal usage. While there is some evidence that the Eastern Kentucky economy is starting to turn around, any such potential economic turn-around does not support this rate increase. Affordability remains a highly important issue for many households in this region. Further, these ratepayers have seen considerable cumulative rate increases over the past several years and the addition of yet another additional rate increase will likely prove unbearable to many households, particularly many working and lower-income families. Lastly, the Company’s rates are already relatively high, as compared with other regional peer utilities. Indeed, the Company’s customer and energy charges are some of the highest in the region. This rate increase will, at best, maintain what are already high and unattractive electricity service rates, and, at worst, will exacerbate an already bad situation. Thus, I am recommending that the Commission limit any revenue increase in this matter. This recommendation is based on a number of considerations that I discuss previously in my testimony but include: (a) a finding by other Attorney General witnesses that the merits and cost information upon which this rate request are based are questionable; (b) KPCo’s customers are unable to afford any rate increase, and (c) a large rate increase to the extent the Company proposes at this time would set the entire economy of Eastern Kentucky back, counteracting any economic expansion that is on the horizon.
Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY’S PROPOSED RATE DESIGN?

A. Given the significant increases to electric rates ratepayers have seen in recent years, and a noticeable shift towards fixed cost recovery, I recommend that the Commission reject the Company’s proposal to increase customer charges for any customer class. Increases in fixed charges for these customers disproportionately hurt low-income customers in a region that has seen significant hardship in recent years. The Company has ultimately not provided sufficient evidence to justify its proposal. This is especially true given the fact that the Company’s existing customer charges recover all of the Company’s existing customer-related costs for most rate classes, including the residential class.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY’S PROPOSED INCREASE IN ITS KEDS?

A. I recommend that the Commission reject the Company’s proposal to increase its KEDS. Furthermore, I recommend that the Commission eliminate the Company’s KEDS, and its associated K-PEGG program since it (1) is not an economically efficient use of ratepayer dollars and (2) the current program suffers from a large number of accountability deficiencies that shift a large amount of the program’s economic development performance risk away from the Company and onto ratepayers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY FOR OCTOBER 3RD, 2017?

A. Yes.
COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application of Kentucky Power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief

CASE No. 2017-00179

AFFIDAVIT OF David E. Dismukes, Ph.D.

State of Louisiana
Parish of East Baton Rouge

David E. Dismukes, Ph.D., being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and the Schedules attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

SUBSCRIBED AND SWORN to before me this 27th day of September, 2017.

NOTARY PUBLIC

My Commission Expires: Commissioned for Life

Dajuana W. Moore, Notary Public No.68583
DAVID E. DISMUKE, PH.D.

Professor, Executive Director &
Director of Policy Analysis
Center for Energy Studies
Louisiana State University
Baton Rouge, LA 70803-0301
Phone: (225) 578-4343
dismukes@lsu.edu

Consulting Economist
Acadian Consulting Group, LLC
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808
Phone: (225) 769-2603
daviddismukes@acadianconsulting.com

URL: www.enrg.lsu.edu
URL: www.acadianconsulting.com

EDUCATION
Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.

Master's Thesis: Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions

Ph.D. Dissertation: An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities

ACADEMIC APPOINTMENTS
Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies
2014-Current Executive Director
2007-Current Director, Division of Policy Analysis
2006-Current Professor
2003-2014 Associate Executive Director
2001-2006 Associate Professor
1999-2001 Research Fellow and Adjunct Assistant Professor
1995-2000 Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)
2014-Current Professor (Joint Appointment with CES)
2010-Current Director, Coastal Marine Institute
2010-2014 Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)
2006-Current Adjunct Professor
2001-2006 Adjunct Associate Professor
1999-2000 Adjunct Assistant Professor
Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics
1995 Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana
2001-Current Consulting Economist/Principal
1995-1999 Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas
1999-2001 Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section
1995 Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section
1993 Planning & Research Economist
1992-1993 Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida
1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida
1991-1992 Research Associate
1989-1991 Senior Research Analyst
1988-1989 Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current Louisiana Representative, Interstate Oil and Gas Compact
Commission; Energy Resources, Research & Technology
Committee.

2007-Current Louisiana Representative, University Advisory Board
Representative; Energy Council (Center for Energy,
Environmental and Legislative Research).

2005 Member, Task Force on Energy Sector Workforce and Economic
Development (HCR 322).

2003-2005 Member, Energy and Basic Industries Task Force, Louisiana
Economic Development Council

PUBLICATIONS: BOOKS AND MONOGRAPHS


PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS


PUBLICATIONS: PEER REVIEWED PROCEEDINGS


**PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS**


PUBLICATIONS: BOOK CHAPTERS


PUBLICATIONS: BOOK REVIEWS


**PUBLICATIONS: TRADE AND PROFESSIONAL JOURNALS**


PUBLICATIONS: OPINION AND EDITORIAL ARTICLES


9


**PUBLICATIONS: REPORTS AND OTHER MANUSCRIPTS**


GRANT RESEARCH


5. **Principal Investigator.** An update of Louisiana’s combined heat and power potentials, current utilizations, and barriers to improved operating efficiencies. (2016). Louisiana Department of Natural Resources. Total Project: $90,000, one year. Status: In progress.


17. **Principal Investigator.** “OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity.” (2008). With Mark J. Kaiser

13


29. **Principal Investigator.** “Marginal Oil and Gas Properties on State Leases in Louisiana:


**ACADEMIC CONFERENCE PAPERS/PRESENTATIONS**


Louisiana. May 20.


ACADEMIC SEMINARS AND PRESENTATIONS


PROFESSIONAL AND CIVIC PRESENTATIONS


101. “Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater


“Background and Overview of LNG Development.” Energy Council Workshop on LNG/CNG. Biloxi, MS: Beau Rivage Resort and Hotel, April 9, 2005.


The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.


185. “Affordable Energy: The Key Component to a Strong Economy.” Presentation before the National Association of Regulatory Utility Commissioners (“NARUC”), November 18, 2003, Atlanta, Georgia.


EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS


3. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District. On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.


36. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.


Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.


Normalization.


Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.


115. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.


REFEREE AND EDITORIAL APPOINTMENTS

Editorial Board Member, 2015-Current, Utilities Policy
Referee, 2014-Current, Utilities Policy
Referee, 2010-Current, Economics of Energy & Environmental Policy
Referee, 1995-Current, Energy Journal
Contributing Editor, 2000-2005, Oil, Gas and Energy Quarterly
Referee, 2005, Energy Policy
Referee, 2004, Southern Economic Journal
Referee, 2002, Resource & Energy Economics
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER


PROFESSIONAL ASSOCIATIONS


HONORS AND AWARDS


Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).
TEACHING EXPERIENCE

Energy and the Environment (Survey Course)
Principles of Microeconomic Theory
Principles of Macroeconomic Theory
Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).
Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).
Lecturer, LSU Honors College, Senior Course on “Society and the Coast.”
Continuing Education. Electric Power Industry Restructuring for Energy Professionals.
“Demand Modeling and Forecasting for Regulators.” Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

“Traditional and Incentive Ratemaking Workshop.” New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.


THESIS/DISSERTATIONS COMMITTEES

Active:
2 Thesis Committee Memberships (Environmental Studies)
1 Ph.D. Dissertation Committee (Economics)

Completed:
6 Thesis Committee Memberships (Environmental Studies, Geography)
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).
Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).
CES Promotion Committee, Division of Radiation Safety (2006).
Search Committee Chair (2006), Research Associate 4 Position.
Search Committee Member (2005), Research Associate 4 Position.
Search Committee Member (2005), CES Communications Manager.
LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).
LSU Faculty Senate (2003-2006).
LSU Faculty Senate Committee on Public Relations (1997-1999).
LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Breifing. “Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South.”


Committee Member (2006), International Association for Energy Economics (“IAEE”) Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

## Table of Exhibits

<table>
<thead>
<tr>
<th>Title</th>
<th>Exhibit</th>
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<tr>
<td>Historic Quarterly Employment - Eastern Kentucky and Total State</td>
<td>Exhibit DED - 1</td>
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<tr>
<td>Historic Monthly Average Earnings - Eastern Kentucky and Total State</td>
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<td>Company's Historic Residential Rates</td>
<td>Exhibit DED - 3</td>
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<td>Peer Analysis Rate per MWh</td>
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<tr>
<td>Analysis of Company's Customer Costs</td>
<td>Exhibit DED - 5</td>
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<td>Survey of Regional Customer Charges</td>
<td>Exhibit DED - 6</td>
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<tr>
<td>Usage by Income</td>
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<td>Consumption as Percent of Income</td>
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<tr>
<td>Analysis of Company's Customer Counts, Sales, and Revenues (2006 -</td>
<td>Exhibit DED - 9</td>
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Historic Quarterly Employment - Eastern Kentucky and Total State

Source: U.S. Census Bureau, Center for Economic Studies, Quarterly Workforce Indicators ("QWI")
Historic Monthly Average Earnings – Eastern Kentucky and Total State

Source: U.S. Census Bureau, Center for Economic Studies, Quarterly Workforce Indicators ("QWI")
## Company’s Historic Residential Rates

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<td>Residential Service (&quot;RS&quot;)</td>
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### Total Monthly Bill

#### RS Customer at System Average Use (1,295 kWh per month)

- **Fixed Charge**
  - Customer Charge per month: $5.86, $8.00, $11.00, $17.50

- **Variable Charge**
  - Energy Charge per kWh: $0.06002, $0.08590, $0.08910, $0.10853
  - Monthly Use: 1295, 1295, 1295, 1295
  - Total Variable Charge: $77.73, $111.24, $115.38, $140.55

- **Total Monthly Bill:** $83.59, $119.24, $126.38, $158.05 (51.20%, 5.54%, 89.08%, 7.86%)

#### RS Customer at 50% System Average Use (648 kWh per month)

- **Fixed Charge**
  - Customer Charge per month: $5.86, $8.00, $11.00, $17.50

- **Variable Charge**
  - Energy Charge per kWh: $0.06002, $0.08590, $0.08910, $0.10853
  - Monthly Use: 648, 648, 648, 648
  - Total Variable Charge: $38.89, $55.66, $57.74, $70.33

- **Total Monthly Bill:** $44.75, $63.66, $68.74, $87.83 (53.59%, 5.79%, 96.25%, 8.49%)

#### RS Customer at 150% System Average Use (1,943 kWh per month)

- **Fixed Charge**
  - Customer Charge per month: $5.86, $8.00, $11.00, $17.50

- **Variable Charge**
  - Energy Charge per kWh: $0.06002, $0.08590, $0.08910, $0.10853
  - Monthly Use: 1943, 1943, 1943, 1943
  - Total Variable Charge: $116.62, $166.90, $173.12, $210.87

- **Total Monthly Bill:** $122.48, $174.90, $184.12, $228.37 (50.33%, 5.44%, 86.46%, 7.63%)

Source: Prior Commission Case Orders; Application, Section II, Exhibit D; and FERC Form 1.
## Peer Analysis Rate per MWh (Residential)

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Source: FERC Form 1.
Peer Analysis Rate per MWh (Residential)

Source: FERC Form 1.
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Source: FERC Form 1.
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Source: FERC Form 1.
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<tr>
<td>Entergy Arkansas, Inc.</td>
<td>12</td>
<td>6</td>
<td>8</td>
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<td>Entergy Mississippi, Inc.</td>
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</tr>
<tr>
<td>Kentucky Utilities Company</td>
<td>3</td>
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<td>4</td>
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<tr>
<td>Louisville Gas and Electric Company</td>
<td>5</td>
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<td>6</td>
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<td>8</td>
<td>5</td>
<td>8</td>
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<tr>
<td>South Carolina Electric &amp; Gas Company</td>
<td>10</td>
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<td>10</td>
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<td>13</td>
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<td>Virginia Electric and Power Company</td>
<td>4</td>
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<td>5</td>
<td>11</td>
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<td>7</td>
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</tbody>
</table>
## Analysis of Company's Customer Costs

<table>
<thead>
<tr>
<th>Account Description</th>
<th>Residential RS</th>
<th>Small General Service SGS</th>
<th>Medium General Service</th>
<th>Large General Service</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>MGS-SEC</td>
<td>MGS-PRI</td>
</tr>
<tr>
<td>Total Customer-Related Costs</td>
<td>12,249,602</td>
<td>3,465,334</td>
<td>933,727</td>
<td>239,813</td>
</tr>
<tr>
<td>Number of Customers</td>
<td>136,607</td>
<td>24,022</td>
<td>6,507</td>
<td>78</td>
</tr>
<tr>
<td>Monthly Customer-Related Costs/Customer</td>
<td>7.47</td>
<td>12.02</td>
<td>11.96</td>
<td>256.21</td>
</tr>
<tr>
<td>Customer Charge Revenue</td>
<td>18,032,091</td>
<td>5,044,708</td>
<td>1,366,505</td>
<td>46,800</td>
</tr>
<tr>
<td>Monthly Customer Charge Revenue/Customer</td>
<td>11.00</td>
<td>17.50</td>
<td>17.50</td>
<td>50.00</td>
</tr>
<tr>
<td>Relationship of Customer Charge Revenues to Customer-Related Costs</td>
<td>147%</td>
<td>146%</td>
<td>146%</td>
<td>20%</td>
</tr>
</tbody>
</table>

Source: Company's workpaper KPCO_R_KPSC_1_73_Attachment73_AEVWP3; and Kentucky Power’s tariff.
## Analysis of Company’s Customer Costs

<table>
<thead>
<tr>
<th></th>
<th>Industrial General Service</th>
<th>Municipal Waterworks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IGS-SE</td>
<td>IGS-PRI</td>
</tr>
<tr>
<td><strong>Customer Related Costs per Company’s CCOSS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Customer-Related Costs</td>
<td>$1,465</td>
<td>$35,582</td>
</tr>
<tr>
<td>Number of Customers</td>
<td>4</td>
<td>35</td>
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<tr>
<td>Monthly Customer-Related Costs/Customer</td>
<td>$30.52</td>
<td>$84.72</td>
</tr>
<tr>
<td>Customer Charge Revenue</td>
<td>$13,248</td>
<td>$115,920</td>
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<tr>
<td>Monthly Customer Charge Revenue/Customer</td>
<td>$276.00</td>
<td>$276.00</td>
</tr>
<tr>
<td>Relationship of Customer Charge Revenues to Customer-Related Costs</td>
<td>904%</td>
<td>326%</td>
</tr>
</tbody>
</table>

Source: Company's workpaper KPCO_R_KPSC_1_73_Attachment73_AEVWP3; and Kentucky Power’s tariff.
### Survey of Regional Customer Charges

<table>
<thead>
<tr>
<th>State</th>
<th>Company</th>
<th>Residential</th>
<th>Commercial</th>
</tr>
</thead>
<tbody>
<tr>
<td>KY</td>
<td>Kentucky Power Company</td>
<td>$11.00</td>
<td>$17.50</td>
</tr>
<tr>
<td>AL</td>
<td>Alabama Power Company</td>
<td>$14.50</td>
<td>N.A.</td>
</tr>
<tr>
<td>MO</td>
<td>Ameren Missouri</td>
<td>$9.00</td>
<td>$11.19</td>
</tr>
<tr>
<td>VA</td>
<td>Appalachian Power Company</td>
<td>$8.35</td>
<td>$10.25</td>
</tr>
<tr>
<td>WV</td>
<td>Appalachian Power Company</td>
<td>$8.00</td>
<td>$9.50</td>
</tr>
<tr>
<td>NC</td>
<td>Duke Energy Carolinas, LLC</td>
<td>$11.80</td>
<td>$19.39</td>
</tr>
<tr>
<td>SC</td>
<td>Duke Energy Carolinas, LLC</td>
<td>$8.29</td>
<td>$10.52</td>
</tr>
<tr>
<td>KY</td>
<td>Duke Energy Kentucky, Inc.</td>
<td>$4.50</td>
<td>$7.50</td>
</tr>
<tr>
<td>NC</td>
<td>Duke Energy Progress</td>
<td>$11.13</td>
<td>$16.45</td>
</tr>
<tr>
<td>SC</td>
<td>Duke Energy Progress</td>
<td>$9.06</td>
<td>$9.91</td>
</tr>
<tr>
<td>AR</td>
<td>Entergy Arkansas, Inc.</td>
<td>$8.40</td>
<td>$24.25</td>
</tr>
<tr>
<td>MS</td>
<td>Entergy Mississippi, Inc.</td>
<td>$6.75</td>
<td>$7.67</td>
</tr>
<tr>
<td>KY</td>
<td>Kentucky Utilities Company</td>
<td>$12.25</td>
<td>$31.50</td>
</tr>
<tr>
<td>KY</td>
<td>Louisville Gas and Electric Company</td>
<td>$12.25</td>
<td>$31.50</td>
</tr>
<tr>
<td>SC</td>
<td>South Carolina Electric &amp; Gas Company</td>
<td>$10.00</td>
<td>$22.75</td>
</tr>
<tr>
<td>NC</td>
<td>Virginia Electric and Power Company</td>
<td>$10.96</td>
<td>$19.79</td>
</tr>
<tr>
<td>VA</td>
<td>Virginia Electric and Power Company</td>
<td>$7.00</td>
<td>$12.40</td>
</tr>
</tbody>
</table>

Note: Appalachian Power Company's charges are based on Distribution Charges only.
Source: Company tariffs.
Usage by Income

Total Site Electricity Usage (Kilowatt-Hours, 2009)

Source: 2009 Residential Electricity Consumption Survey ("RECS")
## Regression Analysis Results

<table>
<thead>
<tr>
<th>Dependent Variable</th>
<th>Coef</th>
<th>SE</th>
<th>t</th>
<th>p-value</th>
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</thead>
<tbody>
<tr>
<td>Ln(Household Income)</td>
<td>0.0663064</td>
<td>0.0184646</td>
<td>3.59</td>
<td>0.0000</td>
</tr>
<tr>
<td>Ln(Square Footage)</td>
<td>0.2248405</td>
<td>0.0284459</td>
<td>7.9</td>
<td>0.0000</td>
</tr>
<tr>
<td>Ln(HH Members)</td>
<td>0.3272310</td>
<td>0.0295888</td>
<td>11.06</td>
<td>0.0000</td>
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<tr>
<td>Constant</td>
<td>4.5289330</td>
<td>0.2130319</td>
<td>21.26</td>
<td>0.0000</td>
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</tbody>
</table>

**Note:** Robust Standard Errors Presented.

**Source:** 2009 Residential Electricity Consumption Survey ("RECS")
Consumption as Percent of Income

Source: 2009 Residential Electricity Consumption Survey (“RECS”)
## Analysis of Company’s Customer Counts, Sales, and Revenues (2006 – 2016)

<table>
<thead>
<tr>
<th>Year</th>
<th>Customers</th>
<th>Sales (MWh)</th>
<th>Revenues ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>175,571</td>
<td>7,122,459</td>
<td>391,934,420</td>
</tr>
<tr>
<td>2007</td>
<td>175,705</td>
<td>7,114,506</td>
<td>406,102,663</td>
</tr>
<tr>
<td>2008</td>
<td>175,646</td>
<td>7,241,902</td>
<td>476,235,627</td>
</tr>
<tr>
<td>2009</td>
<td>174,994</td>
<td>7,068,456</td>
<td>487,997,590</td>
</tr>
<tr>
<td>2010</td>
<td>174,579</td>
<td>7,348,529</td>
<td>541,079,466</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Customers</th>
<th>Sales (MWh)</th>
<th>Revenues ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>173,641</td>
<td>6,983,163</td>
<td>559,169,090</td>
</tr>
<tr>
<td>2012</td>
<td>172,757</td>
<td>6,660,656</td>
<td>501,036,751</td>
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<tr>
<td>2013</td>
<td>172,138</td>
<td>6,537,521</td>
<td>512,201,281</td>
</tr>
<tr>
<td>2014</td>
<td>171,011</td>
<td>6,531,904</td>
<td>556,434,077</td>
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<tr>
<td>2015</td>
<td>170,020</td>
<td>6,218,801</td>
<td>537,055,812</td>
</tr>
<tr>
<td>2016</td>
<td>168,848</td>
<td>5,862,697</td>
<td>572,810,777</td>
</tr>
</tbody>
</table>

Source: FERC Form 1.