COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

1. Provide a copy of all notes and workpapers prepared by Mr. Baron in connection with this proceeding. If Mr. Baron prepared any Excel spreadsheets or other computer generated documents, please provide an electronic version of those documents.

RESPONSE:

See attached.

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2. On page 35, lines 6-7, of his testimony, Mr. Baron states that "manufacturing jobs tend to have high job multipliers." Please provide the actual or approximate number of employees at each of the following manufacturing plants served by KU or LG&E and that are members of the KIUC, as listed on page 3 of Mr. Baron's testimony:

a. AAK, USA K2 LLC
b. Air Liquid U.S. LP
c. Alliance Coal LLC
d. Carbide Industries LLC
e. Cemex
f. Corning Incorporated
g. Clopay Plastic Products Co. Inc.
h. Dow Corning Corporation
i. Ford Motor Company
j. Ingevity
k. Lexmark International Inc.
l. North American Stainless
m. The Chemours Company
n. Toyota Motor Manufacturing, Kentucky Inc.

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RESPONSE:

		Estimated Number of Employees in Facilities Taking Service on KU or LG&E System
a.	AAK, USA K2 LLC	135
b.	Air Liquid U.S. LP	30
c.	Alliance Coal LLC	3,009
d.	Carbide Industries LLC	105
e.	Cemex	154
f.	Corning Incorporated	400
g.	Clopay Plastic Products Co. Inc.	371
h.	Dow Corning Corporation	783
i.	Ford Motor Company	10,150
j.	Ingevity	107
k.	Lexmark International Inc.	2,300
l.	North American Stainless	1,392
m.	The Chemours Company	200
n.	Toyota Motor Manufacturing, Kentucky Inc.	7,600

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3. On page 35, lines 7-8, of Mr. Baron's testimony, he states that, "for every one manufacturing job created or saved about two additional support-related jobs are created." Provide all research, economic reports or other documents that Mr. Baron relied on to make this statement.

RESPONSE:

Mr. Baron relied on the testimony of Dr. Paul A. Coomes, on behalf of KIUC, in KU's and LG&E's 2014 base rate cases (Case Nos. 2014-00371 and 2014-00372), which is included in Mr. Baron's workpapers. In that testimony, Dr. Coomes explains the concept of employment multipliers and how manufacturing industries that export their products out of state generally have the highest employment multipliers. At page 2 of his testimony, he states that:

> My study demonstrates that the most important industries, in terms of economic growth, are those that export their goods and services to customers around the US and the world. Firms in these industries bring new dollars into Kentucky and thereby lift firms in other linked industries, as well as the incomes of Kentucky households. As household incomes grow, so do sales and employment in support industries (and governments) that provide goods and services to local households. The export-based industries are the engines of growth, and therefore have been the target of economic development agencies, while retail and most service businesses are essentially captive and require no special incentives to operate in the state.

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Dr. Coomes explains that an employment multiplier measures the indirect and induced jobs created (or lost) in the area for each direct job at a facility. Direct jobs are related to the specific industry while indirect jobs are those that support the industry.

Dr. Coomes presents data for Kentucky industries from 2013 in his March 4, 2015 report *"The Differential Economic Importance and Electricity Usage of Industries in Kentucky,"* attached to his testimony. On page 9 of his report, he presents a table showing KY employment multipliers ranging from 2.028 to 7.877, well in excess of the 2.0 multiplier referenced in Mr. Baron's testimony. Dr. Coomes explains that his data is from the Kentucky IMPLAN database that is used to analyze economic activity in the state

More recent data from the IMPLAN database shows that the Kentucky manufacturing industry employment multiplier is 2.6, meaning that there are 2.6 indirect jobs in Kentucky for every direct job in manufacturing.

Also attached to this response is a copy of a study that discusses the impact on Kentucky's economy of electric price increases. The study, *"The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices"* was prepared in October 2012 for the Kentucky Energy and Environment Cabinet by Aron Patrick. Among its findings, the study concluded that:

> **Given a 25% forecasted increase in the real price of electricity in Kentucky between 2011 and 2025, this study estimates the Commonwealth will likely lose, or fail to create, approximately 30,000 full-time jobs in the long-term.** Manufacturing establishments were found to be most responsive to changes in

electricity prices and can be expected to permanently shed 17,500 full-time jobs. (excerpted from report Executive Summary)

On page 5, the report discusses the specific vulnerability of Kentucky's electric-intensive manufacturing industry. It states as follows:

> Kentucky's electricity-intensive manufacturing economy is threatened by increasing electricity prices. While the price of electricity is only one of several factors influencing industrial location decisions, Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive economy in the United States. In the twenty-first century, the bulwark of the Kentucky economy is clearly manufactured goods—the Commonwealth's single largest source of economic activity.

KWalton

Vulnerability of Kentucky's Manufacturing Economy - Q
03/31/17 09:02 AM

The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices

Aron Patrick

Kentucky Energy and Environment Cabinet
Department for Energy Development and Independence

October, 2012

energy.ky.gov

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Executive Summary

Kentucky's low electricity prices have fostered the single-most electricity-intensive manufacturing economy in the United States, a manufacturing economy that is now threatened by future electricity price increases. This study builds upon the notion that low energy costs are a catalyst for commercial growth by quantifying the specific vulnerability of the largest economic sectors of the Commonwealth, in terms of total employment, to future electricity price increases. Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, this study modeled the responsiveness of employment across the United States to changes in the price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing, retail services, hospitality, healthcare, and government. *Elasticities* were developed for each of these economic sectors to calculate changes in employment, given a specific change in the price of electricity, and can be generally applied to the 48 contiguous United States.

Given a 25% forecasted increase in the real price of electricity in Kentucky between 2011 and 2025, this study estimates the Commonwealth will likely lose, or fail to create, approximately 30,000 full-time jobs in the long-term. Manufacturing establishments were found to be most responsive to changes in electricity prices and can be expected to permanently shed 17,500 full-time jobs. The other largest employment sectors in Kentucky, retail stores, restaurants, and hotels, were less than half as responsive as the manufacturing sector to increasing electricity prices, and combined, can be expected to fail to create 12,500 full-time jobs. However, in the fourth and fifth largest employment sectors, healthcare and government, no statistically significant relationship could be identified between electricity prices and total employment.

While total employment in Kentucky is expected to continue to rise in other sectors, **the Commonwealth should develop strategies to mitigate vulnerability to energy price increases, volatility, and risk exposure. Additionally, Kentucky should maintain focus on education and workforce development in emerging industries that are less reliant on energy-intensive manufacturing processes**. These forecasted electricity price increases, in addition to the current trend towards off-shoring and automation of manufacturing processes, have the potential to transform the economies of manufacturing states like Kentucky.

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The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices

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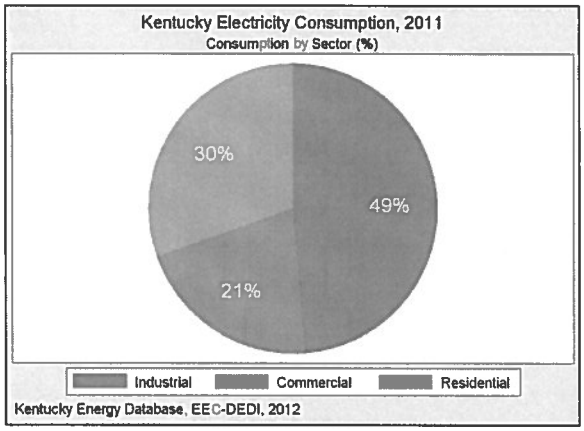
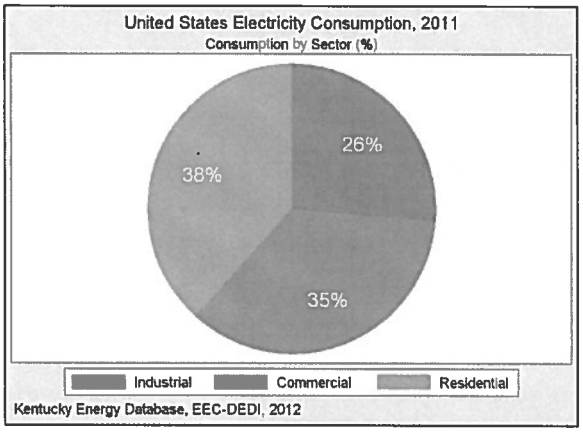
Kentucky's Energy-Intensive Economy

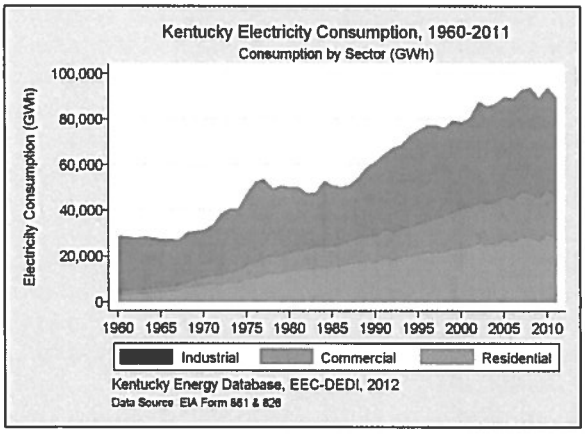
In 2011, 49% of all electricity consumed in Kentucky went to industrial users, compared with 26% for the United States as a whole, as illustrated in Figures 1 and 2 below. The reason for this is obvious—industries requiring large amounts of electricity for production have an incentive to locate in states where they can anticipate that electricity costs will remain low. The industrial nature of Kentucky's electricity load is by no means a recent development. Ever since the first power plants were built in the Commonwealth, most of the electricity produced went to large factories. Over the past 50 years for which there is reliable data, industrial users have consumed an average of 60% of all electricity generated in Kentucky annually, as illustrated in Figure 3 below. These proportions for the United States as a whole have historically been far more balanced, as illustrated in Figure 4 below.

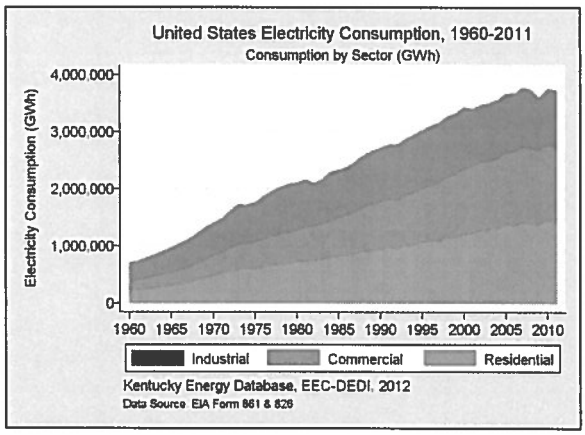
Figures 1 & 2: Electricity Consumption by Economic Sector, Kentucky vs. the United States, 2011





Figures 3 & 4: Electricity Consumption by Economic Sector, Kentucky vs. the United States, 1960-2011





Coal has historically provided the Commonwealth both low-cost electricity and energy security. Nominal electricity prices in Kentucky have increased since 1970 at about 2% annually, which is less than the average rate of inflation during this same period. When adjusted for inflation,[1] as illustrated in Figure 5 on page 3, real electricity prices actually fell in Kentucky from 1980 to 2003, and have risen over the past decade with increases in the price of all fossil fuels. Since 1992, Kentucky has maintained one of the lowest four electricity prices in the nation, running neck and neck with the coal and hydroelectric states of Idaho, Wyoming, Washington, and West Virginia.

Figure 6 on page 3 illustrates that Kentucky is home to the most electricity-intensive economy in the United States. Simply stated, *this means that Kentucky industries use more kilowatt-hours of electricity to produce one dollar of GDP than any other state and are, therefore, more sensitive to changes in electricity prices than any other state.*

In 2009, the most-electricity-intensive sectors nationally were aluminum smelting, iron & steel mills, paper mills, chemical production, and glass manufacturing, which required on average between 0.5 and 4.5 kilowatt-hours of electricity to produce $1 worth of goods. At current Kentucky industrial electricity prices, each dollar of shipments from these industries required between $0.025 and $0.222 worth of electricity. In other words, up to a quarter of total revenues in these industries go to electricity costs. In Kentucky, the most-intensive of these manufacturing processes, which require more than 0.5 kilowatt-hours of electricity to produce $1 of goods, directly contributed $5 billion, or 3.2%, to the Commonwealth's total 2009 GDP and employed 12,685 Kentuckians.[2] The national average electricity-intensity of each NAICS manufacturing sector present in Kentucky is summarized in Table 1 on page 4 along with the total number of employees and the contribution of each industry to Kentucky's 2009 State GDP based on data provided by the U.S. Census Bureau's Annual Survey of Manufactures and the U.S. Bureau of Economic Analysis.[3] This table provides an approximate rank ordering of sensitivity to electricity prices between types of manufacturing operations present in Kentucky.

Figure 5: Total Real Electricity Prices, 1970-2010, Kentucky vs. the United States

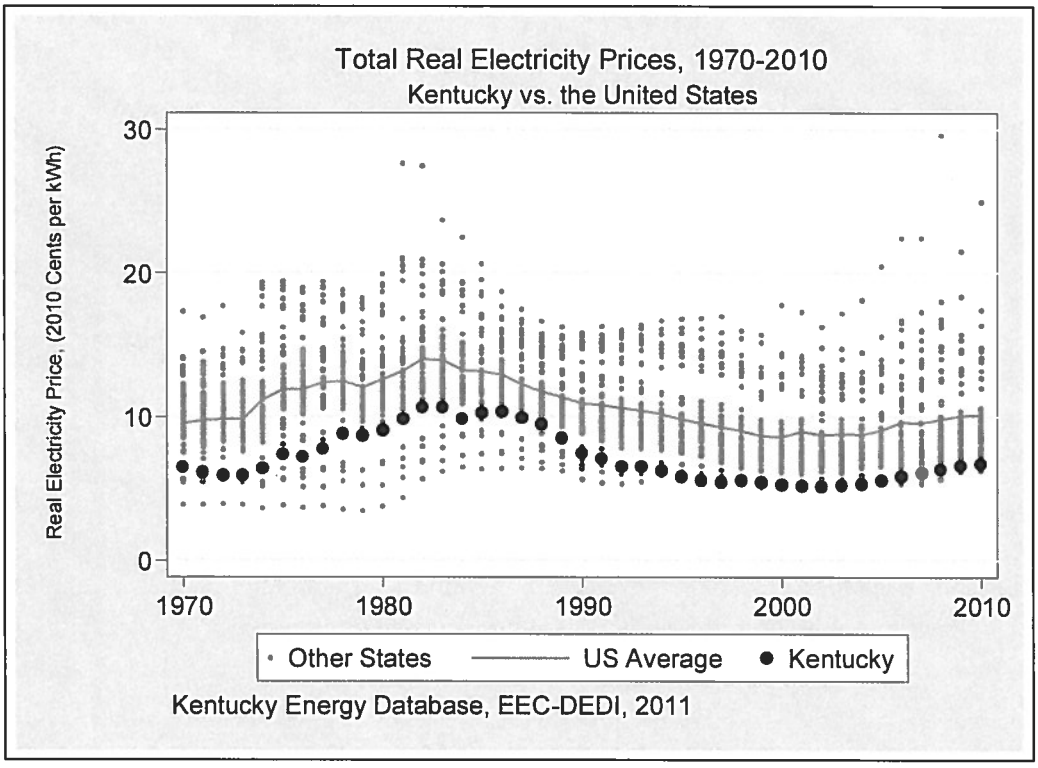


Figure 6: Total Electricity Intensity of Production, 1963-2010, Kentucky vs. the United States

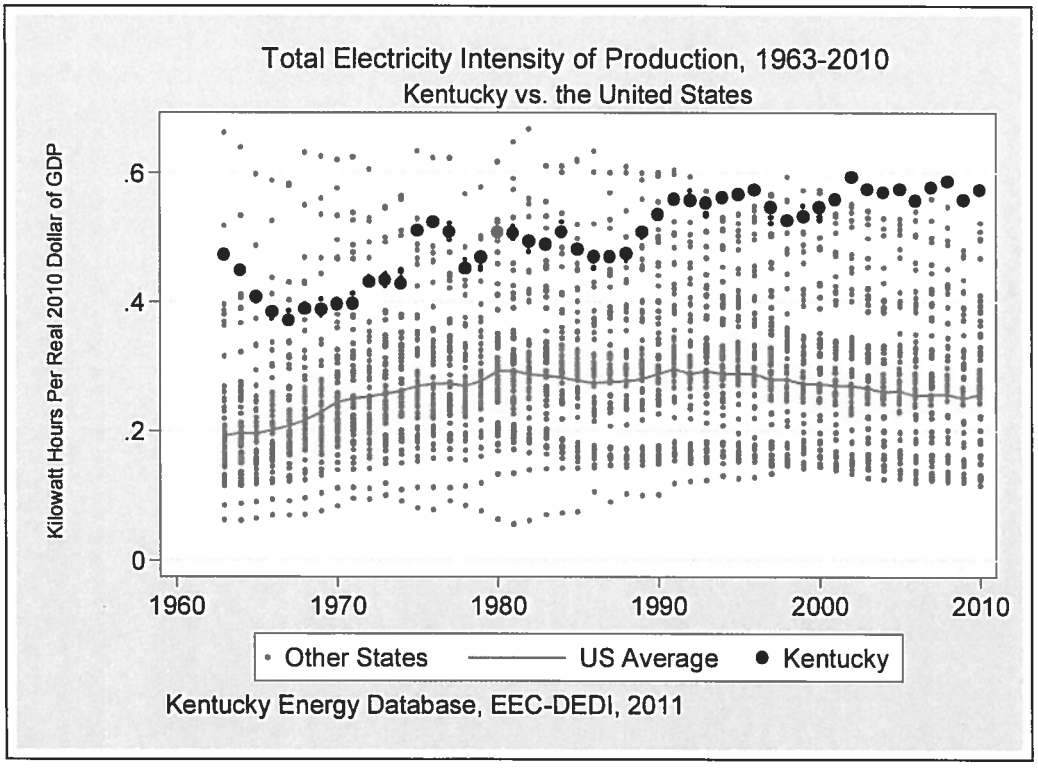


Table 1: National Manufacturing Sector Electricity-Intensity and Kentucky Employment by NAICS, 2009

NAICS 4	NAICS Description	National Electricity Intensity of Production (kWh per $ of Shipment)	Kentucky Average Workers	Kentucky Production Worker Hours (1,000)	Kentucky Value added ($1,000)
3313	Aluminum Production & Processing	4.37313	3,482	6,930	1,083,373
3311	Iron & Steel Mills & Ferroalloy	1.57640	2,954	6,083	232,537
3221	Pulp, Paper, & Paperboard Mills	1.11598	1,192	2,382	1,142,732
3251	Basic Chemical	0.71269	3,043	6,000	2,245,950
3272	Glass & Glass Product	0.60508	2,015	4,151	287,908
3315	Foundries	0.39152	1,595	3,403	104,152
3252	Resin, Syn Rubber, & Artificial Syn Fibers & Filaments	0.35947	1,845	3,799	544,965
3273	Cement & Concrete Product	0.34890	1,688	2,996	236,878
3279	Other Nonmetallic Mineral Product	0.32072	755	1,352	82,074
3132	Fabric Mills	0.30503	857	1,299	
3328	Coating, Engraving, Heat Treating, & Allied Activities	0.29064	730	1,434	62,744
3261	Plastics Product	0.28636	9,552	19,369	1,369,277
3121	Beverage	0.23187	1,941	3,563	
3211	Sawmills & Wood Preservation	0.21894	1,743	3,387	173,367
3359	Other Electrical Equipment & Component	0.21885	1,237	2,283	256,187
3321	Forging & Stamping	0.21571	1,462	2,883	200,502
3262	Rubber Product	0.21049	1,161	2,209	130,931
3116	Animal Slaughtering & Processing	0.17398	8,233	17,208	1,126,612
3114	Fruit & Vegetable Preserving & Specialty Food	0.16088	3,214	6,478	466,909
3118	Bakeries & Tortilla	0.16008	4,018	6,983	740,444
3222	Converted Paper Product	0.15944	5,636	10,950	1,167,297
3344	Semiconductor & Other Electronic Component	0.15703	707	1,315	44,721
3326	Spring & Wire Product	0.14747	2,359	4,496	246,093
3363	Motor Vehicle Parts	0.14719	16,660	31,037	2,942,269
3259	Other Chemical Product & Preparation	0.14596	915	1,965	184,767
3231	Printing & Related Support Activities	0.14519	8,092	15,155	846,289
3327	Machine Shops, Turned Product, & Screw, Nut, & Bolt	0.14463	2,772	5,570	336,332
3329	Other Fabricated Metal Product	0.14187	2,699	4,948	456,340
3219	Other Wood Product	0.14074	5,764	10,705	413,340
3324	Boiler, Tank, & Shipping Container	0.13796	885	1,701	196,781
3336	Engine, Turbine, & Power Transmission Equipment	0.13598	1,209	2,138	127,183
3335	Metalworking Machinery	0.13253	1,331	2,250	139,843
3241	Petroleum & Coal Products	0.13014	740	1,456	
3371	Household & Institutional Furniture & Kitchen Cabinet	0.12103	1,597	2,765	
3115	Dairy Product	0.11755	1,531	3,136	321,496
3364	Aerospace Product & Parts	0.11584	1,257	2,322	420,386
3372	Office Furniture (Including Fixtures)	0.11478	1,017	2,017	
3399	Other Miscellaneous	0.10128	2,006	3,913	325,240
3352	Household Appliance	0.09877	1,576	2,858	
3339	Other General Purpose Machinery	0.09456	3,307	6,293	758,199
3119	Other Food	0.09371	1,570	2,906	579,615
3255	Paint, Coating, & Adhesive	0.09362	907	1,777	537,129
3366	Ship & Boat Building	0.09142	980	2,081	
3334	Ventilation, Heating, Ac, & Commercial Refrigeration	0.08948	2,071	3,765	376,925
3323	Architectural & Structural Metals	0.08879	3,402	6,355	436,994
3353	Electrical Equipment	0.08174	1,107	1,977	293,203
3331	Agriculture, Construction, & Mining Machinery	0.07432	1,407	2,201	209,643
3391	Medical Equipment & Supplies	0.07185	1,242	2,395	165,180
3362	Motor Vehicle Body & Trailer	0.06701	808	1,622	76,925
3256	Soap, Cleaning Compound, & Toilet Preparation	0.05454	957	2,136	442,283
3122	Tobacco	0.04605	593	1,095	
3361	Motor Vehicle	0.03654	11,384	22,724	

Figure 7: Kentucky Gross Domestic Product by Economic Sector, 2009 [4]

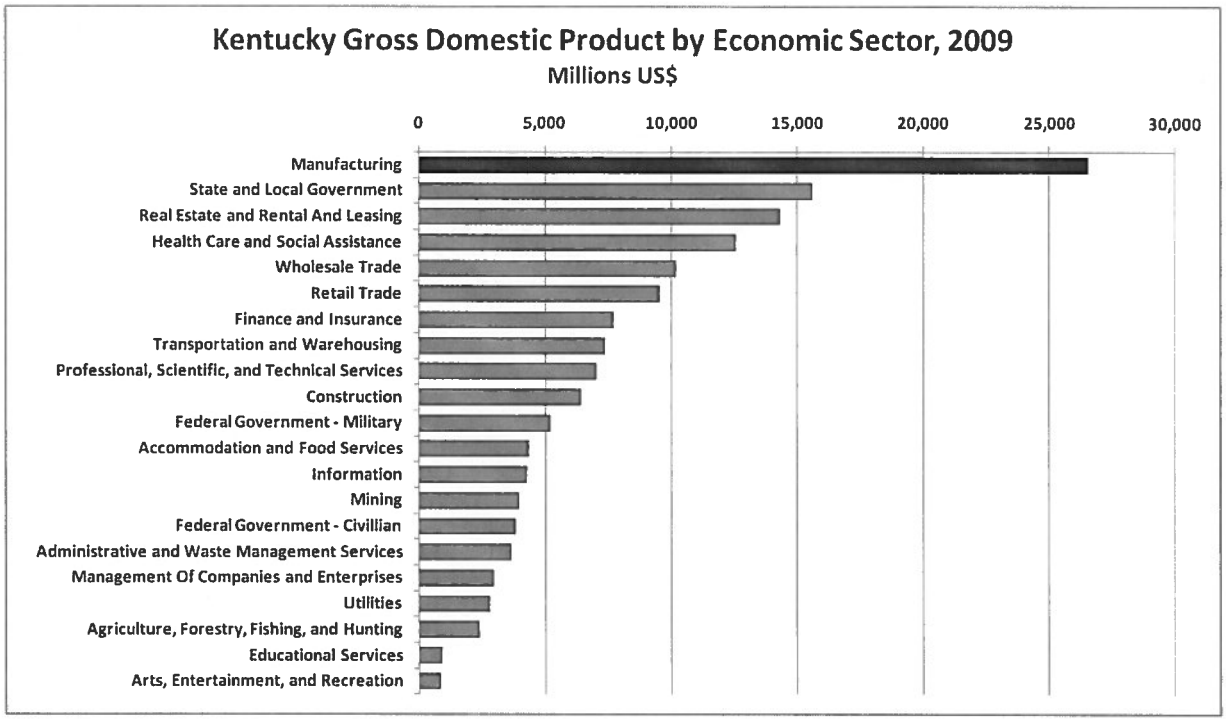
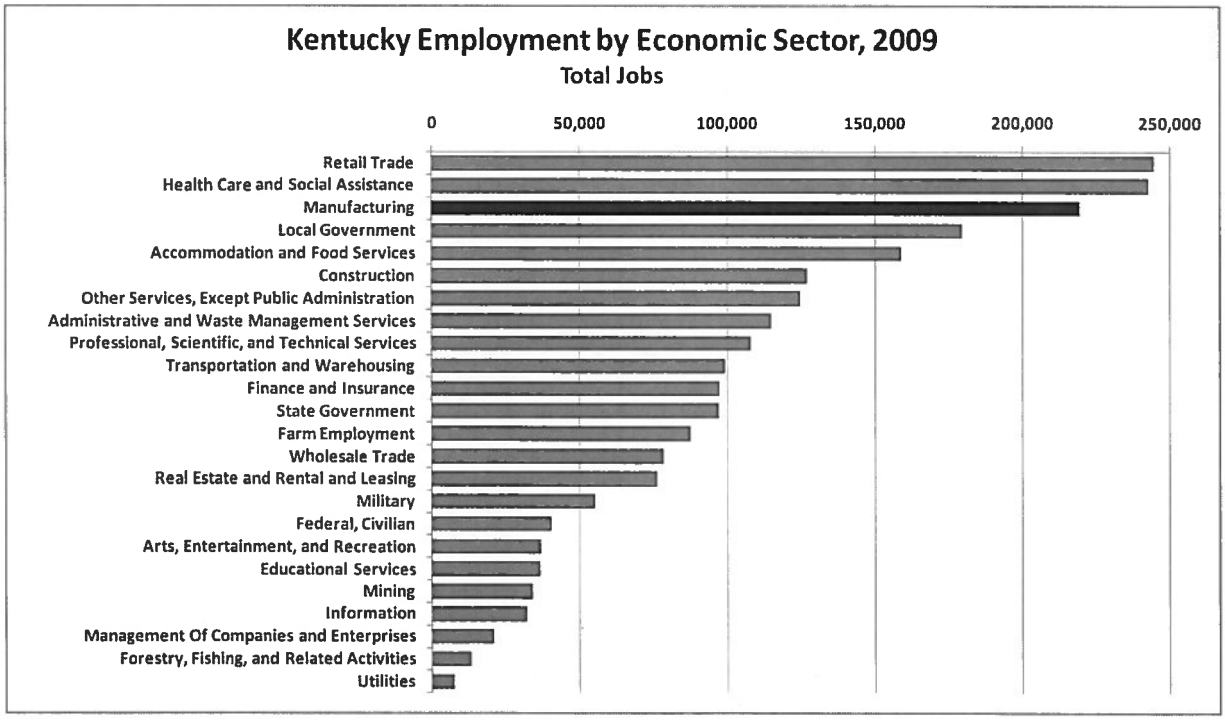


Figure 8: Kentucky Employment by Economic Sector, 2009



Kentucky's electricity-intensive manufacturing economy is threatened by increasing electricity prices. While the price of electricity is only one of several factors influencing industrial location decisions, Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive economy in the United States. In the twenty-first century, the bulwark of the Kentucky economy is clearly manufactured goods—the Commonwealth's single largest source of economic activity. Even mid-recession, as illustrated in Figures 6 and 7 on page 5, manufacturing in Kentucky accounted for more than $26.6 billion in 2009, or 17% of State GDP, and directly employed 213,330 Kentuckians—2.5 times more than were employed as farmers and 11 times more than were employed as coal miners. In addition to being Kentucky's largest source of revenue and a leading source of employment, manufacturing is *sui generis*, fulfilling a unique economic function in that most goods are exported, bringing revenue to the Commonwealth from other economies. This is in contrast to the other top employment opportunities in Kentucky: retail services, health care, local government, food service, and construction, which principally depend upon local sources of revenue. Employment opportunities in manufacturing pay more than the two larger employment sectors, retail and hospitality. Large manufacturers, such as General Electric, Toyota, and Ford Motor in Kentucky, also have a more significant multiplier effect on a regional economy because they encourage suppliers to collocate with manufacturing facilities.[5] And this may well be the greatest significance of coal for the Commonwealth: not the number of persons employed in coal mining operations, nor the direct revenue generated from coal exports, *but rather the sheer size of the manufacturing industry that has located in Kentucky because of low energy costs.*

A variety of econometric studies[6,7] have been conducted to estimate the relationship between electricity prices and employment, also finding that increased electricity prices are associated with reductions in employment. However, none of these studies have taken into account the regional disparities in both the forecasted electricity price increases as well as distribution of electricity-intensive manufacturing as a percentage of total employment or state gross domestic product (GDP). Furthermore, none of these existing studies have specifically analyzed the impact of increasing prices on the most relevant employment sectors in the Commonwealth of Kentucky: manufacturing, retail, hospitality, healthcare and government.

A 2011 report prepared for the Kentucky state government found that increases in the price of electricity are associated with decreases in overall levels of employment. Specifically, the authors posit that a onetime increase of 25% in the price of electricity would reduce the long-run growth rate in total employment from an average of 3.0% to 2.49% per annum.[8] This current study builds upon the their work by using sector-specific employment as the dependent variable rather than total employment in all sectors to identify particular vulnerabilities within the Kentucky economy.

Beyond absolute price, the mere presence of price volatility may make it difficult for electricity-intensive manufacturing businesses to plan ahead and may also discourage capital investment in these engines of economic growth. Electricity price volatility could be included as an independent variable in future studies. For example, one could surmise that during a period of electricity price increases, companies would leave or not expand their existing operations, and this would not necessarily be recovered during periods of declining electricity prices.

Business Response Options to Increasing Electricity Prices

Faced with increasing electricity prices, energy-intensive businesses have the following response options.

1. Pass the price increase directly to consumers, in non-competitive markets.
2. Ignore the price increase and accept a reduction in profit margins.
3. Implement energy efficiency measures to lower total electricity consumption.
4. Substitute electricity with alternative energy sources, where available and competitively priced.
5. Seek government incentives or intervention.
6. Implement efficiency in other areas, including labor costs.
7. Relocate to an area where costs of production will be lower.
8. Close.

Option 1, passing the price increases directly to product end users, will only be a viable option if that industry has a captive or non-competitive market. If market competition is tight or if there are already lower-cost alternatives available to consumers, manufacturers may have limited room to increase prices. Electricity-intensive industries will not likely be able to choose option 2, since electricity expenditures are such a significant portion of their costs of doing business. In such cases, businesses have probably also already implemented energy efficiency measures, option 3, to increase profit margins. However, as much as possible, more efficient use of electricity is preferable under most conditions.

The use of energy substitutes, option 4, for energy-intensive industries in Kentucky may mean substituting direct natural gas combustion for electricity. However, natural gas price volatility, supply, and pipeline access may be prohibiting factors to large scale natural gas substitution.

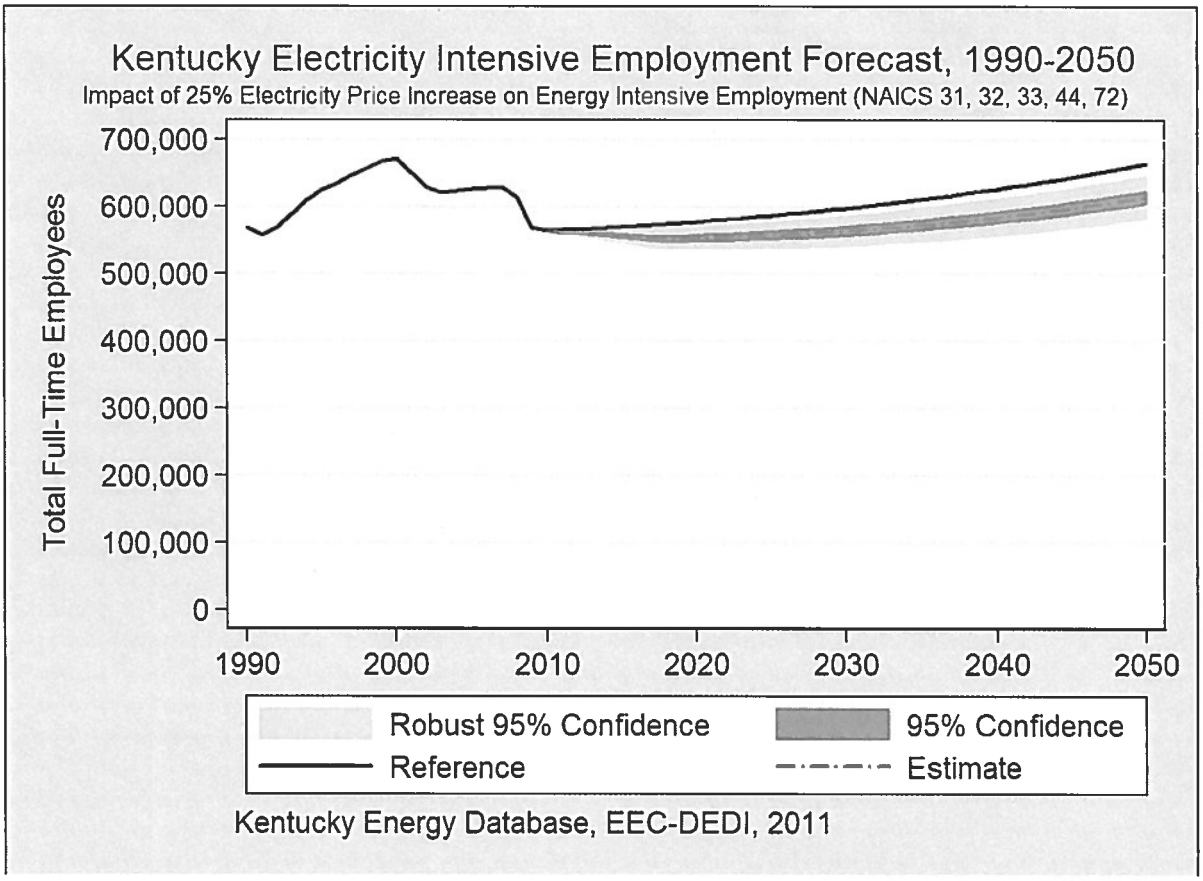
Businesses may also turn to government to either subsidize increasing electricity costs or offset them through taxpayer or ratepayer-funded incentives, option 5. Indeed, many other state governments already offer such incentives to electricity-intensive industries; however, in practice, the long-term affordability of such subsidies must be part of the government's evaluation criterion.

Whenever a business chooses options 6, 7, or 8, there should be a negative impact on total employment. Options 7 and 8 could be measured in total number of employees, whereas option 6 would be better measured using total labor hours or wage data.

Findings

This study builds upon the notion that low energy costs are a catalyst for commercial growth by quantifying the precise vulnerability of the largest economic sectors of the Commonwealth, in terms of total employment, to future electricity price increases. Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, discussed in greater detail in the Statistical Appendix on pages 13 to 19, this study modeled the responsiveness of employment across the United States to changes in the price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing, retail services, hospitality, healthcare, and government. *Elasticities* were developed for each of these economic sectors to calculate changes in employment, given a specific change in the price of electricity, and can be generally applied to the 48 contiguous United States.

Figure 9: Kentucky Electricity Intensive Employment Forecast, 1990-2050



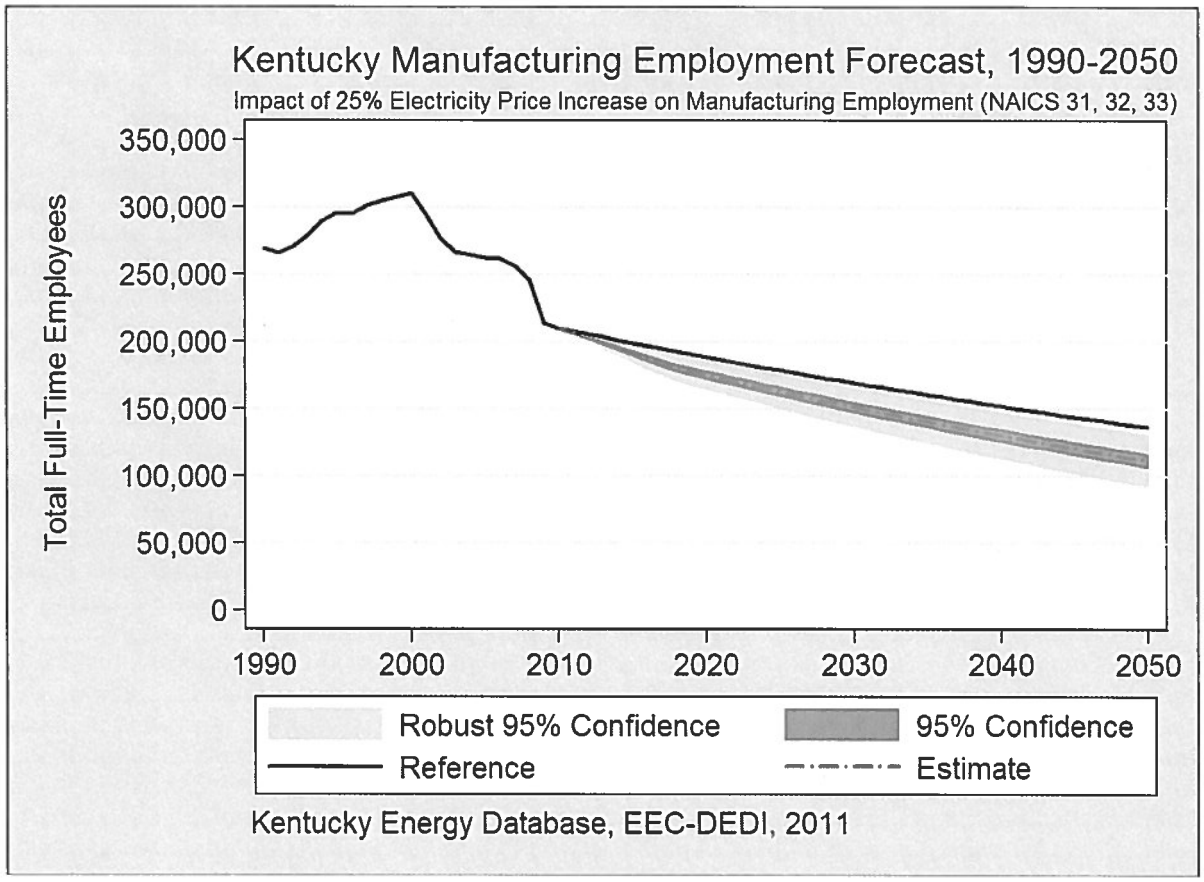
Given the potential cumulative increase of 25% in real electricity prices between 2011 and 2025, this multiple regression model estimates that Kentucky will likely lose, or fail to create, 30,000 full-time jobs long-term. Manufacturing establishments were the most vulnerable to electricity price increases and can be expected to permanently shed 17,500 full-time jobs. Evidence suggests that, once lost, similar manufacturing employment opportunities will never return. The relative extent of this finding is intuitive given that there are 12,685 jobs in the most-electricity intensive manufacturing sectors alone.

Retail stores, restaurants, and hotels were less than half as responsive as the manufacturing sector to increasing electricity prices, and combined, can be expected to fail to create 12,500 full-time jobs. However, in the fourth and fifth largest employment sectors, healthcare and government, no statistically significant relationship between electricity prices and total employment could be identified.

The employment forecast illustrated in Figure 9 above is an aggregation of each of the sector-specific forecasts for the energy-intensive sectors, manufacturing, retail, and hospitality (NAICS 31, 32, 33, 44, & 72). The estimated electricity-related job losses were subtracted from a reference forecast for each sector that simply extrapolated the 20-year average annual growth rate (AGR). The 95% confidence intervals, both with and without robust standard errors, are displayed in gray surrounding the single-point estimations. The delta between the estimate and reference case is the isolated effect of electricity price increases on employment.

Impact on Manufacturing Employment

Figure 10: Kentucky Manufacturing Employment Forecast, 1990-2050

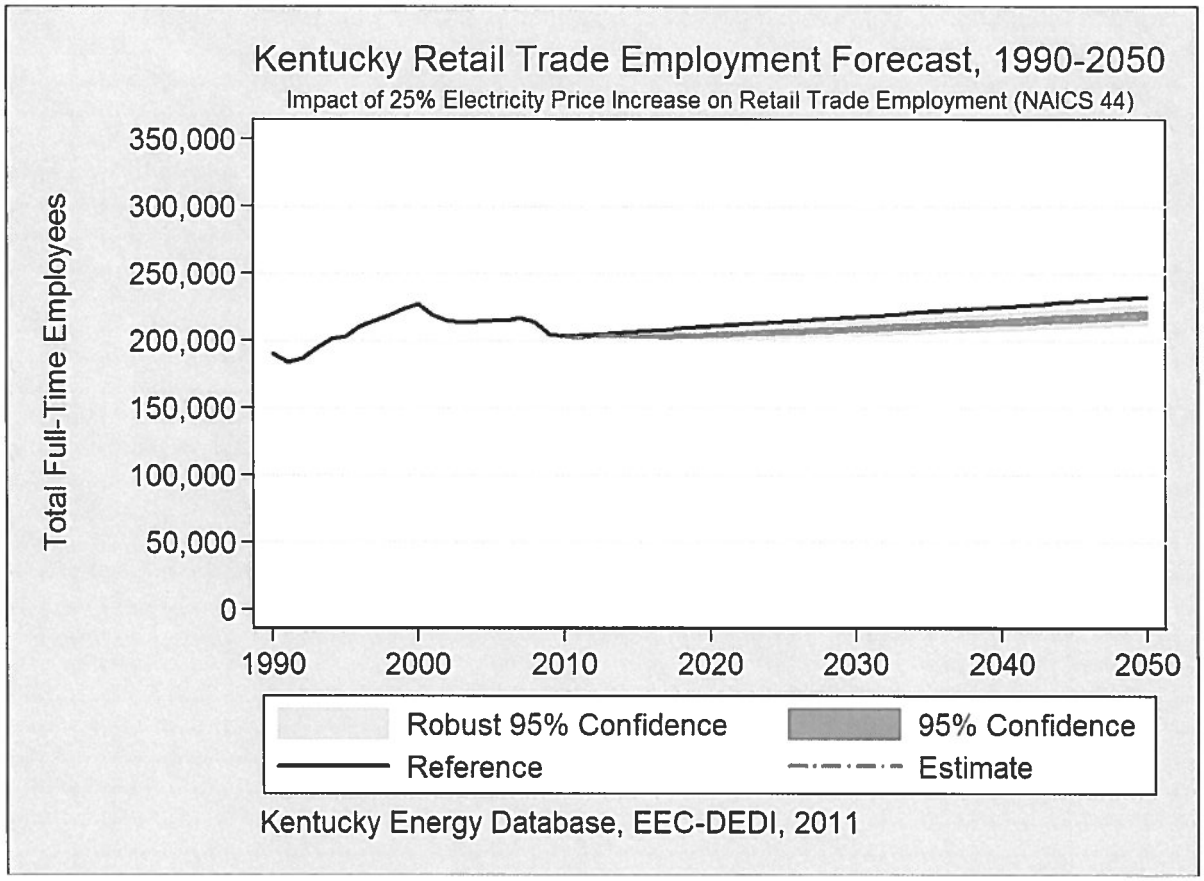


Of the sectors analyzed, manufacturing, Kentucky's largest economic sector, was the most-responsive sector to changes in electricity prices. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 3.37% in absolute manufacturing employment, and with 95% confidence, between -2.77% and -3.97%. This finding was statistically significant below the 0.001 level. When using robust standard errors, however, the 95% confidence interval widened to between -0.83% and -5.92% and the significance level dropped to 0.01. Overall economic activity and time were also significant factors in predicting employment in the manufacturing sector; however, educational attainment as well as the total population levels were not. Time had a statistically significant negative coefficient, reflecting the general trend of contraction of manufacturing both in Kentucky and nationally. Given a 25% increase in real electricity prices by 2025, manufacturing establishments in Kentucky would be expected to permanently shed an additional 17,660 full-time jobs long-run as a direct result of price increases, and with 95% confidence using robust standard errors between 5,764 and 31,022 full-time jobs, *ceteris paribus*.

The manufacturing employment forecast, illustrated in Figure 10 above, was developed by applying the elasticities for the manufacturing sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of -1.16%, and then subtracting predicted historical electricity-related losses, for a net reference AGR of -1.07%.

Impact on Retail Trade Employment

Figure 11: Kentucky Retail Trade Employment Forecast, 1990-2050

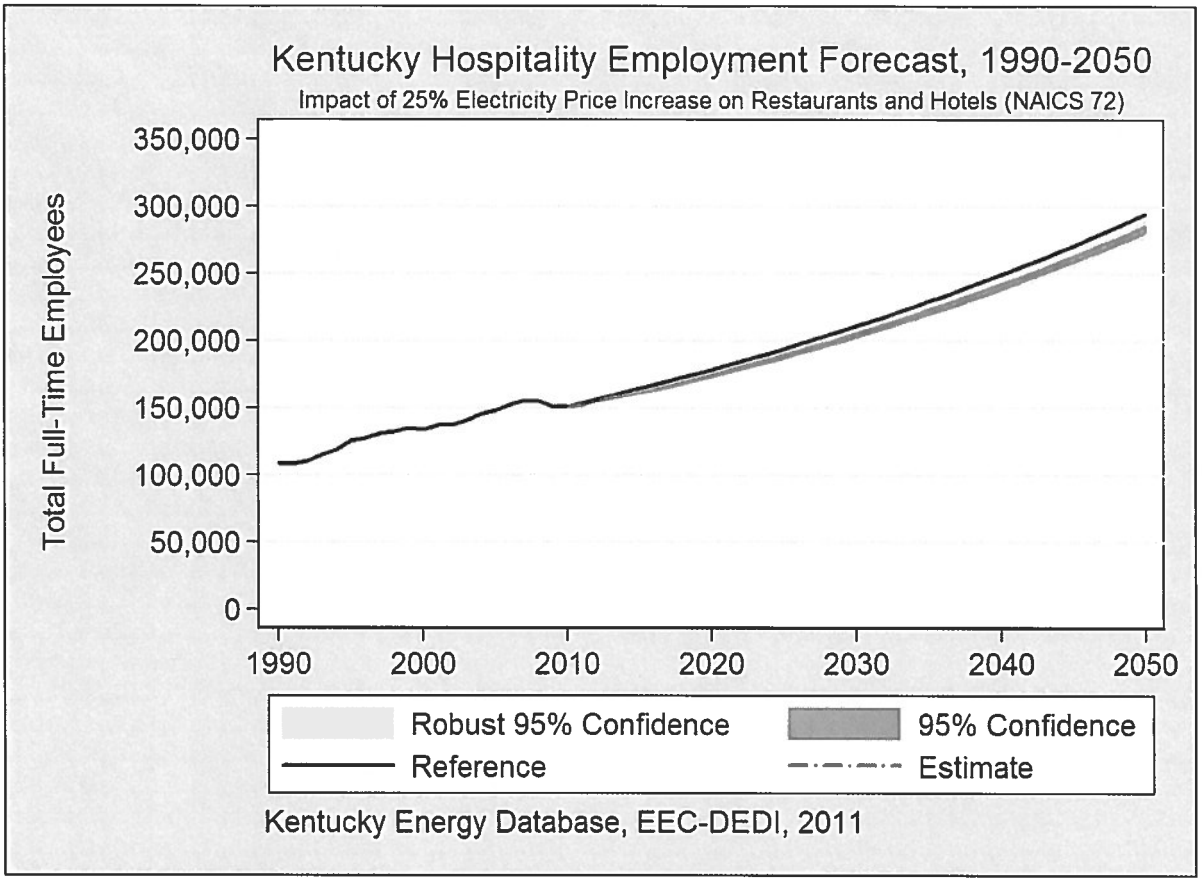


Retail trade, Kentucky's largest employment sector in terms of total employment, was less than half as responsive as the manufacturing sector to increasing electricity prices. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 1.57% in total employment, and with 95% confidence between -1.30% and -1.84%. When using robust standard errors, however, the 95% confidence interval widened between -0.77% and -2.39%. These findings were statistically significant below the 0.001 level. Education was not a significant factor in determining retail employment; whereas economic activity and total population levels were. Given a 25% increase in real electricity prices by 2025, retail establishments in Kentucky would be expected to fail to create 7,225 full-time jobs long-run, and with 95% confidence using robust standard errors, between 3,916 and 12,160 full-time jobs, *ceteris paribus*.

The retail employment forecast, illustrated in Figure 11 above, was developed by applying the elasticities for the retail sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of 0.3584%, and then subtracting predicted historical electricity-related losses, for a net reference AGR of 0.3393%.

Impact on Hospitality Employment

Figure 12: Kentucky Hospitality Employment Forecast, 1990-2050



Employment in hospitality industries such as restaurants and hotels demonstrated a similar, but weaker, responsiveness as retail employment. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 1.42% in total employment, and with 95% confidence between -1.12% and -1.71%. When using robust standard errors, however, the 95% confidence interval widened between -0.78% and -2.06%. This finding was statistically significant below the 0.001 level. Education and total population do not appear to be significant factors in determining hospitality sector employment; whereas economic activity and time were both significant. Given a 25% increase in real electricity prices by 2025, restaurants and hotels in Kentucky would be expected to shed 5,352 full-time jobs long-run, and with 95% confidence using robust standard errors, between 2,940 and 7,765 full-time jobs, *ceteris paribus*.

The retail employment forecast, illustrated in Figure 12 above, was developed by applying the elasticities for the retail sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of 1.6857%.

Impact on Healthcare Employment

Employment in the healthcare industry was much less sensitive to increases in electricity prices, and responsiveness was not statistically significant when using robust standard errors. Specifically, a 10% increase in the price of electricity appears to be associated with a 0.43% reduction in overall healthcare employment. However, with 95% confidence and robust standard errors, these effects are not necessarily distinguishable from zero. Healthcare employment was better predicted by educational attainment of the population, overall economic activity, total population levels, and time. Given that the independent variable of interest, real electricity prices, was not significant when using robust standard errors, no forecast for this sector was developed.

Impact on Government Employment

In government employment, no relationship between electricity prices and total employment could be identified, whereas educational attainment of the population, overall economic activity, and total population levels appeared to have statistically significant effects. Given that the independent variable of interest, real electricity prices, was not significant in any model, no forecast for this sector was developed.

Conclusion

This study demonstrated that electricity price increases alone may force businesses to seek ways to reduce costs or close, causing substantial job losses in Kentucky's electricity-intensive manufacturing sector, and slowing overall long-term job creation in other sectors. The timing of this transition could exacerbate high unemployment and slow economic growth in the near-term. The Commonwealth's vulnerability to these dynamics could also be worsened if leadership is unaware of them and inadequately prepared for the transition. Kentucky's neighboring states of Indiana, Ohio, and West Virginia exhibit similar vulnerabilities due to the potential for increasing electricity costs and the relative size of their manufacturing sectors.

While total employment in the Commonwealth is expected to continue to rise in other sectors, the Commonwealth should maintain focus on education and workforce development in emerging industries that are less reliant on energy-intensive manufacturing processes as well as consider strategies to mitigate vulnerability to price increases and risk exposure.

Data Analyzed

Total employment in Kentucky's top five economic sectors, in terms of number of employees as illustrated in Figure 8 on page 5, served as the dependent variables of interest in this study. Total employment by industry was collected from the Bureau of Economic Analysis (BEA) for all 51 entities and all years from 1990 to 2010. [9] Data was collected for each state as well as the District of Columbia, in each year, and for each industry, organized by North American Industry Classification System (NAICS) codes.

The primary explanatory variable of interest in this study was the natural logarithm of total real electricity price in each state and year expressed in 2010 US$ per kWh. Electricity prices are defined here as the quotient of the total revenue received by electric utilities in state i and in year t divided by the total kilowatt-hours of electricity sold in that state and year. Electricity *prices* differ from electricity *rates*, which are only a subset of the total cost and often do not include taxes, environmental surcharges, and fuel costs that vary substantially across time and geography. Thus, electricity prices more accurately reflect the cost for one kilowatt-hour of electricity paid by consumers in a given state and year. This variable was assembled using a variety of datasets from the Energy Information Administration (EIA), including data from the State Energy Data System (SEDS) for years 1990 to 2009 for all states,[10] and where certified data was not yet available using Form EIA-861[11] and Form EIA-826 for the year 2010.[12] The correlation between historical electricity prices derived from Form EIA-861 and EIA-826 to the corresponding certified variables was 0.999; thus, there is almost no difference between the historical data and the 2010 update other than it has not yet been certified and included in SEDS.

The following control variables were used: educational attainment, defined as the percentage of the adult population (age 25 years and older) with a bachelor's degree (or higher), collected from the United States Census American Community Survey; population, also collected from the United States Census; state Gross Domestic Product (GDP), collected from the BEA; and year. The following control variables were also tested but ultimately excluded because their effects were not statistically significant: labor force unionization, Standard & Poor's 500 Index, and per capita personal income.

There were a total of 51 states included (N=51), the 50 United States as well as the District of Columbia. However, the model's performance would have been improved by ~5% if the District of Columbia had been excluded. All currency variables, namely the price of electricity and State Gross Domestic Product, were adjusted for inflation to 2010 US$ using the Bureau of Labor Statistics (BLS) Consumer Price Index (CPI), which is intended to account for the generally rising cost of goods during this time period.

Analytical Method

Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, this study modeled the responsiveness of employment across the United States to changes in the real price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing (NAICS 31, 32, & 33), retail services (NAICS 44), hospitality (NAICS 72), healthcare (NAICS 62), and government (NAICS 92). Elasticities were developed for each sector to calculate changes in employment given a specific change in the electricity prices and can be generally applied to any state and year.

To develop these elasticity coefficients, data were organized into a multidimensional panel, i.e. both time series and cross sectional, enabling simultaneous modeling of the relationships of multiple statistics across both space and time (N x t). Since each observation is non-random, and not independent, for example electricity prices in state i and year t are not independent of prices in state i in year t-1, a fixed effects model was used, which builds upon Ordinary Least Squares (OLS) regression by isolating the time-independent constant difference between states that is correlated with the explanatory variables. Two multiple regression of panel data models with fixed effects, both with and without robust standard errors, were constructed for each of the top five employment sectors in Kentucky, for a total of 10 separate multiple regression models.

The multiple regression of panel data model with fixed effects can be generally given by,

$$Y_{it} = \beta_0 + \sum_{j=1}^{k-1} \beta_j X_{jit} + \alpha_i + \varepsilon_{it}$$

Where i and t index states and years, such that y_{it} is the dependent variable of interest, employment by industry, in state i in year t, β_0 is the constant y intercept across all states, X is a k by 1 vector of explanatory variables, $\beta_j X_{jit}$ is the product of the observation for each independent variable j through k for state i in year t and the coefficient of X, k is the total number of included independent variables, α_i is the time-invariant fixed effect for state i, and ε_{it} are the residuals, and where $\varepsilon_{it} \sim N(0, \sigma^2)$, or are approximately normally distributed with a mean of zero.

Multiple regression of panel data using fixed effects facilitated controlling for the numerous factors inherently affecting sector-specific employment as well as electricity prices from state to state that have not been accounted for in the independent variables included in this study to isolate the primary national effect of the variable of interest, real electricity prices, on each of the dependent variables, employment by industry. Since this study aims to isolate the unique effect of electricity prices on employment, the model was rerun five times to derive the coefficient for each of the industries of interest by NAICS code.

A fixed effects model specifically assumes the existence of unobserved time-invariant heterogeneity, often referred to as unobserved variable bias, which in addition to the included independent variables, is affecting the dependent variable. The fixed effects model will attempt to control for these missing or unobserved between unit (interstate) factors, the fixed effects, to isolate the specific net effect of the independent variables of interest on all units (nationally). The fixed effects model also assumes that these between-unit effects are both time invariant and correlated with the independent variables. A fixed effect model is also functionally, although not computationally, equivalent to assigning an independent indicator

variable, or dummy variable (0 or 1), for each state, to isolate the specific effect for each state without having to create the 51 additional independent variables.

The Hausman test, which is often used in econometrics to determine the appropriateness of a fixed effect versus a random effect model, is not required here because this study is modeling the entire population of states (*N*), thus necessitating a fixed effects model and obviating a random effects model. A random effect model is only suitable to model the sample (*n*) of the population that has been selected at random.

Table 2 on page 16 shows the multiple regression models with fixed effects estimated for each of the top five employment sectors. These five models were subsequently rerun using robust standard errors in order to prevent biased estimation that could be caused by the presence of outliers in manufacturing employment, such as the District of Columbia, as well as the presence of the residual heteroscedasticity as identified by the Breusch–Pagan post estimation test. Robust standard errors were calculated using the Huber-White sandwich estimator.[13] The resulting five multiple regression models with fixed effects and robust standard errors are shown in Table 3 on page 17. However, using robust standard errors had little impact on the relationships of interest; the effect of electricity prices on manufacturing employment remained significant with a p-value of 0.010.

Prior to analysis, all variables were converted to their natural logarithms such that the estimated coefficients for each may be simply interpreted as elasticities, which measure the percentage change in the dependent variable given a percentage change in one of the independent variables. For electricity prices specifically, the independent variable of interest in this study, the coefficients summarized in the first row of Tables 2 and 3 are the estimated electricity price elasticity of employment for each specific economic sector, which is the expected percentage change in employment given a percentage change in the price of electricity, *ceteris paribus*, or holding all other included independent variables constant.

Since these elasticities were derived through regression of national historical data, they may be generally applied to any state and year and to the United States as a whole for each respective economic sector. The only difficult math in this process is in the development of the elasticity coefficients themselves. Therefore, assuming a reliable electricity price forecast has already been developed, the long-term change in employment in a given sector for other states and for different changes in the price of electricity can be calculated by simply multiplying the number of employees in that sector currently by the forecasted percentage change in real electricity prices, i.e. inflation adjusted, multiplied by the specified elasticity coefficient for that sector. For example, given that there were 209,609 employees in all manufacturing sectors in Kentucky in 2010, and assuming real electricity prices increased by 25%, and given that the electricity price elasticity of manufacturing employment calculated here is 0.337, then the estimated long-term job losses resulting from the increase in electricity prices would 17,660, as illustrated below.

	209,609	*Number of Employees in NAICS Sectors 31, 32, & 33*
x	0.25	*% Change in Electricity Price*
x	0.337	*Sector-Specific Elasticity Coefficient*
=	17,660	*Resulting Long-Term Job Losses*

The employment forecasts illustrated in Figures 12 through 21 on the following pages were produced by integrating the elasticities developed in this study into the Kentucky Electricity Portfolio Model. This facilitated creating dynamic employment forecasts for different electricity price scenarios that were responsive to the forecasted change in real prices in each future year. No lags have been assumed.

Table 2: Model of Electricity Prices & Employment by Economic Sector

Logged Variables	Manufacturing Employment	Retail Employment	Food & Accommodation Employment	Healthcare Employment	Government Employment
Price of Electricity (Real 2010 US$)	-0.337 ***	-0.158 ***	-0.142 ***	-0.0426 **	0.00084
	(-0.0307)	(-0.0136)	(-0.0152)	(-0.0158)	(-0.0101)
Educational Attainment	0.0249	-0.108	-0.0679	-0.536 ***	-0.14 **
	(-0.146)	(-0.065)	(-0.0728)	(-0.0758)	(-0.0482)
State GDP (Real 2010 US$)	0.744 ***	0.509 ***	0.318 ***	0.17 ***	0.253 ***
	(-0.0514)	(-0.0228)	(-0.0255)	(-0.0265)	(-0.0169)
Population	0.166 **	0.26 ***	0.129 ***	0.37 ***	0.258 ***
	(-0.0532)	(-0.0236)	(-0.0264)	(-0.0275)	(-0.0175)
Year	-76.05 ***	-11.31 ***	21.11 ***	55.21 ***	3.801 *
	(-5.536)	(-2.457)	(-2.752)	(-2.861)	(-1.819)
Constant	579.4 **	88.85 ***	-153.9 ***	-413.5 ***	-22.72
	(-41.38)	(-18.36)	(-20.57)	(-21.39)	(-13.6)
R-Squared	0.7776	0.956	0.9219	0.8885	0.9344
Observations (*N x t*)	1069	1071	1069	1071	1071
Number of States (*N*)	51	51	51	51	51

Standard Errors in Parentheses
Asterisk Denotes Statistical Significance at the Following Levels: * p<0.05, ** p<0.01, *** p<0.001
All Variables Transformed into their Natural Logarithms

Table 3: Model of Electricity Prices & Employment by Economic Sector With Robust Standard Errors

Logged Variables	Manufacturing Employment	Retail Employment	Food & Accommodation Employment	Healthcare Employment	Government Employment
Price of Electricity (Real 2010 US$)	-0.337 *	-0.158 ***	-0.142 ***	-0.0426	0.00084
	(-0.127)	(-0.0404)	(-0.032)	(-0.0377)	(-0.0285)
Educational Attainment	0.0249	-0.108	-0.0679	-0.536	-0.14
	(-0.598)	(-0.23)	(-0.216)	(-0.345)	(-0.155)
State GDP (Real 2010 US$)	0.744 ***	0.509 ***	0.318 ***	0.17	0.253 ***
	(-0.141)	(-0.115)	(-0.0789)	(-0.0939)	(-0.0719)
Population	0.166	0.26	0.129	0.37 *	0.258 *
	(-0.19)	(-0.134)	(-0.0835)	(-0.155)	(-0.124)
Year	-76.05 **	-11.31	21.11 *	55.21 ***	3.801
	(-22.38)	(-10.79)	(-9.212)	(-14.23)	(-5.988)
Constant	579.4 **	88.85	-153.9 *	-413.5 ***	-22.72
	(-166.9)	(-80.3)	(-68.98)	(-106.3)	(-44.06)
R-Squared	0.7776	0.956	0.9219	0.8885	0.9344
Observations (*N x t*)	1069	1071	1069	1071	1071
Number of States (*N*)	51	51	51	51	51

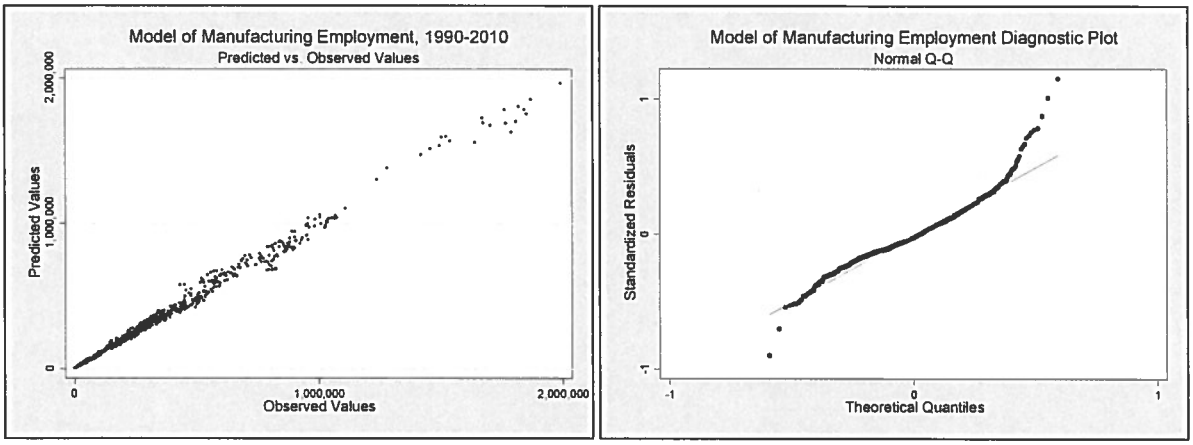
Robust Standard Errors in Parentheses
Asterisk Denotes Statistical Significance at the Following Levels: * $p<0.05$, ** $p<0.01$, *** $p<0.001$
All Variables Transformed into their Natural Logarithms.

Model Diagnostic Plots

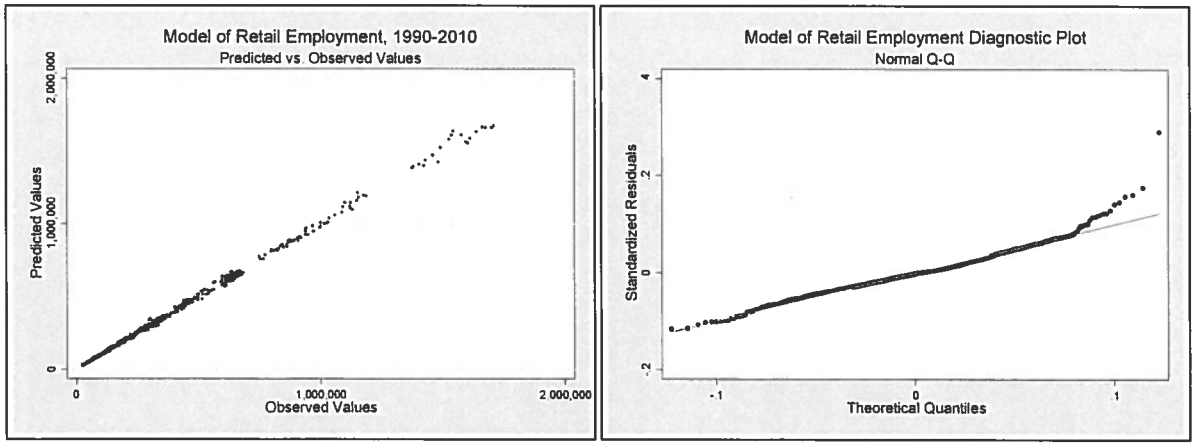
For each economic sector below, the diagnostic plot on the left shows the model's predicted employment versus employment that was actually observed in that state and year, such that all deviations from a perfect line illustrate model error (ε_{it}). The predicted values in all graphics include not only the homogenous, i.e. national, model components, including the constant (β_0) and the product of each variable j to k and the coefficient of each ($\beta_j X_{jit}$), but also the time-invariant interstate fixed effect (α_i) in the response variable, employment, estimated for each state.

The Q-Q plot on the right illustrates the standardized residuals of the model for each economic sector versus their normal theoretical quantiles and are intended to demonstrate that the residuals are approximately normally distributed with a mean of zero, such that $\varepsilon_{it} \sim N(0, \sigma^2)$.

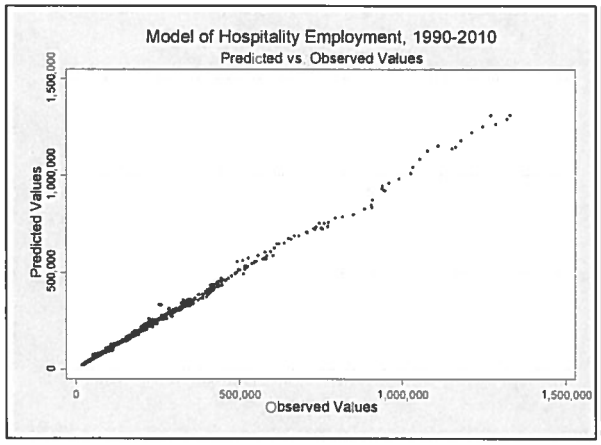
Figures 13 & 14: Model of Manufacturing Employment Diagnostic Plots

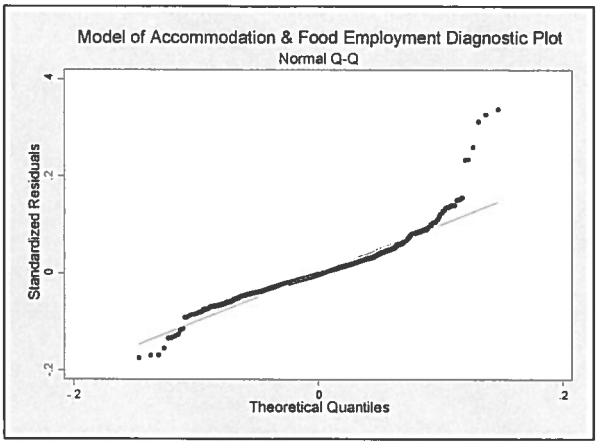


Figures 15 & 16: Model of Retail Employment Diagnostic Plots

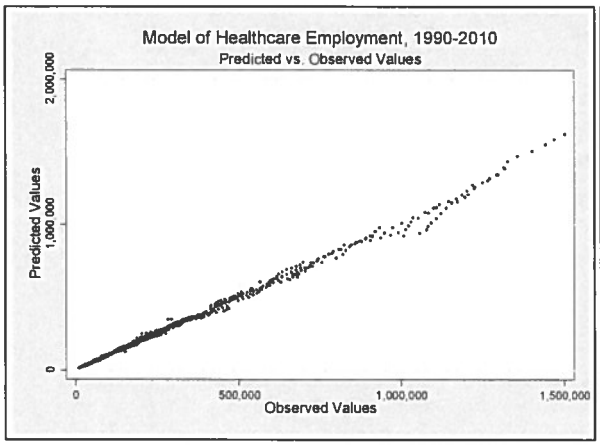


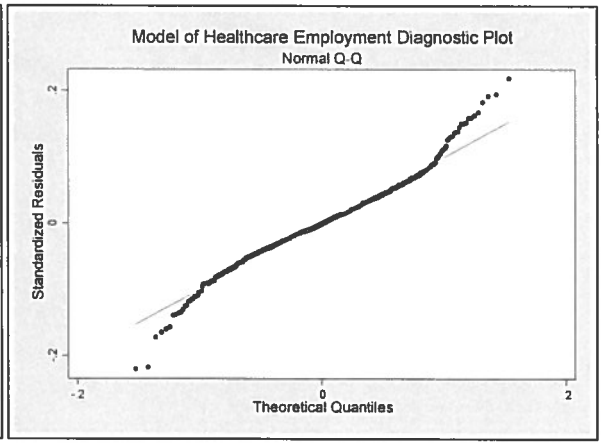
Figures 17 & 18: Model of Food & Accommodation Employment Diagnostic Plots



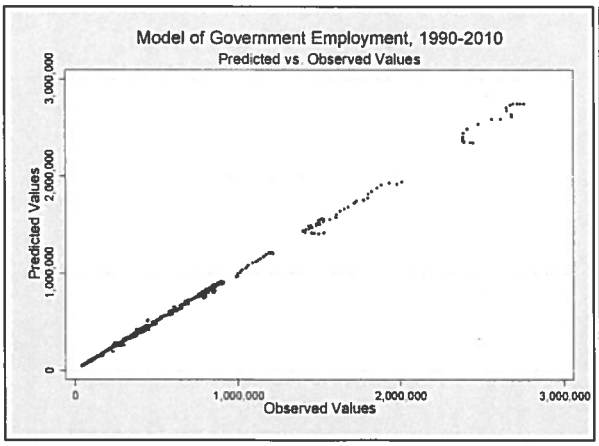


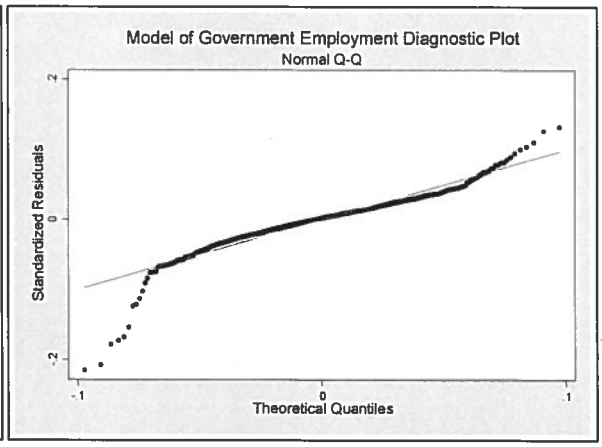
Figures 19 & 20: Healthcare Employment Diagnostic Plots





Figures 21 & 22: Model of Government Employment Diagnostic Plots





Acknowledgments

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References

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[2] United States Bureau of Economic Analysis, GDP and Total Employment by Industry. http://bea.gov/regional/index.htm

[3] Electricity intensity data was calculated by dividing total electricity consumption for each NAICS sector by the total value of shipments that sector as collected in the U.S. Census Annual Survey of Manufacturers.

[4] Chart data derived from the United States Bureau of Economic Analysis, GDP and Total Employment by Industry. http://bea.gov/regional/index.htm

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

4. Please provide copies of all electronic files used in the preparation of Mr. Baudino's testimony exhibits with all data and formulas intact.

RESPONSE:

Please refer to the attached work papers and electronic files.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

5. Please provide copies of all articles, publications, and other sources documents referenced in Mr. Baudino's testimony and exhibits.

RESPONSE:

Please refer to the work papers and electronic documents provided in response to Question No. 4. Please note that Mr. Baudino did not provide the following material due to copyright restrictions:

1. Value Line reports.
2. Excerpt from Dr. Morin's *New Regulatory Finance.*
3. Excerpt from *A Random Walk Down Wall Street* by Dr. Malkiel.
4. Documents cited in footnotes 1 through 3, which may be obtained using the web addresses contained in the footnotes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

6. Reference Exhibit No._(RAB-6), page 2:

a. Please provide a list of each firm relied on by Mr. Baudino to develop the median earnings and book value growth rates and the individual growth rate estimates for each firm.

b. Please provide a list of each firm relied on by Mr. Baudino to develop the average dividend yield of 0.81% and the individual dividend yield for each firm.

c. Please provide all workpapers and supporting documents for the Value Line median growth rates and dividend yields.

d. Please indicate how many of the firms included in arriving at the median earnings and book value growth rates pay common dividends.

RESPONSE:

a. Please refer to the spreadsheet entitled "Value Line Summary Feb 14 2017.xlsx". This is the data from which Mr. Baudino developed his Exhibit No. _(RAB-6). The Value Line Summary data does not provide a list of the individual firms that comprise the median earnings and book value growth rates used by Mr. Baudino.

b. Please refer to part a. above.

c. Please refer to part a. above.

d. Please refer to part a. above.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

7. Provide a copy of all notes and workpapers prepared by Dr. Goins in connection with this proceeding. If Dr. Goins prepared any Excel spreadsheets or other computer-generated documents please provide an electronic version of those documents.

RESPONSE:

All non-privileged responsive documents are provided in the attachment to this response.

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

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

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

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Kentucky Utilities Company
Fixed Cost of Large-Frame Combustion Turbines
Based on 12 Months Ended June 30, 2018

Description		Brown CTs	Trimble County CTs	Paddys Run 13 CTs	Total	BIP Peak Unadjusted
Plant		$ 285,515,838	$ 248,172,766	$ 39,574,165	$ 573,262,768	$ 1,270,954,484
Accumulated Depreciation		$ 162,922,503	$ 111,210,802	$ 15,526,405	$ 289,659,711	$ 506,456,928
Net Plant		$ 122,593,334	$ 136,961,964	$ 24,047,759	$ 283,603,057	$ 764,497,556
Total Working Capital						28,600,478
Accumulated Deferred Income Taxes		37,916,634	45,143,182	8,170,625	$ 91,230,442	156,281,533
Accumulated Deferred Investment Tax Credit						24,034,541
Net Cost Rate Base		$ 84,676,700	$ 91,818,782	$ 15,877,134	$ 192,372,616	$ 612,781,961
Rate of Return		7.29%	7.29%	7.29%	7.29%	7.29%
Return		$ 6,172,826	$ 6,693,475	$ 1,157,423	$ 14,023,725	$ 44,671,045
Depreciation Expenses		$ 13,397,159	$ 10,663,309	$ 1,886,537	$ 25,947,005	$ 45,505,094
Non-Burdened Non-Fuel Operation and Maintenance Expenses		$ 3,417,067	$ 1,560,485	$ 358,517	$ 5,336,069	$ 33,774,624
Burdened Non-Fuel Operation and Maintenance Expenses		$ 110,382	$ 439,142	$ 129,138	$ 678,662	
Income Taxes	0.385574631	$ 2,895,210	$ 3,139,407	$ 542,860	$ 6,577,477	$ 20,951,836
Property Taxes		$ 197,748	$ 216,317	$ 38,727	$ 452,792	$ 4,462,862
Other Taxes						$ 2,317,433
Revenue Requirement		$ 26,190,393	$ 22,712,135	$ 4,113,203	$ 53,015,730	$ 151,682,894
Nameplate Capacity		781,431	783,666	83,754	1,648,851	
Cost per kW per Month (Nameplate Capacity)		$ 2.79	$ 2.42	$ 4.09	$ 2.68	#DIV/0!
Net Peak Demand on Plant (Form 7, Pages 402-403, line 6)		726,140	626,460	69,090	1,421,690	1,492,399
Cost per kW per Month (Net Peak Demand on Plant)		$ 3.01	$ 3.02	$ 4.96	$ 3.11	$ 8.47
Loss Factor (Transmission)		0.0281	0.0281	0.0281	0.0281	0.0281
Cost per kW per Month (Transmission)		$ 3.09	$ 3.11	$ 5.10	**$ 3.20**	$ 8.71
Loss Factor (Primary)		0.0613	0.0613	0.0613	0.0613	0.0613
Cost per kW per Month (Primary)		$ 3.20	$ 3.22	$ 5.28	**$ 3.31**	$ 9.02

Louisville Gas & Electric Company
Fixed Cost of Large-Frame Combustion Turbines
Based on 12 Months Ended June 30, 2018

Description		Brown CTs	Trimble County CTs	Paddys Run 13 CTs	Total
Plant		$ 84,366,777	$ 130,992,227	$ 44,779,461	$ 260,138,465
Accumulated Depreciation		$ 39,753,883	$ 58,228,903	$ 18,010,212	$ 115,992,998
Net Plant		$ 44,612,894	$ 72,763,324	$ 26,769,249	$ 144,145,467
Accumulated Deferred Income Taxes		12,875,811	24,015,326	9,124,081	$ 46,015,218
Net Cost Rate Base		$ 31,737,083	$ 48,747,998	$ 17,645,168	$ 98,130,249
Rate of Return		7.23%	7.23%	7.23%	7.23%
Return		$ 2,294,741	$ 3,524,711	$ 1,275,829	$ 7,095,281
Depreciation Expenses		$ 3,853,798	$ 5,368,005	$ 2,176,201	$ 11,398,004
Non-Burdened Non-Fuel Operation and Maintenance Expenses		$ 962,488	$ 953,783	$ 414,082	$ 2,330,353
Burdened Non-Fuel Operation and Maintenance Expenses		$ 200,083	$ (251,785)	$ (45,732)	$ (97,434)
Income Taxes	0.3864	$ 1,091,539	$ 1,676,598	$ 606,873	$ 3,366,771
Property Taxes		$ 68,035	$ 113,803	$ 43,219	$ 225,057
Revenue Requirement		$ 8,470,684	$ 11,385,115	$ 4,470,472	$ 24,318,033
Nameplate Capacity		199,869	409,734	94,446	704,049
Cost per kW per Month (Nameplate Capacity)		$ 3.53	$ 2.32	$ 3.94	$ 2.88
Net Peak Demand on Plant		179,860	327,540	77,910	585,310
Cost per kW per Month (Net Peak Demand on Plant)		$ 3.92	$ 2.90	$ 4.78	$ 3.46
Loss Factor (Transmission)		0.0285	0.0285	0.0285	0.0285
Cost per kW per Month (Transmission)		$ 4.04	$ 2.98	$ 4.92	**$ 3.56**
Loss Factor (Primary)		0.0559	0.0559	0.0559	0.0559
Cost per kW per Month (Primary)		$ 4.16	$ 3.07	$ 5.06	**$ 3.67**

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Kentucky Utilities Company and Louisvillle Gas & Electric Company

Weighted Cost of Capital

Kentucky Utilities Company			
Component of Capital	**Percent**	**Rate**	**Weighted Cost of Capital**
Short-Tern Debt	2.47%	0.74%	0.02%
Long-Term Debt	44.25%	4.12%	1.82%
Common Equity	53.26%	10.23%	5.45%
			7.29%

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Kentucky Utilities and Louisville Gas & Electric Company
Accumlated Deferred Income Taxes

As of December 31, 2015

FERC Account			Reference
282	$	2,010,522,465	Form 1 Page 275
283	$	300,871,419	Form 1 Page 277
190	$	(617,651,807)	Form 1 Page 234
255	$	127,520,084	Form 1 Page 267
Sub-total	$	1,821,262,161	

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	Ownership Percentage		Generator Nameplate	Net Summer	Allocated Gross Capacity	
Plant Name	KU	LGE	Ratings	Capacity	KU	LGE
Brown 5	47%	53%	123.3	130	57.95	65.35
Brown 6	62%	38%	177	146	109.74	67.26
Brown 7	62%	38%	177	146	109.74	67.26
Brown 8	100%		126	121	126.00	0.00
Brown 9	100%		126	121	126.00	0.00
Brown 10	100%		126	121	126.00	0.00
Brown 11	100%		126	121	126.00	0.00
Trimble County 5	71%	29%	198.9	159	141.22	57.68
Trimble County 6	71%	29%	198.9	159	141.22	57.68
Trimble County 7	63%	37%	198.9	159	125.31	73.59
Trimble County 8	63%	37%	198.9	159	125.31	73.59
Trimble County 9	63%	37%	198.9	159	125.31	73.59
Trimble County 10	63%	37%	198.9	159	125.31	73.59
Paddys Run 13	47%	53%	178.2	147	83.75	94.45
Total			2352.90	2007.00	1648.85	704.05

-0.147010073

Allocated Net Capacity	
KU	LGE
61.10	68.90
90.52	55.48
90.52	55.48
121.00	0.00
121.00	0.00
121.00	0.00
121.00	0.00
112.89	46.11
112.89	46.11
100.17	58.83
100.17	58.83
100.17	58.83
100.17	58.83
69.09	77.91
1421.69	585.31

			LG&E Ownership %	KU Ownership %
Brown 1,2,3	Coal-fired	681	n/a	100
Brown 5	CT	130	53	47
Brown 6	CT	146	38	62
Brown 7	CT	146	38	62
Brown 8,9,10,11	CT	484	n/a	100
Brown Solar	Solar	8	39	61
Cane Run 7	CCGT	662	22	78
Cane Run 11	CT	14	100	n/a
Dix Dam 1,2,3	Hydroelectric	31.5	n/a	100
Ghent 1,2,3,4	Coal-fired	1,917	n/a	100
Haefling 1,2	CT	24	n/a	100
Mill Creek 1,2,3,4	Coal-fired	1,465	100	n/a
Ohio Falls 1-8	Hydroelectric	60	100	n/a
Paddy's Run 11, 12	CT	35	100	n/a
Paddy's Run 13	CT	147	53	47
Trimble County 1	Coal-fired	370	100[1]	n/a
Trimble County 2	Coal-fired	549	19[2]	81
Trimble County 5,6	CT	318	29	71
Trimble County 7, 8, 9, 10	CT	636	37	63
Zorn 1	CT	14	100	n/a

			LG&E Ownership	KU Ownership	
681	0.0%	100.0%	-	681.0	
130	53.0%	47.0%	68.9	61.1	
146	38.0%	62.0%	55.5	90.5	
146	38.0%	62.0%	55.5	90.5	
484	0.0%	100.0%	-	484.0	
8	39.0%	61.0%	3.1	4.9	
662	22.0%	78.0%	145.6	516.4	
14	100.0%	0.0%	14.0	-	
32	0.0%	100.0%	-	31.5	
1,917	0.0%	100.0%	-	1,917.0	
24	0.0%	100.0%	-	24.0	
1,465	100.0%	0.0%	1,465.0	-	
60	100.0%	0.0%	60.0	-	
35	100.0%	0.0%	35.0	-	
147	53.0%	47.0%	77.9	69.1	
370	100.0%	0.0%	370.0	-	
549	19.0%	81.0%	104.3	444.7	
318	29.0%	71.0%	92.2	225.8	
636	37.0%	63.0%	235.3	400.7	
14	100.0%	0.0%	14.0	-	
7,837.5			2,796.4	5,041.1	7,837.5

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Table 2. LG&E: Present and Proposed CSR Credits

	Credit ($/kVA-mo)		
Voltage	Pres	Prop	Chng
Primary	6.50	3.67	-44%
Transmission	6.40	3.56	-44%

Table 2. KU: Present and Proposed CSR Credits

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

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

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

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Summary of 2018/2019 Base Residual Auction Results

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Capacity Cleared & Resource Clearing Prices

	Base Residual Auction	
LDA/External Source Zone	Total Resources Cleared for PJM LSEs (MW)	Capacity Performance Resource Clearing Price ($/MW day)
RTO *	166,836.9	$164.77
MAAC	66,071.2	$164.77
EMAAC	31,069.0	$225.42
SWMAAC	11,180.7	$164.77
PS	5,300.8	$225.42
PSNORTH	3,168.0	$225.42
DPLSOUTH	1,693.5	$225.42
PEPCO	5,478.7	$164.77
ATSI	10,171.6	$164.77
ATSI-CLEVELAND	2,258.1	$164.77
COMED	23320.4	$215.00
BGE	3296.9	$164.77
PL	9526.9	$164.77
NORTH	0.0	NA
WEST 1	0.0	NA
WEST 2	0.0	NA
SOUTH 1	0.0	NA
SOUTH 2	0.0	NA

* RTO resources do not include resources modeled in External Source Zones.

Zonal UCAP Obligations, Zonal Capacity Prices, & Zonal CTR Credit Rates

	Base Residual Auction			
Zone	Base Zonal UCAP Obligation (MW)	Preliminary Zonal Capacity Price ($/MW-day)	Base Zonal CTR Credit Rate ($/MW-UCAP Obligation-day)	Preliminary Zonal Net Load Price ($/MW-day)
AE	2,964.6	$223.09	$7.13	$215.97
AEP **	12,694.5	$162.44	$0.00	$162.44
APS	9,806.7	$162.44	$0.00	$162.44
ATSI	14,546.3	$162.44	$0.00	$162.44
BGE	7,948.5	$156.03	$0.00	$156.03
COMED **	25,454.6	$212.67	$4.21	$208.46
DAYTON	3,946.1	$162.44	$0.00	$162.44
DEOK **	5,117.8	$162.44	$0.00	$162.44
DLCO	3,273.0	$162.44	$0.00	$162.44
DOM	23,137.4	$162.44	$0.00	$162.44
DPL	4,686.7	$223.09	$7.13	$215.97
EKPC **	2,518.7	$162.44	$0.00	$162.44
JCPL	7,018.8	$223.09	$7.13	$215.97
METED	3,329.3	$162.44	$0.00	$162.44
PECO	9,704.3	$223.09	$7.13	$215.97
PENLC	3,289.9	$162.44	$0.00	$162.44
PEPCO	7,315.9	$154.74	$0.00	$154.74
PL	8,201.7	$152.74	$0.00	$152.74
PS	11,419.6	$223.09	$7.13	$215.97
RECO	462.6	$223.09	$7.13	$215.97
Total	**166,836.9**			

** Obligation affected by FRR quantities.

2018/2019 BRA Resource Clearing Results

Resource Clearing Prices

LDA/External Source Zone	System Marginal Price* ($/MW-day)	Locational Price Adder (Decrement)** ($/MW-day)	Capacity Performance Resource Clearing Price ($/MW-day)	Base Capacity Resource Price Decrement in LDA ($/MW-day)	Base Capacity Resource Clearing Price ($/MW-day)	Base Capacity Demand Resource Price Decrement in LDA ($/MW-day)	Base Capacity DR/EE Resource Clearing Price ($/MW-day)
RTO	$164.77	$0.00	$164.77	($14.79)	$149.98	$0.00	$149.98
MAAC	$164.77	$0.00	$164.77	($14.79)	$149.98	$0.00	$149.98
EMAAC	$164.77	$60.65	$225.42	($14.79)	$210.63	$0.00	$210.63
SWMAAC	$164.77	$0.00	$164.77	($14.79)	$149.98	($90.03)	$59.95
PS	$164.77	$0.00	$225.42	($14.79)	$210.63	$0.00	$210.63
PSNORTH	$164.77	$0.00	$225.42	($14.79)	$210.63	$0.00	$210.63
DPLSOUTH	$164.77	$0.00	$225.42	($14.79)	$210.63	$0.00	$210.63
PEPCO	$164.77	$0.00	$164.77	($14.79)	$149.98	($108.89)	$41.09
ATSI	$164.77	$0.00	$164.77	($14.79)	$149.98	$0.00	$149.98
ATSI-CLEVELAND	$164.77	$0.00	$164.77	($14.79)	$149.98	$0.00	$149.98
COMED	$164.77	$50.23	$215.00	($14.79)	$200.21	$0.00	$200.21
BGE	$164.77	$0.00	$164.77	($14.79)	$149.98	($90.03)	$59.95
PL	$164.77	$0.00	$164.77	($89.77)	$75.00	$0.00	$75.00
NORTH ***	NA	NA	NA	NA	NA	NA	NA
WEST 1 ***	NA	NA	NA	NA	NA	NA	NA
WEST 2 ***	NA	NA	NA	NA	NA	NA	NA
SOUTH 1 ***	NA	NA	NA	NA	NA	NA	NA
SOUTH 2 ***	NA	NA	NA	NA	NA	NA	NA

*System Marginal Price is the clearing price for Capacity Performance Resources in unconstrained area of RTO
** Locational Price Adder (positive number) is with respect to the immediate higher level LDA. Locational Price Decrement (negative number) is with respect to the unconstrained area of RTO.
*** No external capacity modeled in the External Source Zones was offered in 2018/2019 BRA

Cleared & Make-Whole MWs

LDA/External Source Zone	Capacity Performance Resources Cleared [MW]	Base Capacity Generation Resources Cleared [MW]	Base Capacity DR/EE Resources Cleared [MW]	Total Resources Cleared [MW]	Capacity Performance Resources Make-whole [MW]	Base Capacity Generation Resources Make-whole [MW]	Base Capacity DR/EE Resources Make-whole [MW]	Total Make-whole [MW]
RTO ***	140,600.4	16,277.1	9,959.4	166,836.9	38.6	0	0	38.6
MAAC	53,469.0	8,856.8	3,745.4	66,071.2	38.6	0	0	38.6
EMAAC	22,970.6	6,573.5	1,524.9	31,069.0	0	0	0	0
SWMAAC	9,420.5	672.8	1,087.4	11,180.7	0	0	0	0
PS	4,821.2	111.4	368.2	5,300.8	0	0	0	0
PSNORTH	3,008.0	30.0	130.0	3,168.0	0	0	0	0
DPLSOUTH	1,270.3	345.4	77.8	1,693.5	0	0	0	0
PEPCO	4,875.7	103.0	500.0	5,478.7	0	0	0	0
ATSI	8,583.5	750.7	837.4	10,171.6	0	0	0	0
ATSI-CLEVELAND	2,002.5	0.0	255.6	2,258.1	0	0	0	0
COMED	20,564.4	891.5	1,864.5	23,320.4	0	0	0	0
BGE	2,139.7	569.8	587.4	3,296.9	0	0	0	0
PL	8,380.4	663.7	482.8	9,526.9	38.6	0	0	38.6
NORTH	0	0	NA	0	0	0	0	0
WEST 1	0	0	NA	0	0	0	0	0
WEST 2	0	0	NA	0	0	0	0	0
SOUTH 1	0	0	NA	0	0	0	0	0
SOUTH 2	0	0	NA	0	0	0	0	0

*** RTO resources do not include resources modeled in External Source Zones.

Resource Credits

LDA/External Source Zone	Capacity Performance Resources Cleared [MW]	Base Capacity Generation Resources Cleared [MW]	Base Capacity DR/EE Resources Cleared [MW]	Total Resources Cleared [MW]	Resource Credits for Capacity Performance Resources [$/day]	Resource Credits for Base Capacity Generation Resources [$/day]	Resource Credits for Base Capacity DR/EE Resources [$/day]	Total Resource Credits [$/day]
Rest of RTO	57,983.5	5,778.1	3,512.1	67,273.7	$9,553,941.30	$866,599.44	$526,744.76	$10,947,285.49
Rest of MAAC	12,697.5	946.8	650.3	14,294.6	$2,092,167.08	$142,001.06	$97,531.99	$2,331,700.13
Rest of EMAAC	16,879.1	6,116.7	1,078.9	24,074.7	$3,804,886.72	$1,288,360.52	$227,248.71	$5,320,495.95
Rest of SWMAAC	2,405.1	0.0	0.0	2,405.1	$396,288.33	$0.00	$0.00	$396,288.33
Rest of PS	1,813.2	81.4	238.2	2,132.8	$408,731.54	$17,145.28	$50,172.07	$476,048.89
PSNORTH	3,008.0	30.0	130.0	3,168.0	$678,063.36	$6,318.90	$27,381.90	$711,764.16
DPLSOUTH	1,270.3	345.4	77.8	1,693.5	$286,351.03	$72,751.60	$16,387.01	$375,489.64
PEPCO	4,875.7	103.0	500.0	5,478.7	$803,369.09	$15,447.94	$20,545.00	$839,362.03
Rest of ATSI	6,581.0	750.7	581.8	7,913.5	$1,084,351.37	$112,589.99	$87,258.36	$1,284,199.72
ATSI-CLEVELAND	2,002.5	0.0	255.6	2,258.1	$329,951.93	$0.00	$38,334.89	$368,286.81
COMED	20,564.4	891.5	1,864.5	23,320.4	$4,421,346.00	$178,487.22	$373,291.55	$4,973,124.76
BGE	2,139.7	569.8	587.4	3,296.9	$352,558.37	$85,458.60	$35,214.63	$473,231.60
PL	8,380.4	663.7	482.8	9,526.9	$1,380,838.51	$49,777.50	$36,210.00	$1,466,826.01
NORTH	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00
WEST 1	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00
WEST 2	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00
SOUTH 1	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00
SOUTH 2	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00
Total	140,600.4	16,277.1	9,959.4	166,836.9	$25,592,844.61	$2,834,938.05	$1,536,320.87	$29,964,103.53

Make-Whole MW & Credits

LDA/External Source Zone	Capacity Performance Resources Make-whole [MW]	Base Capacity Generation Resources Make-whole [MW]	Base Capacity DR/EE Resources Make-whole [MW]	Total Make-whole [MW]	Make-whole Credits for Capacity Performance Resources [$/day]	Make-whole Credits for Base Capacity Generation Resources [$/day]	Make-whole Credits for Base Capacity DR/EE Resources [$/day]	Additional Make-whole Adjustments due to NEPA [$/day]	Total Make-Whole Credits [$/day]
Rest of RTO	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
Rest of MAAC	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
Rest of EMAAC	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
Rest of SWMAAC	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
Rest of PS	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
PSNORTH	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
DPLSOUTH	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
PEPCO	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
Rest of ATSI	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
ATSI-CLEVELAND	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
COMED	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
BGE	0.0	0.0	0.0	0.0	$0.00	$0.00	$0.00	$0.00	$0.00
PL	38.6	0.0	0.0	38.6	$6,360.12	$0.00	$0.00	$0.00	$6,360.12
NORTH	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00	$0.00
WEST 1	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00	$0.00
WEST 2	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00	$0.00
SOUTH 1	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00	$0.00
SOUTH 2	0.0	0.0	NA	0.0	$0.00	$0.00	NA	$0.00	$0.00
Total	38.6	0.0	0.0	38.6	$6,360.12	$0.00	$0.00	$0.00	$6,360.12

Qualifying Transmission Upgrade (QTU) MWs & Credits

Sink LDA	QTU Import Capability Cleared into Sink LDA [MW]	QTU Clearing Price ** ($/MW-Day)	QTU Credits ($/day)
MAAC	0	$0.00	$0.00
EMAAC	0	$60.65	$0.00
SWMAAC	0	$0.00	$0.00
PS	0	$0.00	$0.00
PSNORTH	0	$0.00	$0.00
DPLSOUTH	0	$0.00	$0.00
PEPCO	0	$0.00	$0.00
ATSI	0	$0.00	$0.00
ATSI-CLEVELAND	0	$0.00	$0.00
COMED	0	$50.23	$0.00
BGE	0	$0.00	$0.00
PL	0	$0.00	$0.00
Total			$0.00

** Locational Price Adder with respect to the immediate higher level LDA

2018/2019 BRA Load Pricing Results

RPM Parameters	
IRM	15.7%
Pool Average EFORd	6.35%
FPR	1.0835
RTO Reliability Requirement [MW]	160,607.4
Obligation Peak Load Scaling Factor	1.03879

LDA Capacity Price

LDA	LDA Base UCAP Obligation [MW]	System Marginal Price [$/MW-day]	Locational Price Adder* [$/MW-day]	Adjustment due to Base Capacity Resource Price Decrement [$/day]	Adjustment due to Base Capacity Resource Price Decrement [$/MW-day]	Adjustment due to Base Capacity DR/EE Resource Price Decrement [$/day]	Adjustment due to Base Capacity DR/EE Resource Price Decrement [$/MW-day]	Adjustment due to Price Decrements for External Resources [$/day]	Adjustment due to Price Decrements for External Resources [$/MW-day]	Adjustment due to Make-Whole [$/MW-day]	LDA Capacity Price [$/MW-day]
RTO	166,836.9	$164.77	$0.00	($388,037.84)	($2.33)	$0.00	$0.00	NA	NA	$0.00	$162.44
MAAC	66,341.8	$164.77	$0.00	$0.00	($2.33)	$0.00	$0.00	NA	NA	$0.00	$162.44
EMAAC	36,256.5	$164.77	$60.65	$0.00	($2.33)	$0.00	$0.00	NA	NA	$0.00	$223.09
SWMAAC	15,264.4	$164.77	$0.00	$0.00	($2.33)	($97,898.62)	($6.41)	NA	NA	$0.00	$156.03
PEPCO	7,315.9	$164.77	$0.00	$0.00	($2.33)	($9,430.00)	($7.70)	NA	NA	$0.00	$154.74
COMED	25,454.6	$164.77	$50.23	$0.00	($2.33)	$0.00	$0.00	NA	NA	$0.00	$212.67
BGE	7,948.5	$164.77	$0.00	$0.00	($2.33)	$0.00	($6.41)	NA	NA	$0.00	$156.03
PL	8,201.7	$164.77	$0.00	($85,964.57)	($12.81)	$0.00	$0.00	NA	NA	$0.78	$152.74

*Locational Price Adder with respect to RTO

Calculation of Zonal Capacity Prices for PS, DPL, and ATSI

Sub-Zone/Zone	Reference LDA** Capacity Price [MW]	Cleared Capacity [MW]	Additional Locational Price Adder with respect to Reference LDA [$/MW-day]	Additional Adjustment due to Base Capacity Resource Price Decrement with respect to Reference LDA [$/day]	Additional Adjustment due to Base Capacity Resource Price Decrement with respect to Reference LDA [$/MW-day]	Additional Adjustment due to Base Capacity DR/EE Resource Price Decrement with respect to Reference LDA [$/day]	Additional Adjustment due to Base Capacity DR/EE Resource Price Decrement with respect to Reference LDA [$/MW-day]	Additional Make-Whole Costs with respect to Reference LDA [$/day]	Additional Adjustment due to Make-whole with respect to Reference LDA [$/MW-day]	Preliminary Zonal Capacity Price [$/MW-day]
Rest of PS		2,132.8	$0.00	$0.00		$0.00		$0.00		
PSNORTH		3,168.0	$0.00	$0.00		$0.00		$0.00		
PS	$223.09	5,300.8	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.09
Rest of DPL		3,928.8	$0.00	$0.00		$0.00		$0.00		
DPLSOUTH		1,693.5	$0.00	$0.00		$0.00		$0.00		
DPL	$223.09	5,622.3	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.09
Rest of ATSI		7,913.5	$0.00	$0.00		$0.00		$0.00		
ATSI-CLEVELAND		2,258.1	$0.00	$0.00		$0.00		$0.00		
ATSI	$162.44	10,171.6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$162.44

**Reference LDA is EMAAC LDA for PS and DPL zones and RTO for ATSI zone.

Preliminary Zonal Results

Zone	LDA1	LDA2	LDA3	2014 W/N Coincident Peak Load [MW]	Zonal Forecast Peak Load Scaling Factor	2018/2019 Prelim. Zonal Peak Load Forecast [MW]	Obligation Peak Load Scaling Factor	Base Zonal RPM Scaling Factor	Base Zonal UCAP Obligation [MW]	Preliminary Zonal Capacity Price [$/MW-day]	Zone
AE	MAAC	EMAAC		2,610.0	1.00920	2,634.0	1.03879	1.04834	2,964.6	$223.09	AE
AEP ***				11,053.4	1.02039	11,278.7	1.03879	1.05996	12,694.5	$162.44	AEP ***
APS				8,350.0	1.04347	8,713.0	1.03879	1.08395	9,806.7	$162.44	APS
ATSI			ATSI	12,760.0	1.01285	12,924.0	1.03879	1.05214	14,546.3	$162.44	ATSI
BGE	MAAC	SWMAAC	BGE	6,940.0	1.01758	7,062.0	1.03879	1.05705	7,948.5	$156.03	BGE
COMED ***			COMED	21,641.5	1.04502	22,615.7	1.03879	1.08555	25,454.6	$212.67	COMED ***
DAYTON				3,290.0	1.06565	3,506.0	1.03879	1.10699	3,946.1	$162.44	DAYTON
DEOK ***				4,450.6	1.02166	4,547.0	1.03879	1.06128	5,117.8	$162.44	DEOK ***
DLCO				2,830.0	1.02756	2,908.0	1.03879	1.06742	3,273.0	$162.44	DLCO
DOM				19,090.0	1.07685	20,557.0	1.03879	1.11861	23,137.4	$162.44	DOM
DPL	MAAC	EMAAC	DPL	4,020.0	1.03582	4,164.0	1.03879	1.07600	4,686.7	$223.09	DPL
EKPC ***				2,124.2	1.05348	2,237.8	1.03879	1.09434	2,518.7	$162.44	EKPC ***
JCPL	MAAC	EMAAC		6,090.0	1.02397	6,236.0	1.03879	1.06369	7,018.8	$223.09	JCPL
METED	MAAC			2,850.0	1.03789	2,958.0	1.03879	1.07815	3,329.3	$162.44	METED
PECO	MAAC	EMAAC		8,380.0	1.02888	8,622.0	1.03879	1.06879	9,704.3	$223.09	PECO
PENLC	MAAC			2,770.0	1.05523	2,923.0	1.03879	1.09616	3,289.9	$162.44	PENLC
PEPCO	MAAC	SWMAAC	PEPCO	6,540.0	0.99388	6,500.0	1.03879	1.03243	7,315.9	$154.74	PEPCO
PL	MAAC		PL	7,145.0	1.01987	7,287.0	1.03879	1.05943	8,201.7	$152.74	PL
PS	MAAC	EMAAC	PS	10,160.0	0.99862	10,146.0	1.03879	1.03736	11,419.6	$223.09	PS
RECO	MAAC	EMAAC		405.0	1.01481	411.0	1.03879	1.05418	462.6	$223.09	RECO
				143,499.7		148,230.2			166,836.9		

Notes:

*** *Obligation affected by FRR quantities*

2018/2019 DY BRA CTRs

LDA CTRs

LDA	Base UCAP Obligation [MW]	Internal Resources Cleared in LDA	Total CTRs * [MW]	QTU Equivalents [MW]	Remaining CTRs for Incremental Rights-Eligible Required Transmission Enhancements, Customer-Funded Upgrades, & LSEs [MW]	Customer-Funded Upgrades ICTRs [MW]	Incremental Rights-Eligible Required Transmission Enhancements ICTRs [MW]	Remaining CTRs for LSEs [MW]
MAAC	66,341.8	66,871.2	270.6	0	270.6	148.1	122.5	0
EMAAC	36,256.5	31,069.8	5,157.5	0	5,157.5	0	898.0	4,259.5
SWMAAC	15,264.4	11,180.7	4,083.7	0	4,083.7	0	1,044.0	3,039.7
PS Equivalent	11,419.6	5,300.8	6,118.8	0	6,118.8	0	0	6,118.8
DPL Equivalent	4,686.7	5,622.3	0.0	0	0	0	0	0
PEPCO	7,315.9	5,478.7	1,837.2	0	1,837.2	0	315	1,522.2
ATSI Equivalent	14,546.3	10,171.6	4,374.7	0	4,374.7	0	0	4,374.7
COMED	25,454.6	23,320.4	2,134.2	0	2,134.2	0	0	2,134.2
BGE	7,948.5	3296.9	4,651.6	0	4,651.6	0	306	4,345.6
PL	8,201.7	9526.9	0.0	0	0	0	0	0

* CTRs are reduced to allow for certain grandfathered congestion credits.

Allocation of LSE CTRs, Economic Value of LSE CTRs, Zonal CTR Credit Rates, & Zonal CTR Settlement Rates

				MAAC		EMAAC		SWMAAC	
				Locational Price Adder	$0.00	Locational Price Adder	$60.65	Locational Price Adder	$0.00
Zone	LDA1	LDA2	LDA3	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]
AE	MAAC	EMAAC		0.0	$0.00	348.3	$21,124.14	0.0	$0.00
AEP				0.0	$0.00	0.0	$0.00	0.0	$0.00
APS				0.0	$0.00	0.0	$0.00	0.0	$0.00
ATSI			ATSI	0.0	$0.00	0.0	$0.00	0.0	$0.00
BGE	MAAC	SWMAAC	BGE	0.0	$0.00	0.0	$0.00	1582.8	$0.00
COMED			COMED	0.0	$0.00	0.0	$0.00	0.0	$0.00
DAYTON				0.0	$0.00	0.0	$0.00	0.0	$0.00
DEOK				0.0	$0.00	0.0	$0.00	0.0	$0.00
DLCO				0.0	$0.00	0.0	$0.00	0.0	$0.00
DOM				0.0	$0.00	0.0	$0.00	0.0	$0.00
DPL	MAAC	EMAAC	DPL	0.0	$0.00	550.6	$33,394.42	0.0	$0.00
EKPC				0.0	$0.00	0.0	$0.00	0.0	$0.00
JCPL	MAAC	EMAAC		0.0	$0.00	824.6	$50,011.41	0.0	$0.00
METED	MAAC			0.0	$0.00	0.0	$0.00	0.0	$0.00
PECO	MAAC	EMAAC		0.0	$0.00	1140.1	$69,146.66	0.0	$0.00
PENLC	MAAC			0.0	$0.00	0.0	$0.00	0.0	$0.00
PEPCO	MAAC	SWMAAC	PEPCO	0.0	$0.00	0.0	$0.00	1456.9	$0.00
PL	MAAC		PL	0.0	$0.00	0.0	$0.00	0.0	$0.00
PS	MAAC	EMAAC	PS	0.0	$0.00	1341.6	$81,368.82	0.0	$0.00
RECO	MAAC	EMAAC		0.0	$0.00	54.3	$3,296.14	0.0	$0.00
			Totals	0.0	$0.00	4259.5	$258,341.61	3039.7	$0.00

	PS Equivalent		DPL Equivalent		PEPCO		ATSI Equivalent		COMED	
	Locational Price Adder	$0.00	Locational Price Adder	$0.00	Locational Price Adder	$0.00	Locational Price Adder	$0.00	Locational Price Adder	$50.23
Zone	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]
AE	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
AEP	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
APS	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
ATSI	0.0	$0.00	0.0	$0.00	0.0	$0.00	4374.7	$0.00	0.0	$0.00
BGE	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
COMED	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	2,134.2	$107,198.74
DAYTON	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
DEOK	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
DLCO	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
DOM	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
DPL	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
EKPC	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
JCPL	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
METED	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
PECO	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
PENLC	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
PEPCO	0.0	$0.00	0.0	$0.00	1522.2	$0.00	0.0	$0.00	0.0	$0.00
PL	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
PS	6118.8	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
RECO	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00	0.0	$0.00
Totals	6118.8	$0.00	0.0	$0.00	1522.2	$0.00	4374.7	$0.00	2134.2	$107,198.74

	BGE		PL					
	Locational Price Adder	$0.00	Locational Price Adder	$0.00				
Zone	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	CTRs Allocated to LSEs [MW]	Economic Value of LSE CTRs [$/day]	Preliminary CTRs Allocated = Max of the LDA CTRs Allocated to LSEs [MW]	Total Preliminary Economic Value of LSE CTRs [$/day]	Base Zonal CTR Credit Rate [$/MW UCAP Obligation per Day]	Preliminary Zonal CTR Settlement Rate [$/MW CTR per day]
AE	0.0	$0.00	0.0	$0.00	348.3	$21,124.14	$7.13	$60.65
AEP	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
APS	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
ATSI	0.0	$0.00	0.0	$0.00	4,374.7	$0.00	$0.00	$0.00
BGE	4345.6	$0.00	0.0	$0.00	4,345.6	$0.00	$0.00	$0.00
COMED	0.0	$0.00	0.0	$0.00	2,134.2	$107,198.74	$4.21	$50.23
DAYTON	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
DEOK	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
DLCO	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
DOM	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
DPL	0.0	$0.00	0.0	$0.00	550.6	$33,394.42	$7.13	$60.65
EKPC	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
JCPL	0.0	$0.00	0.0	$0.00	824.6	$50,011.41	$7.13	$60.65
METED	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
PECO	0.0	$0.00	0.0	$0.00	1,140.1	$69,146.66	$7.13	$60.66
PENLC	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
PEPCO	0.0	$0.00	0.0	$0.00	1,522.2	$0.00	$0.00	$0.00
PL	0.0	$0.00	0.0	$0.00	0.0	$0.00	$0.00	$0.00
PS	0.0	$0.00	0.0	$0.00	6,118.8	$81,368.82	$7.13	$13.30
RECO	0.0	$0.00	0.0	$0.00	54.3	$3,296.14	$7.13	$60.66
Totals	4345.6	$0.00	0.0	$0.00		$365,540.35		

Notes:
Locational Price Adder is respect to immediate higher level LDA.
A Weighted Locational Price Adder is used in the case of PS, DPL, or ATSI Equivalent.
Economic Value of CTRs = CTRs Allocated * Locational Price Adder

2018/2019 BRA ICTRs

Incremental Capacity Transfer Rights (ICTRs)	MAAC	Adjusted MAAC	EMAAC	SWMAAC	PS	PSNORTH	DPLSOUTH	Adjusted DPLSOUTH	PEPCO	BGE
Incremental Rights-Eligible Required Transmission Enhancements	Certified ICTR * (MW)	Adjusted ICTR * (MW)	Certified ICTR (MW)	Certified ICTR (MW)	Certified ICTR (MW)	Certified ICTR (MW)	Certified ICTR * (MW)	Adjusted ICTR * (MW)	Certified ICTR (MW)	Certified ICTR (MW)
Regional Facilities (500 kV and above)										
b0457 Doms-Lexington circuit wave traps (effective 2012/2013)	160.0	26.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
b0559 Capacitor at Meadow Brook substation (effective 2012/2013)	106.0	17.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
b1507 Rebuild Mt Storm - Doubs 500 kV (effective 2015/2016)	117.0	19.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
b0487, b0489 Build new 500 kV transmission facilities from Susquehanna to Roseland (effective 2015/2016)	0.0	0.0	898.0	0.0	68.9	105.5	0.0	0.0	0.0	0.0
b1694 Rebuild Loudoun - Brambleton 500 kV (effective 2016/2017)	339.0	56.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
b2375 Build 2nd Loudoun - Brambleton 500 kV line (effective 2018/2019)	0.0	0.0	0.0	256.0	0.0	0.0	0.0	0.0	0.0	0.0
ICTRs (MW) for Regional Facilities	722.0	119.9	898.0	256.0	68.9	105.5	0.0	0.0	0.0	0.0
Lower Voltage Facilities										
b0497 Install Second Conastone-Graceton 230 kV circuit, Replace Conastone 230 kV breaker 2323/2302 (effective 2017/2018)	18.0	2.7	0.0	237.0	0.0	0.0	0.0	0.0	0.0	124.0
b1304.1, b1304.2, b1304.3, b1304.4 Various upgrades in PS (effective 2015/2016)	0.0	0.0	0.0	0.0	340.2	494.5	0.0	0.0	0.0	0.0
b1398 Build two new parallel underground circuits from Gloucester to Camden (effective 2015/2016)	0.0	0.0	0.0	0.0	90.1	0.0	0.0	0.0	0.0	0.0
b1251.1, b1251 Re-build the existing and build a second Raphael Bagley 230 kV (2017/2018)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	182.0
b2443 Construct new underground 230 kV line from Takoma to Station C (2018/2019)	0.0	0.0	0.0	551.0	0.0	0.0	0.0	0.0	115.0	0.0
ICTRs (MW) for Lower Voltage Facilities	18.0	2.7	0.0	788.0	430.3	494.5	0.0	0.0	115.0	306.0
Customer-Funded Upgrades										
R05 Replace Wave Traps at Bedington and Black Oak 500 kV (effective 2009/2010)	159.0	26.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T1-062 Uprate bus equipment at Wye Mills 69 kV substation (2016/2017)	0.0	0.0	0.0	0.0	0.0	0.0	57.0	0.0	0.0	0.0
T3-062 Upgrade Easton Trappe Tap 69 kV circuit to 136/174 MVA SN/SE (2017/2018)	0.0	0.0	0.0	0.0	0.0	0.0	35.0	0.0	0.0	0.0
Z1-017 Brunner Ck 500 kV (2018/2019)	734.0	121.7	0.0	0.0	0.0	0.0	15.0	0.0	0.0	0.0
ICTRs for Customer-Funded Upgrades (MW)	893.0	148.1	0.0	0.0	0.0	0.0	107.0	0.0	0.0	0.0
Total ICTRs into Sink LDA (MW)	1633.0	270.7	898.0	1044.0	499.2	600.0	107.0	0.0	115.0	306.0

* Certified ICTRs are adjusted if the Remaining CTRs for Incremental Rights Eligible Required Transmission Enhancements, Customer Funded Upgrades, and LSEs into LDA are less than the Total Certified ICTRs into the LDA

Cost Allocation Percentages for Incremental Rights-Eligible Required Transmission Enhancements Zone/Responsible Customer	Regional Facilities	Lower Voltage Facility: b0497	Lower Voltage Facility: b1304.1 - b1304.4	Lower Voltage Facility: b1398	Lower Voltage Facility: b1251, b1251.1	Lower Voltage Facility: b2443
AE	1.58%	0.96%	0.21%	0.00%	0.00%	0.00%
AEP	15.32%	0.00%	0.00%	0.00%	0.00%	0.00%
APS	5.87%	0.00%	0.00%	0.00%	4.42%	0.00%
ATSI	7.76%	0.00%	0.00%	0.00%	0.00%	0.00%
BGE	4.18%	0.00%	0.00%	0.00%	66.95%	0.00%
COMED	12.58%	0.00%	2.11%	0.00%	4.12%	0.00%
DAYTON	2.01%	0.00%	0.12%	0.00%	0.49%	0.00%
DEOK	3.21%	0.00%	0.00%	0.00%	0.00%	0.00%
DLCO	1.69%	0.00%	0.00%	0.00%	0.00%	0.00%
DOM	12.42%	0.00%	0.00%	0.00%	18.76%	97.11%
DPL	2.42%	16.77%	0.00%	0.00%	0.00%	0.00%
EKPC	2.15%	0.00%	0.00%	0.00%	0.00%	0.00%
JCPL	3.54%	9.59%	1.06%	12.82%	0.00%	0.00%
METED	1.77%	1.47%	0.00%	0.00%	0.00%	0.18%
PECO	5.18%	30.64%	0.00%	31.88%	0.00%	0.00%
PENELEC	1.92%	0.00%	2.79%	0.00%	0.05%	0.00%
PEPCO	3.90%	0.00%	0.95%	0.87%	5.21%	2.71%
PL	5.05%	16.33%	0.00%	0.00%	0.00%	0.00%
PS	5.97%	14.00%	63.81%	51.40%	0.00%	0.00%
RECO	0.25%	0.52%	1.53%	1.25%	0.00%	0.00%
ConEd	0.57%	0.49%	9.05%	0.00%	0.00%	0.00%
Neptune	0.42%	0.94%	0.06%	1.10%	0.00%	0.00%
East Coast Power (ECP)	0.20%	0.29%	1.92%	0.81%	0.00%	0.00%
Hudson Transmission Partners (HTP)	0.20%	0.00%	14.60%	0.79%	0.00%	0.00%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Note: Cost Allocation Percentages are based on July 2015 Transmission Enhancement Worksheet available at http://www.pjm.com/~/media/committees-groups/subcommittees/mrc/postings/transmission-enhancement-worksheet-july-2015.xlsx or 2015 cost responsibility assignments from the OATT (from 1.1.15 update). The cost allocation percentages may change during actual Delivery Year

Allocation of Required Transmission Enhancement ICTRs to Zone/Responsible Customer

Zone/Responsible Customer	MAAC: ICTRs for Regional Facilities and Necessary Lower Voltage Facilities (MW)	MAAC: ICTRs for Lower Voltage Facility: b0497 (MW)	MAAC: Total ICTRs (MW)	MAAC (Locational Price Adder $0.00): Economic Value of ICTRs ($/day)	EMAAC: ICTRs for Regional Facilities and Necessary Lower Voltage Facilities (MW)	EMAAC (Locational Price Adder $60.65): Economic Value of ICTRs ($/day)
AE	1.8	0.2	2.1	$0.00	13.7	$833.29
AEP	18.4	0.0	18.4	$0.00	137.6	$8,343.06
APS	7.0	0.0	7.0	$0.00	52.7	$3,197.82
ATSI	9.3	0.0	9.3	$0.00	69.7	$4,226.38
BGE	5.0	0.0	5.0	$0.00	37.5	$2,276.58
COMED	14.0	0.0	14.0	$0.00	111.2	$6,743.61
DAYTON	2.4	0.0	2.4	$0.00	18.0	$1,094.72
DEOK	3.0	0.0	3.0	$0.00	28.8	$1,748.28
DLCO	2.0	0.0	2.0	$0.00	15.2	$920.44
DOM	14.9	0.0	14.9	$0.00	111.5	$6,764.39
DPL	2.9	0.4	3.4	$0.00	21.8	$1,323.47
EKPC	2.6	0.0	2.6	$0.00	19.3	$1,170.97
JCPL	4.2	0.3	4.5	$0.00	31.8	$1,928.03
METED	2.1	0.0	2.2	$0.00	15.9	$964.01
PECO	6.2	0.8	7.0	$0.00	46.5	$2,823.22
PENELEC	2.3	0.0	2.3	$0.00	17.2	$1,045.70
PEPCO	4.8	0.0	4.8	$0.00	35.7	$2,167.66
PL	6.1	0.4	6.5	$0.00	45.3	$2,750.42
PS	7.2	0.4	7.5	$0.00	53.6	$3,251.48
RECO	0.3	0.0	0.3	$0.00	2.2	$136.16
ConEd	0.7	0.0	0.7	$0.00	5.1	$310.44
Neptune	0.5	0.0	0.5	$0.00	3.8	$228.75
East Coast Power (ECP)	0.2	0.0	0.2	$0.00	1.8	$108.93
Hudson Transmission Partners (HTP)	0.2	0.0	0.2	$0.00	1.8	$108.93
Total	119.9	2.7	122.5	$0.00	898.0	$54,463.70

Zone/Responsible Customer	SWMAAC: ICTRs for Regional Facilities and Necessary Lower Voltage Facilities (MW)	SWMAAC: ICTRs for Lower Voltage Facility: b0497 (MW)	SWMAAC: ICTRs for Lower Voltage Facility: b2443 (MW)	SWMAAC: Total ICTRs (MW)	SWMAAC (Locational Price Adder $0.00): Economic Value of ICTRs ($/day)
AE	1.9	21.3	0.0	23.2	$0.00
AEP	39.2	0.0	0.0	39.2	$0.00
APS	15.0	0.0	0.0	15.0	$0.00
ATSI	19.9	0.0	0.0	19.9	$0.00
BGE	10.7	0.0	0.0	10.7	$0.00
COMED	31.7	0.0	0.0	31.7	$0.00
DAYTON	5.1	0.0	0.0	5.1	$0.00
DEOK	8.2	0.0	0.0	8.2	$0.00
DLCO	4.3	0.0	0.0	4.3	$0.00
DOM	31.8	0.0	535.1	566.9	$0.00
DPL	6.2	39.7	0.0	46.0	$0.00
EKPC	5.5	0.0	0.0	5.5	$0.00
JCPL	9.1	22.7	0.0	31.8	$0.00
METED	4.5	3.5	1.0	9.0	$0.00
PECO	13.3	72.6	0.0	85.9	$0.00
PENELEC	4.9	0.0	0.0	4.9	$0.00
PEPCO	10.2	0.0	14.9	25.1	$0.00
PL	12.9	38.7	0.0	51.6	$0.00
PS	15.3	33.2	0.0	48.5	$0.00
RECO	0.6	1.2	0.0	1.9	$0.00
ConEd	1.5	1.2	0.0	2.6	$0.00
Neptune	1.1	2.2	0.0	3.3	$0.00
East Coast Power (ECP)	0.5	0.7	0.0	1.2	$0.00
Hudson Transmission Partners (HTP)	0.5	0.0	0.0	0.5	$0.00
Total	256.0	237.0	551.0	1044.0	$0.00

Zone/Responsible Customer	PS: ICTRs for Regional Facilities and Necessary Lower Voltage Facilities (MW)	PS: ICTRs for Lower Voltage Facility: b1304.1-b1304.4 (MW)	PS: ICTRs for Lower Voltage Facility: b1398 (MW)	PS: Total ICTRs (MW)	PS (Locational Price Adder $0.00): Economic Value of ICTRs ($/day)
AE	1.1	0.7	0.0	1.8	$0.00
AEP	10.6	0.0	0.0	10.6	$0.00
APS	4.0	0.0	0.0	4.0	$0.00
ATSI	5.3	0.0	0.0	5.3	$0.00
BGE	2.9	0.0	0.0	2.9	$0.00
COMED	8.5	7.2	0.0	15.7	$0.00
DAYTON	1.4	0.4	0.0	1.8	$0.00
DEOK	2.2	0.0	0.0	2.2	$0.00
DLCO	1.2	0.0	0.0	1.2	$0.00
DOM	8.6	0.0	0.0	8.6	$0.00
DPL	1.7	0.0	0.0	1.7	$0.00
EKPC	1.5	0.0	0.0	1.5	$0.00
JCPL	2.4	3.6	11.6	17.6	$0.00
METED	1.2	0.0	0.0	1.2	$0.00
PECO	3.6	0.0	46.1	49.7	$0.00
PENELEC	1.3	9.2	0.0	10.5	$0.00
PEPCO	2.7	3.2	0.8	6.7	$0.00
PL	3.5	0.0	0.0	3.5	$0.00
PS	4.1	217.1	28.4	249.6	$0.00
RECO	0.2	8.6	1.1	9.9	$0.00
ConEd	0.4	30.8	0.0	31.2	$0.00
Neptune	0.3	0.2	1.1	1.6	$0.00
East Coast Power (ECP)	0.1	6.5	0.8	7.4	$0.00
Hudson Transmission Partners (HTP)	0.1	49.7	0.7	50.5	$0.00
Total	68.9	340.2	90.1	499.2	$0.00

Zone/Responsible Customer	PSNORTH: ICTRs for Regional Facilities and Necessary Lower Voltage Facilities (MW)	PSNORTH: ICTRs for Lower Voltage Facility: b1304.1-b1304.4 (MW)	PSNORTH: Total ICTRs (MW)	PSNORTH (Locational Price Adder $0.00): Economic Value of ICTRs ($/day)	PEPCO: ICTRs for Lower Voltage Facility: b2443 (MW)	PEPCO (Locational Price Adder $0.00): Economic Value of ICTRs ($/day)
AE	1.7	1.0	2.7	$0.00	0.0	$0.00
AEP	16.2	0.0	16.2	$0.00	0.0	$0.00
APS	6.2	0.0	6.2	$0.00	0.0	$0.00
ATSI	8.2	0.0	8.2	$0.00	0.0	$0.00
BGE	4.4	0.0	4.4	$0.00	0.0	$0.00
COMED	13.3	10.4	23.7	$0.00	0.0	$0.00
DAYTON	2.1	0.6	2.7	$0.00	0.0	$0.00
DEOK	3.4	0.0	3.4	$0.00	0.0	$0.00
DLCO	1.8	0.0	1.8	$0.00	0.0	$0.00
DOM	13.1	0.0	13.1	$0.00	111.7	$0.00
DPL	2.6	0.0	2.6	$0.00	0.0	$0.00
EKPC	2.3	0.0	2.3	$0.00	0.0	$0.00
JCPL	3.7	5.2	8.9	$0.00	0.0	$0.00
METED	1.9	0.0	1.9	$0.00	0.2	$0.00
PECO	5.5	0.0	5.5	$0.00	0.0	$0.00
PENELEC	2.0	13.4	15.4	$0.00	0.0	$0.00
PEPCO	4.2	4.7	8.9	$0.00	3.1	$0.00
PL	5.3	0.0	5.3	$0.00	0.0	$0.00
PS	6.3	315.5	321.8	$0.00	0.0	$0.00
RECO	0.3	11.5	11.8	$0.00	0.0	$0.00
ConEd	0.6	44.8	45.4	$0.00	0.0	$0.00
Neptune	0.4	0.3	0.7	$0.00	0.0	$0.00
East Coast Power (ECP)	0.2	9.5	9.7	$0.00	0.0	$0.00
Hudson Transmission Partners (HTP)	0.2	72.2	72.4	$0.00	0.0	$0.00
Total	105.5	494.5	600.0	$0.00	115.0	$0.00

Zone/Responsible Customer	BGE: ICTRs for Lower Voltage Facility: b0497 (MW)	BGE: ICTRs for Lower Voltage Facility: b1251, b1251.1 (MW)	BGE: Total ICTRs (MW)	BGE (Locational Price Adder $0.00): Economic Value of ICTRs ($/day)
AE	11.1	0.0	11.1	$0.00
AEP	0.0	0.0	0.0	$0.00
APS	0.0	8.0	8.0	$0.00
ATSI	0.0	0.0	0.0	$0.00
BGE	0.0	121.8	121.8	$0.00
COMED	0.0	7.5	7.5	$0.00
DAYTON	0.0	0.9	0.9	$0.00
DEOK	0.0	0.0	0.0	$0.00
DLCO	0.0	0.0	0.0	$0.00
DOM	0.0	34.1	34.1	$0.00
DPL	20.8	0.0	20.8	$0.00
EKPC	0.0	0.0	0.0	$0.00
JCPL	11.9	0.0	11.9	$0.00
METED	1.8	0.0	1.8	$0.00
PECO	38.0	0.0	38.0	$0.00
PENELEC	0.0	0.1	0.1	$0.00
PEPCO	0.0	9.5	9.5	$0.00
PL	20.3	0.0	20.3	$0.00
PS	17.4	0.0	17.4	$0.00
RECO	0.6	0.0	0.6	$0.00
ConEd	0.6	0.0	0.6	$0.00
Neptune	1.2	0.0	1.2	$0.00
East Coast Power (ECP)	0.4	0.0	0.4	$0.00
Hudson Transmission Partners (HTP)	0.0	0.0	0.0	$0.00
Total	124.0	182.0	306.0	$0.00

DPLSOUTH	
Locational Price Adder	$0.00
No ICTRs for Regional Facilities/ Necessary Lower Voltage Facilities and no ICTRs for Lower Voltage Facilities.	

Notes
Economic Value of ICTRs = Total ICTRs * Locational Price Adder
ICTRs allocated and Economic Value of CTRs are not final and are subject to change due to Incremental Auction results.

ICTR Credits

LDA	Customer-Funded ICTR Credits ($/day)	Incremental Rights-Eligible Required Transmission Enhancements ICTR Credits ($/day)
MAAC	$0.00	$0.00
EMAAC	$0.00	$54,463.70
SWMAAC	$0.00	$0.00
PS	$0.00	$0.00
PSNORTH	$0.00	$0.00
DPLSOUTH	$0.00	$0.00
PEPCO	$0.00	$0.00
BGE	$0.00	$0.00
Total	$0.00	$54,463.70

KWalton

PJM-alm-history.xls
03/31/17 09:14 AM

Summary of PJM-Initiated Load Management Events

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Running Total: # of Events Step 1	Step 2
				OPERATIONS INFORMATION						
1	1991/92	1991	Sep 16 (Mon)	1, 2, 3, and 4	14:33	14:33	20:09	Members could choose to use this as a compliance event		
2	1992/93	1992	Jul 14 (Tue)	1, 2, and 3	15:10	15:10	16:31	Members could choose to use this as a compliance event		
3	1993/94	1994	Jan 19 (Wed.)	1, 2, 3, and 4	5:06	6:00	22:32	5% voltage reduction 6:45 - 20:28. Manual load shed 7:05 - 7:41 and 9:22 - 13:07 (max. 1500 MW). Event occurred outside ALM period.		
4	1993/94	1994	Jan 20 (Thur.)	1, 2, 3, and 4	7:40	7:40	0:00	Event occurred outside ALM compliance period		
5	1993/94	1994	Jan 21 (Fri.)	1 and 2		0:01	11:51	Event occurred outside ALM compliance period		
6	1995/96	1995	Aug 3 (Thur)	2	12:00	12:00	18:00			
7	1995/96	1996	May 20 (Mon)		15:06	15:06	18:32	5% voltage reduction. Event occurred outside ALM compliance period		
8	1995/96	1996	May 21 (Tue)	3 and 4	11:17	11:17	16:00	Event occurred outside ALM compliance period		
				2	11:17	11:17	16:17			
				1	11:17	11:17	16:28			
9	1998/99	1998	Jun 26 (Fri)	2	10:10	13:00	14:15			
10	1999/2000	1999	Jun 8 (Tue)	2 and 4	9:31	12:00	18:00		0	1
11	1999/2000	1999	Jul 6 (Tue)	2 and 4	9:18	13:00	19:00	5% voltage reduction 13:58 - 18:10		
				1 and 3	12:50	12:50	19:00		1	2
12	1999/2000	1999	Jul 19 (Mon)	1 and 3	12:55	12:55	16:25	5% volt. red. 12:55 - 14:06 (East only)		
				2 and 4	13:12	13:12	16:25	No compliance report needed for Step 2	2	3
13	1999/2000	1999	Jul 23 (Fri)	2 and 4	9:50	12:00	17:00		2	4
14	1999/2000	1999	Jul 28 (Wed)	2 and 4	9:00	12:00	17:13	PP&L (EDC) customers excluded		4 PL
				1 and 3	14:38	14:38	17:13		3	5 non-PL
15	1999/2000	1999	Jul 30 (Fri)	2 and 4	9:28	12:00	17:58			5 PL
				1 and 3	13:45	13:45	17:58		4	6 non-PL
16	1999/2000	2000	May 8 (Mon)	1, 2, 3, and 4	13:30	13:30	18:40	5% volt. red. 15:45 - 18:04. Event occurred outside ALM compliance period	5	6 / 7
17	1999/2000	2000	May 9 (Tue)	1, 2, 3, and 4	9:03	12:30	18:30	Event occurred outside ALM compliance period	6	7 / 8
18	2001/02	2001	Jul 25 (Wed)	1, 2, 3, and 4	13:29	13:29	17:25	LRPP Emergency: 14:08 - 17:25	1	1
19	2001/02	2001	Aug 8 (Wed)	2 and 4	10:30	13:00	18:30	LRPP Emergency: 12:40 - 18:00		2
				1 and 3	12:40	13:30	18:00		2	
20	2001/02	2001	Aug 9 (Thu)	2 and 4	10:00	12:30	19:00	5% volt. red.: 14:40 - 18:15 (East), 15:10 - 17:09 West		3
				1 and 3	11:04	12:00	18:30	LRPP Emergency: 11:20 - 19:00	3	
21	2001/02	2001	Aug 10 (Fri)	2 and 4	8:30	11:00	14:40			4
				1 and 3	10:54	12:00	13:10		4	
22	2002/03	2002	Jul 3 (Wed)	1, 2, 3, and 4	9:35	12:00	18:00	Demand Side Response Emergency: 12:00 - 17:00	1	1
23	2002/03	2002	Jul 29 (Mon)	2 and 4	11:10	13:10	18:00		1	2
24	2002/03	2002	Jul 30 (Tue)	2 and 4	10:00	12:00	18:00		1	3
25*	2005/06	2005	Jul 27 (Wed)	2 and 4	11:00	13:00	18:10	Mid-Atlantic and Dominion only.		1
				1 and 3	11:00	14:00	18:10	5% volt. red.: 13:39 - 17:30 (BC, DOM, PEP, PED)	1	
								5% volt. red.: 14:21 - 17:30 (PE, JC, PS, Eastern PL)		
26	2005/06	2005	Aug 4 (Thu)	2 and 4	12:30	14:30	17:15	Mid-Atlantic only	1	2

OPERATIONS INFORMATION

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Running Total: # of Events Step 1	Step 2
27	2006/07	2006	Aug 2 (Wed)	2 and 4	12:34	13:00	19:33	Mid-Atlantic only		1
				1 and 3	15:11	15:30	19:33		1	
28	2006/07	2006	Aug 3 (Thu)	2	12:15	14:15	19:00	Mid-Atlantic only		2
				1	13:00	14:00	19:00		2	
29	2007/08	2007	Aug 8 (Wed)	2 and 4	11:44	13:44	18:35	BGE and PEPCO zones		1
				2 and 4	12:08	14:08	17:50	Mid-Atlantic region		1
				2 and 4	12:08	14:08	18:35	DOM zone		1
				1 and 3	12:20	13:20	18:35	BGE and PEPCO zones	1	
				1 and 3	15:30	16:30	17:50	Mid-Atlantic and DOM	1	
					15:55	15:55	17:09	5% voltage reduction. Mid-Atlantic only		
					17:09	17:09	17:59	5% volt. red. continued for BGE and PEPCO zones only		
30	2009/10	2010	May 26 (Wed)	2	15:15	17:15	19:59	DC portion of PEPCO zone only. Event occurred outside compliance period		1
31	2010/11	2010	Jun 11 (Fri)	2	13:58	15:58	20:12	DC portion of PEPCO zone only		1
32	2010/11	2010	Jul 7 (Wed)	2	11:37	13:37	19:07	DOM zone		1
				2	12:30	14:30	18:32	AE, BGE, DPL, JCPL, PECO, PS, RECO zones		1
				2	12:30	14:30	18:32	PEPCO zone		2
33	2010/11	2010	Aug 11 (Wed)	2	11:15	13:15	19:15	DC portion of PEPCO zone only		3
34	2010/11	2010	Sep 23 (Thu)	1	11:00	12:00	18:00	MD, VA and WV portions of APS zone only	1	
				2	11:00	13:00	19:00	MD, VA and WV portions of APS zone only		1
				2	12:30	14:30	20:00	BGE zone		2
35	2010/11	2010	Sep 24 (Fri)	2	10:30	12:30	18:30	BGE zone		3
								PEPCO zone		4
								MD, VA and WV portions of APS zone only		2
36	2010/11	2011	May 26 (Thu)	2	14:20	16:20	18:20	Norfolk portion of DOM zone only. Event occurred outside compliance period		2
37	2010/11	2011	May 31 (Tue)	2	15:05	17:05	19:05	Event occurred outside compliance period.		
								METED, PENLC, PL, RECO zones		1
								AE, DPL, JCPL, PECO, PS zones		2
								DOM zone		3
								BGE zone		4
								PEPCO zone		5
38	2011/12	2011	Jul 22 (Fri)	2	10:00	12:00	18:00	BGE zone		1
				1	11:00	12:00	17:30	BGE zone	1	
				2	11:30	13:30	18:30	JCPL, METED zones		1
				2	11:30	13:30	19:00	PECO zone		1
				2	11:30	13:30	19:30	DPL, DLCO zones		1
39	2012/13	2012	Jul 17 (Tue)	2	13:08	15:08	19:05	AEP, DOM zones		1
40	2012/13	2012	Jul 18 (Wed)	2	13:22	15:22	17:23	BGE, JCPL, PECO, PENLC, PEPCO zones		1
				2	13:38	15:38	17:29	DPL zone		1
				1	14:28	15:28	17:34	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	1	
41	2013/14	2013	Jul 15 (Mon)	2	13:50	15:50	18:22	ATSI zone		1
42	2013/14	2013	Jul 16 (Tue)	2	11:30	13:30	16:30	ATSI zone		2
43	2013/14	2013	Jul 18 (Thu)	2	12:40	14:40	18:00	ATSI zone		3
				2	12:40	14:40	17:00	PECO, PL zones		1
				2	13:00	15:00	18:00	Canton portion of AEP zone only		1

OPERATIONS INFORMATION

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Running Total: # of Events Step 1	Step 2
44	2013/14	2013	Sep 10 (Tue)	2	13:50	15:50	21:30	ATSI zone		4
				2	14:45	16:45	21:30	Canton portion of AEP zone only		2
45	2013/14	2013	Sep 11 (Wed)	2	11:30	13:30	19:30	AEP zone Note: 3rd event for Canton portion of AEP zone		1
				2	12:00	14:00	20:00	ATSI zone		5
				2	12:30	14:30	18:30	DOM zone		1
				2	13:00	15:00	17:00	AE, JCPL, PS, RECO zones		1
				2	13:00	15:00	17:30	METED zone		1
				2	13:00	15:00	17:30	PECO, PL zones		2
				2	13:00	15:00	18:00	BGE, DPL, PEPCO zones		1
				2	13:00	15:00	18:30	PENLC zone		1
				1	13:00	14:00	17:15	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	1	
				2	13:00	15:00	18:30	DLCO zone		1
	2013/14	2014	Jan 6 (Mon)					5% voltage reduction: 19:52 - 20:45		
46	2013/14	2014	Jan 7 (Tue)	1	4:30	5:30	11:00	AEP,APS,ATSI,COMED,DAYTON,DEOK,DLCO,DOM,EKPC zones	1	
				1	4:30	5:30	11:00	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	2	
				2	4:30	6:30	11:00	APS,COMED,DAYTON,DEOK,EKPC zones		1
				2	4:30	6:30	11:00	AEP zone Note: 4th event for Canton portion of AEP zone		2
				2	4:30	6:30	11:00	AE,BGE,DPL,DLCO,DOM,JCPL,METED,PENLC,PEPCO,PS, RECO zones		2
				2	4:30	6:30	11:00	PECO, PL zones		3
				2	4:30	6:30	11:00	ATSI zone		6
								Event occurred outside compliance period.		
47	2013/14	2014	Jan 7 (Tue)	1	15:00	16:00	18:15	AEP,APS,ATSI,COMED,DAYTON,DEOK,DLCO,DOM,EKPC zones	2	
				1	15:00	16:00	18:15	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	3	
				2	15:00	17:00	18:15	APS,COMED,DAYTON,DEOK,EKPC zones		2
				2	15:00	17:00	18:15	AEP zone Note: 5th event for Canton portion of AEP zone		3
				2	15:00	17:00	18:15	AE,BGE,DPL,DLCO,DOM,JCPL,METED,PENLC,PEPCO,PS, RECO zones		3
				2	15:00	17:00	18:15	PECO, PL zones		4
				2	15:00	17:00	18:15	ATSI zone		7
								Event occurred outside compliance period.		
48	2013/14	2014	Jan 8 (Wed)	1	5:00	6:00	7:00	AEP,APS,ATSI,COMED,DAYTON,DEOK,DLCO,DOM,EKPC zones	3	
				1	5:00	6:00	7:00	AE, BGE, DPL, JCPL, METED, PECO, PENLC, PEPCO, PL, PS, RECO zones	4	
				2	5:00	7:00	7:00	APS,COMED,DAYTON,DEOK,EKPC zones		3
				2	5:00	7:00	7:00	AEP zone Note: 6th event for Canton portion of AEP zone		4
				2	5:00	7:00	7:00	AE,BGE,DPL,DLCO,DOM,JCPL,METED,PENLC,PEPCO,PS, RECO zones		4
				2	5:00	7:00	7:00	PECO, PL zones		5
				2	5:00	7:00	7:00	ATSI zone		8
								Event occurred outside compliance period.		
49	2013/14	2014	Jan 22 (Wed)	1	14:00	15:00	21:00	BGE, PEPCO zones	5	
				2	14:00	16:00	21:00	BGE, PEPCO zones		5
								Event occurred outside compliance period.		
50	2013/14	2014	Jan 23 (Thu)	1	4:30	5:30	8:30	APS, DOM zones	4	
				1	4:30	5:30	8:30	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	5	
				1	4:30	5:30	8:30	BGE, PEPCO zones	6	
				2	4:30	6:30	8:30	APS zone		4
				2	4:30	6:30	8:30	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		5
				2	4:30	6:30	8:30	BGE, PECO, PEPCO, PL zones		6
								Event occurred outside compliance period.		

OPERATIONS INFORMATION

Event #	Delivery Year	Year	Date	Step(s) Invoked	Time of Notification	Start Time	Time Released	Notes	Running Total: # of Events Step 1	Step 2
51	2013/14	2014	Jan 23 (Thu)	1	14:00	15:00	19:00	APS, DOM zones	5	
				1	14:00	15:00	19:00	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	6	
				1	14:00	15:00	19:00	BGE, PEPCO zones	7	
				2	14:00	16:00	19:00	APS zone		5
				2	14:00	16:00	19:00	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		6
				2	14:00	16:00	19:00	BGE, PECO, PEPCO, PL zones		7
								Event occurred outside compliance period.		
52	2013/14	2014	Jan 24 (Fri)	1	4:30	5:30	8:45	APS, DOM zones	6	
				1	4:30	5:30	8:45	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	7	
				1	4:30	5:30	8:45	BGE, PEPCO zones	8	
				2	4:30	6:30	8:45	APS zone		6
				2	4:30	6:30	8:45	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		7
				2	4:30	6:30	8:45	BGE, PECO, PEPCO, PL zones		8
								Event occurred outside compliance period.		
53	2013/14	2014	Mar 4 (Tue)	1	4:30	5:30	8:30	AEP,ATSI,COMED,DAYTON,DEOK,DLCO,EKPC zones	4	
				1	4:30	5:30	8:30	APS, DOM zones	7	
				1	4:30	5:30	8:30	AE, DPL, JCPL, METED, PECO, PENLC, PL, PS, RECO zones	8	
				1	4:30	5:30	8:30	BGE, PEPCO zones	9	
				2	4:30	6:30	8:30	COMED,DAYTON,DEOK,EKPC zones		4
				2	4:30	6:30	8:30	AEP, DLCO zones Note: 7th event for Canton portion of AEP zone		5
				2	4:30	6:30	8:30	APS zone		7
				2	4:30	6:30	8:30	AE,DPL,DOM,JCPL,METED,PENLC,PS, RECO zones		8
				2	4:30	6:30	8:30	ATSI, BGE, PECO, PEPCO, PL zones		9
								Event occurred outside compliance period.		

*** Prior to Event #25, all events were Mid-Atlantic only.**

**** Average committed capacity reduction when event occurs in a capacity compliance period. Average expected energy reduction, as reported by CSPs, when event is outside of capacity compliance period.**

LM Step Definitions:

Step 1: PJM-dispatchable, Short Lead Time (<= 1 hour)
Step 2: PJM-dispatchable, Long Lead Time (> 1 hour)
Step 3: Company-dispatchable, Short Lead Time (<= 1 hour)
Step 4: Company-dispatchable, Long Lead Time (> 1 hour)

Eastern PJM = AE, DPL, JCPL, PECO, and PS zones
LRPP: Load Response Pilot Program
Mid-Atlantic = AE, BGE, DPL, JCPL, METED, PECO, PEPCP, PENLC, PL, PS, RECO (effective 2002/03) zones

LM Capacity

Committed/Expected MW**

LM Capacity

Committed/Expected MW**

LM Capacity

Committed/Expected MW**

47
137
2,725
60
849
967
253
3,450
2,296
1,670
2,135
690
690
1,791

LM Capacity

Committed/Expected MW**
798
6,048
1,887
3,042
Cancelled prior to start time
140
633

LM Capacity

Committed/Expected MW**
1,266
706
1,592

Summary of PJM-Initiated Load Management Events***

				OPERATIONS INFORMATION								LM Capacity
Event #	Delivery Year	Year	Date	Type(s) Invoked	Notification Period Invoked	Product(s) Invoked	Time of Notification	Start Time	Time Released	Zone(s) Dispatched	Notes	Committed/Expected MW**
54	2014/15	2015	Apr 21 (Tue.)	Pre-Emergency	Long_120	L, E	18:20	20:20	21:30	PENLC		99
					Short_60	L	18:20	19:20	21:30			
				Emergency	Long_120	L, E	18:20	20:20	21:30			
55	2014/15	2015	Apr 22 (Wed.)	Pre-Emergency	Long_120	L, E	5:30	7:30	12:30	PENLC		113
					Short_60	L	5:30	6:30	12:30			
				Emergency	Long_120	L, E	5:30	7:30	12:30			

*** Prior to Event #25, all events were Mid-Atlantic only.**
**** Average committed capacity reduction when event occurs in a capacity compliance period. Average expected energy reduction, as reported by CSPs, when event is outside of capacity compliance period.**
***** Beginning with Event #54, the report was restructured to reflect new options for Type, Notification Period, and Products.**

Definitions:
Step 1: PJM-dispatchable, Short Lead Time (<= 1 hour)
Step 2: PJM-dispatchable, Long Lead Time (> 1 hour)
Step 3: Company-dispatchable, Short Lead Time (<= 1 hour)
Step 4: Company-dispatchable, Long Lead Time (> 1 hour)
Pre-Emergency: Load management that can be invoked prior to the declaration of a system emegency
Emergency: Load management that can be invoked susequent to the declaration of a system emegency
L (Limited): Committed to providing up to 10 load reductions of 6 hours duration in the months Jun-Sep
E (Extended Summer): Committed to providing an unlimited number of interruptions of 10 hours durarion during a period of Jun-Oct and the following May
A (Annual): Committed to providing an unlimited number of interruptions of 10 hours duration
Long_120: Full load reduction must be implemented within 120 minutes of the notification time
Short_60: Full load reduction must be implemented within 60 minutes of the notification time
Quick_30: Full load reduction must be implemented within 30 minutes of the notification time

Eastern PJM = AE, DPL, JCPL, PECO, and PS zones
LRPP: Load Response Pilot Program
Mid-Atlantic = AE, BGE, DPL, JCPL, METED, PECO, PEPCP, PENLC, PL, PS, RECO (effective 2002/03) zones

KWalton

PJM-rpm-auctions-resource-clearing-price-summary.x
03/31/17 09:07 AM

Resource Clearing Prices for all RPM Auctions held to date

DOCS # 72686- 9/23/16

	Capacity Product Type *	RTO	MAAC	MAAC + APS	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-CLEVELAND	COMED	BGE	PL	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2
DY 07/08																				
BRA	*	$40.80	**	**	$197.67	$188.54	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 08/09																				
BRA	*	$111.92	**	**	$148.80	$210.11	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$10.00	**	**	$10.00	$223.85	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 09/10																				
BRA	*	$102.04	**	$191.32	**	$237.33	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$40.00	**	$86.00	**	**	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 10/11																				
BRA	*	$174.29	**	**	**	**	**	**	$186.12	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$50.00	**	**	**	**	**	**	$50.00	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 11/12																				
BRA	*	$110.00	**	**	**	**	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	*	$55.00	**	**	**	**	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$5.00	**	**	**	**	**	**	**	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 12/13																				
BRA	*	$16.46	$133.37	**	$139.73	$133.37	**	$185.00	$222.30	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	*	$16.46	$16.46	**	$153.67	$16.46	**	$153.67	$153.67	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	*	$13.01	$13.01	**	$48.91	$13.01	**	$48.91	$48.91	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$2.51	$2.51	**	$2.51	$2.51	**	$2.51	$2.51	**	N/A	N/A	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 13/14																				
BRA	*	$27.73	$226.15	**	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	*	$20.00	$20.00	**	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	*	$7.01	$10.00	**	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	*	$4.05	$30.00	**	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 14/15																				
BRA	Annual	$125.99	$136.50	**	$136.50	$136.50	$136.50	$225.00	$136.50	$136.50	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Ext Summer	$125.99	$136.50	**	$136.50	$136.50	$136.50	$225.00	$136.50	$136.50	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$125.47	$125.47	**	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$5.54	$16.56	**	$16.56	$16.56	$16.56	$410.95	$16.56	$16.56	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$5.54	$16.56	**	$16.56	$16.56	$16.56	$410.95	$16.56	$16.56	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$0.03	$5.23	**	$5.23	$5.23	$5.23	$399.62	$5.23	$5.23	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Ext Summer	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Limited	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Annual	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Ext Summer	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Limited	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 15/16																				
BRA	Annual	$136.00	$167.46	**	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Ext Summer	$136.00	$167.46	**	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	**	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$118.54	$150.00	**	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$136.00	$153.56	**	$153.56	$153.56	$167.46	$167.46	$153.56	$153.56	$216.54	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Ext Summer	$136.00	$153.56	**	$153.56	$153.56	$167.46	$167.46	$153.56	$153.56	$216.54	**	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Limited	$123.56	$141.12	**	$141.12	$141.12	$155.02	$155.02	$141.12	$141.12	$204.10	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Annual	$163.20	$184.77	**	$184.77	$184.77	$185.00	$185.00	$184.77	$184.77	$163.20	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Ext Summer	$163.20	$184.77	**	$184.77	$184.77	$185.00	$185.00	$184.77	$184.77	$163.20	**	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Limited	$100.76	$122.33	**	$122.33	$122.33	$122.56	$122.56	$122.33	$122.33	$100.76	**	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 16/17																				
BRA	Annual	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$114.23	$114.23	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Ext Summer	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$114.23	$114.23	**	**	**	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$94.45	$94.45	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$60.00	$119.13	**	$119.13	$119.13	$244.22	$244.22	$119.13	$119.13	$100.52	$100.52	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$60.00	$119.13	**	$119.13	$119.13	$244.22	$244.22	$119.13	$119.13	$100.52	$100.52	**	**	**	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$53.93	$89.35	**	$89.35	$89.35	$214.44	$214.44	$89.35	$89.35	$94.45	$94.45	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$31.00	$71.00	**	$71.00	$71.00	$99.01	$212.53	$71.00	$71.00	$101.50	$101.50	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Ext Summer	$31.00	$71.00	**	$71.00	$71.00	$99.01	$212.53	$71.00	$71.00	$101.50	$101.50	**	**	**	N/A	N/A	N/A	N/A	N/A
2IA	Limited	$31.00	$71.00	**	$71.00	$71.00	$99.01	$212.53	$71.00	$71.00	$101.50	$101.50	**	**	**	N/A	N/A	N/A	N/A	N/A
TA	CP	$134.00	$134.00	**	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Annual	$5.02	$10.02	**	$10.02	$10.02	$54.76	$184.97	$10.02	$10.02	$5.02	$5.02	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Ext Summer	$5.02	$10.02	**	$10.02	$10.02	$54.76	$184.97	$10.02	$10.02	$5.02	$5.02	**	**	**	N/A	N/A	N/A	N/A	N/A
3IA	Limited	$5.02	$10.02	**	$10.02	$10.02	$54.76	$184.97	$10.02	$10.02	$5.02	$5.02	**	**	**	N/A	N/A	N/A	N/A	N/A
DY 17/18																				
BRA	Annual	$120.00	$120.00	**	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	N/A	$120.00	$120.00	N/A
BRA	Ext Summer	$120.00	$120.00	**	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$53.98	N/A	N/A	N/A	N/A	N/A
BRA	Limited	$106.02	$106.02	**	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02	$106.02	$106.02	$40.00	N/A	N/A	N/A	N/A	N/A
1IA	Annual	$84.00	$84.00	**	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	N/A	N/A	N/A	N/A	N/A
1IA	Ext Summer	$84.00	$84.00	**	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	N/A	N/A	N/A	N/A	N/A
1IA	Limited	$84.00	$84.00	**	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	N/A	N/A	N/A	N/A	N/A
TA	CP	$151.50	$151.50	**	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	N/A	N/A	N/A	N/A	N/A
2IA	Annual	$26.50	$26.50	**	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	Ext Summer	$26.50	$26.50	**	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	NA ***	NA ***	NA ***	NA ***	NA ***
2IA	Limited	$26.50	$26.50	**	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	NA ***	NA ***	NA ***	$26.50	NA ***
DY 18/19																				
BRA	CP	$164.77	$164.77	**	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$164.77	$215.00	$164.77	$164.77	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE GEN	$149.98	$149.98	**	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$149.98	$200.21	$149.98	$75.00	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE DR/EE	$149.98	$149.98	**	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$149.98	$200.21	$59.95	$75.00	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	CP	$27.15	$27.15	**	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$27.15	$30.00	$27.15	$27.15	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	BASE GEN	$22.51	$22.51	**	$80.04	$22.51	$80.04	$80.04	$35.68	$22.51	$22.51	$22.51	$25.36	$22.51	$22.51	NA ***	NA ***	NA ***	NA ***	NA ***
1IA	BASE DR/EE	$22.51	$22.51	**	$80.04	$22.51	$80.04	$80.04	$35.68	$22.51	$22.51	$22.51	$25.36	$22.51	$22.51	NA ***	NA ***	NA ***	NA ***	NA ***
DY 19/20																				
BRA	CP	$100.00	$100.00	**	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$100.00	$202.77	$100.30	$100.00	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE GEN	$80.00	$80.00	**	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$80.00	$182.77	$80.30	$80.00	NA ***	NA ***	NA ***	NA ***	NA ***
BRA	BASE DR/EE	$80.00	$80.00	**	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$80.00	$182.77	$80.30	$80.00	NA ***	NA ***	NA ***	NA ***	NA ***

* The Annual, Extended Summer and Limited capacity product types were implemented starting with the 2014/2015 Delivery Year

** LDA was not modeled

*** There were no Sell Offers in these External Source Zones.

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ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

8. On page 4, lines 15-17, Dr. Goins states, "Some of these CSR customers have invested millions of dollars in production processes designed to operate efficiently using nonfirm electric service."

a. Please provide all studies, analysis, reports and other information created by or relied upon by Dr. Goins that specifically describes the "investment in production processes" made by CSR customers and how they were "designed" to operate with "nonfirm electric service."

b. Please describe how the design or operation of these "production processes" would be impacted if they were served by firm electric service instead of nonfirm service.

c. Please describe the degree of nonfirm electric service (e.g, number of interruption events, duration of interruptions, frequency of interruption events) that these production processes were designed to efficiently utilize.

d. What is Dr. Goins' definition of nonfirm electric service?

RESPONSE:

a. Dr. Goins' statement relies on the testimony of KIUC witnesses Mary Jean Riley (2016-00370), Mark Watson (2016-00370), and Michael Simons (2016-00371).

b. Please see the response to 1-8(a) above.

c. Please see the response to 1-8(a) above.

d. Non-firm electric service is a derivative utility product available when a supplier's available capacity built to serve firm load exceeds firm demand.

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9. Per Dr. Goins' recommendation on page 6, lines 13-15, is it his position that the Companies should offer a CSR Rider option regardless of the system's need for current or the timing of the need for future capacity?

RESPONSE:

Yes.

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10. Referring to page 8, lines 13-16, is it Dr. Goins' position that the Companies have no duty or responsibility to consider the load of a CSR Rider customer in non-curtailable hours in planning to reliably and economically serve system load?

a. During the course of the year, outside of the 100 hours in which the Companies can ask the CSR Rider customer to curtail its load, is a CSR Rider customer's load firm or nonfirm load?

RESPONSE:

No. Considerations of CSR load in non-curtailable hours primarily affect a utility's short-term decisions regarding unit commitment and dispatch, and potentially the types (but not total amount) of generating capacity evaluated and selected in capacity resource plans. None of these considerations negate the fact that from a long-term perspective, KU and LG&E do not build or acquire capacity to serve non-firm CSR load.

a. CSR load does not become firm simply because limits on curtailments have been exceeded. As Dr. Goins repeatedly points out in his direct testimony, the principal value of interruptible load is reflected in the utility's avoidance of long-run marginal costs for peaking capacity. The utility can avoid that capacity and its associated costs only because CSR load is considered non-firm from a planning perspective. Attempts to link the classification of CSR load to permissible hours of physical curtailment reflect a basic misunderstanding of why economists (as well as KU and LG&E in prior cases) emphasize the value of interruptible load as a long-run planning resource. Look at this issue from a different perspective and consider the following. A generating unit built to serve firm load does not become a non-

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firm capacity resource simply because it is out-of-service due to a forced or scheduled outage. The same is true of CSR load. Similarly, KU's and LG&E's peaking generators do not operate the same number of hours each year, yet KU and LG&E do not recommend varying the portion of a peaking unit's embedded cost recovered in base rates on the basis of each unit's hours of operation in the test year. KU and LG&E should apply the same principle in developing CSR credits.

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11. On page 8, lines 16-19, Dr. Goins states that interruptible service is a "lower quality product" and that interruptible customers face "significant financial penalties if they do not interrupt load when required."

a. In what ways is the service that a CSR Rider customer receives from the Companies' a "lower quality product?"

b. Will a CSR Rider customer still receive electric power from the Companies should the CSR Rider customer fail to curtail load when requested?

c. What is Dr. Goins' definition of a "significant" financial penalty?

RESPONSE:

a. Electricity products can be differentiated by numerous factors, including price, availability, and reliability. For example, a rate option available only to transmission customers is a different product from a rate option available only to secondary distribution customers. Service under Rider CSR (and, in part, Rate FLS) is non-firm, interruptible service—not firm service, which is a higher quality product. Because CSR service is non-firm, most people would consider it a lower quality product compared to firm service.

b. Whether the customer continues receiving electric service during a failure-to-comply event depends on unknown factors (for example, the relationship between the CSR load and the availability of operating reserve capacity at the time of noncompliance). Moreover, Rider CSR already protects the utility and firm customers from a CSR customer's potential failure to comply with curtailment requests. For example, Rider CSR includes a $16 per kVA failure-to-comply penalty as well as provisions that allow the utility to terminate the

customer's CSR service or install curtailment compliance control equipment at the customer's expense. Both KU and LG&E can use these rider provisions to help ensure customer compliance with curtailment requests.

c. Dr. Goins considers Rider CSR's Non-Compliance Charge ($16 per kVA) to be a significant financial penalty. He also considers a customer's potential loss of CSR service because of failure to comply with a curtailment request to be an even more significant financial penalty.

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12. Referring to page 10, lines 13-15, outside of the hours of potential curtailment for a CSR Rider customer, should the Companies consider a CSR Rider customer's load in its capacity planning?

a. Do the Companies have an obligation to serve a CSR Rider customer's load outside of the hours of potential curtailment?

b. Do the Companies have an obligation to serve a CSR Rider customer's load should it fail to curtail load when requested?

RESPONSE:

Dr. Goins believes that the treatment of CSR interruptible load in the joint KU/LG&E integrated and plan is reasonable.

a. KU and LG&E have an obligation to provide service under applicable provisions of their electric tariffs, including provisions of Rider CSR. If KU and LG&E have capacity available to serve CSR load during non-curtailable hours, then the companies should use best efforts to serve the load. To do otherwise would be imprudent. Serving CSR load in non-curtailable hours is simply a reasonable business strategy to maximize the value of capacity resources built or acquired to serve firm load.

b. Please see KIUC's response to KU's and LG&E's request 1-11(b).

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13. Referring to page 11, lines 5-6, what is the Companies' "cost of providing nonfirm service"? Please provide all analysis, workpapers, reports, etc. to support your response.

RESPONSE:

Please see Goins Direct at 7:27–8:19 and 10:11–12:20 (in particular the Bonbright quote).

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14. Referring to page 11, lines 9-10, what is Dr. Goins' definition of "long-run" and "short-run?"

RESPONSE:

In basic economics, the *long-run* refers to the period of time required for a supplier to add new production capacity, while *short-run* refers to a period in which production capacity is fixed. In the short-run, when KU's and LG&E production capacity is fixed, embedded costs reflect sunk costs that are irrelevant with respect to determining the price of interruptible service.

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15. Referring to page 11, lines 16-20, please provide any reports, analysis, or other data that describe the "long-term contractual and/or operational commitment" that CSR Rider customers have made since the Companies' last rate case based on the existing CSR Rider credit.

RESPONSE:

Please see KIUC's response to KU's and LG&E's request 1-8. In addition, the cited portion of Dr. Goins' testimony is not limited only to commitments that CSR customers have been made since the last rate case.

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16. Referring to page 14, lines 7-10, please provide all reports, tariffs, or other documents used to determine the range of interruptible rate options.

RESPONSE:

The attachment to this response includes copies of interruptible rate options offered by the cited utilities.

KWalton

EKPC Interruptible.pdf
03/31/17 09:04 AM

Section D
Interruptible Service

Standard Rider

This Interruptible Rate is a rider to Rate Sections A, B, C, E, and G.

Applicable

In all territory served by EKPC.

Availability of Service

This schedule shall be made available at any load center, to any member cooperative where an ultimate "Customer" will contract for an interruptible demand of not less than 250 kW and not more than 20,000 kW, subject to a maximum number of hours of interruption per year and a notice period as listed below. Note that hours of interruption per year or annual hours of interruption refer to the 12-month period ended May 31.

Monthly Rate

A monthly demand credit per kW is based on the following matrix:

	Annual Hours of Interruption			
Notice Minutes	200	300	400	
30	$4.20	$4.90	$5.60	(T)

Determination of Measured Load - Billing Demand

The billing demand (kilowatt demand) is based on EKPC's system peak demand (coincident peak) which is the highest average rate at which energy is used during any fifteen minute interval in the below listed hours for each month and adjusted for power factor as provided herein:

Months	Hours Applicable for Demand Billing – EPT	
November through April	6:00 a.m. to 9:00 p.m.	(T)
May through October	10:00 a.m. to 10:00 p.m.	

DATE OF ISSUE June 23, 2015
Month / Date / Year
DATE EFFECTIVE Service rendered on and after August 1, 2015
Month / Date / Year
ISSUED BY Don Mosier
(Signature of Officer)
TITLE Executive VP and Chief Operating Officer

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Brent Kirtley
EFFECTIVE
8/1/2015
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Section D (con't.)

The interruptible billing demand shall be equal to the amount by which the monthly billing demand exceeds the minimum billing demand as specified in the contract.

Conditions of Service for Customer Contract

1. The customer will, upon notification by the Cooperative, reduce his load being supplied by the Cooperative to the contract capacity level specified by the contract.

2. The Cooperative will endeavor to provide the Customer as much advance notice as possible of the interruption of service. However, the Customer shall interrupt service within the notice period as contracted.

3. Service will be furnished under the Cooperatives "General Rules and Regulations" or "Terms and Conditions" except as set out herein and/or provisions agreed to by written contract.

4. No responsibility of any kind shall attach to the Cooperative for, or on account of, any loss or damage caused by, or resulting from, any interruption or curtailment of this service.

5. The Customer shall own, operate, and maintain all necessary equipment for receiving electric energy and all telemetering and communications equipment, within the Customer's premises, required for interruptible service.

6. The minimum original contract period shall be one year and thereafter until terminated by giving at least sixty days previous written notice. The Cooperative may require a contract be executed for a longer initial term when deemed necessary by the size of the load and other conditions.

7. The Fuel Adjustment Clause, as specified in the General Wholesale Power Rate Schedule, is applicable.

Calculation of Monthly Bill

The monthly bill is calculated on the following basis:

A. Sum of metering point charge and substation charge, plus
B. Minimum billing demand in kW multiplied by the firm capacity rate, plus
C. Interruptible billing demand in kW multiplied by interruptible rate, plus
D. Energy usage in kWh multiplied by the energy rate.

DATE OF ISSUE June 23, 2015
Month / Date / Year
DATE EFFECTIVE Service rendered on and after August 1, 2015
Month / Date / Year
ISSUED BY
(Signature of Officer)
TITLE Executive VP and Chief Operating Officer

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Section D (con't.)

Number and Duration of Interruptions

A. There shall be no more than two (2) interruptions during any 24 hour calendar day. No interruption shall last more than twelve hours (T)

B. Interruptions may occur between 6:00 a.m. and 9:00 p.m. EPT during the months of November through April and between 10:00 a.m. and 10:00 p.m. EPT during the months of May through October.

C. The maximum number of annual hours of interruption shall be in accordance with the customer contracted level of interruptible service.

Charge for Failure to Interrupt

If Customer fails to interrupt load as requested by the Cooperative, the Cooperative shall bill the uninterrupted load at a rate equal to five (5) times the applicable firm power demand charge for that billing month. Uninterrupted load is equal to actual load during requested interruption minus firm load.

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P.U.C.O. NO. 20

RIDER IRP-D
(Interruptible Power - Discretionary)

Availability of Service

Service pursuant to this rider is available to customers that have provided reasonable evidence to the Company that their electric service can be interrupted within a 10-minute notice period. Customers shall contract for electrical capacity sufficient to meet normal maximum requirements but not less than 1,000 KW of interruptible capacity.

The total interruptible power contract capacity for all customers served under this rider, contracts and agreements offered by the Company will be limited to 75,000 KW in the Columbus Southern Power Rate Zone and 450,000 KW in the Ohio Power Rate Zone. Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development or competitive response incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

The Company communicates interruption information to the customer, monitors customer load and receives customer replacement electricity decisions through its Customer Communications System or a successor system. All costs associated with providing the initial, required Customer Communications System will be borne by the customer.

Interruption Conditions

The Company reserves the right to interrupt, in its sole discretion, service under this rider at any time. Such interruptions shall be designated as Discretionary Interruptions and shall not exceed 200 hours of interruption during any year. For the purposes of this provision, a year shall be defined as a consecutive twelve (12) month period commencing on May 1 and ending on April 30. Discretionary Interruptions will be called simultaneously for all customers served under this rider.

In addition to the annual limitation as specified above, the hours of Discretionary Interruption shall be limited as follows:

1. A Discretionary Interruption, beginning and ending as specified in the Interruption Notice provision below, shall constitute one (1) event.

2. A Discretionary Interruption event shall not be less than three (3) consecutive hours, unless there are less than three (3) hours of Discretionary Interruption remaining for the year.

3. There shall not be more than 12 hours of Discretionary Interruption per day.

4. During the calendar months of March through November, there shall not be more than one (1) Discretionary Interruption event per day.

Filed pursuant to Order dated August 8, 2012 in Case No. 11-346-EL-SSO

Issued: August 16, 2012 Effective: Cycle 1 September 2012

Issued by
Pablo Vegas, President
AEP Ohio

P.U.C.O. NO. 20

RIDER IRP-D
(Interruptible Power - Discretionary)

Interruption Conditions (Cont'd)

5. During the calendar months of December, January and February, there shall not be more than two (2) Discretionary Interruption events per day. Any such Discretionary Interruption events shall be separated by not less than three (3) consecutive hours without Discretionary Interruption.

Emergency Interruptions pursuant to the AEP Emergency Operating Plan, for system integrity purposes or for emergency sales to other utilities, shall not count toward the total hours of interruption specified above or toward the five (5) limits specified above.

Interruption Notice

The Company will endeavor to provide the customer as much advance notice as possible of a Discretionary Interruption. Such notice shall specify the starting and ending hour of the Discretionary Interruption. Discretionary Interruptions shall begin and end on the clock hour. The Company shall provide notice to the customer a minimum of 100 minutes prior to the commencement of a Discretionary Interruption. After such notice, the customer will be required to interrupt service within 100 minutes if so requested by the Company. In emergency situations, the customer will be required to interrupt service immediately.

Failure to Comply With A Request For Interruption

1. If the customer fails to interrupt load as requested by the Company for a Discretionary Interruption, the customer will be required to pay for the entire uninterrupted energy for the duration of the Discretionary Interruption at two (2) times the Replacement Electricity price offered by the Company. The uninterrupted energy will be calculated for each 30-minute period during the Discretionary Interruption as one-half of the difference between the 30-minute integrated demand and the sum of the customer's contract capacities under any schedule where service is not interrupted.

2. If the customer fails to interrupt load as requested by the Company for an Emergency Interruption, the customer will be required to refund all rate discounts received under this rider during the preceding 12 months for the uninterrupted demand. The uninterrupted demand will be calculated as the difference between the maximum 30-minute integrated demand during each Emergency Interruption and the sum of the customer's contract capacities under any schedule where service is not interrupted. The rate discount will be the demand credit as specified in this rider.

3. If the customer fails to interrupt load as requested by the Company during an Emergency Interruption, the Company further reserves the right to:

   a) Interrupt the customer's entire load.

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RIDER IRP-D
(Interruptible Power - Discretionary)

Failure to Comply With A Request For Interruption (Cont'd)

b) Discontinue service to the customer under this rider if the customer fails to interrupt load twice during any 12-month period as requested by the Company. The Company may thereafter charge the customer, as specified in the Term of Contract provision of this rider, for any additional costs beyond the firm service rate incurred by the Company as a result of the customer transferring to firm service without providing proper notice.

Term of Contract

The customer shall contract for capacity sufficient to meet normal maximum power requirements under the applicable standard service rate schedule. In no event will the amount of interruptible capacity contracted for be less than 1,000 KW at any delivery point. The Company will not be required to supply capacity in excess of that contracted for except by mutual agreement. In the absence of such agreement, if the customer's demand exceeds the contract capacity, the Company may promptly notify the customer to reduce demand and may interrupt the service if such reduction is not accomplished.

Contracts under this rider shall be made for an initial period of not less than 2 years and shall remain in effect unless either party shall give at least 1-year's written notice to the other of the intention to discontinue service from the Company.

A new initial contract period will not be required for existing customers who increase their contract capacity requirements after the original notice period unless new or additional facilities are required, in which case, the Company may, at its option, require a longer initial contract period.

While the customer will be required to provide at least 1-year's notice to discontinue service from the Company, the customer will be required to provide 5-year's notice prior to transferring to firm service. Concurrent with providing the Company with notice to transfer to firm service, the customer will also be required to enter into a firm service contract or agreement that will become effective at the end of the notice period.

The customer may transfer to firm service with less than 5-year's notice, upon mutual agreement between the customer and the Company, subject to the following conditions:

1. If the Company has sufficient capacity to provide the customer firm service and would incur no additional costs beyond the firm service rate until after the 5-year contract notice requirement is fulfilled, the customer will be billed under the applicable firm service schedule.

2. If the Company has insufficient capacity to provide the customer firm service prior to the expiration of the notice period, the customer will be billed under the applicable firm service schedule plus all additional costs incurred by the Company in obtaining power from alternative electricity suppliers in order to provide firm service to the customer.

P.U.C.O. NO. 20

RIDER IRP-D
(Interruptible Power - Discretionary)

Firm Service Designation

The customer must designate a firm service contract capacity for such service.

Replacement Electricity

When a Discretionary Interruption is called pursuant to the Interruption Conditions provision contained herein, and if requested by the customer, the Company will use its best efforts to supply replacement electricity in order for the customer to avoid an interruption. The customer will be required to specify an hourly KW capacity, in multiples of 1,000 KW, of such replacement electricity 65 minutes in advance of the commencement of each hour of the Discretionary Interruption.

The purchase and delivery of such replacement electricity will be subject to the following terms and conditions of service:

1. The customer agrees to pay the price offered by the Company. Such price shall be provided by the Company 100 minutes in advance of the commencement of each hour of the Discretionary Interruption.

2. Best efforts shall mean actions of the Company that are reasonable, prudent and consistent with good utility practice. Best efforts do not include fiduciary or extraordinary actions.

3. Once replacement electricity is being supplied to the customer, if the customer is notified that replacement electricity is no longer available, the terms of this provision will cease to apply and the customer must comply with all other provisions of this rider regarding interruption.

4. If any replacement electricity source fails to deliver scheduled replacement electricity, the Company reserves the right to interrupt service to the customer. Further, the customer will indemnify and hold the Company harmless for any damages to persons or property occurring at the customer's premises resulting from the interruption of the customer when the replacement electricity source fails to deliver replacement electricity as scheduled.

5. The Company reserves the right to interrupt the sale of replacement electricity to the customer if, in the sole judgement of the Company, such electricity is required to maintain service to the Company's customers with a higher priority of service according to the AEP Emergency Operating Plan, for system integrity purposes or for emergency sales to other utilities. Any such interruption shall be remedied as quickly as reasonably possible and must be preceded by the exhaustion of other reasonable alternatives consistent with good utility practice to avoid the interruption.

6. All costs of any metering, communications and other equipment necessary for providing replacement electricity will be borne by the customer. Such costs will include the costs of any equipment required to verify the scheduled delivery of replacement electricity from a replacement electricity source to the Company.

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P.U.C.O. NO. 20

RIDER IRP-D
(Interruptible Power - Discretionary)

7. The customer will be responsible for all costs resulting when the demand exceeds the replacement electricity capacity specified by the customer. The Company will compensate the customer for replacement electricity available for, but not used by the customer at a rate of 2.5¢ per KWH, except when the unused replacement electricity causes additional costs to the Company by creating operating instability on the Company's system. If the unused replacement electricity causes additional costs due to system instability, the Company shall notify the customer as soon as possible so the customer can take appropriate action to prevent incurring further costs.

Monthly Rate

In addition to the monthly charges for service under the applicable standard service rate schedule under which the customer receives service, the customer shall receive a Demand Credit for monthly interruptible demand as follows:

Generation Demand Credit ($ per KW)

Delivery Voltage	OPCO Rate Zone	CSP Rate Zone
Secondary	(8.21)	(8.21)
Primary	(8.21)	(8.21)
Subtransmission	(8.21)	(8.21)
Transmission	(8.21)	(8.21)

The Demand Credit shall apply to the customer's monthly interruptible demand. Monthly interruptible demand shall be the difference between the monthly billing demand determined in accordance with the standard service rate schedule under which the customer receives service and the customer designated firm service contract capacity. In no event shall the customer's monthly interruptible demand be greater than the customer's interruptible service contract capacity.

Special Terms and Conditions

This rider is subject to the Company's Terms and Conditions of Service and all provisions of the rate schedule under which the customer takes service.

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TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power)

AVAILABILITY OF SERVICE.

Available for service to customers who contract for service under one of the Company's interruptible service options. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 75,000kW.

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

CONDITIONS OF SERVICE.

The Company will offer eligible customers the option to receive interruptible power service. This interruptible service will be consistent with PJM's Limited Demand Response, Emergency – Capacity Only Program, subject to any limitations on the availability of that Program by PJM. If insufficient MWs are available for PJM enrollment by Kentucky Power, the Company shall offer to substitute one of the other PJM Emergency Demand Response Programs that is available. To be eligible for the credit, customers must be able to provide interruptible load (not including behind the meter diesel generation) of at least one (1) MW at a single site and commit to a minimum four (4) year contract term. The contract shall provide that 90 days prior to each contract anniversary date, the customer shall re-nominate the amount of interruptible load for the upcoming contract year, except that the cumulative reductions over the life of the contract shall not exceed 20% of the original interruptible load nominated under the contract. If no re-nomination is received at least 90 days prior to the contract anniversary date, the prior year's interruptible load shall apply for the forthcoming contract year.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written offer containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet normal maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

RATE. (Tariff Code 321)

Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's rules as capacity for the purpose of the Company's FRR obligation.

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect the firm service rates otherwise available to the Customer.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated I in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

(Cont'd on Sheet No. 12-2)

DATE OF ISSUE: July 10, 2015

DATE EFFECTIVE: Service Rendered On And After June 30, 2015

ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of An Order By The Public Service Commission

In Case No. 2012-00578 Dated June 22, 2015

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bent Kirtley
EFFECTIVE
6/30/2015
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by an Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 and 22-15 of this Tariff Schedule, unless the Customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427. T

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge Adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-7 of this Tariff Schedule. T

CAPACITY CHARGE.

Bills computed according to the rate set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.

TERM OF CONTRACT

The length of the agreement and the terms and conditions of service will be stated in the agreement between the Company and the Customer.

CONFIDENTIALITY

All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR5:001, Section 7 and the request is granted.

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By Authority Of An Order By The Public Service Commission

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KENTUCKY
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TARIFF C.S.-I.R.P.
(Contract Service - Interruptible Power) (Cont'd.)

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

N

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission.

N

SPECIAL TERMS AND CONDITIONS

Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist, the Customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 1,000 KW.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company

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ISSUED BY: JOHN A. ROGNESS III

TITLE: Director Regulatory Services

By Authority Of an Order of the Public Service Commission

In Case No. 2014-00396 Dated June 22, 2015

KENTUCKY
PUBLIC SERVICE COMMISSION

JEFF R. DEROUEN
EXECUTIVE DIRECTOR

TARIFF BRANCH

Brent Kirtley

EFFECTIVE

6/30/2015

PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

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RIDER ELR
Economic Load Response Program Rider

APPLICABILITY:

This Economic Load Response Program Rider ("Program") is available to customers taking service from the Company at primary voltages or higher voltages provided that all of the following seven conditions are met at the time of initiation of service to the customer under this Rider and on a continuing basis thereafter: (i) the customer took service under the Program as of May 31, 2016 or the customer was historically eligible for Rider ELR and provided written notice of intent to participate in the Program on or before May 31, 2015 for up to an additional 136,250 kW of Curtailable Load effective on or after June 1, 2016; (ii) the customer can successfully demonstrate to the Company that it can reduce its measured load to a pre-established contract Firm Load (as defined under Other Provisions, paragraph A., below) within two hours of notification provided by the Company without the need of a generator (A customer may intend to use a generator to reduce its usage to below its Firm Load, but if the generator does not operate, the customer must still reduce its usage to or below its Firm Load. Failure of a customer to reduce its usage to or below its Firm Load shall result in the consequences listed in the Emergency Curtailment Event Section herein.); (iii) the customer executes the Company's standard Program contract; (iv) the customer is taking generation service from the Company or a Competitive Retail Electric Service ("CRES") provider using consolidated billing; (v) the customer is not participating in any other load curtailment or demand response program, including without limitation a demand response program offered by PJM Interconnection, L.L.C. ("PJM") or any other independent system operator; (vi) the customer commits its demand response capability to Company for integration into Company's R.C. § 4928.66 compliance programs; and, (vii) the Commission finds that the demand response capabilities of customers electing service under this rider shall count towards the Company's compliance with the peak demand reduction benchmarks set forth in R.C. § 4928.66 as applied by the Commission's applicable rules and regulations and shall be considered incremental to interruptible load on the Company's system that existed in 2008. Nothing herein shall preclude a customer from requesting and receiving an exemption from any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs to the extent the exemption is requested to reasonably encourage the commitment of customer-sited capabilities to the Company.

RATES:

In addition to any other charges under any other rate schedules applicable to customer's service, customers participating in the Program shall also pay the charges and receive the credit set forth below:

Charges:

Program Administrative Charge: $150.00 per month

ECE Charge:

During an Emergency Curtailment Event (as defined under Other Provisions, paragraph D., below), the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any and all hours during such event shall be assessed an ECE Charge which is calculated for each hour of the event as follows. Revenue collected by the Company as a result of any ECE Charge less amounts associated with the Commercial Activity Tax ("CAT") (as defined below) shall be credited towards costs to be collected through the DSE1 charge of Rider DSE:

RIDER ELR
Economic Load Response Program Rider

ECE Charge = (AL x PJM LMP x 300%) x (1 + LAF) x ([1/(1-CAT)])

Where:

AL = the customer's actual hourly load during an Emergency Curtailment Event that exceeds the customer's pre-established contract Firm Load.

PJM LMP = the final Real-Time Locational Marginal Price as defined and specified by PJM at the appropriate pricing node during the applicable hour(s).

CAT = the Commercial Activity Tax rate as established in Section 5751.03 of the Ohio Revised Code.

LAF = Loss Adjustment Factor
3.0% for primary voltages
0.1% for subtransmission voltages
0.0% for transmission voltages

Program Credit ("PC"):

Customers taking service under this Rider shall receive a monthly Program Credit which shall be calculated as follows:

PC = CL x ($5.00) /kW/month

Where:

CL is the Curtailable Load, which shall be calculated by the Company for each customer by subtracting the customer's contract Firm Load from its monthly highest thirty (30) minute integrated kW load occurring during the non-holiday weekday hours of 11 a.m. to 5 p.m. Eastern Standard Time (equivalent to noon to 6 p.m. EDT). In no circumstance can the CL be negative nor can the CL be in excess of a contract amount determined based upon the customers 12 month history as of February 1, 2008. Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

RIDER ELR
Economic Load Response Program Rider

Minimum Bill:

The application of the Program Credit shall not produce a total monthly bill for any customer, after including the effects of all rate schedules, riders, and if applicable, the CRES consolidated billing, that results in an average price per kWh less than two (2) cents per kWh.

OTHER PROVISIONS:

A. Firm Load

For purposes of this Rider, "Firm Load" shall be that portion of a customer's electric load that is not subject to curtailment. A customer may request a reduction to its contract Firm Load no more than once in any twelve month period. The Firm Load may be reduced to the extent that such reduction is consistent with other terms and conditions set forth in this Rider. Any such change in Firm Load shall be applied beginning with the customer's January bill immediately following the year in which the change has been approved by the Company, provided that advance written request is provided to the Company no less than thirty (30) days prior to the effective billing month of the change. The Company may increase the Firm Load at any time if the Company, at its sole discretion, determines the Firm Load is at a level that the customer fails to demonstrate that they can reach. The Company shall promptly notify the customer of any such change.

B. Load Response Program Contract

Customers taking service under this optional Rider shall execute the Company's standard Program contract which, among other things, will establish the Customer's Firm Load and commit the Customer's demand response capability to Company for purposes of Company's compliance with the peak demand reduction benchmarks set forth in R.C. § 4928.66 as applied by the Commission's applicable rules and regulations.

C. Metering

The customer must arrange for interval metering consistent with the Company's Miscellaneous Charges, Tariff Sheet 75.

RIDER ELR
Economic Load Response Program Rider

D. Emergency Curtailment Event

Upon advance notification provided by the Company, a customer taking service under this Rider must curtail all load above its Firm Load during an Emergency Curtailment Event consistent with the Company's instructions. For purposes of this Rider, an Emergency Curtailment Event shall be one in which the Company, a regional transmission organization and/or a transmission operator determines, in its respective sole discretion, that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area. PJM, which is the regional transmission organization of which the Company is a member, may also initiate an Emergency Curtailment Event upon their sole determination that a pre-emergency situation exists.

If an Emergency Curtailment Event is requested solely by the Company or a transmission operator, a customer will be given no less two hours advance notification to curtail all load above its Firm Load during the Emergency Curtailment Event. An Emergency Curtailment Event requested solely by the Company or a transmission operator may occur anytime during the year with no restrictions on the number of events or the duration of an event.

If the Emergency Curtailment Event is requested by PJM, a customer will be notified by the Company of the start time of the Emergency Curtailment Event as determined by PJM. The start time of the Emergency Curtailment Event will be approximately thirty (30) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. However, PJM at its sole discretion may grant a customer an exception to the thirty (30) minute advance notification time of either sixty (60) minutes or one hundred and twenty (120) minutes based on the customer's physical capability to provide load reduction. A customer wishing to seek such exception must submit to the Company a completed request form that the Company will then submit to PJM. If PJM approves the customer request for an exception for sixty (60) minutes, then the start time of any PJM-called Emergency Curtailment Events for that customer will be approximately sixty (60) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. If PJM approves the customer request for an exception for one hundred and twenty (120) minutes, then the start time of any PJM-called Emergency Curtailment Events for that customer will be approximately one hundred and twenty (120) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. The maximum duration that load must be curtailed when an Emergency Curtailment Event is called by PJM will be six (6) hours and shall be limited to ten events per planning year as defined by PJM and will only occur between 12:00 PM (Noon) to 8:00 PM (Eastern Prevailing Time) for the months of June through September on weekdays other than PJM Holidays.

RIDER ELR
Economic Load Response Program Rider

During the entire period of an Emergency Curtailment Event, the customer's actual measured load must remain at or below its Firm Load with such load being measured every clock half hour. A customer's actual measured load shall be determined using the greater of the customer's highest lagging kVA or highest kW during the Emergency Curtailment Event.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds its contract Firm Load, the Company may disconnect the customer from the transmission system for the duration of the Emergency Curtailment Event, at the customer's expense. The Company shall not be liable for any direct or indirect costs, losses, expenses, or other damages, special or otherwise, including, without limitation, lost profits that arise from such disconnection.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds 110% of its Firm Load, the customer shall be subject to all four (4) of the following: (i) forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred; (ii) pay the ECE Charge set forth in the Rates section of this Rider; (iii) pay the sum of all Program Credits received by the customer under the Program during the immediately preceding twelve billing months which shall include credits from this Rider and the Economic Development Rider; and (iv) the Company's right, at its sole discretion, to remove the customer from the Program for a minimum of 12 months.

If at any time during the Emergency Curtailment Event a customer's actual measured load is greater than 100% and less than or equal to 110% of its Firm Load during the Emergency Curtailment Event, the customer shall forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred and shall pay the ECE Charge set forth in the Rates section of this Rider.

In no event shall the penalties for non-performance listed above be less than PJM's non-performance penalties plus ECE charge for a non-performing customer during the Emergency Curtailment Event.

In a calendar year when an Emergency Curtailment Event has not been requested of customers by PJM on this Rider between June 1 and September 7, the Company shall simultaneously interrupt all customers on this Rider by September 30 in order to meet the Company's PJM test obligations for Load Management Resources. The duration of this test will be one hour. The Company will schedule the test and Customers shall receive advance notification of the test. All provisions of this Rider shall apply to this test.

In the event of any conflict between the terms and conditions set forth in this Rider and other service reliability requirements and/or obligations of the Company, the latter shall prevail.

RIDER ELR
Economic Load Response Program Rider

E. Notification

Emergency Curtailment Event notifications called by PJM will be stated such that customers must curtail their actual measured load to Firm Load prior to the start time of the Emergency Curtailment Event set forth in the PJM notification to the Company. Emergency Curtailment Event notifications called for either by the Company or a transmission operator will be stated such that customers must curtail actual measured load to Firm Load within two hours of the time the Company sends such notification to the customer. The Company will provide customers a notification of when Emergency Curtailment Events have ended. Receipt of notifications set out in this paragraph shall be the sole responsibility of the customer.

Notification of an Emergency Curtailment Event consists of an electronic message issued by the Company to a device or devices such as telephone, facsimile, pager or email, selected and provided by the customer and approved by the Company. Two-way information capability shall be incorporated by the Company and the customer in order to provide confirmation of receipt of notification messages. Operation, maintenance and functionality of such communication devices selected by the customer shall be the sole responsibility of the customer.

F. Term

This Rider shall become effective for service rendered beginning June 1, 2016, and shall expire with service rendered through May 31, 2024.

A customer may terminate its participation in the Program consistent with other terms and conditions to be effective June 1st, so long as the customer provides written notice to the Company no less than 38 months prior to the requested June 1st date upon which the requested termination would become effective. Except as otherwise provided in this Rider, a qualifying customer may return to the Program after a hiatus from the Program of at least one (1) year on the first day of the customer's billing cycle upon at least thirty days prior written notice of the customer's intent to return.

G. Conditions

Payment by the customer of all charges herein is a condition of service under this Economic Load Response Program Rider.

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RIDER ELR
Economic Load Response Program Rider

APPLICABILITY:

This Economic Load Response Program Rider ("Program") is available to customers taking service from the Company at primary voltages or higher voltages provided that all of the following seven conditions are met at the time of initiation of service to the customer under this Rider and on a continuing basis thereafter: (i) the customer took service under the Program as of May 31, 2016 or the customer was historically eligible for Rider ELR and provided written notice of intent to participate in the Program on or before May 31, 2015 for up to an additional 136,250 kW of Curtailable Load effective on or after June 1, 2016; (ii) the customer can successfully demonstrate to the Company that it can reduce its measured load to a pre-established contract Firm Load (as defined under Other Provisions, paragraph A., below) within two hours of notification provided by the Company without the need of a generator (A customer may intend to use a generator to reduce its usage to below its Firm Load, but if the generator does not operate, the customer must still reduce its usage to or below its Firm Load. Failure of a customer to reduce its usage to or below its Firm Load shall result in the consequences listed in the Emergency Curtailment Event Section herein.); (iii) the customer executes the Company's standard Program contract; (iv) the customer is taking generation service from the Company or a Competitive Retail Electric Service ("CRES") provider using consolidated billing; (v) the customer is not participating in any other load curtailment or demand response program, including without limitation a demand response program offered by PJM Interconnection, L.L.C. ("PJM") or any other independent system operator; (vi) the customer commits its demand response capability to Company for integration into Company's R.C. § 4928.66 compliance programs; and, (vii) the Commission finds that the demand response capabilities of customers electing service under this rider shall count towards the Company's compliance with the peak demand reduction benchmarks set forth in R.C. § 4928.66 as applied by the Commission's applicable rules and regulations and shall be considered incremental to interruptible load on the Company's system that existed in 2008. Nothing herein shall preclude a customer from requesting and receiving an exemption from any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs to the extent the exemption is requested to reasonably encourage the commitment of customer-sited capabilities to the Company.

RATES:

In addition to any other charges under any other rate schedules applicable to customer's service, customers participating in the Program shall also pay the charges and receive the credit set forth below:

Charges:

Program Administrative Charge: $150.00 per month

ECE Charge:

During an Emergency Curtailment Event (as defined under Other Provisions, paragraph D., below), the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any and all hours during such event shall be assessed an ECE Charge which is calculated for each hour of the event as follows. Revenue collected by the Company as a result of any ECE Charge less amounts associated with the Commercial Activity Tax ("CAT") (as defined below) shall be credited towards costs to be collected through the DSE1 charge of Rider DSE:

RIDER ELR
Economic Load Response Program Rider

ECE Charge = (AL x PJM LMP x 300%) x (1 + LAF) x ([1/(1-CAT)])

Where:

AL = the customer's actual hourly load during an Emergency Curtailment Event that exceeds the customer's pre-established contract Firm Load.

PJM LMP = the final Real-Time Locational Marginal Price as defined and specified by PJM at the appropriate pricing node during the applicable hour(s).

CAT = the Commercial Activity Tax rate as established in Section 5751.03 of the Ohio Revised Code.

LAF = Loss Adjustment Factor
3.0% for primary voltages
0.1% for subtransmission voltages
0.0% for transmission voltages

Program Credit ("PC"):

Customers taking service under this Rider shall receive a monthly Program Credit which shall be calculated as follows:

PC = CL x ($5.00) /kW/month

Where:

CL is the Curtailable Load, which shall be calculated by the Company for each customer by subtracting the customer's contract Firm Load from its monthly highest thirty (30) minute integrated kW load occurring during the non-holiday weekday hours of 11 a.m. to 5 p.m. Eastern Standard Time (equivalent to noon to 6 p.m. EDT). In no circumstance can the CL be negative nor can the CL be in excess of a contract amount determined based upon the customers 12 month history as of February 1, 2008. Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

RIDER ELR
Economic Load Response Program Rider

Minimum Bill:

The application of the Program Credit shall not produce a total monthly bill for any customer, after including the effects of all rate schedules, riders, and if applicable, the CRES consolidated billing, that results in an average price per kWh less than two (2) cents per kWh.

OTHER PROVISIONS:

A. Firm Load

For purposes of this Rider, "Firm Load" shall be that portion of a customer's electric load that is not subject to curtailment. A customer may request a reduction to its contract Firm Load no more than once in any twelve month period. The Firm Load may be reduced to the extent that such reduction is consistent with other terms and conditions set forth in this Rider. Any such change in Firm Load shall be applied beginning with the customer's January bill immediately following the year in which the change has been approved by the Company, provided that advance written request is provided to the Company no less than thirty (30) days prior to the effective billing month of the change. The Company may increase the Firm Load at any time if the Company, at its sole discretion, determines the Firm Load is at a level that the customer fails to demonstrate that they can reach. The Company shall promptly notify the customer of any such change.

B. Load Response Program Contract

Customers taking service under this optional Rider shall execute the Company's standard Program contract which, among other things, will establish the Customer's Firm Load and commit the Customer's demand response capability to Company for purposes of Company's compliance with the peak demand reduction benchmarks set forth in R.C. § 4928.66 as applied by the Commission's applicable rules and regulations.

C. Metering

The customer must arrange for interval metering consistent with the Company's Miscellaneous Charges, Tariff Sheet 75.

RIDER ELR
Economic Load Response Program Rider

D. Emergency Curtailment Event

Upon advance notification provided by the Company, a customer taking service under this Rider must curtail all load above its Firm Load during an Emergency Curtailment Event consistent with the Company's instructions. For purposes of this Rider, an Emergency Curtailment Event shall be one in which the Company, a regional transmission organization and/or a transmission operator determines, in its respective sole discretion, that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area. PJM, which is the regional transmission organization of which the Company is a member, may also initiate an Emergency Curtailment Event upon their sole determination that a pre-emergency situation exists.

If an Emergency Curtailment Event is requested solely by the Company or a transmission operator, a customer will be given no less two hours advance notification to curtail all load above its Firm Load during the Emergency Curtailment Event. An Emergency Curtailment Event requested solely by the Company or a transmission operator may occur anytime during the year with no restrictions on the number of events or the duration of an event.

If the Emergency Curtailment Event is requested by PJM, a customer will be notified by the Company of the start time of the Emergency Curtailment Event as determined by PJM. The start time of the Emergency Curtailment Event will be approximately thirty (30) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. However, PJM at its sole discretion may grant a customer an exception to the thirty (30) minute advance notification time of either sixty (60) minutes or one hundred and twenty (120) minutes based on the customer's physical capability to provide load reduction. A customer wishing to seek such exception must submit to the Company a completed request form that the Company will then submit to PJM. If PJM approves the customer request for an exception for sixty (60) minutes, then the start time of any PJM-called Emergency Curtailment Events for that customer will be approximately sixty (60) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. If PJM approves the customer request for an exception for one hundred and twenty (120) minutes, then the start time of any PJM-called Emergency Curtailment Events for that customer will be approximately one hundred and twenty (120) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. The maximum duration that load must be curtailed when an Emergency Curtailment Event is called by PJM will be six (6) hours and shall be limited to ten events per planning year as defined by PJM and will only occur between 12:00 PM (Noon) to 8:00 PM (Eastern Prevailing Time) for the months of June through September on weekdays other than PJM Holidays.

RIDER ELR
Economic Load Response Program Rider

During the entire period of an Emergency Curtailment Event, the customer's actual measured load must remain at or below its Firm Load with such load being measured every clock half hour. A customer's actual measured load shall be determined using the greater of the customer's highest lagging kVA or highest kW during the Emergency Curtailment Event.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds its contract Firm Load, the Company may disconnect the customer from the transmission system for the duration of the Emergency Curtailment Event, at the customer's expense. The Company shall not be liable for any direct or indirect costs, losses, expenses, or other damages, special or otherwise, including, without limitation, lost profits that arise from such disconnection.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds 110% of its Firm Load, the customer shall be subject to all four (4) of the following: (i) forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred; (ii) pay the ECE Charge set forth in the Rates section of this Rider; (iii) pay the sum of all Program Credits received by the customer under the Program during the immediately preceding twelve billing months which shall include credits from this Rider and the Economic Development Rider; and (iv) the Company's right, at its sole discretion, to remove the customer from the Program for a minimum of 12 months.

If at any time during the Emergency Curtailment Event a customer's actual measured load is greater than 100% and less than or equal to 110% of its Firm Load during the Emergency Curtailment Event, the customer shall forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred and shall pay the ECE Charge set forth in the Rates section of this Rider.

In no event shall the penalties for non-performance listed above be less than PJM's non-performance penalties plus ECE charge for a non-performing customer during the Emergency Curtailment Event.

In a calendar year when an Emergency Curtailment Event has not been requested of customers by PJM on this Rider between June 1 and September 7, the Company shall simultaneously interrupt all customers on this Rider by September 30 in order to meet the Company's PJM test obligations for Load Management Resources. The duration of this test will be one hour. The Company will schedule the test and Customers shall receive advance notification of the test. All provisions of this Rider shall apply to this test.

In the event of any conflict between the terms and conditions set forth in this Rider and other service reliability requirements and/or obligations of the Company, the latter shall prevail.

RIDER ELR
Economic Load Response Program Rider

E. Notification

Emergency Curtailment Event notifications called by PJM will be stated such that customers must curtail their actual measured load to Firm Load prior to the start time of the Emergency Curtailment Event set forth in the PJM notification to the Company. Emergency Curtailment Event notifications called for either by the Company or a transmission operator will be stated such that customers must curtail actual measured load to Firm Load within two hours of the time the Company sends such notification to the customer. The Company will provide customers a notification of when Emergency Curtailment Events have ended. Receipt of notifications set out in this paragraph shall be the sole responsibility of the customer.

Notification of an Emergency Curtailment Event consists of an electronic message issued by the Company to a device or devices such as telephone, facsimile, pager or email, selected and provided by the customer and approved by the Company. Two-way information capability shall be incorporated by the Company and the customer in order to provide confirmation of receipt of notification messages. Operation, maintenance and functionality of such communication devices selected by the customer shall be the sole responsibility of the customer.

F. Term

This Rider shall become effective for service rendered beginning June 1, 2016, and shall expire with service rendered through May 31, 2024.

A customer may terminate its participation in the Program consistent with other terms and conditions to be effective June 1st. so long as the customer provides written notice to the Company no less than 38 months prior to the requested June 1st date upon which the requested termination would become effective. Except as otherwise provided in this Rider, a qualifying customer may return to the Program after a hiatus from the Program of at least one (1) year on the first day of the customer's billing cycle upon at least thirty days prior written notice of the customer's intent to return.

G. Conditions

Payment by the customer of all charges herein is a condition of service under this Economic Load Response Program Rider.

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RIDER ELR
Economic Load Response Program Rider

APPLICABILITY:

This Economic Load Response Program Rider ("Program") is available to customers taking service from the Company at primary voltages or higher voltages provided that all of the following seven conditions are met at the time of initiation of service to the customer under this Rider and on a continuing basis thereafter: (i) the customer took service under the Program as of May 31, 2016 or the customer was historically eligible for Rider ELR and provided written notice of intent to participate in the Program on or before May 31, 2015 for up to an additional 136,250 kW of Curtailable Load effective on or after June 1, 2016; (ii) the customer can successfully demonstrate to the Company that it can reduce its measured load to a pre-established contract Firm Load (as defined under Other Provisions, paragraph A., below) within two hours of notification provided by the Company without the need of a generator (A customer may intend to use a generator to reduce its usage to below its Firm Load, but if the generator does not operate, the customer must still reduce its usage to or below its Firm Load. Failure of a customer to reduce its usage to or below its Firm Load shall result in the consequences listed in the Emergency Curtailment Event Section herein.); (iii) the customer executes the Company's standard Program contract; (iv) the customer is taking generation service from the Company or a Competitive Retail Electric Service ("CRES") provider using consolidated billing; (v) the customer is not participating in any other load curtailment or demand response program, including without limitation a demand response program offered by PJM Interconnection, L.L.C. ("PJM") or any other independent system operator; (vi) the customer commits its demand response capability to Company for integration into Company's R.C. § 4928.66 compliance programs; and, (vii) the Commission finds that the demand response capabilities of customers electing service under this rider shall count towards the Company's compliance with the peak demand reduction benchmarks set forth in R.C. § 4928.66 as applied by the Commission's applicable rules and regulations and shall be considered incremental to interruptible load on the Company's system that existed in 2008. Nothing herein shall preclude a customer from requesting and receiving an exemption from any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs to the extent the exemption is requested to reasonably encourage the commitment of customer-sited capabilities to the Company.

RATES:

In addition to any other charges under any other rate schedules applicable to customer's service, customers participating in the Program shall also pay the charges and receive the credit set forth below:

Charges:

Program Administrative Charge: $150.00 per month

ECE Charge:

During an Emergency Curtailment Event (as defined under Other Provisions, paragraph D., below), the portion of the customer's actual measured load that exceeds its pre-established contract Firm Load for any and all hours during such event shall be assessed an ECE Charge which is calculated for each hour of the event as follows. Revenue collected by the Company as a result of any ECE Charge less amounts associated with the Commercial Activity Tax ("CAT") (as defined below) shall be credited towards costs to be collected through the DSE1 charge of Rider DSE:

RIDER ELR
Economic Load Response Program Rider

ECE Charge = (AL x PJM LMP x 300%) x (1 + LAF) x ([1/(1-CAT)])

Where:

AL = the customer's actual hourly load during an Emergency Curtailment Event that exceeds the customer's pre-established contract Firm Load.

PJM LMP = the final Real-Time Locational Marginal Price as defined and specified by PJM at the appropriate pricing node during the applicable hour(s).

CAT = the Commercial Activity Tax rate as established in Section 5751.03 of the Ohio Revised Code.

LAF = Loss Adjustment Factor
3.0% for primary voltages
0.1% for subtransmission voltages
0.0% for transmission voltages

Program Credit ("PC"):

Customers taking service under this Rider shall receive a monthly Program Credit which shall be calculated as follows:

PC = CL x ($5.00) /kW/month

Where:

CL is the Curtailable Load, which shall be calculated by the Company for each customer by subtracting the customer's contract Firm Load from its monthly highest thirty (30) minute integrated kW load occurring during the non-holiday weekday hours of 11 a.m. to 5 p.m. Eastern Standard Time (equivalent to noon to 6 p.m. EDT). In no circumstance can the CL be negative nor can the CL be in excess of a contract amount determined based upon the customers 12 month history as of February 1, 2008. Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

RIDER ELR
Economic Load Response Program Rider

Minimum Bill:

The application of the Program Credit shall not produce a total monthly bill for any customer, after including the effects of all rate schedules, riders, and if applicable, the CRES consolidated billing, that results in an average price per kWh less than two (2) cents per kWh.

OTHER PROVISIONS:

A. Firm Load

For purposes of this Rider, "Firm Load" shall be that portion of a customer's electric load that is not subject to curtailment. A customer may request a reduction to its contract Firm Load no more than once in any twelve month period. The Firm Load may be reduced to the extent that such reduction is consistent with other terms and conditions set forth in this Rider. Any such change in Firm Load shall be applied beginning with the customer's January bill immediately following the year in which the change has been approved by the Company, provided that advance written request is provided to the Company no less than thirty (30) days prior to the effective billing month of the change. The Company may increase the Firm Load at any time if the Company, at its sole discretion, determines the Firm Load is at a level that the customer fails to demonstrate that they can reach. The Company shall promptly notify the customer of any such change.

B. Load Response Program Contract

Customers taking service under this optional Rider shall execute the Company's standard Program contract which, among other things, will establish the Customer's Firm Load and commit the Customer's demand response capability to Company for purposes of Company's compliance with the peak demand reduction benchmarks set forth in R.C. § 4928.66 as applied by the Commission's applicable rules and regulations.

C. Metering

The customer must arrange for interval metering consistent with the Company's Miscellaneous Charges, Tariff Sheet 75.

RIDER ELR
Economic Load Response Program Rider

D. Emergency Curtailment Event

Upon advance notification provided by the Company, a customer taking service under this Rider must curtail all load above its Firm Load during an Emergency Curtailment Event consistent with the Company's instructions. For purposes of this Rider, an Emergency Curtailment Event shall be one in which the Company, a regional transmission organization and/or a transmission operator determines, in its respective sole discretion, that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area. PJM, which is the regional transmission organization of which the Company is a member, may also initiate an Emergency Curtailment Event upon their sole determination that a pre-emergency situation exists.

If an Emergency Curtailment Event is requested solely by the Company or a transmission operator, a customer will be given no less two hours advance notification to curtail all load above its Firm Load during the Emergency Curtailment Event. An Emergency Curtailment Event requested solely by the Company or a transmission operator may occur anytime during the year with no restrictions on the number of events or the duration of an event.

If the Emergency Curtailment Event is requested by PJM, a customer will be notified by the Company of the start time of the Emergency Curtailment Event as determined by PJM. The start time of the Emergency Curtailment Event will be approximately thirty (30) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. However, PJM at its sole discretion may grant a customer an exception to the thirty (30) minute advance notification time of either sixty (60) minutes or one hundred and twenty (120) minutes based on the customer's physical capability to provide load reduction. A customer wishing to seek such exception must submit to the Company a completed request form that the Company will then submit to PJM. If PJM approves the customer request for an exception for sixty (60) minutes, then the start time of any PJM-called Emergency Curtailment Events for that customer will be approximately sixty (60) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. If PJM approves the customer request for an exception for one hundred and twenty (120) minutes, then the start time of any PJM-called Emergency Curtailment Events for that customer will be approximately one hundred and twenty (120) minutes from the time the Company receives notification from PJM of the Emergency Curtailment Event. The maximum duration that load must be curtailed when an Emergency Curtailment Event is called by PJM will be six (6) hours and shall be limited to ten events per planning year as defined by PJM and will only occur between 12:00 PM (Noon) to 8:00 PM (Eastern Prevailing Time) for the months of June through September on weekdays other than PJM Holidays.

RIDER ELR
Economic Load Response Program Rider

During the entire period of an Emergency Curtailment Event, the customer's actual measured load must remain at or below its Firm Load with such load being measured every clock half hour. A customer's actual measured load shall be determined using the greater of the customer's highest lagging kVA or highest kW during the Emergency Curtailment Event.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds its contract Firm Load, the Company may disconnect the customer from the transmission system for the duration of the Emergency Curtailment Event, at the customer's expense. The Company shall not be liable for any direct or indirect costs, losses, expenses, or other damages, special or otherwise, including, without limitation, lost profits that arise from such disconnection.

If at any time during the Emergency Curtailment Event a customer's actual measured load exceeds 110% of its Firm Load, the customer shall be subject to all four (4) of the following: (i) forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred; (ii) pay the ECE Charge set forth in the Rates section of this Rider; (iii) pay the sum of all Program Credits received by the customer under the Program during the immediately preceding twelve billing months which shall include credits from this Rider and the Economic Development Rider; and (iv) the Company's right, at its sole discretion, to remove the customer from the Program for a minimum of 12 months.

If at any time during the Emergency Curtailment Event a customer's actual measured load is greater than 100% and less than or equal to 110% of its Firm Load during the Emergency Curtailment Event, the customer shall forfeit its Program Credit for the month in which the Emergency Curtailment Event occurred and shall pay the ECE Charge set forth in the Rates section of this Rider.

In no event shall the penalties for non-performance listed above be less than PJM's non-performance penalties plus ECE charge for a non-performing customer during the Emergency Curtailment Event.

In a calendar year when an Emergency Curtailment Event has not been requested of customers by PJM on this Rider between June 1 and September 7, the Company shall simultaneously interrupt all customers on this Rider by September 30 in order to meet the Company's PJM test obligations for Load Management Resources. The duration of this test will be one hour. The Company will schedule the test and Customers shall receive advance notification of the test. All provisions of this Rider shall apply to this test.

In the event of any conflict between the terms and conditions set forth in this Rider and other service reliability requirements and/or obligations of the Company, the latter shall prevail.

RIDER ELR
Economic Load Response Program Rider

E. Notification

Emergency Curtailment Event notifications called by PJM will be stated such that customers must curtail their actual measured load to Firm Load prior to the start time of the Emergency Curtailment Event set forth in the PJM notification to the Company. Emergency Curtailment Event notifications called for either by the Company or a transmission operator will be stated such that customers must curtail actual measured load to Firm Load within two hours of the time the Company sends such notification to the customer. The Company will provide customers a notification of when Emergency Curtailment Events have ended. Receipt of notifications set out in this paragraph shall be the sole responsibility of the customer.

Notification of an Emergency Curtailment Event consists of an electronic message issued by the Company to a device or devices such as telephone, facsimile, pager or email, selected and provided by the customer and approved by the Company. Two-way information capability shall be incorporated by the Company and the customer in order to provide confirmation of receipt of notification messages. Operation, maintenance and functionality of such communication devices selected by the customer shall be the sole responsibility of the customer.

F. Term

This Rider shall become effective for service rendered beginning June 1, 2016, and shall expire with service rendered through May 31, 2024.

A customer may terminate its participation in the Program consistent with other terms and conditions to be effective June 1st, so long as the customer provides written notice to the Company no less than 38 months prior to the requested June 1st date upon which the requested termination would become effective. Except as otherwise provided in this Rider, a qualifying customer may return to the Program after a hiatus from the Program of at least one (1) year on the first day of the customer's billing cycle upon at least thirty days prior written notice of the customer's intent to return.

G. Conditions

Payment by the customer of all charges herein is a condition of service under this Economic Load Response Program Rider.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

17. Referring to page 15, lines 8-10, please provide all analysis, workpapers, reports, or other documents prepared by or reviewed by Dr. Goins that assess the potential customer impacts of the Companies' CSR Rider proposals.

RESPONSE:

Please see the attachment to this response. Also, see KIUC's response to KU's and LG&E's request 1-8(a).

KWalton

KIUC Response_KU & LGE 1-17_attachment.pdf
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KIUC Response to KU/LG&E 1-17
Attachment KIUC 1-17

KIUC Customer Bill Impacts with KU/LGE Proposed CSR Reductions

		Annual Cost ($000)*		Change	
Customer	**Utility**	**Current**	**Proposed**	**Cost**	**Percent**
NAS	KU	$ 50,875	$ 62,474	$ 11,599	22.80%
Alliance Coal	KU	**	**	**	**
Carbide	LGE	$ 11,683	$ 13,766	$ 2,082	17.82%
Cemex	LGE	$ 10,720	$ 12,432	$ 1,712	15.97%
Total		$ 73,278	$ 88,672	$ 15,393	21.01%

* Reflects 12 months ending August 2016
** Alliance not on CSR for full 12 months

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00370**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'S RESPONSE TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S INITIAL REQUEST FOR INFORMATION

18. Given that the Companies are filing a forward test year case, should they consider the most current load forecast information in developing their rates, including the CSR Rider?

RESPONSE:

Rates for KU's and LG&E's customers should reflect each company's cost-of-service for the relevant test year approved by the KPSC. The CSR credits should be based on the long-run avoided cost of peaking capacity.

COMMONWEALTH OF KENTUCKY

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ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)	**CASE NO. 2016-00371**

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19. Referring to page 17, lines 15-24:

a. What is Dr. Goins' definition of off-peak?

b. Please provide any analysis, reports, workpapers, etc. that support Dr. Goins' statement that "baseload capacity is typically used to serve off-peak loads."

c. What is Dr. Goins' definition of "baseload capacity?"

d. Please provide any reports, analysis, workpapers, etc. that Dr. Goins relied upon to conclude that "off-peak demands do not drive a utility's need for capacity."

RESPONSE:

a. Off-peak typically refers to all hours not considered peak hours when capacity may be constrained due to high demand.

b. Baseload capacity is usually defined as large-scale generating units designed to operate during most hours of the year. In contrast, peaking capacity is usually defined as smaller-scale generating units designed to operate primarily during limited peak hours or emergency conditions.

c. See the response to request 1-19(b) above.

d. Basic economics and capacity planning fundamentals demonstrate that utilities plan to buy or acquire capacity resources sufficient to meet peak demand. If a supplier planned only to have enough capacity to meet off-peak demands, the supplier would find itself short of capacity during peak hours when demands are highest.

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20. Referring to page 19, lines 9-16 and lines 18-24, please provide all workpapers, analysis, reports prepared by Dr. Goins related to the bill impact assessment for KIUC's CSR customers.

a. Did these analyses include any review of the financial viability, national or international competitiveness implications, or job impact of the proposed CSR Rider changes on these customers? If so, please provide all reports, studies, analysis, workpaper, etc.

b. Please provide all reports, studies, analyses, and workpapers, supporting Dr. Goins' statement regarding the "potential harmful effects of its proposals on business development and job retention in Kentucky."

RESPONSE:

Please see KIUC's responses to KU's and LG&E's requests 1-8(a) and 1-17.

a. Please see KIUC's response to KU's and LG&E's request 1-8(a).

b. Please see KIUC's response to KU's and LG&E's request 1-8(a).

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21. Referring to page 21, lines 15-17, is there a minimum number of years that CSR Rider credits should be in effect before they can be changed? Please provide all analysis, reports, studies, workpapers, etc. that support this conclusion.

RESPONSE:

No. However, any changes should only be made when empirical evidence clearly demonstrates that changes are justified, and after consultation with key stakeholders—in particular, CSR customers and the Commission. In general, justifiable changes in the CSR credits could be driven by a variety of factors, including but not limited to changes in KU's and LG&E's long-run avoided cost of peaking capacity, the relative relationship of long-run avoided capacity costs to the companies' embedded cost of capacity reflected in base rates, the types of interruptible service options offered, and changes in the terms under which interruptible service is provided (for example, hour of physical curtailments, notice requirements, and curtailment frequency and duration). Such factors could be explored in the post-rate case stakeholder assessment of interruptible service that Dr. Goins recommends in his testimony.

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22. Referring to page 25, lines 13-15, please provide all studies, analyses, reports, workpapers, etc. that show the impact of the Companies' proposed CSR Rider changes on the competitiveness of CSR customers and the attractiveness of Kentucky's business environment.

RESPONSE:

Please see KIUC's responses to KU's and LG&E's requests 1-8(a), 1-15, 1-17, and 1-20.

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23. Provide a copy of all notes, data, and workpapers prepared by, or on behalf of, Mr. Kollen in connection with this proceeding, including workpapers used to generate any and all tables and exhibits. Include all notes, workpapers, and data used to make your recommend revenue requirement adjustments. If any Excel spreadsheets or other computer generated documents were prepared by or on behalf of Mr. Kollen, please provide an electronic version of those documents with all formulas intact.

RESPONSE:

Mr. Kollen previously filed his workpapers in Excel format along with his testimony and exhibits. Mr. Kollen relied on the Company's filing and responses to discovery in this proceeding in support of his adjustments. The discovery responses he relied on are cited in his testimony and provided as exhibits.

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24. Refer to page 20, line 9 of Mr. Kollen's testimony regarding the cycled approach to vegetation management. Please describe and produce all empirical support, objective evidence, studies, or analyses serving as the basis for Mr. Kollen's assertion that "the proposed change in approach does not inherently require additional maintenance expense."

RESPONSE:

The scope and cost of vegetation management is a controllable cost. The Companies are free to change from a targeted to a cycled approach at any time and can do so without Commission authorization. This does not require additional maintenance expense at the onset or over time. The Companies propose initial increases for several years, which they assert will be offset through reductions in subsequent years, although they offer no commitments that the costs will be revenue neutral. Mr. Kollen does not believe that any empirical studies are necessary to determine that a change in approach does not inherently require additional maintenance expense. If the Companies are correct, then they should not change their approach. Mr. Kollen further notes that the studies provided by the Companies in response to discovery do not provide empirical support for the change in approach, but rather seek to quantify the cost under a series of assumptions with respect to the cycled approach. The primary assumptions are that the Companies will substantially increase the scope of vegetation management over the next several years. If those same assumptions were applied to the targeted approach, costs also would increase over the next several years, likely by the same magnitude.

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25. Is Mr. Kollen a Certified Depreciation Professional?

RESPONSE:

No. Mr. Kollen is a member of the Society of Depreciation Professionals as well as other professional organizations.

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26. Please provide a list of each course, training or seminar Mr. Kollen has attended related specifically to utility depreciation.

RESPONSE:

None.

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27. Has Mr. Kollen ever recommended depreciation rates or dismantlement accruals that include terminal net salvage estimates? If the response is yes, please provide the docket number of each case in which Mr. Kollen recommended depreciation rates or dismantlement accruals that included terminal net salvage estimates.

RESPONSE:

To the best of his recollections, Mr. Kollen reviewed and/or addressed terminal net salvage and dismantlement accruals in numerous proceedings as follows:

LPSC Docket No. U-22092

GPSC Docket No. 14311-U

KPSC Case No. 2003-00433

KPSC Case No. 2003-00434

KPSC Case No. 2005-00341

FERC Docket No. ER07-956

KPSC Case Nos. 2007-00564, 2008-00251

KPSC Case Nos. 2007-00565, 2008-00252

FERC Docket No. ER08-1056

FPSC Docket No. 080677-EI

WPSC Docket No. 05-UR-104

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KPSC Case No. 2009-00329

FERC Docket No. EL10-55

FERC Docket No. ER10-2001

FERC Docket No. ER11-2161

LPSC Docket No. U-23327

WPSC Docket No. 4220-UR-117

KPSC Case No. 2011-00036

PUCT Docket No. 40020

KPSC Case No. 2012-00221

KPSC Case No. 2012-00222

PUCT Docket No. 40604

PUCT Docket No. 40443

WVPSC Case No. 14-0702-E-42T

PSCC Docket No. 14AL-0660E

WVPSC Case No. 14-1152-E-42T

KPSC Case No. 2014-00396

KPSC Case No. 2014-00371

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KPSC Case No. 2014-00372

FERC Docket No. EL01-88

PUCNY Docket No. 16-G-058

PUCNY Docket No. 16-G-059

FPSC Case No. 160021-EI

KPSC Case No. 2016-00162

PUCT Docket No. 45414

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In the Matter of:

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AFFIDAVIT

STATE OF NC)
COUNTY OF Surry)

Richard A. Baudino, being duly sworn, deposes and states: that the attached are his sworn data responses and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Subscribed and sworn to or affirmed before me this 29th day of March, 2017.

Laura C. East
Notary Public

my comm. expires: 4.9.18

LAURA C. EAST NOTARY PUBLIC SURRY COUNTY, NC

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00371**

AFFIDAVIT

STATE OF Georgia)
COUNTY OF Fulton)

Lane Kollen, being duly sworn, deposes and states: that the attached are his sworn data responses and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Subscribed and sworn to or affirmed before me
this 31st day of March, 2017.

Jessica K. Inman

Notary Public

JESSICA K INMAN
NOTARY PUBLIC
CHEROKEE COUNTY, GEORGIA
MY COMMISSION EXPIRES
JULY 31, 2019

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00371**

AFFIDAVIT

STATE OF Georgia)
COUNTY OF Fulton)

Stephen J. Baron, being duly sworn, deposes and states: that the attached are his sworn data responses and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Subscribed and sworn to or affirmed before me
this 31st day of March, 2017.

Notary Public

JESSICA K INMAN
NOTARY PUBLIC
MY COMMISSION EXPIRES
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NOS.**
OF BASE RATES	)	**2016-00371**

AFFIDAVIT

COMMONWEALTH OF VIRGINIA)
COUNTY OF FAIRFAX)

Dennis Goins, being duly sworn, deposes and states: that the attached are his sworn data responses and that the statements contained are true and correct to the best of his knowledge, information, and belief.

Dennis W. Goins

Subscribed and sworn to or affirmed before me
this 27th day of March, 2017.

Notary Public

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

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT	)	**CASE NOS.**
OF BASE RATES	)	**2016-00370**

AFFIDAVIT

COMMONWEALTH OF VIRGINIA)
COUNTY OF FAIRFAX)

Dennis Goins, being duly sworn, deposes and states: that the attached are his sworn data responses and that the statements contained are true and correct to the best of his knowledge, information, and belief.

Dennis W. Goins

Subscribed and sworn to or affirmed before me
this 27th day of March, 2017.

Notary Public

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