COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2016-00370

AND

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)))	CASE NO. 2016-00371

SUPPLEMENTAL TESTIMONY AND EXHIBITS OF STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 2017

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SUPPLEMENTAL TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed Direct Testimony.

Q. What is the purpose of your Supplemental Testimony?

A. I am responding to the Companies' Supplemental Responses to Commission Staff First Request for Information Question No. 53 (LG&E, KU), Question No. 97 (KU) and Question No. 109 (LG&E) in which the Companies presented revised hourly load analyses and class cost of service studies. The revised studies and analyses were developed in response to the errors that I identified and discussed in my Direct Testimony associated with the Companies' future test year hourly load projections.

I will explain why I continue to believe that there are problems with the analyses that result in inaccurate hourly load projections for the future test year, and therefore unreliable class cost of service studies. Notwithstanding these continuing problems, I will also present an alternative class cost of service study for each Company using a 5 coincident peak methodology.

Also, I describe how the one customer on KU Rate FLS (North American Stainless) was physically interrupted 43 times in 2015 and 26 times in 2016. These physical interruptions are for up to 95% of the NAS load. According to the FLS tariff, KU interrupts NAS to facilitate compliance with system contingencies and industry performance criteria when there are unplanned generation outages, de-rates of generating units or when Automatic Reserve Sharing is invoked. These physical interruptions are in addition to the curtailment provisions of the CSR Rider. The cost of service studies relied on by the Companies did not factor in the system-wide benefits provided by using the NAS load as a system generation resource. Nor did the Companies' cost-of-service studies consider that service under rate FLS is of inferior quality since it is subject to constant and frequent physical interruptions.

Based on the above, I continue to recommend that the overall revenue increase in this case be apportioned to rate classes on a uniform percentage basis.

Q. Have you reviewed the corrections and modifications that the Companies' have made in their hourly load projections?

A. Yes. In supplemental data responses, the Companies have acknowledged that their originally filed hourly load projections were erroneous. This caused the demand allocations factors used in both the BIP and LOLP class cost of service studies to be incorrect, resulting in turn in erroneous cost of service study results. The Companies have addressed the re-ordering errors that I discussed in my Direct Testimony and have corrected these errors. KU has also attempted to improve its hourly load projections for Rate FLS, to correct what I believe were significant problems with the methodology itself (beyond the re-ordering error that I addressed).

Q. Do you believe that the Companies' revised, corrected hourly load projections are reasonable?

A. No. While the re-ordering errors have been corrected, the Companies' fundamental methodology is continuing to produce what I believe are unreliable results.

Q. Would you explain the fundamental problem with Companies' load forecasting methodology?

A. The Companies' methodology begins with 8,760 of actual hourly load data for an historic period, the 12 months ending June 2016. This historic hourly load data is comprised of actual metered data for Rates FLS (KU) and RTS (KU and LG&E), a combination of actual metered data for Rate TOD Primary (KU and LG&E) and sample load research data for the remaining classes. The forecast process is designed to adjust this historic hourly data for each of the Companies' twelve rate classes to the future test year, the period 12 months ending June 2018. To extrapolate the historic data two years into the future, the Companies used a series of energy based adjustments and reconciliations to another forecast, the so-called Energy Management System ("EMS") forecast. The EMS forecast is a system level (not rate class level) forecast of hourly system loads. In sum, the estimated 8,760 hourly loads for each of the twelve rate schedules for the future test year is a forecast built upon a forecast.

The complexity of this process is undoubtedly one reason why the significant errors I originally identified went undetected by the Companies. But the fundamental problem with the data still exists. Using a forecast built upon a forecast to predict 8,760 of hourly load data for twelve rate schedules two years into the future is inherently unreliable.

Q. Is there a particular problem with KU's Rate FLS?

A. Yes. Unlike other rate classes, the hourly loads for FLS are a direct function of the manufacturing process (i.e., electric consuming equipment) of a single customer. Unless there is a change in the connected load of this customer, or in the manufacturing process, the load of this customer would not change from the historic to the forecasted period. While the intensity of use of the manufacturing equipment can change, for example, because additional hours of operation are added or reduced due to business conditions, the maximum hourly kW demand in a month would not change. KU's methodology ignores the fundamental relationship between kW demand and kWh energy usage, resulting in erroneous results.

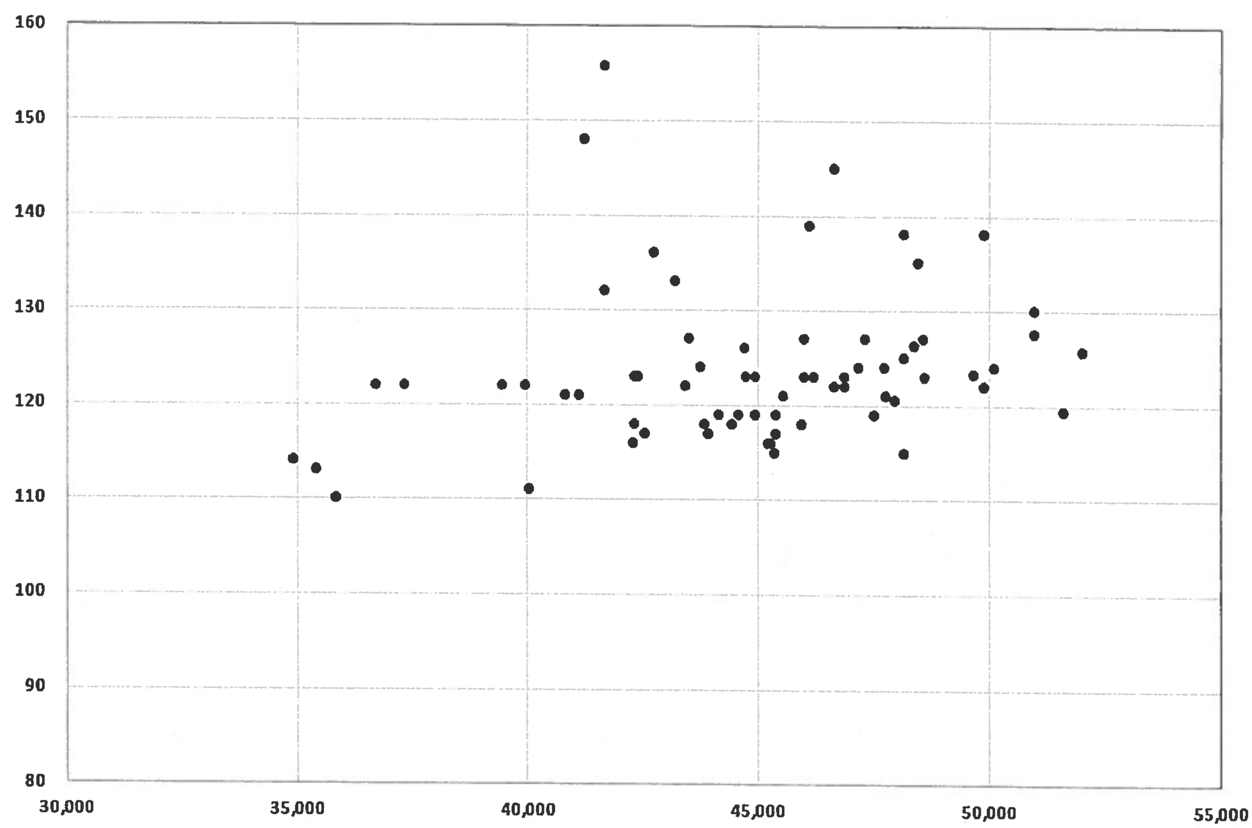
Q. Can you demonstrate the continuing problem with KU's revised and corrected FLS hourly load forecast?

A. Yes. The Companies' methodology essentially increased hourly loads of a rate class by the percentage change in the projected energy usage for the same month in the forecasted period vs. the historic actual period. While this methodology might be appropriate for a broadly diversified rate class with thousands or hundreds of thousands of customers (for example, the residential class), it does not work with a rate class such as FLS with a single customer or even a rate class with a relatively few very large customers like the RTS rate class.

Q. Have you analyzed the FLS demand and energy data to confirm that your conclusion is correct?

A. Yes. Figure 1 below is a chart that plots the relationship between monthly peak demand and monthly energy use for Rate FLS over the 67 month period July 2011 through February 2017. The vertical axis of the chart is maximum hourly mW demand in the month and the horizontal axis is monthly mWh energy usage.

Figure 1
FLS Monthly Energy vs. Peak Demand
July 2011 - February 2017



This chart shows that there is no relationship between monthly kW demand and monthly energy use for the single FLS customer. Most of the demands fall into a relatively tight band around 120 mW, while monthly energy usage varies quite extensively. This is exactly that type of relationship that would be expected if the physical equipment (Electric Arc Furnaces, in the case of NAS) remained relatively constant in terms of connected load and operating protocols.

Q. Why does this confirm that the Companies' hourly load forecast methodology continues to produce erroneous results, at least for KU's Rate FLS?

A. One of the major steps in the Companies' methodology is to adjust the historic period (July 2015 – June 2016) hourly loads each month by the percentage change in monthly energy usage between the forecasted test year (July 2017 – June 2018) and the same month in the historic period. This same methodology continues to be used by KU in its revised/corrected hourly load projection. As I showed using the data analyzed in Figure 1, this type of energy adjustment applied to actual FLS kW demands leads to overstated hourly demands for the test year.

For example, in KU's original FLS forecast, the Company projected a maximum kW demand for FLS of 196,844 kW in the future test year, compared to a maximum kW demand of 147,700 kW during the historic, actual period.[1] In its revised/corrected analysis, KU is now projecting a maximum demand of 164,000 kW, which is still 11% greater than the maximum demand for the historic period. Because nothing in the NAS manufacturing process will change from the historic to future test year, there is no reasonable basis to assume that the customer's demand will grow by 16,300 kW (11%).

Q. Does this mean that at least for KU the revised class cost of service studies continue to be unreliable?

A. Yes. If the demand allocation factors for FLS are incorrect, then the allocation factors for all of the rate classes are also incorrect because the summation of these allocation factors must equal 100%.

[1] This maximum demand occurred in November 2015, as shown in Table 1 of my Direct Testimony.

Q. Notwithstanding your continuing concerns about the Companies' revised, corrected hourly load data projections, have you developed any alternative class cost of service studies using the Companies' revised hourly load data?

A. Yes. As I discussed in my Direct Testimony, there are a number of methodological problems with both the Companies' BIP and LOLP class cost of service studies (beyond the use of erroneous demand allocation factors that has been addressed in the Companies' revised studies) that call into question the reasonableness of either of these methodologies as a basis to measure rate class cost responsibility.

In a number of prior LG&E and KU rate classes, I have presented alternative class cost of service studies. Using the Companies' revised load data presented in their Supplement Responses to Staff 1-53, I have developed an alternative cost of service study that I believe represents a reasonable alternative to the Companies' revised BIP and LOLP cost studies.

Q. Would you describe the alternative methodology that you have used to measure rate class cost responsibility in these rate cases?

A. Yes. I have developed a cost of service study for each Company using a 5 Coincident Peak ("5 CP") methodology. This methodology is considered a coincident peak methodology and is discussed and recognized in the NARUC Electric Utility Cost Allocation Manual ("The Average Seasonal Coincident Peak Method," page 78).[2] Baron Supplemental Testimony Exhibit__(SJB-1) contains page 78 from the NARUC Manual.

[2] The NARUC manual was discussed in my Direct Testimony.

Q. Would you describe the 5 CP methodology?

A. The 5 CP method is based on each rate class's contribution to the 5 highest monthly System peaks. The PJM RTO uses a 5 CP method based on the 5 highest hourly peaks to allocate generation costs to its members, which include East Kentucky Power Cooperative, Kentucky Power and Duke Kentucky. Since PJM is the country's largest RTO, a version of the 5 CP method is probably the country's most widely used generation cost allocation methodology.

During the test year in this case, these 5 highest monthly peaks occurred during the months of June, July, August, September and January (4 summer months, 1 winter month). The 5 CP method recognizes the importance of meeting System peak loads in the allocation of each Companies' generation and transmission demand costs to rate classes. The fixed costs associated with generation resources and transmission plant are incurred to meet the System's peak loads. On a combined basis, which is used for joint planning by both of the Companies, the System peaks during the summer months. As I discussed in my Direct Testimony on page 30, the Companies' most recent Integrated Resource Plan ("IRP") shows that the combined System is planned to the meet summer peak demand, while also recognizing the importance of the winter peak.

Q. What are the results of your alternative class cost of service studies?

A. Baron Supplemental Testimony Exhibits__(SJB-2) and (SJB-3) present the summary results for KU and LG&E using the 5 CP methodology. Table 1 below summarizes the rates of return for the 5 CP study, as well as the Companies' revised BIP and LOLP studies for KU. Table 2 presents similar results for LG&E.

Table 1
Kentucky Utilities
Summary of Class Cost of Service Results

		KU Revised BIP	KU Revised LOLP	Average 5 Monthly CP
Residential	Rate RS	3.83%	3.96%	3.82%
General Service	GS	9.20%	9.12%	8.71%
All Electric Schools	AES	4.45%	6.13%	5.56%
Power Service	PS-Secondary	9.66%	9.31%	9.13%
Power Service	PS-Primary	11.92%	11.17%	11.00%
Time of Day	TOD-Secondary	6.91%	6.47%	6.27%
Time of Day	TOD-Primary	5.12%	4.61%	4.88%
Rate RTS	Transmission	4.96%	4.77%	5.29%
Fluctuating Load Service	FLS - Transmission	1.45%	3.41%	7.77%
Outdoor Lighting	ST & POL	8.40%	9.22%	10.09%
Lighting Energy	LE	9.18%	17.14%	46.34%
Traffic Energy	TE	8.68%	9.88%	9.86%
Total		5.56%	5.56%	5.56%

Table 2
Louisville Gas and Electric Company
Summary of Class Cost of Service Results

		LG&E Revised BIP	LG&E Revised LOLP	Average 5 Monthly CP
Residential	Rate RS	2.62%	1.74%	1.97%
General Service	Rate GS	7.37%	8.42%	7.57%
Rate PS	Primary	6.58%	7.80%	7.13%
Rate PS	Secondary	8.89%	10.14%	9.43%
Rate TOD	Primary	4.52%	6.16%	6.05%
Rate TOD	Secondary	12.03%	12.79%	12.06%
Rate RTS	Transmission	3.70%	6.61%	6.91%
Special Contract	Customer #1	2.05%	4.08%	4.12%
Special Contract	Customer #2	2.45%	4.01%	3.60%
Street Lighting	Rate RLS, LS, DSK	5.27%	5.90%	6.34%
Street Lighting	Rate LE	6.85%	15.12%	28.68%
Traffic Street Lighting	Rate TLE	7.27%	9.91%	9.29%
Total		4.92%	4.92%	4.92%

Q. How do the results of your alternative cost of service studies compare to the Companies' revised BIP and LOLP studies?

A. As can be seen in Table 1, the rates of return for KU's large industrial rate classes (FLS, RTS) are higher, and for FLS, are much higher and above the average retail rate of return. Similar results are shown in Table 2 for LG&E's large industrial rate classes. Based on these class cost of service studies, these large industrial rate classes should receive an average or lower than average rate increase.

Q. Given the results in Tables 1 and 2, what is your recommendation as to how the overall revenue increase approved by the Commission in these rate cases should be apportioned to each rate class?

A. While I believe my alternative 5 CP cost of service studies are more reasonable than either of the Companies' filed cost studies, I recognize that there can be legitimate disagreements among knowledgeable analysts regarding the appropriateness of any individual cost allocation method. In addition, I continue to have a concern about the reasonableness of the Companies' projected hourly load data, which forms an essential and critical input into any cost of service study using that data. As such, I continue to recommend that the Commission approve a uniform percentage increase to each rate class.

Q. Are there any additional factors about Rate FLS that the Commission should consider?

A. Yes. The Commission should also recognize that the FLS rate incorporates curtailment provisions that are unrelated to the CSR Rider and which permit KU to physically interrupt NAS on only 5 minutes notice for up to 10 minutes. These 10 minute interruptions can occur up to 20 times per month. These physical interruptions are for up to 95% of the NAS electric arc furnace load and according to the tariff are to "*facilitate Company compliance with system contingencies and with industry performance criteria.*" The FLS tariff further provides that "*Company's right to interrupt under this provision is restricted to responses to unplanned outages or de-rates … or when Automatic Reserve Sharing is invoked.*"

As discussed by KIUC witness Mary Jean Riley, under this tariff provision NAS was physically interrupted 43 times in 2015 and 26 times in 2016. While KU can and has interrupted NAS frequently, there is no recognition in KU's cost-of-service study of the inferior quality of service provided to the FLS customer. Furthermore, since KU interrupts NAS to facilitate compliance with system contingencies and industry performance criteria when there are unplanned generation outages, de-rates of generating units or when Automatic Reserve Sharing is invoked, it is evident that the Company achieves some benefit or cost savings from such interruptions. No such benefits or cost savings are recognized in any of the class cost of service studies developed in this case. All else being equal, to the extent that there is a system-wide benefit from such physical interruptions, the reported rates of return presented in Table 1 above for Rate FLS would be understated.

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
5th day of April 2017.

Jessica K. I

Notary Public

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

COMMONWEALTH OF KENTUCKY

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SUPPLEMENTAL TESTIMONY

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2016-00370

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SUPPLEMENTAL TESTIMONY

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
Tel: (202) 898-2200
Fax: (202) 898-2213
www.naruc.org

$25.00

2. The Average Seasonal System Coincident Peak Method

Because of heating and air conditioning loads, a utility may experience peak demands of comparable magnitude during different seasons of the year. The peak demands during those seasons may be considerably higher than those for the remaining months of the year, and the actual peak month may rotate from year to year between the seasons. In addition, the high level of usages may be sustained longer in one season than the other.

The calculation of the average seasonal CP demand allocation requires data for the company's transmission peak demands for the allocation periods selected and the demands of the customer groups at the same hours and days for each of those periods. The problem of implementation is the same as for the 1CP demand allocation method, except that data for more than one period is needed.

The average seasonal CP demand allocation ratio is computed by dividing the sum of the customer group's demands at the peak periods by the sum of the utility's transmission demands during those same periods. The demand ratios are computed as follows:

$$\text{Seasonal CP Demand Ratio} = \frac{\text{Sum of Customer Seasonal CP Demands \& Demand Losses}}{\text{Sum of Seasonal Transmission System Peaks}}$$

Implementation of the average seasonal CP demand allocation method will involve the same type of data and the same difficulties, except that data for more than one allocation period are required. See Table 5-3 for sample application of seasonal CP allocation methodology.

TABLE 5-3

EXAMPLE OF AVERAGE SEASONAL SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP total for months of July, August and September*	1539
System CP total for the same month(MW)	43390
Customer group average seasonal demand ratio	.03547

* Selection of July-September period is based on criterion of using months with system CP demand of at least 90% of system annual CP demand. Actual selection may consider historical occurrence of CP demand in additional months.

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SUPPLEMENTAL TESTIMONY

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

	3	4	5	7	9	10	11
Description	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**	**Time of Day TOD-Secondary**
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales	$ 1,464,489,053	$ 554,543,189	$ 198,233,994	$ 12,037,991	$ 174,459,441	$ 13,950,651	$ 116,879,945
Intercompany Sales	8,422,903	2,829,615	838,290	70,541	997,112	76,947	776,255
Curtailable Service Rider	(17,395,776)	(7,120,998)	(1,976,552)	(148,835)	(1,986,750)	(146,294)	(1,450,867)
LATE PAYMENT CHARGES	3,857,505	3,012,898	568,302	3,750	98,651	5,535	41,764
OTHER SERVICE CHARGES	2,108,282	1,967,237	136,875	853	1,335	51	982
RENT FROM ELEC PROPERTY	3,142,645	1,482,454	381,029	24,338	299,997	21,828	214,750
OTHER MISC REVENUES	22,338,060	20,843,640	1,450,249	9,036	14,148	542	10,403
Total Operating Revenues	$ 1,486,962,672	$ 577,558,036	$ 199,632,189	$ 11,997,674	$ 173,883,935	$ 13,909,259	$ 116,473,232
Operating Expenses							
Operation and Maintenance Expenses	$ 933,774,239	$ 370,519,405	$ 108,753,033	$ 7,668,256	$ 99,088,941	$ 7,651,162	$ 75,124,153
Depreciation and Amortization Expenses	228,062,837	105,274,953	27,341,782	1,798,932	22,530,220	1,641,041	16,175,658
Regulatory Credits and Accretion Expenses	-	-	-	-	-	-	-
Property Taxes	24,894,101	11,724,943	3,012,499	193,374	2,390,314	173,697	1,709,843
Other Taxes	12,926,774	6,088,418	1,564,302	100,414	1,241,220	90,196	887,871
Gain Disposition of Allowances	-	-	-	-	-	-	-
State and Federal Income Taxes	84,161,734	$ 18,153,353	$ 20,304,092	$ 655,829	$ 16,884,437	$ 1,569,567	$ 6,969,485
Total Operating Expenses	$ 1,283,819,685	$ 511,761,071	$ 160,975,708	$ 10,416,805	$ 142,135,132	$ 11,125,663	$ 100,867,011
Net Operating Income (Unadjusted)	$ 203,142,987	$ 65,796,965	$ 38,656,481	$ 1,580,869	$ 31,748,803	$ 2,783,596	$ 15,606,221
Net Cost Rate Base	$ 3,639,079,759	$ 1,716,633,054	$ 441,219,651	$ 28,182,298	$ 347,387,076	$ 25,275,870	$ 248,673,398

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

Description	3 Total System	12 Time of Day TOD-Primary	13 Retail Transmission Service RTS	14 Fluctuating Load Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales	$ 1,464,489,053	$ 251,561,897	$ 86,711,460	$ 29,892,107	$ 26,032,396	$ 29,470	$ 156,512
Intercompany Sales	8,422,903	1,865,957	664,530	245,327	57,429	208	692
Curtailable Service Rider	(17,395,776)	(3,173,152)	(1,103,242)	(288,197)	-	-	(889)
LATE PAYMENT CHARGES	3,857,505	107,885	18,686	-	33	-	-
OTHER SERVICE CHARGES	2,108,282	439	48	-	461	-	-
RENT FROM ELEC PROPERTY	3,142,645	460,648	147,497	38,866	70,983	13	241
OTHER MISC REVENUES	22,338,060	4,653	505	-	4,883	-	-
Total Operating Revenues	$ 1,486,962,672	$ 250,828,328	$ 86,439,484	$ 29,888,104	$ 26,166,186	$ 29,691	$ 156,555
Operating Expenses							
Operation and Maintenance Expenses	$ 933,774,239	$ 174,786,955	$ 60,688,793	$ 21,215,964	$ 8,165,873	$ 16,913	$ 94,791
Depreciation and Amortization Expenses	228,062,837	34,771,890	11,324,625	2,947,236	4,239,593	694	16,213
Regulatory Credits and Accretion Expenses	-	-	-	-	-	-	-
Property Taxes	24,894,101	3,661,591	1,174,574	305,406	545,913	89	1,859
Other Taxes	12,926,774	1,901,356	609,922	158,588	283,476	46	965
Gain Disposition of Allowances	-	-	-	-	-	-	-
State and Federal Income Taxes	84,161,734	$ 9,638,438	$ 3,588,566	$ 1,758,729	$ 4,619,188	$ 4,868	$ 15,183
Total Operating Expenses	$ 1,283,819,685	$ 224,760,229	$ 77,386,479	$ 26,385,922	$ 17,854,043	$ 22,611	$ 129,011
Net Operating Income (Unadjusted)	$ 203,142,987	$ 26,068,098	$ 9,053,005	$ 3,502,182	$ 8,312,143	$ 7,080	$ 27,544
Net Cost Rate Base	$ 3,639,079,759	$ 533,415,050	$ 170,797,077	$ 45,005,986	$ 82,196,367	$ 15,194	$ 278,739

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

	3	4	5	7	9	10	11
Description	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**	**Time of Day TOD-Secondary**
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue -- Actual	$ 1,486,962,672	$ 577,558,036	$ 199,632,189	$ 11,997,674	$ 173,883,935	$ 13,909,259	$ 116,473,232
Pro-Forma Adjustments:							
Adj to eliminate Off System ECR revenues	(1,635,232)	$ (609,965)	$ (368,766)	$ (23,373)	$ (168,730)	$ (13,653)	$ (105,682)
	0	0	0	0	0	0	0
Total Pro-Forma Operating Revenue	$ 1,485,327,440	$ 576,948,071	$ 199,263,423	$ 11,974,301	$ 173,715,205	$ 13,895,606	$ 116,367,550
Operating Expenses							
Operation and Maintenance Expenses	$ 933,774,239	$ 370,519,405	$ 108,753,033	$ 7,668,256	$ 99,088,941	$ 7,651,162	$ 75,124,153
Depreciation and Amortization Expenses	228,062,837	105,274,953	27,341,782	1,798,932	22,530,220	1,641,041	16,175,658
Regulatory Credits and Accretion Expenses	-	-	-	-	-	-	-
Property Taxes	24,894,101	11,724,943	3,012,499	193,374	2,390,314	173,697	1,709,843
Other Taxes	12,926,774	6,088,418	1,564,302	100,414	1,241,220	90,196	887,871
Gain Disposition of Allowances	-	-	-	-	-	-	-
State and Federal Income Taxes	84,161,734	$ 18,153,353	$ 20,304,092	$ 655,829	$ 16,884,437	$ 1,569,567	$ 6,969,485
Specific Assignment of Curtailable Service Rider Credit	(1)	(0)	(0)	(0)	(0)	(0)	(0)
Allocation of Curtailable Service Rider Credits	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Adjustments to Operating Expenses:	0	-	0	0	0	0	0
Eliminate advertising expenses	(838,116)	(317,361)	(113,448)	(6,889)	(99,842)	(7,984)	(66,890)
Federal & State Income Tax Adjustment	(164,668)	(35,518)	(39,726)	(1,283)	(33,036)	(3,071)	(13,636)
Total Expense Adjustments	$ (1,002,784)	$ (352,879)	$ (153,174)	$ (8,172)	$ (132,877)	$ (11,055)	$ (80,526)
Total Operating Expenses	$ 1,282,816,901	$ 511,408,192	$ 160,822,534	$ 10,408,632	$ 142,002,254	$ 11,114,608	$ 100,786,485
Net Operating Income (Adjusted)	$ 202,510,539	$ 65,539,878	$ 38,440,889	$ 1,565,669	$ 31,712,950	$ 2,780,997	$ 15,581,065
Net Cost Rate Base	$ 3,639,079,759	$ 1,716,633,054	$ 441,219,651	$ 28,182,298	$ 347,387,076	$ 25,275,870	$ 248,673,398
Rate of Return	**5.56%**	**3.82%**	**8.71%**	**5.56%**	**9.13%**	**11.00%**	**6.27%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

	3	12	13	14	15	16	17
Description	**Total System**	**Time of Day TOD-Primary**	**Retail Transmission Service RTS**	**Fluctuating Load Service FLS - Transmission**	**Outdoor Lighting ST & POL**	**Lighting Energy LE**	**Traffic Energy TE**
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue -- Actual	$ 1,486,962,672	$ 250,828,328	$ 86,439,484	$ 29,888,104	$ 26,166,186	$ 29,691	$ 156,555
Pro-Forma Adjustments:							
Adj to eliminate Off System ECR revenues	(1,635,232)	$ (210,279)	$ (68,614)	$ (23,719)	$ (42,194)	$ (66)	$ (192)
	0	0	0	0	0	0	0
Total Pro-Forma Operating Revenue	$ 1,485,327,440	$ 250,618,049	$ 86,370,870	$ 29,864,385	$ 26,123,992	$ 29,625	$ 156,363
Operating Expenses							
Operation and Maintenance Expenses	$ 933,774,239	$ 174,786,955	$ 60,688,793	$ 21,215,964	$ 8,165,873	$ 16,913	$ 94,791
Depreciation and Amortization Expenses	228,062,837	34,771,890	11,324,625	2,947,236	4,239,593	694	16,213
Regulatory Credits and Accretion Expenses	-	-	-	-	-	-	-
Property Taxes	24,894,101	3,661,591	1,174,574	305,406	545,913	89	1,859
Other Taxes	12,926,774	1,901,356	609,922	158,588	283,476	46	965
Gain Disposition of Allowances	-	-	-	-	-	-	-
State and Federal Income Taxes	84,161,734	$ 9,638,438	$ 3,588,566	$ 1,758,729	$ 4,619,188	$ 4,868	$ 15,183
Specific Assignment of Curtailable Service Rider Credit	(1)	(0)	(0)	(0)	-	-	(0)
Allocation of Curtailable Service Rider Credits	$ 1	$ 0	$ 0	$ 0	$ -	$ -	$ 0
Adjustments to Operating Expenses:	0	0	0	0	0	0	0
Eliminate advertising expenses	(838,116)	(143,967)	(49,624)	(17,107)	(14,898)	(17)	(90)
Federal & State Income Tax Adjustment	(164,668)	(18,858)	(7,021)	(3,441)	(9,038)	(10)	(30)
Total Expense Adjustments	$ (1,002,784)	$ (162,825)	$ (56,646)	$ (20,548)	$ (23,936)	$ (26)	$ (119)
Total Operating Expenses	$ 1,282,816,901	$ 224,597,404	$ 77,329,833	$ 26,365,374	$ 17,830,107	$ 22,585	$ 128,891
Net Operating Income (Adjusted)	$ 202,510,539	$ 26,020,645	$ 9,041,037	$ 3,499,011	$ 8,293,885	$ 7,040	$ 27,471
Net Cost Rate Base	$ 3,639,079,759	$ 533,415,050	$ 170,797,077	$ 45,005,986	$ 82,196,367	$ 15,194	$ 278,739
Rate of Return	**5.56%**	**4.88%**	**5.29%**	**7.77%**	**10.09%**	**46.34%**	**9.86%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2016-00370

AND

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)))	CASE NO. 2016-00371

SUPPLEMENTAL TESTIMONY

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

Description	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Ultimate Consumers	$ 965,204,065	$ 379,200,073	$ 135,825,835	$ 11,517,853	$ 151,571,212	$ 116,918,595	$ 77,629,237
Sales for Resale	42,971,045	15,545,980	5,051,887	601,688	6,971,340	6,729,278	2,959,628
Curtailable Service Rider	(4,334,522)	(1,972,091)	(560,873)	(49,676)	(637,276)	(490,361)	(327,529)
Forfeited Discounts	2,623,527	2,068,557	375,660	4,867	83,927	29,247	50,540
Misc Service Revenues	3,775,989	3,513,478	227,290	848	33,247	100	262
Rent From Electric Property	3,785,840	1,964,634	473,238	34,339	445,403	342,344	226,706
Other Electric Revenue	11,598,968	6,019,200	1,449,896	105,208	1,364,614	1,048,865	694,577
Unbilled Revenue	-	-	-	-	-	-	-
Total Operating Revenues	$ 1,025,624,912	$ 406,339,831	$ 142,842,934	$ 12,215,127	$ 159,832,466	$ 124,578,068	$ 81,233,422
Operating Expenses	$ -	$ -	0	0	0	0	0
Operation and Maintenance Expenses	$ 685,621,903	$ 294,226,068	$ 85,380,051	$ 8,306,474	$ 98,080,499	$ 89,635,290	$ 43,257,915
Depreciation Expenses	138,842,527	72,208,380	17,377,981	1,255,830	16,342,679	12,472,556	8,364,675
Regulatory Credits	-	-	-	-	-	-	-
Accretion Expense	-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs	-	-	-	-	-	-	-
Amortization Expense	-	-	-	-	-	-	-
Property and Other Taxes	32,529,209	16,993,979	4,066,494	291,392	3,794,504	2,894,842	1,941,775
Amortization of Investment Tax Credit	(1,002,535)	(523,746)	(125,327)	(8,981)	(116,945)	(89,218)	(59,845)
Other Expenses	-	-	-	-	-	-	-
State and Federal Income Taxes	48,157,086	(4,056,985)	12,715,060	812,728	15,452,575	6,333,164	10,764,075
Total Operating Expenses	$ 904,148,189	$ 378,847,695	$ 119,414,259	$ 10,657,444	$ 133,553,313	$ 111,246,634	$ 64,268,596
Utility Operating Income	$ 121,476,723	$ 27,492,136	$ 23,428,675	$ 1,557,684	$ 26,279,153	$ 13,331,434	$ 16,964,826
Net Cost Rate Base	$ 2,380,933,927	$ 1,235,568,230	$ 297,621,858	$ 21,596,089	$ 280,115,986	$ 215,301,684	$ 142,576,717

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

Description	Total System	Rate RTS Transmission	Special Contract Customer #1	Special Contract Customer #2	Street Lighting Rate RLS, LS, DSK	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Ultimate Consumers	$ 965,204,065	$ 64,284,636	$ 6,341,748	$ 3,292,762	$ 18,141,167	$ 210,819	$ 270,128
Sales for Resale	42,971,045	4,097,615	399,948	211,291	378,490	12,337	11,561
Curtailable Service Rider	(4,334,522)	(254,172)	(27,684)	(14,173)	-	-	(688)
Forfeited Discounts	2,623,527	10,395	-	-	334	-	-
Misc Service Revenues	3,775,989	12	-	-	751	-	-
Rent From Electric Property	3,785,840	153,538	19,122	10,062	115,568	208	678
Other Electric Revenue	11,598,968	470,408	58,585	30,828	354,074	636	2,078
Unbilled Revenue	-	-	-	-	-	-	-
Total Operating Revenues	$ 1,025,624,912	$ 68,762,433	$ 6,791,718	$ 3,530,770	$ 18,990,385	$ 224,001	$ 283,758
Operating Expenses	$ -	0	0	0	0	0	0
Operation and Maintenance Expenses	$ 685,621,903	$ 51,551,295	$ 5,246,772	$ 2,773,651	$ 6,824,290	$ 149,690	$ 189,907
Depreciation Expenses	138,842,527	5,553,322	695,397	365,469	4,175,239	6,661	24,338
Regulatory Credits	-	-	-	-	-	-	-
Accretion Expense	-	-	-	-	-	-	-
Depreciation for Asset Retirement Costs	-	-	-	-	-	-	-
Amortization Expense	-	-	-	-	-	-	-
Property and Other Taxes	32,529,209	1,279,207	161,306	84,877	1,013,495	1,617	5,721
Amortization of Investment Tax Credit	(1,002,535)	(39,425)	(4,971)	(2,616)	(31,235)	(50)	(176)
Other Expenses	-	-	-	-	-	-	-
State and Federal Income Taxes	48,157,086	3,573,227	172,484	65,942	2,272,816	28,232	23,767
Total Operating Expenses	$ 904,148,189	$ 61,917,626	$ 6,270,988	$ 3,287,324	$ 14,254,604	$ 186,150	$ 243,557
Utility Operating Income	$ 121,476,723	$ 6,844,807	$ 520,730	$ 243,447	$ 4,735,780	$ 37,850	$ 40,200
Net Cost Rate Base	$ 2,380,933,927	$ 96,561,132	$ 12,025,718	$ 6,328,140	$ 72,681,184	$ 130,621	$ 426,568

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

Description	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue -- Actual	$ 1,025,624,912	$ 406,339,831	$ 142,842,934	$ 12,215,127	$ 159,832,466	$ 124,578,068	$ 81,233,422
Pro-Forma Adjustments:							
Remove Off-System ECR revenues	(8,423,260)	(3,297,837)	(1,848,542)	(80,619)	(1,002,890)	(833,194)	(537,754)
Customer Account Changes							
Total Pro-Forma Operating Revenue	$ 1,017,201,652	$ 403,041,994	$ 140,994,392	$ 12,134,509	$ 158,829,576	$ 123,744,874	$ 80,695,668
Operating Expenses							
Operation and Maintenance Expenses	$ 685,621,903	$ 294,226,068	$ 85,380,051	$ 8,306,474	$ 98,080,499	$ 89,635,290	$ 43,257,915
Depreciation and Amortization Expenses	138,842,527	72,208,380	17,377,981	1,255,830	16,342,679	12,472,556	8,364,675
Property and Other Taxes	32,529,209	16,993,979	4,066,494	291,392	3,794,504	2,894,842	1,941,775
Amortization of Investment Tax Credit	(1,002,535)	(523,746)	(125,327)	(8,981)	(116,945)	(89,218)	(59,845)
State and Federal Income Taxes	48,157,086	(4,056,985)	12,715,060	812,728	15,452,575	6,333,164	10,764,075
Specific Assignment of Interruptible Credit	-	-	-	-	-	-	-
Allocation of Interruptible Credits	-	-	-	-	-	-	-
Adjustments to Operating Expenses:							
Eliminate advertising expenses	(984,863)	(386,924)	(138,592)	(11,752)	(154,658)	(119,300)	(79,210)
Federal & State Income Tax Adjustment	(3,074,551)	259,015	(811,783)	(51,888)	(986,557)	(404,336)	(687,224)
Total Expense Adjustments	(4,059,414)	(127,909)	(950,375)	(63,640)	(1,141,216)	(523,636)	(766,434)
Total Operating Expenses	$ 900,088,775	$ 378,719,786	$ 118,463,883	$ 10,593,803	$ 132,412,097	$ 110,722,998	$ 63,502,162
Net Operating Income -- Pro-Forma	$ 117,112,877	$ 24,322,208	$ 22,530,509	$ 1,540,705	$ 26,417,479	$ 13,021,876	$ 17,193,507
Cost of Service Summary -- Pro-Forma							
Net Operating Income -- Pro-Forma	$ 117,112,877	$ 24,322,208	$ 22,530,509	$ 1,540,705	$ 26,417,479	$ 13,021,876	$ 17,193,507
Net Cost Rate Base	$ 2,380,933,927	$ 1,235,568,230	$ 297,621,858	$ 21,596,089	$ 280,115,986	$ 215,301,684	$ 142,576,717
ECR Plan Eliminations	-	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve	-	-	-	-	-	-	-
Cash Working Capital	-	-	-	-	-	-	-
Adjusted Net Cost Rate Base	$ 2,380,933,927	$ 1,235,568,230	$ 297,621,858	$ 21,596,089	$ 280,115,986	$ 215,301,684	$ 142,576,717
Rate of Return	**4.92%**	**1.97%**	**7.57%**	**7.13%**	**9.43%**	**6.05%**	**12.06%**

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2018

5 CP METHODOLOGY

Description	Total System	Rate RTS Transmission	Special Contract Customer #1	Special Contract Customer #2	Street Lighting Rate RLS, LS, DSK	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue -- Actual	$ 1,025,624,912	$ 68,762,433	$ 6,791,718	$ 3,530,770	$ 18,990,385	$ 224,001	$ 283,758
Pro-Forma Adjustments:							
Remove Off-System ECR revenues	(8,423,260)	(461,699)	(42,712)	(23,117)	(290,133)	(2,399)	(2,365)
Customer Account Changes							
Total Pro-Forma Operating Revenue	$ 1,017,201,652	$ 68,300,733	$ 6,749,005	$ 3,507,653	$ 18,700,252	$ 221,602	$ 281,393
Operating Expenses							
Operation and Maintenance Expenses	$ 685,621,903	$ 51,551,295	$ 5,246,772	$ 2,773,651	$ 6,824,290	$ 149,690	$ 189,907
Depreciation and Amortization Expenses	138,842,527	5,553,322	695,397	365,469	4,175,239	6,661	24,338
Property and Other Taxes	32,529,209	1,279,207	161,306	84,877	1,013,495	1,617	5,721
Amortization of Investment Tax Credit	(1,002,535)	(39,425)	(4,971)	(2,616)	(31,235)	(50)	(176)
State and Federal Income Taxes	48,157,086	3,573,227	172,484	65,942	2,272,816	28,232	23,767
Specific Assignment of Interruptible Credit	-	-	-	-	-	-	-
Allocation of Interruptible Credits	-	-	-	-	-	-	-
Adjustments to Operating Expenses:							
Eliminate advertising expenses	(984,863)	(65,594)	(6,471)	(3,360)	(18,511)	(215)	(276)
Federal & State Income Tax Adjustment	(3,074,551)	(228,130)	(11,012)	(4,210)	(145,106)	(1,802)	(1,517)
Total Expense Adjustments	(4,059,414)	(293,724)	(17,483)	(7,570)	(163,617)	(2,018)	(1,793)
Total Operating Expenses	$ 900,088,775	$ 61,623,902	$ 6,253,505	$ 3,279,754	$ 14,090,987	$ 184,133	$ 241,764
Net Operating Income -- Pro-Forma	$ 117,112,877	$ 6,676,832	$ 495,500	$ 227,900	$ 4,609,264	$ 37,469	$ 39,628
Cost of Service Summary -- Pro-Forma							
Net Operating Income -- Pro-Forma	$ 117,112,877	$ 6,676,832	$ 495,500	$ 227,900	$ 4,609,264	$ 37,469	$ 39,628
Net Cost Rate Base	$ 2,380,933,927	$ 96,561,132	$ 12,025,718	$ 6,328,140	$ 72,681,184	$ 130,621	$ 426,568
ECR Plan Eliminations	-	-	-	-	-	-	-
Adjustment to Reflect Depreciation Reserve	-	-	-	-	-	-	-
Cash Working Capital	-	-	-	-	-	-	-
Adjusted Net Cost Rate Base	$ 2,380,933,927	$ 96,561,132	$ 12,025,718	$ 6,328,140	$ 72,681,184	$ 130,621	$ 426,568
Rate of Return	4.92%	6.91%	4.12%	3.60%	6.34%	28.68%	9.29%