COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

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

DIRECT TESTIMONY OF
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Filed: November 23, 2016

Table of Contents

I. INTRODUCTION 1

II. QUALIFICATIONS 5

III. RATE DESIGN AND THE ALLOCATION OF THE INCREASE 6

A. ALLOCATION OF THE REVENUE INCREASE 6
B. RESIDENTIAL SERVICE (RS) 9
C. RESIDENTIAL TIME-OF-DAY ENERGY AND DEMAND SERVICES 23
D. GENERAL SERVICE (GS) AND ALL ELECTRIC SCHOOLS SERVICE (AES). 25
E. POWER SERVICE (PS) 26
F. LARGE CUSTOMER RATES (TODS, TODP, RTS, FLS) 37
G. CURTAILABLE SERVICE RIDER (CSR) 50
H. LIGHTING RATES 55
I. REDUNDANT CAPACITY (RC) 57

IV. MISCELLANEOUS SERVICE CHARGES 58

A. POLE AND STRUCTURE ATTACHMENTS (RATE PSA) 58
B. UNAUTHORIZED RECONNECTION CHARGE 62

V. COST OF SERVICE STUDY 64

Exhibits

Exhibit WSS-1 – Qualifications
Exhibit WSS-2 – Cost Components for Residential Service Rate RS
Exhibit WSS-3 – Cost Support for CSR Credits
Exhibit WSS-4 – Cost Support for Lighting Rates LS and RLS
Exhibit WSS-5 – Cost Support for LED Lighting Rates
Exhibit WSS-6 – Cost Support for Redundant Capacity Charge
Exhibit WSS-7 – Cost Support for Pole Attachment Charge
Exhibit WSS-8 – Cost Support for Duct Attachment Charge
Exhibit WSS-9 – Change in Miscellaneous Revenues for Attachment Charges
Exhibit WSS-10 – Cost Support for Unauthorized Reconnection Charge
Exhibit WSS-11 – COS BIP Methodology
Exhibit WSS-12 – COS LOLP Methodology
Exhibit WSS-13 – Zero Intercept Overhead Conductor
Exhibit WSS-14 – Zero Intercept Underground Conductor
Exhibit WSS-15 – Zero Intercept Line Transformers
Exhibit WSS-16 – COS Functional Assignment BIP Methodology
Exhibit WSS-17– COS Functional Assignment LOLP Methodology
Exhibit WSS-18 – COS Class Allocation BIP Methodology
Exhibit WSS-19 – COS Class Allocation LOLP Methodology

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. By whom and in what capacity are you employed?

A. I am the managing partner for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Kentucky Utilities Company ("KU" or "the Company"), which provides electric service in Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the proposed allocation of the revenue increases for KU's operations; (ii) to support KU's proposed rates, and (iii) to sponsor the fully allocated cost of service studies based on KU's embedded cost of providing service for the fully forecasted test year, which is the 12 months ending June 30, 2018.

Q. Please summarize your testimony.

A. In developing its proposed rates in this proceeding, KU relied heavily on the results of the cost of service studies. For the most part, the Company's class cost of service studies were prepared using methodologies that have been accepted by the Kentucky

Public Service Commission ("Commission") in previous rate cases. In this proceeding, however, KU is presenting two versions of the cost of service study. In one version, the Base-Intermediate-Peak ("BIP") methodology used in prior cost of service studies for time-differentiating and allocating fixed production costs will be utilized. In the other version, a methodology is used to allocate fixed production costs that is more reflective of the way generation resources are planned by the Company. This alternative version allocates costs by weighting hourly class loads by the hourly Loss of Load Probability ("LOLP"), which is a key measure that has been used by KU and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies'") for planning their generation resources for many years. I will present information comparing the results of the LOLP version of the cost of service study to the BIP version that has been used in prior rate cases.

The purpose of a class cost of service study is to determine the contribution that each customer class is making towards KU's overall rate of return. Rates of return are calculated for each rate class. A class cost of service study is also used as a tool for developing unit charges for electric service. Cost of service is a standard measure of reasonableness for utility rate design.

In this filing, KU is proposing rate design changes to begin to address fundamental changes that are taking place within the electric utility industry. Across the United States, electric utilities are beginning to see competitive pressures from various forms of distributed generation (e.g., solar generation, natural gas generation, and wind generation). As a result of customers installing behind-the-meter electric generation, and also customers finding ways to conserve energy or use energy more efficiently, many utilities are experiencing steep declines in their sales per customer. Regardless of the environmental benefits that may result from these initiatives, it is important that the utility ensure that the rate design is structured in a way that recovers the actual cost of serving customers who install distributed generation and pursue behind-the-meter energy efficiency measures. With improperly designed rates, it is possible for the utility's other customers (for example, customers who cannot or do not install distributed generation) to be unduly penalized by having costs improperly shifted onto them from customers who install distributed generation or reduce their energy consumption. Therefore, it is important for the utility to design its rates so that the actual cost of providing service is recovered through rates even when customers reduce their energy consumption but still require the same utility infrastructure to serve them. For example, if a customer reduces its energy consumption through the installation of solar generation, but falls back on the utility to deliver power to the customer when the solar generation is not operating, the utility still needs the same distribution infrastructure to serve the customer even though the customer might be using less energy.

KU is therefore taking some initial steps toward implementing rate changes that will provide appropriate and equitable cost recovery in a changing utility industry. We are proposing to separate out the infrastructure and variable cost components of the energy charge for Residential Service (RS), General Service (GS) and other two-part rates that include only a customer charge and an energy charge.

The purpose of this change in the presentation of these rate schedules is to provide more information to customers, stakeholders and employees about which costs are avoidable through the installation of distributed generation (i.e., the variable cost component) and which costs are less likely to be avoided (i.e., the fixed cost component). We are also proposing changes to the large customer rates, specifically Time-of-Day Secondary Service (TODS), Time-of-Day Primary Service (TODP), Retail Transmission Service (RTS), and Fluctuating Load Service (FLS), to provide better assurance that the actual costs of transmission and distribution service are recovered from customers that install distributed generation. I will discuss these changes in greater detail later in my testimony.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 16(7) and 16(8)?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

- Cost of Service Studies — Section 16(7)(v) — Tab 52
- Revenue Summary — Section 16(8)(m) — Tab 66

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Rate Design and the Allocation of the Increase, (IV) Increase in Miscellaneous Service Charges, and (VI) Cost of Service Study.

II. QUALIFICATIONS

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From 2014 through 2015 I completed an additional 12 hours of Electrical Engineering coursework at the University of Louisville's Speed School of Engineering (courses in computer design, microcontroller programming, digital signal processing, and computer communications). In addition, from 2012 through 2015, I was an instructor at Louisville's Walden School and a private tutor and instructor in advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.

Concerning my professional background, from May 1979 until July 1996, I was employed by LG&E. From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed or supervised the preparation of cost of service and rate studies for over 150 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. Therefore, including my time at LG&E, I have more than 35 years of experience in the utility industry. A more detailed description of my qualifications is included in Exhibit WSS-1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 50 regulatory and court proceedings in 13 different jurisdictions including the Kentucky Public Service Commission. I have testified on behalf of both KU and LG&E on numerous occasions. A listing of my testimony in other proceedings is included in Exhibit WSS-1.

Q. Please describe your work and testimony experience as they relate to topics addressed in your testimony?

A. I have performed or supervised the development of cost of service and rate studies for over 150 utilities throughout North America. I have also testified on numerous occasions regarding the rates proposed by electric, gas and water utilities, including KU.

III. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE REVENUE INCREASE

Q. Please summarize how KU proposes to allocate the revenue increase to the classes of service.

A. KU relied on the results of the cost of service studies to determine the revenue increases allocated to the classes of service. Specifically, larger relative portions of the overall revenue increase are allocated to the rate classes with low rates of return on rate base, and smaller relative portions of the overall increase are allocated to the rate classes with high rates of return. In other words, KU is proposing higher percentage increases for rate classes that have low rates of return and lower percentage increases for rate classes that have higher rates of return. KU is proposing rate increases for all rate classes except for Lighting Energy Service. A comparison of the rate of return at current rates and the percentage revenue increase proposed for each rate class is shown below in Table 1:

	Rate of Return on Rate Base		Revenue
Rate Class	**BIP Version**	**LOLP Version**	**Increase**
Residential Service	4.16%	4.36%	5.94%
General Service	9.10%	9.20%	5.06%
All Electric Schools	5.27%	6.77%	5.34%
Primary Service-Secondary	9.61%	9.26%	5.06%
Primary Service-Primary	11.83%	10.70%	4.71%
Time-of-Day Secondary Service	6.42%	6.06%	5.55%
Time-of-Day Primary Service	4.48%	4.05%	6.61%
Retail Transmission Service	4.55%	4.50%	6.71%
Fluctuating Load Service	1.50%	1.24%	7.25%
Lighting Energy Service	9.83%	18.57%	0.00%
Traffic Energy Service	10.02%	11.34%	4.71%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	6.14%
Total All Classes	5.56%	5.56%	6.45%

Table 1

Table 2 shows the same results as Table 1 except that the data is sorted from the highest to the lowest percentage increase:

	Rate of Return on Rate Base		Revenue
Rate Class	BIP Version	LOLP Version	Increase
Fluctuating Load Service	1.50%	1.24%	7.25%
Retail Transmission Service	4.55%	4.50%	6.71%
Time-of-Day Primary Service	4.48%	4.05%	6.61%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	6.14%
Residential Service	4.16%	4.36%	5.94%
Time-of-Day Secondary Service	6.42%	6.06%	5.55%
All Electric Schools	5.27%	6.77%	5.34%
Primary Service-Secondary	9.61%	9.26%	5.06%
General Service	9.10%	9.20%	5.06%
Primary Service-Primary	11.83%	10.70%	4.71%
Traffic Energy Service	10.02%	11.34%	4.71%
Lighting Energy Service	9.83%	18.57%	0.00%
Total All Classes	5.56%	5.56%	6.45%

Table 2

As illustrated in Table 2, the percentage increases allocated to the rate classes are essentially inversely proportional to the class rate of return. In allocating the revenue increase to the classes, one of the Company's objectives was to limit the maximum increase to any class to approximately one percentage point above the overall increase. This results in the class with the lowest rate of return receiving a 7.25 percent increase and the class with the highest rate of return receiving a zero percent increase. The decision was made not to assign an increase for any rate class with a rate of return exceeding 15 percent. All other rate classes with a rate of return under 15 percent were allocated a rate increase within a bandwidth of approximately 1 to 1.75 percentage points of the average increase.

Q. Are there any rate classes that are not shown on the above table?

A. Yes. Residential Time of Day Service (RTOD) is a small rate class currently serving only 25 customers. This rate class was included with Rate RS in the cost of service study. KU is proposing an increase of 5.91 percent for this rate class.

Q. Are classes with the higher rates of return subsidizing classes with low rates of return?

A. Yes, from a cost of service perspective, they are. Of course, cost of service is just one factor that must be considered. Economic factors such as job creation and retention are also important considerations.

Q. Is KU proposing to eliminate all subsidies in this proceeding?

A. No. KU's objective is to eliminate subsidies gradually over time. While KU does want to address the issue of subsidies, the Company proposes to do so in a manner that doesn't create unduly large increases for any one major rate class.

Q. Have you prepared schedules showing the proposed revenue increase for each standard rate schedule?

A. Yes. The revenue increase for each rate class is shown on Schedule M-2.1 of Section 16(8)(m) of the Filing Requirements. The detailed billing calculations for each rate schedule are shown on Schedule M-2.3. The proposed unit charges for each rate schedule are shown on Schedule M-2.3.

B. RESIDENTIAL SERVICE (RS)

Q. Please provide a brief description of Rate RS.

A. Rate RS is the standard rate schedule available to single-family residential service. Approximately 431,000 residential customers are served under this rate schedule.

Rate RS has a two-part rate structure that includes a Basic Service Charge and an Energy Charge.

Q. What are the charges that KU is proposing for Rate RS?

A. KU is proposing to *increase* the Basic Service Charge from $10.75 per month to $22.00 per month. The Company is proposing to *decrease* the energy charge from $0.08870 per kWh to $0.08523 per kWh.

Q. Is the Company proposing any changes in the presentation of the charges for Rate RS?

A. Yes, KU is proposing that the energy charge be broken down into a variable cost component (Variable Energy Charge) and a fixed cost component (Infrastructure Energy Charge). The Variable Energy Charge is $0.03508 per kWh and the Infrastructure Energy Charge is $0.05015 per kWh. These charges would also apply to Volunteer Fire Department Service (Rate VFD).

Q. Why is the Company proposing this change?

A. The purpose of showing the energy charge as consisting of both a variable cost component and a fixed cost component is solely educational and informational at this point in time. The Company wants customers, stakeholders and employees to be aware that two types of costs are included in the energy charge for Rate RS and other rates that have a two-part rate structure consisting of a Basic Service Charge and an Energy Charge. The energy cost component consists of costs, such as fuel expenses and variable operation and maintenance expenses, that vary directly with the kWh usage of customers. The fixed cost component consists of demand-related costs that do not vary directly with energy usage, such as depreciation expenses, return, taxes, and fixed operation and maintenance expenses related to utility infrastructure. It is important for customers, stakeholders and employees to understand that not all costs are automatically reduced when customers use less energy. For example, the fixed costs associated with poles, transformers, conductors, power plants, office buildings, etc., are not automatically reduced when consumers reduce their energy usage. As greater emphasis is placed on distributed generation and energy conservation in our society, it is important for customers, stakeholders and utility employees to understand the distinction between fixed and variable costs.

Q. What is the breakdown of total costs among these three cost components for Rate RS?

A. The following table shows how the cost of providing service to customers under Rate RS is broken down between customer-related fixed costs, demand-related fixed costs, and energy-related variable costs:

Cost Component	Percentage of Cost
Customer-Related Fixed Costs	20.9%
Demand-Related Fixed Costs (Infrastructure Demand Costs)	43.0%
Energy-Related Variable Costs	36.1%

Table 3

Q. How are these costs currently recovered from Rate RS customers?

A. Rate RS, as well as a number of other KU rate schedules that serve smaller commercial and industrial customers (for example Rate GS), are currently structured as a *two-part rate* consisting of a customer charge (Basic Service Charge) and an energy charge. The Basic Service Charge is billed as a flat monthly charge per customer, and the energy charge is a variable charge billed on a cents-per-kWh basis. Under a two-part rate design, all *three cost components* (customer costs, demand costs and energy costs) are recovered through *two rate components* (customer charge and energy charge). Unlike the three- and multi-part rates that are used for KU's larger customers, the two-part rate for Rate RS does not utilize a demand charge. Therefore, demand costs (costs associated with transformers, overhead and underground conductor, transmission lines, and generation capacity) must be recovered through either the customer charge or the energy charge. For Rate RS, all demand costs and a portion of the customer costs are currently being recovered through the energy charge. The following table compares the percentage of costs broken down by component (customer cost, demand cost, and energy cost) to the percentage of recovery through the rate components (customer charge and energy charge):

Component	Percentage of Cost	Rate Design
Customer	20.9%	9.3%
Demand	43.0%	0.0%
Energy	36.1%	90.7%

Table 4

As can be seen from this table, all demand costs and a significant portion of customer costs are currently recovered through a variable energy charge.

Q. What are three- and multi-part rate designs?

A. A *three-part rate* is a rate structure that includes a customer charge, energy charge and demand charge. KU's rate for medium commercial and industrial customers (Rate PS) is a three-part rate consisting of a customer charge, energy charge and demand charge. The rates for large commercial and industrial customers (Rate TODS, TODP, RTS, and FLS) are structured as a *multi-part rate* consisting of a customer charge, energy charge and multi-part demand charge that is unbundled between production fixed cost components and transmission/distribution fixed cost components. The reason that a two-part rate structure traditionally has been used in the industry for residential and small commercial and industrial accounts is that the cost of the metering technology necessary to bill a three- or multi-part rate for small customers has been prohibitive. This is changing in the industry. As utilities install advanced metering technology for all types of customers, it becomes more feasible to use three- or multi-part rates for residential and general service (small commercial and small industrial) customers.

Q. Does recovering fixed customer and demand costs through a variable energy charge create problems?

A. Yes, it certainly does. The Company must install generation, transmission and distribution infrastructure to serve customers. The costs associated with this infrastructure are fixed. As explained earlier, some of these fixed costs are demand-related and are thus related to utility infrastructure that is sized to meet maximum loads that customers place on the system, while other fixed costs are customer-related and are thus related to the number of customers that the utility serves. These fixed costs typically will not change if a customer uses more energy or if a customer uses less energy. For example, once the Company installs a distribution line, transformer, service line, and meter to serve a customer, the operation and maintenance expenses, depreciation expenses, property taxes, interest expenses, and other such costs are not decreased if a customer uses less energy. Once the facilities are installed they are invariant to customer usage and are therefore fixed. If the costs are improperly recovered through a volumetric charge rather than a fixed charge, then when a customer uses less energy these fixed costs will not be recovered from the customer, and those costs must be recovered from other customers. This is particularly problematic if a customer reduces energy consumption by installing distributed generation technology such as solar panels or a wind turbine but falls back on the utility when sunlight is unavailable or when the wind isn't blowing. In those instances, the customer will have reduced its energy usage with distributed generation but will still require the same generation, transmission and distribution capacity to meet its demand requirements. The customer will have reduced the billing of fixed costs collected through the energy charge but will not have caused the utility to reduce its fixed costs. In those instances, the fixed costs are thus shifted to customers who have not installed distributed generation technology.

Q. At this point, has distributed generation created problems for KU?

A. Nothing significant. However, the installation of customer-owned distributed generation is already creating problems with the erosion of fixed cost recovery for utilities in western states, such as New Mexico, Arizona, Nevada, and Colorado. At this point, it is important for KU to be aware of what is going on in other jurisdictions and to begin educating its customers, stakeholders and employees about the kinds of costs that are fixed and those that are variable and thus avoidable. In the short term, only variable costs are avoidable as a result of self-generation and conservation efforts by consumers. But even if distributed generation never becomes a major factor on KU's system, the changes that KU is proposing are still beneficial because the Company is moving toward a more cost-based rate structure. Thus, KU's rates provide for a more fair and equitable recovery of costs from customers.

Q. With the emergence of customer-owned distributed generation, what ratemaking frameworks are other utilities and commissions exploring to ensure

that costs are fairly and equitably recovered from customers?

A. They are looking into a number of options. In a recent rate case in New Mexico for which I was a witness, the commission staff proposed a rate design that would insure that all production, transmission and distribution fixed costs would be recovered fully from customers with distributed generation. Other utilities are considering the implementation of three- and multi-part rates for residential and small commercial and industrial customers. Under some of the approaches being adopted by utilities, residential customers would be billed under a rate that includes one or more types of demand charges; for example, the residential rate could include a demand charge that is billed on the basis of the customer's maximum monthly demand (that recovers transmission and distribution fixed costs) and a demand charge billed on the basis of the customer's demand determined at the time of the utility's system peak (coincident peak demand) (that recovers generation fixed costs.) Ultimately, rates that make use of multi-part rate structures allow utilities to price electric service in a more cost-based manner, thus greatly reducing, if not eliminating, intra-class subsidies.

Some utilities are also considering the use of straight-fixed variable ("SFV") rate designs that would collect all transmission and distribution costs through a monthly customer charge. An SFV rate is a rate design in which all the utility's fixed costs, or fixed transmission and distribution costs, would be recovered through a flat monthly charge, such as a customer charge. SFV rate designs have been used extensively in the natural gas industry to deal with declining usage, downward spiraling margins, and the equitable recovery of fixed costs. An SFV rate design would not only help protect the utility against lost revenue due to energy conservation and the installation of distributed generation but it would also ensure that fixed costs are fairly and reasonably distributed. Only the utility's avoidable costs would be recovered through an energy charge, specifically, the utility's variable energy costs. All fixed costs would be recovered through the customer charge or other fixed charge, thus fully ensuring the fixed costs are inappropriately shifted onto customers that do not implement distributed generation.

Other utilities are proposing revenue decoupling mechanisms to allow the utility to encourage the introduction of behind-the-meter distributed generation technologies without resulting in an erosion of fixed cost recovery. Revenue decoupling is designed to decouple the link between energy usage and the amount of net revenues collected by the utility. It is generally implemented as a rate adjustment mechanism that operates with annual surcharges or surcredits. With decoupling, the annual amount of net revenues, or fixed cost revenues, (total revenues less variable energy expenses) for a rate class would be compared to the fixed-cost revenue requirement determined from the utility's rate case for that rate class, as adjusted to reflect increases or decreases in the number of customers served. If the net revenues collected from the customer class for a 12-month period is less than the fixed-cost revenue requirement for the customer class determined from the rate case (as adjusted for changes in the number of customers served) then a surcharge is calculated based on the deficiency and then applied to kWh sales in a subsequent 12-month period. Likewise, if the net revenues collected from the customer class for a 12-month period are greater than the fixed cost revenue requirement for the customer class determined from the rate case (again, as adjusted for changes in the number of customers served) then a surcredit is calculated based on the excess revenues and applied sales in a subsequent 12-month period. Since decoupling allows the utility to collect net revenues equivalent to the fixed-cost revenue requirement from its last case, the utility would be protected against the loss of revenues due to the adoption of distributed generation technologies by customers. Decoupling and other lost revenue mechanisms have been implemented by several utilities in conjunction with energy conservation and demand-side management programs. Decoupling is often identified as a way to align the interests of the utility and customers in the adoption of energy saving technologies.

Q. Are these options that KU and LG&E should be evaluating?

A. Yes. It is important for the Companies to continue to monitor developments in the industry. But at this point, breaking out the energy charge in the Company's two-part rates into fixed and variable cost components is a good first step toward educating customers, stakeholders and employees about what makes up the cost of providing service to customers.

Q. What is the basis for the proposed increase in the Basic Service Charge for Rate RS?

A. The Company is proposing a cost-based Basic Service Charge that reflects the customer-related costs from the Company's cost of service study. As will be explained in greater detail in the portion of my testimony dealing with the cost of service study, the methodology that is used to classify costs as customer related corresponds to the methodology that has been accepted by the Commission in the past. The methodology for classifying costs as customer-related also corresponds to one of the standard methodologies set forth in the *Electric Utility Cost Allocation Manual* published by the National Association of Utility Regulatory Commissioners ("NARUC").

Q. Have you prepared an exhibit showing the calculation of the cost components for Rate RS?

A. Yes. Exhibit WSS-2 shows the calculation of the unit customer cost, demand related cost, and energy costs from the BIP version of the cost of service study. From this calculation, the customer cost is $23.93 per customer per month; the demand-related cost is $0.04849/kWh; and the energy cost is $0.03508/kWh. In the proposed rate, KU is proposing a Basic Service Charge of $22.00 which is below the unit cost from the cost of service study. The difference is recovered through the Infrastructure Energy Charge which KU is proposing to be $0.05015/kWh. The Company is proposing a Variable Energy Charge of $0.03508/kWh, which is the same as calculated from the cost of service study.

Q. Why is the Basic Service Charge rounded?

A. The Basic Service Charge is rounded to keep the charge as simple and easy to use as possible. The Companies are also proposing that the Basic Service Charge be the same for both KU and LG&E. The Companies are proposing a residential customer charge that represents the lowest rate that can be cost supported for KU and LG&E.

Because LG&E's customer cost is equal to $22.04 per month and KU's is equal to $23.93 per month, a customer charge of $22.00 was selected for the Companies because it reflected the lowest of the two unit costs after giving effect to rounding.

Q. Please explain the costs that are recovered through the Basic Service Charge.

A. The Basic Service Charge recovers the minimum system that each customer must have in place to access the electric grid. The customer charge also recovers the cost of operating and maintaining this minimum system as well as other costs not related to customer usage, such as meter reading, billing and customer service costs. The minimum system comprises the meter, service drop from the transformer, the transformer, the minimum size of wire, and poles extending to the distribution substation that is necessary to provide a customer with access to the electric grid. Once the cost of this minimum system is determined using the zero-intercept methodology (discussed later in my testimony), it can be allocated to each customer.

Q. What other costs need to be recovered from customers?

A. Customers often need more equipment than the minimum system in order to receive adequate service. The cost of this equipment above the minimum is related to the customer's usage level and is a demand-related fixed cost that is recovered through either a demand or energy charge. A cost of service study is performed for the purpose of allocating costs as accurately as possible based on cost causation. In a cost of service study, it is important to distinguish the distribution system costs related to demand from the distribution system costs that are related to the minimum system which are not related to demand, as discussed in the NARUC <u>Electric Utility</u>

Cost Allocation Manual. As discussed earlier, the Company must install the minimum amount of equipment to provide customers with access to the electric grid. This minimum amount of equipment is not related to the volume of electricity used by the customer, and each customer must have that minimum amount of equipment in place to obtain electric service. These non-volumetric fixed distribution costs are associated with serving the customer and therefore should be borne by the customer through a fixed customer charge regardless of usage. The remainder of the distribution costs, which are related to installed capacity, are classified as demand-related and are collected through a kWh energy charge for Rate RS or through a kW charge for customer classes billed under a three- or multi-part rate that has a demand charge. This split of distribution system costs between volumetric and fixed assures that customers only have to pay for what they are actually using, namely the basic minimum system that all customers require plus as much additional equipment as required to meet their needs.

Q. Does the current Basic Service Charge of $10.75 recover all KU's customer-related costs for Rate RS?

A. No. The current Basic Charge of $10.75 per customer per month does not recover all of the customer-related fixed costs of $23.93. Based on Exhibit WSS-2, there are $13.18 in customer-related fixed costs per customer per month (calculated as $23.93 - $10.75 = $13.18) that are not being collected through the Basic Service Charge. When this under-recovery of $13.18 per customer per month is multiplied by the billing units of 5,167,560 customer months for Rate RS during the test year, the result is $68,108,441 in fixed customer-related costs that are not being recovered through the Basic Service Charge under the current rate design. When these customer charge fixed costs are recovered through the Energy Charge instead, the result is about 1.1 cents per kWh of non-volumetric fixed cost collected through the Energy Charge (calculated as $68,108,441/ 6,091,291,833 kWh = $0.011/kWh). Thus, the current Basic Service Charge is $13.18 per customer per month too low and the Energy Charge is 1.1 cents per kWh too high based on data from the cost of service study. This recovery of non-volumetric fixed costs through the energy charge assessed on a kWh basis results in intra-class subsidies and in unrecovered fixed costs if kWh usage declines due to energy efficiency, conservation or mild weather.

Q. Will KU's proposed residential rate help to eliminate subsidies?

A. Yes. There are two types of subsidies that need to be considered – inter-class subsidies and intra-class subsidies. The term "*inter-class subsidies*" refers to subsidies that are provided from or to one class of customers to or from another class of customers, and the "*intra-class subsidies*" refers to subsidies that are provided from or to customers within the same rate class. KU's proposed rates are designed to make progress towards reducing both *inter*- and *intra-class* rate subsidies. As will be discussed, the apportionment of the total revenue increase to the customers was developed in such a manner as to provide a reduction in *inter-class subsidies*.

The rate making principle to follow to avoid *intra-class subsidies* is that fixed costs should be recovered through fixed charges (such as the customer charge and demand charge), and variable costs should be recovered through variable charges (such as the energy charge and the fuel adjustment charge). If fixed costs are recovered through variable charges, such as the energy charge assessed on a kWh basis, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of the utility's fixed costs, while customers using less energy than the average customer in the class are paying less than their fair share of the utility's fixed costs. These fixed costs should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is not the correct cost driver for collecting fixed costs.

The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. In order to eliminate this source of intra-class subsidies, KU proposes a rate design that more closely follows the ratemaking principle of recovering fixed costs through fixed charges and variable costs through variable charges than does its current rate design.

Increasing the Basic Service Charge will eliminate subsidies by bringing the charges toward the actual cost of providing service. Increasing the Basic Service Charge from $10.75 to $22.00 will eliminate subsidies that high usage customers are currently providing low usage customers.

C. RESIDENTIAL TIME-OF-DAY ENERGY AND DEMAND SERVICES

Q. Please provide a brief description of KU's residential time-of-day rates.

A. KU offers two time-of-day rates, RTOD-Energy and RTOD-Demand. Rate RTOD-Energy is a time-of-day rate that includes a time differentiated energy charge. Under the rate, customers are charged a significantly lower energy charge for off-peak usage. There are approximately 25 customers currently taking service under RTOD-Energy. The Company is not proposing any structural changes to Rate RTOD-Energy.

Rate RTOD-Demand is a time-of-day rate that includes a flat energy charge but a time differentiated demand charge. There are currently no customers taking service under RTOD-Demand. KU is proposing structural changes to Rate RTOD-Demand to more accurately reflect costs and thus encourage customers to sign up for the rate.

Q. What are the charges that KU is proposing for Rate RTOD-Energy?

A. KU is proposing to *increase* the Basic Service Charge from $10.75 per month to $22.00 per month and to *decrease* the off-peak energy charge from $0.05740 per kWh to $0.05266 per kWh. The Company is proposing to increase the Basic Service Charge to the same level as being proposed for Rate RS. The off-peak energy charge is being reduced to a level that yields a revenue increase for Rate RTOD-Energy that is approximately equal to the percentage increase for Rate RS.

Q. What structural changes is KU proposing for Rate RTOD-Demand?

A. KU is proposing to eliminate the off-peak demand charge and replace it with a base demand charge that is applied to the customer's maximum usage whenever it occurs. This is the same structure that has been used for several years for KU's large customer rates and seems to operate effectively. Using a base demand charge rather than an off-peak demand charge prevents customers from being penalized for improvements in load factor. KU is proposing to *increase* the Basic Service Charge from $10.75 per month to $22.00 per month and to *decrease* the off-peak energy charge from $0.04370 per kWh to $0.03508 per kWh. The Company is proposing to replace the demand charge for off peak hours of $3.70 per kW with a demand charge for all hours of $3.44 per kW, and to decrease the demand charge for on peak hours from $13.05 per kW to $7.87 per kW.

D. GENERAL SERVICE (GS) AND ALL ELECTRIC SCHOOLS SERVICE (AES)

Q. Please provide a brief description of Rate GS.

A. Rate GS is the standard rate schedule available to small commercial and industrial customers served at secondary voltages (available voltages *less than* 2,400/4,160Y volts). The rate schedule is limited to customers whose 12-month average monthly demands do not exceed 50 kW. Approximately 83,000 small commercial and industrial customers are served under this rate schedule. Rate GS has a two-part rate structure that includes a Basic Service Charge and an Energy Charge.

Q. What are the charges that KU is proposing for Rate GS?

A. KU is proposing to increase the Basic Service Charge for Rate GS from $25.00 per month to $31.50 per month for single-phase service and from $40.00 to $50.40 per month for three-phase service. The Company is proposing to increase the energy charge from $0.10426 per kWh to $0.10685 per kWh. As with Rate RS, the energy charge for Rate GS will be broken down into Variable Energy Charge and

Infrastructure Energy Charge. The Variable Energy Charge is $0.03548 per kWh and the Infrastructure Energy Charge is $0.07137 per kWh.

Q. Please provide a brief description of Rate AES.

A. Rate AES is a rate generally available for school buildings, although the rate is closed to new customers and is limited to customers that were qualified for, and being served on, Rate AES as of July 1, 2011. There are approximately 590 schools taking service under Rate AES. KU is proposing to increase the Basic Service Charge for Rate AES from $25.00 per month to $85.00 per month for single-phase service and from $40.00 to $140.00 per month for three-phase service. The Company is proposing to increase the energy charge from $0.08369 per kWh to $0.08519 per kWh. As with Rates RS and GS, the energy charge for Rate AES will be broken down into Variable Energy Charge and Infrastructure Energy Charge. The Variable Energy Charge is $0.03523 per kWh and the Infrastructure Energy Charge is $0.04996 per kWh.

E. POWER SERVICE (PS)

Q. What are the charges that KU is proposing for PS?

A. PS is a rate available for large commercial and industrial customers served at secondary voltages (available voltages *less than* 2,400/4,160Y volts) whose 12-month average loads exceed 50 kW but do not exceed 250 kW and for large commercial and industrial customers served at primary voltages (2,400/4,160Y volts, 7,200/12,470Y volts, or 34,500 volts) whose 12-month average do not exceed 250 kW. KU is not proposing an increase to Basic Service Charge for customers served at secondary voltages. Therefore, the Basic Service will remain at $90 per customer per month for secondary voltage customers. The Company is proposing to increase the Basic Service Charge from $200.00 to $240.00 per customer per month for customers served at primary voltages. The Company is not proposing to change the Energy Charge for either secondary voltage customers. Thus, the energy charge will remain at $0.03572 per kWh for secondary voltage service. KU is proposing to increase the energy charge from $0.03446 to $0.03472 per kWh for primary voltage service. For secondary voltage service, the Company is proposing to increase the Summer Demand Charge from $19.05 to $20.71/kW/Mo and to increase the Winter Demand Charge from $16.95 to $18.43/kW/Mo. For primary voltage service, the Company is proposing to increase the Summer Demand Charge from $19.51 to $20.78/kW/Mo and to increase the Winter Demand Charge from $17.41 to $18.54/kW/Mo.

Q. In its Order in Case No. 2015-00417 dated June 29, 2016, the Commission ordered KU to include in its next application for a general adjustment in rates testimony in support of the monthly billing demand provisions of Rate PS. Will you be the witness addressing this issue?

A. Yes.

Q. How is the billing demand determined under Rate PS?

A. For Rate PS, the monthly billing demand is determined as the greater of the following:

a) the maximum measured load in the current billing period but not less than 50 kW for secondary service or 25 kW for primary service, or

b) a minimum of 50% of the highest measured demand in the preceding eleven (11) monthly billing periods, or

c) a minimum of 60% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

Q. Is this a standard provision in the electric utility industry?

A. Yes. It is common for utilities to determine billing demands on the basis of a minimum demand (as in provisions (a) and (c) as shown above) or based on a percentage of the highest demands during a previous 11-month period (as in provision (b) as shown above) or both. Determining billing demands on the basis of a percentage of the highest demand during a previous 11-month or other period is referred to as a "demand ratchet" in the electric utility industry, and is a standard practice in the industry. In a standard treatise on electric utility ratemaking, Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies* (CRC Press: 2009), the author states:

> A *demand ratchet* processes a customer's metered maximum demand for the prior eleven months by applying a specified percentage to those demands in all or a portion of those months and then selects the highest resulting calculated demand as the current month's billing demand – if it exceeds the current month's maximum demand. (*Id.*, at pp. 312.)

Not only are demand ratchets standard provisions in the industry, but the use of a demand ratchet percentage of 50% or greater is also common.

Q. Do other utilities in Kentucky, Indiana, and Ohio have demand ratchets?

A. Yes. The medium and large power tariffs of the major utilities in the region use some form of a demand ratchet. Below is a summary of the ratchets used by investor-owned utilities in Kentucky, Indiana, and Ohio:

i) For Kentucky Power Company's Medium General Service Tariff M.G.S., the monthly billing demand is the maximum of (a) the minimum billing demand of 6 kW or (b) 60% of the greater of (1) the customer's contract capacity in excess of 100 kW or (2) the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 kW.

ii) For Duke Energy Kentucky's and Duke Energy Ohio's Rate DS Service at Secondary Voltage, the billing demand is the higher of (a) 85% of the highest monthly kW demand established in the summer period and effective for the next succeeding 11 months or (b) 1 kW for single phase secondary voltage service and 5 kW for three-phase secondary voltage service.

iii) For Indianapolis Power & Light Company's Rate PL Primary Service, the billing demand cannot be less than 60% of the highest billing demand that has been established in any of the immediately preceding 11 months and in no case less than 500 kW.

iv) For Indiana Michigan Power Company, the monthly billing demand in Indiana cannot be less than 60% of the customer's highest previously established monthly billing demand during the past 11 months, or 100 kVA.

v) For Ohio Edison, the monthly billing demand is the maximum of 1) the measured demand during the month; 2) 5 kW; or 3) the contract demand (where the contract demand is 60% of the customer's expected, typical monthly peak load.)

Q. Is the ratchet provision in KU's Rate PS in line with these other utilities?

A. Yes. All of these utilities except Duke Energy Kentucky and Duke Energy Ohio have a 60% ratchet provision. Duke Energy Kentucky and Duke Energy Ohio have an even higher ratchet percentage of 85%, but the ratchet is only applied to demands metered during the summer months. The ratchet percentage used in KU's Rate PS is lower than these other utilities.

Q. What is the justification for including a demand ratchet in a large power tariff such as Rate PS?

A. A utility must install distribution, transmission, and generation facilities to serve a customer's demand. Just because a customer's demand is not always at the maximum level does not mean that the fixed costs of the facilities installed to meet the customer's maximum demand will disappear. The fixed costs of the facilities installed to meet a customer's maximum demand will be incurred even when the customer has a lower demand. In the case of localized facilities, such as primary and secondary distribution lines, transformers, substations, and transmission facilities, the utility must install sufficient capacity to meet the customer's maximum demand, whenever the demand occurs. Therefore, a utility's transmission and distribution fixed costs are correlated to the customers' maximum demands, not their average monthly demands. Generation fixed costs are correlated to customer demands at the time of the system peak. For most but not all customers, the customer's maximum demands occur near the system peak. For system peak demands, which drive the cost of generation fixed assets, customer load diversity has an effect on the generation requirements that individual customer demands place on the system. Therefore, while a 100% ratchet percentage is justified for the recovery of transmission and distribution fixed costs, a lower ratchet could possibly be justified for the recovery of generation fixed costs. For this reason, in an unbundled rate environment in which generation fixed costs are billed separately from transmission and distribution fixed costs, a 100% ratchet percentage would be justified for the transmission and distribution component, while a lower percentage, such as 50%, would typically be used for the generation fixed cost component of the rate. With a bundled rate, such as KU's Rate PS, in which generation, transmission and distribution fixed costs are recovered through a single demand charge, it is not uncommon to see demand ratchets for a bundled demand charge in the 50 to 90% range.

Q. Do demand ratchets more accurately reflect the actual cost of providing service?

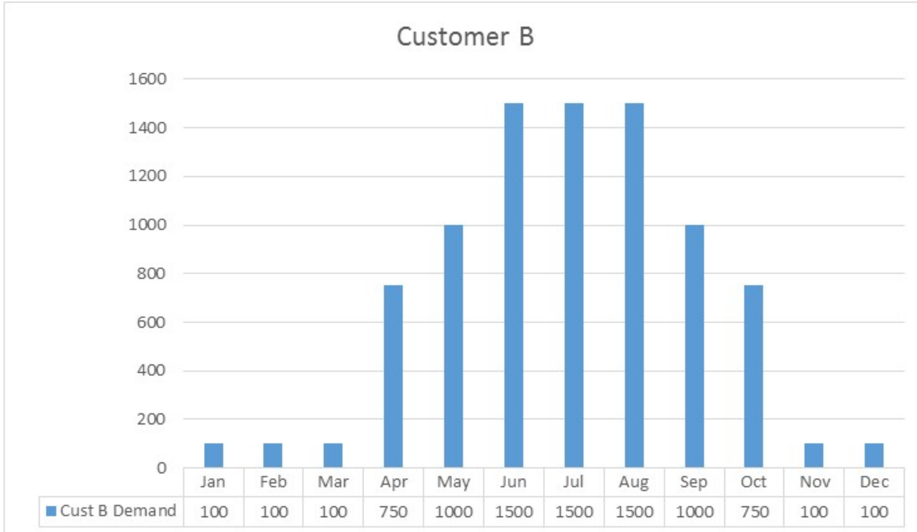
A. Yes, in general they do. Because demand-related fixed costs do not disappear when customers have lower demands during the year, demand ratchets ensure that customers with month-to-month fluctuations in their demand pay an appropriate share of fixed costs. Without demand ratchets, customers with demands that fluctuate from month to month end up being subsidized by customers with steady demands.

Q. Can you provide an example that shows how, without a demand ratchet,

customers with steady demands end up subsidizing customers with fluctuating demands?

A. Yes. Consider two customers – Customer A and Customer B – both with a maximum demand of 1,500 kW during the year. In this example, Customer A has a steady demand of 1,500 kW every month. Customer B has a demand of 1,500 kW that only occurs during the summer peak months, but during the non-summer months Customer B's demands are significantly lower. For purposes of this example, we will assume that both customers' summer demands are coincident with the summer system peak. This is a simplifying but not unrealistic assumption. The following two graphs show the monthly demands for Customer A and Customer B.

Graph 1



Graph 2

In this example, if there are no significant topographical differences between serving the two customers, the fixed generation, transmission and distribution costs would be essentially the same for both customers. Both customers have a 1,500 kW demand coincident with the summer system peak; therefore, the generation fixed costs necessary to serve both customers would be the same. Both customers have a maximum non-coincident demand of 1,500 kW; therefore, the transmission and distribution delivery costs would be the same for both customers. Therefore, in this example, the fixed generation, transmission and distribution costs are the same to serve both customers. Yet, even though it costs the same to serve both customers, without a demand ratchet, the demand charge revenues collected from the two customers are starkly different. The following table shows the demand charge revenue that would be collected from the two customers under the current Rate PS Secondary demand charges without a ratchet:

	Customer A			Customer B		
Month	kW Demand	Demand Charge	Demand Charge Revenue	kW Demand	Demand Charge	Demand Charge Revenue
Jan	1,500	16.95	$ 25,425	100	16.95	$ 1,695
Feb	1,500	16.95	25,425	100	16.95	1,695
Mar	1,500	16.95	25,425	100	16.95	1,695
Apr	1,500	16.95	25,425	750	16.95	12,713
May	1,500	19.05	28,575	1000	19.05	19,050
Jun	1,500	19.05	28,575	1500	19.05	28,575
Jul	1,500	19.05	28,575	1500	19.05	28,575
Aug	1,500	19.05	28,575	1500	19.05	28,575
Sep	1,500	19.05	28,575	1000	19.05	19,050
Oct	1,500	16.95	25,425	750	16.95	12,713
Nov	1,500	16.95	25,425	100	16.95	1,695
Dec	1,500	16.95	25,425	100	16.95	1,695
Total			**$ 320,850**			**$ 157,725**

Table 6

As can be seen from the table, KU would collect less than half the revenue in demand charges from Customer B than from Customer A, even though the fixed costs associated with serving the two customers are the same. Without a ratchet Customer A would be overpaying and Customer B would be underpaying for service. In other words, Customer A would be subsidizing Customer B.

Q. What happens in the example if the Company's current demand ratchet for Rate PS is used?

A. Under the demand ratchet for Rate PS, the billing demand cannot fall below 50% of the customer's monthly demands during the preceding 11 months. If the same load pattern used in the example reoccurs year after year, then Customer B's billing demand could not fall below 750 kW (1,500 x 50% = 750 kW). Of course, Customer

A's billing demand could not fall below 750 kW either, but in this example Customer A's demand is a constant 1,500 kW and thus Customer A is unaffected by the demand ratchet. The table below shows the demand charge revenue that would be collected from the two customers under the current Rate PS demand charges with the current ratchet:

	Customer A			Customer B		
Month	kW Demand	Demand Charge	Demand Charge Revenue	kW Demand	Demand Charge	Demand Charge Revenue
Jan	1,500	16.95	$ 25,425	750	16.95	$ 12,713
Feb	1,500	16.95	25,425	750	16.95	12,713
Mar	1,500	16.95	25,425	750	16.95	12,713
Apr	1,500	16.95	25,425	750	16.95	12,713
May	1,500	19.05	28,575	1000	19.05	19,050
Jun	1,500	19.05	28,575	1500	19.05	28,575
Jul	1,500	19.05	28,575	1500	19.05	28,575
Aug	1,500	19.05	28,575	1500	19.05	28,575
Sep	1,500	19.05	28,575	1000	19.05	19,050
Oct	1,500	16.95	25,425	750	16.95	12,713
Nov	1,500	16.95	25,425	750	16.95	12,713
Dec	1,500	16.95	25,425	750	16.95	12,713
Total			**$ 320,850**			**$212,813**

Table 7

As can be seen, the demand ratchet in Rate PS significantly reduces the subsidies received by Customer B. In this example, the subsidies still exist but they are reduced.

Q. Would it be possible to eliminate all fixed-cost subsidies?

A. In this idealized example it would be possible to eliminate all subsidies. This can be done by increasing the ratchet percentage to 100%. If a 100% demand ratchet is applied, Customer B's billing demand would be 1,500 kW each month (100% x 1,500 kW = 1,500 kW). Again, Customer A's billing demands would be unchanged. With a 100% ratchet, the demand billings would be the same for both customers, as illustrated in the following table:

	Customer A			Customer B		
Month	**kW Demand**	**Demand Charge**	**Demand Charge Revenue**	**kW Demand**	**Demand Charge**	**Demand Charge Revenue**
Jan	1,500	16.95	$ 25,425	1500	16.95	$ 25,425
Feb	1,500	16.95	25,425	1500	16.95	25,425
Mar	1,500	16.95	25,425	1500	16.95	25,425
Apr	1,500	16.95	25,425	1500	16.95	25,425
May	1,500	19.05	28,575	1500	19.05	28,575
Jun	1,500	19.05	28,575	1500	19.05	28,575
Jul	1,500	19.05	28,575	1500	19.05	28,575
Aug	1,500	19.05	28,575	1500	19.05	28,575
Sep	1,500	19.05	28,575	1500	19.05	28,575
Oct	1,500	16.95	25,425	1500	16.95	25,425
Nov	1,500	16.95	25,425	1500	16.95	25,425
Dec	1,500	16.95	25,425	1500	16.95	25,425
Total			**$ 320,850**			**$ 320,850**

Table 8

Q. If a 100% percent demand ratchet would eliminate all of the subsidies in the example, then why isn't KU proposing to use a 100% demand ratchet percentage?

A. As mentioned earlier, the example is somewhat idealized. Specifically, it was assumed that both customers' maximum demands occur at the time of the system peak. This means that the cost of the generation capacity installed to serve both customers would be the same. Not all customers with a load pattern that fluctuates like Customer B will have a maximum demand that occurs at the time of the Companies' system peak. Some low-load factor customers will have a maximum demand that coincides with the system peak and others may not. The relationship between a customer's demand at the time of the system peak and the customer's maximum demand is referred to as the coincidence factor. Coincidence factors for commercial and industrial customers during a month will typically range from 50% to 100%. Because coincidence factors are on average less than 100% it is reasonable to use a demand ratchet for generation fixed costs that is less than 100%. This is the reason that demand ratchets for generation fixed costs are typically between 50% to 90% for rates that are not billed based on a coincident peak demand.

Q. Do demand ratchets encourage customers to use power more efficiently?

A. Yes. Demand ratchets encourage customers to manage their peak demands and purchase energy at a more constant rate. If a customer avoids monthly spikes in its demands, then the customer can avoid the application of the ratchet. Therefore, a ratchet provides an incentive for customers to maintain more steady demands, without month-to-month load fluctuations, which will result in a lower average cost of providing service. Because a utility must install capacity to meet spikes in a customer's demands, if a customer avoids demand spikes the utility can then install less distribution, transmission and generation capacity to serve the customer's load. Demand ratchets induce customers to use power more efficiently and allow demand rates to send a better price signal.

F. LARGE CUSTOMER RATES (TODS, TODP, RTS, FLS)

Q. What are the standard large customer rates offered by KU?

A. KU offers four standard rates for large commercial and industrial customers: Time-of-Day Secondary Service (TODS), Time-of-Day Primary Service (TODP), Retail Transmission Service (RTS), and Fluctuating Load Service (FLS). TODS is available to customers served at secondary voltages (available voltages *less than* 2,400/4,160Y volts) with average demands between 250 kW to 5,000 kW. TODP is available to customers served at primary voltages (2,400/4,160Y volts, 7,200/12,470Y volts, or 34,500 volts) with average demands greater than 250 kVA. RTS is available to customers served at transmission voltages (69,000 volts or higher) with average demands greater than 250 kVA. FLS is available to customers served at primary or transmission voltage whose demands are 20,000 kW or greater. Customers with demands of 20,000 kW or greater whose loads either increase or decrease 20 MVA or more per minute or whose load either increase or decrease 70 MVA or more in ten minutes, when any such increases or decreases occur more than once during any hour of the month, are required to take service under FLS. The proposed charges for TODS, TODP, RTS, and FLS are shown on pages 9, 10, 11, and 12, respectively, of Schedule M-2.3 of the Filing Requirements.

Q. Do all of these rate schedules have the same basic rate structure?

A. Yes. All four of these rates have a rate structure consisting of a Basic Service Charge, an Energy Charge, and a Maximum Load Charge comprising a Peak Demand Charge, an Intermediate Demand Charge, and a Base Demand Charge. For example, the unit charges for TODS are ***currently*** as follows:

Basic Service Charge	$200.00 per customer
Energy Charge	$0.03527 per kWh
Maximum Load Charge:	
Peak Demand Charge	$6.13/kW/Mo.
Intermediate Demand Charge	$4.53/kW/Mo.
Base Demand Charge	$5.20/kW/Mo.

The Peak Demand Charge applies to billing demands (maximum demands) that occur during the weekday hours ("Peak Demand Period") from 1:00 PM to 7:00 PM during the summer months of May through September (summer peak months") and during the weekday hours from 6:00 AM to 12:00 Noon during winter months of October through April (winter peak months). The Intermediate Demand Charge applies to billing demands that occur during the weekday hours ("Intermediate Demand Period") from 10:00 AM to 10:00 PM during the summer peak months and from 6:00 AM to 10:00 PM during the winter peak months. The Base Demand Charge applies to the billing demands that occur at any time during the month.

Q. Is there a cost basis for this rate structure?

A. Yes. KU and LG&E must install sufficient generation resources to meet its peak demands. Peak demand conditions occur during the summer peak months and the winter peak months. Furthermore, peak conditions occur during hours between 6:00 AM in the morning and 10:00 PM at night, but varying by season. KU and LG&E must also install sufficient transmission and distribution facilities to deliver the power to the individual customers, no matter when they need power, whether it is during the peak or intermediate period or otherwise. Over the years, the Companies have structured the Peak Demand Charge and the Intermediate Demand Charge so that these charges would essentially provide recovery of generation fixed costs. The Base Demand Charge was structured so that the charge would basically provide recovery of transmission and distribution demand-related costs. (The structure was initially developed by LG&E and included only a peak and base charge, but was eventually adopted by KU and modified to include an intermediate charge to give customers greater opportunities to control their demands and reduce their demand costs.) Therefore, the Maximum Load Charge was, and is, essentially unbundled between generation fixed costs, which are recovered through the Peak and Intermediate Demand Charges, and transmission and distribution demand-related fixed costs, which are recovered through the Base Demand Charge.

Q. How are the billing demands determined?

A. The billing demands for the Peak and Intermediate Demand Charges are determined as the greater of (a) the maximum measured load during the Peak or Intermediate Demand Periods, or (b) 50% of the highest measured demand for the Peak or Intermediate Demand Periods during the preceding 11 monthly billing periods. This means that a 50% demand ratchet applies to the Peak and Intermediate Demand Charges. The billing demands for the Base Demand Charge is determined as the greater of (a) the maximum measured load during the month (i.e., all hours of the months), (b) 75% of the highest measured demand determined the same way in the preceding 11 monthly billing periods, or (c) 75% of the contract capacity based on the customer's maximum load. This means that a 75% demand ratchet applies to the Base Demand Charge. A higher ratchet was implemented for the Base Demand Charge because the charge was designed to recover transmission and distribution demand-related costs which must be adequately sized to meet the customer's maximum demand whenever the demand occurs.

Q. What changes is KU proposing to the rate structure?

A. KU proposes to keep the same basic rate structure but to increase the demand ratchet for the Base Demand Charge to 100%. The Company is not proposing to change the demand ratchets for the Peak and Intermediate Charges at this time.

Q. Why is KU proposing this change?

A. The modification to the demand ratchets for the large customer rates is being proposed in conjunction with the elimination of the Company's standard rider for Supplemental or Standby Service (Rider SS). The Company has concluded that Rider SS is not adequate in light of fundamental changes that are taking place in the electric utility industry. Rider SS is available to customers who are regularly supplied with electric energy from generating facilities (distributed generation) owned by the customer and who desire to contract with KU for reserve, breakdown, supplemental or standby service. Fundamental changes are taking place in the electric utility industry whereby more customers are installing distributed generation to meet their power needs and falling back on the utility to supply power when their facilities are not operating. In some jurisdictions, there has been a surge in the installation of customer-owned renewable distributed generation such as solar generation or wind generation. In general, utilities are supportive of these initiatives as long as the utility's other customers are not subsidizing customers that install distributed generation facilities. Therefore, it is important for utilities to have a rate structure that prevents the subsidization of distributed generation by customers who have chosen not to install distributed generation.

It is also important for a utility to implement rates that allow the utility to recover the appropriate amount of fixed costs associated with serving customers who have installed distributed generation facilities but who want to rely on the utility to provide generation, transmission and distribution service when the distributed generation facilities are not operating. But KU also wants to offer a rate design that provides reasonable cost recovery while not discriminating against customers who install distributed generation and that isn't excessively harsh or onerous to customers who install distributed generation but want backup service.

Q. Why is the current standby rate inadequate?

A. In addition to the administrative problems with the rider that are addressed in the Direct Testimony of Robert M. Conroy, there has generally been an unwillingness on the part of customers with distributed generation to sign up under the rider because it is viewed as "too harsh" or "too onerous". Rider SS, which is a rider that would generally be applicable to customers served under Rates PS, TODS, TODP, RTS, or FLS, requires a standby customer to establish a contract demand for its entire load. The customer would then be billed a minimum demand charge that is the greater of (1) the customer's total demand charge billed under the customer's primary rate schedule (PS, TODS, TODP, RTS, or FLS), or (2) the demand charge calculated by applying the demand charges set forth in Rider SS to the customer's contact demand. Currently, the demand charges set forth in Rider SS are as follows:

Secondary Voltage:	$12.84 per kW (or kVA) per month
Primary Voltage:	$11.63 per kW (or kVA) per month
Transmission Voltage:	$10.58 per kW (or kVA) per month

These charges were designed to provide full recovery of all production, transmission, and distribution fixed costs. Therefore, for a customer who has installed its own distributed generation facilities, the customer will have paid for its own generation facilities plus the full fixed costs per kW (or kVA) of KU's generation facilities on a monthly basis. From the customer's perspective, under this arrangement the customer will view this as paying for the cost of generation assets twice.

Q. But if the utility is standing ready to provide generation backup service to customers who have installed their own generation, then shouldn't the customer pay a portion of the fixed costs?

A. Yes, they should. The challenge, though, is determining the appropriate level of fixed costs that the customer should pay. The amount that a distributed generator should pay largely depends on the operating characteristics of the distributed generation facilities that are installed. In all cases, a standby customer should pay for all of the transmission and distribution plant installed to serve the customer's maximum demand. As discussed earlier in the portion of my testimony addressing the demand ratchet for Rate PS, sufficient transmission and distribution capacity needs to be installed to deliver power to the customer whenever the customer needs it. For a customer who has installed distributed generation facilities, the utility must have transmission and distribution capacity to deliver sufficient power to meet the customer's load requirements whenever the customer's distributed generation facilities aren't operating. But for generation capacity, the cost of backing up the customer depends on the operating characteristics of the customer's generating facilities. For example, if the customer has installed solar generation, then the utility would be called upon to provide backup power whenever there isn't sufficient sunlight to energize the solar panels, which is likely to occur during periods when the utility is experiencing peak load conditions, such as during a winter system peak which typically occurs during nighttime hours. Likewise, if the customer has installed wind generation, then the utility would be called upon to provide backup power whenever the wind isn't blowing, which is also likely to occur during summer and winter system peak load conditions. Therefore, for these types of distributed generation facilities, it is highly likely that the utility would be called upon to provide backup power during time periods when the utility is experiencing peak load conditions. On the other hand, if the customer has installed a coal- or gas-fired generating facility that operates basically continuously at a low forced outage rate, then it is less likely that the utility would be called upon to provide generation backup power during peak load conditions. Therefore, it would, in general, be less costly to provide generation backup service to a customer who has a generating facility that is operated 24 hours per day, seven days per week, but with a random forced outage rate than to provide generation backup service to a customer whose generating facility is subject to wind conditions and available sunlight.

Q. How will the costs of providing backup service be addressed if Rider SS is eliminated?

A. Under KU's proposal, a customer with distributed generation facilities who relies on KU to provide backup service to its generating facilities would be served on the same rate as any other customer. Therefore, the Company will not discriminate between a customer who has distributed generation facilities and any other customer with similar fluctuating load requirements. If a customer with distributed generation meets the load requirements for one of the Company's standard rate schedules, then the customer will be served under that rate schedule. However, this policy necessitates a change in the demand ratchet for Rates TODS, TODP, RTS, and FLS.

Q. Please explain how serving standby customers under TODS, TODP, RTS, and FLS and changing the ratchet will help provide proper recovery of fixed generation, transmission, and distribution demand-related costs.

A. As explained earlier, generation fixed costs are essentially recovered through the Peak and Intermediate Demand Charges. A 50% demand ratchet is applied in determining the billing demand for these rate components. Importantly, the billing demands are based on measured demands during the Peak and Intermediate Billing Periods. Therefore, if a standby or other customer has a demand that occurs during the peak and intermediate hours (and most customers do), then the Peak and Intermediate Demand Charges will apply to those demands. But if the customer's demand occurs outside of the Peak and Intermediate Billing Periods, then there will be no measured demands during those periods and the Peak and Intermediate Demand Charges will not apply.

Furthermore, the 50% ratchet will be applied based on the maximum demands that have occurred during the preceding 11 months. ***KU is not proposing to change the ratchet percentages applicable to the Peak and Intermediate Demand Charges at this time.*** The structure for determining the billing demand allows the Company to recover at least 50% of a maximum demand that occurred during the peak and intermediate periods for the current and preceding 11 months. This demand ratchet therefore provides recovery of at least 50% of the annual fixed generation costs that the Company has incurred to supply generation capacity to the customer. At this point, the Company believes that the 50% demand ratchet, along with the change to the proposed ratchet for the Base Demand Charge, strikes a reasonable balance *between* (i) providing a pricing structure for recovering a reasonable portion of the annual fixed generation costs incurred to provide service to standby customers and to customers with intermittent loads that fluctuate from month to month *and* (ii) offering a pricing structure that isn't unduly harsh or onerous to standby or customers with intermittent loads. It should be kept in mind that the two components that provide recovery of generation fixed costs – the Peak and Intermediate Demand Charges – represent most of the total demand charges billed under Rates TODS, TODP, RTS, and FLS. Under KU's current rates, the peak and intermediate demand charges represent from approximately 67% to 75% of the total demand charges. (For example, by calculating a simple percentage of the peak and intermediate demand charges to the total of the peak, intermediate and base demand charges for Rate TODS, the percentage is 67% [($4.53 + $6.13) ÷ ($4.53 + $6.13 + $5.20) = 67%]. For Rate TODP, the percentage to the total is 75% [($4.39 + $5.89) ÷ ($5.89 + $4.39 + $3.34) = 75%]. Therefore, peak and intermediate demand charges, which represent most of the demand charges for these rate schedules, will be unaffected by the proposed change in the ratchet.

For transmission and distribution costs, it is important to increase the ratchet percentage to provide assurance that the fixed costs of the transmission and distribution facilities installed to deliver power to customers any time they need the power are appropriately recovered from standby customers and from customers with large month-to-month fluctuations in their loads. As explained in the portion of my testimony dealing with the demand ratchets for Rate PS, transmission and distribution facilities must be sized to deliver the maximum load that the customer creates on the system. Unlike generation facilities, transmission and distribution facilities are designed to meet localized demands placed on the system by customers. The Company is therefore proposing to implement a 100% ratchet for the component of the demand charge that provides for recovery of transmission and distribution fixed costs. The 100% ratchet will only apply to the Base Demand Charge which currently represents between 25% and 33% of the total demand charges (based on the above calculations).

Q. What is the effective *overall* demand ratchet if you consider all three rate components?

A. As I explained, for TODS, TODP, RTS, and FLS, the 100% ratchet would only apply to the Base Demand Charge and the current 50% ratchet would continue to apply to the Peak and Intermediate Demand Charges. Based on a simple analysis, since the 50% ratchet would apply to the demand charge components (Peak and Intermediate Demand Charge) that represent between 67% to 75% of the demand charges, whereas the 100% ratchet would apply to the demand charge component (Base Demand Charge) that represents between 25% and 33% of the cost, the simple weighted effect of both ratchets works out to be equivalent to a demand ratchet of 62.5% to 66.5%. [75% x 50% + 25% x 100% = 62.5% and 67% x 50% + 33% x 100% = 66.5%.] These effective ratchet percentages are not out of line with demand ratchet percentages typically included in rates applicable to large commercial and industrial customers.

Q. Will changing the demand ratchet for the Base Demand Charge have a large impact on customer's bills?

A. Because the impact will be factored into the determination of the revenue requirement for the rate classes, the change will not result in any more or any less revenue calculated for the class. Specifically, the revenues calculated at the proposed rates are determined by applying the proposed Base Demand Charges for TODS, TODP, RTS and FLS to billing demands for the test year that are reflective of the revised ratchet.

In other words, in determining the proposed revenue for the Base Demand Charges the charges are multiplied by billing demands that are higher than what would otherwise be billed during the forecasted test year. Therefore, from the Company's perspective, the change is revenue neutral. The Company is not expected to collect any more revenue from customers as a result of making this change. While the proposed demand ratchet may protect against revenue erosion if customers install distributed generation, it is not anticipated that the Company will collect additional revenues coming out of the rate case as a result of this change. However, on an individual customer basis, the change will affect some customers more than others. Specifically, the change will result in larger increases to customers with large fluctuations in their monthly demands and in smaller increases to customers with steady demands that don't fluctuate from month to month. A number of manufacturing customers on KU and LG&E's system will benefit from the change, particularly high-load-factor manufacturing or commercial customers with relatively constant demands from month to month. Of course, customers with intermittent loads will see a larger increase.

Q. Do you have any other comments about the proposed change in the demand ratchet?

A. Yes. It is important to note that this proposal will create a level playing field for customers who install distributed generation and rely on KU for backup service and customers with large fluctuations in their monthly demands. From the utility's perspective there is not much difference between serving either type of customer.

Therefore, the proposed rate structure represents a non-discriminatory approach to serving both types of customers while helping to ensure that the utility's other customers are not subsidizing standby customers or customers with large swings in their monthly demands.

G. CURTAILABLE SERVICE RIDER (CSR)

Q. Please describe the proposed changes to CSR.

A. The Curtailable Service Rider is a rider that provides a credit to industrial or commercial customers that will interrupt a portion of their load when called upon by KU. Curtailable customers receive a discount in the form of a credit to their demand charges in exchange for their willingness to receive curtailable service on a designated portion of their load. A customer taking service under CSR is subject to a maximum of 375 hours of curtailment (or interruption) during a 12-month period. KU is proposing to lower the CSR credit from $6.40 to $3.20 per kVA of curtailable billing demand for transmission voltage service and from $6.50 to $3.31 per kVA for primary voltage service. As also discussed in Mr. Conroy's testimony, the Company is proposing to restrict the rider so that it will only be available to customers served under the schedule as of the date new rates go into effect as a result of this proceeding.

Q. What is the basis for the proposed credit?

A. As also discussed in the Direct Testimony of David S. Sinclair, KU is proposing to determine the credit based on the fixed carrying costs of the large-frame combustion turbines jointly owned by KU. Specifically, the credit is based on Brown Units 8, 9, 10, and 11, which are wholly owned by KU, and on KU's portion of the fixed costs of the jointly-owned Brown Units 5, 6, and 7, Trimble County Units 5, 6, 7, 8, 9, and 10, and Paddy's Run Unit 13. These units were installed during the late 1990s and early 2000s. It is appropriate to use the fixed carrying costs of these combustion turbine units because these units would be dispatchable for a similar number of hours as the hours of curtailment set forth in the CSR tariff. These units are typically dispatched after KU and LG&E's base load coal-fired steam units, gas-fired combined cycle facility, solar generation facility, and hydro-electric units. Traditionally, load designated to be served under CSR has been used to avoid or defer the installation of peaking units such as combustion turbines which have been dispatched fewer hours of the year than coal-fired steam generating units or gas-fired combined cycle generating units. In the past, the CSR credit has been based on the avoidance or deferral of a hypothetical combustion turbine unit. The Companies currently expect they will have no need to install peaking or other generation capacity through the end of the forecasted test year. Therefore, instead of using the cost of a hypothetical future combustion turbine unit that may or may not be installed during the next decade or more to establish the credit, the Company is proposing to use the fixed carrying costs of the most-recently installed conventional combustion turbines as the basis for the CSR credits.

Q. What do you mean by a "conventional combustion turbine"?

A. A conventional combustion turbine, as opposed to a combined-cycle combustion turbine, is a single cycle turbine for which there is no heat-recovery system that allows heat from the combustion gas to be reused to operate at higher efficiencies. Combined-cycle units have higher fixed costs but operate at greater capability and higher efficiencies, which allows the units to be operated for more hours during the year. KU's combined cycle unit will typically operate for more than 8,000 hours during the year. The operational hours of a combined cycle generating unit or of a coal-fired steam generating unit are in no way comparable to the hours of curtailment set forth in the CSR tariff.

Q. What is a "large-frame combustion turbine"?

A. Beginning in the 1980s, utilities began installing larger combustion turbines that achieved higher efficiencies than their earlier, and typically smaller, counterparts. Large-frame combustion turbines operate at higher capabilities and higher pressures allowing the units to achieve higher efficiencies. All the combustion turbines that KU installed since 1999 have been large-frame units.

Q. How many hours are these combustion turbines dispatched during a 12-month period?

A. It varies from year to year, but the Companies' large-frame combustion turbines will typically be dispatched from 200 to 1,500 hours during a 12-month period. The following table shows the number of hours that the large-frame Brown, Trimble and Paddy's Run combustion turbines owned or jointly-owned by KU were dispatched during the 12 months ended June 30, 2016:

Kentucky Utilities Company's Large-Scale Conventional Combustion Turbine Units	
Generating Unit	**Hours of Operations**
Brown Unit 5	644
Brown Unit 6	270
Brown Unit 7	257
Brown Unit 8	1465
Brown Unit 9	1341
Brown Unit 10	1958
Brown Unit 11	678
Trimble 5	1614
Trimble 6	982
Trimble 7	1632
Trimble 8	371
Trimble 9	1081
Trimble 10	382
Paddy's Run 13	973

Table 9

These units will typically operate for more hours than the maximum number of hours of annual curtailment under the CSR tariff, and they typically have start-up times that are shorter than the 30-minute period that CSR customers can respond to a curtailment. Brown 8, 9, 10, and 11 and Trimble 8 and 10 are quick-start units that can be brought on line and fully loaded in 10 minutes or less. Trimble 8 and 10 are often held in reserve as quick-start capacity for emergencies. While the combustion turbine units listed in Table 9 have operating characteristics that offer greater flexibility than curtailable load, these are still the generating units in the Companies' fleet that are the most comparable in terms of the hours' use of the units and the startup times to the terms and conditions of the CSR rate schedule. The Companies' combined-cycle and coal-fired base load units will typically operate over 8,000 hours per year and have longer startup times, and the Company's older combustion turbines will typically operate less than 100 hours during a 12-month period. Furthermore, the large-frame units listed in the above table are the most recent combustion turbines installed by the Companies.

Q. How are the fixed carrying costs for the large-frame combustion turbine units calculated?

A. The carrying costs are calculated based on the total fixed cost of the units for the fully-forecasted test-year. The fixed carrying charges for the units include the following standard cost-of-service components: (1) return on net investment (rate base), (2) income taxes, (3) depreciation expenses, (4) operation and maintenance expenses, and (5) property taxes. These are the standard items included in a utility's revenue requirements.

Q. Have you prepared an exhibit showing the derivation of the CSR credits?

A. Yes. Exhibit WSS-3 shows the calculation of the CSR credit based on the fixed carrying costs of the Brown, Trimble County, and Paddy's Run 13 combustion turbines. This analysis shows that the credit should be \$3.20/kVA/Month for transmission voltage service and \$3.31/kVA/Month for primary voltage service.

Q. Why is KU proposing to restrict the CSR schedule so that it will only be available to existing customers after the new rates go into effect?

A. As mentioned earlier, KU has no need for additional generation capacity during the next decade or so. The Companies have not issued any curtailments under Rider

CSR since January 2015. Because the current generation mix was planned to take into account CSR capacity and its use in avoiding combustion turbine capacity, the Companies believe that it is appropriate to provide *current* CSR customers a credit based on the actual fixed cost of the most recent combustion turbines that were installed by the Companies.

H. LIGHTING RATES

Q. Explain how the rate increases were determined for the lighting rates?

A. KU offers two rates that include the lighting fixture along with the delivered energy to operate the lights. Those two rates are Lighting Service (LS) and Restricted Lighting Service (RLS). The Company also offers two types of delivered energy service to customers who own their own lighting fixtures or traffic lights. Those two rates are Lighting Energy Service (LE) and Traffic Lighting Service (TE).

The proposed rates for each type of light under Rate LS and Rate RLS were determined by allocating the revenue requirement for the lighting class to each light type based on the cost of each type of lighting fixture. Those costs include the carrying charges, distribution energy costs, and operation and maintenance expenses. The maximum increase for any type of fixture was capped at 20%. KU is proposing comparatively smaller increases for mercury vapor lights because incandescent and mercury vapor lights are no longer being replaced and, in some cases, they are approaching their depreciable lives. The current unit revenue requirement of fixtures under Rate LS and Rate RLS is shown in Exhibit WSS-4. The proposed charge for each fixture type is shown on pages 16 through 21 of Schedule M-2.3 of the Filing Requirements.

KU is not proposing an increase to Rate LE. Therefore, the Energy Charge for Rate LE remains at $0.07328/kWh. For Rate TE, the Company is not proposing to increase the Basic Service Charge from its current level of $4.00 per delivery point per month; however, KU is proposing to increase the Energy Charge from $0.08740/kWh to $0.09289/kWh.

Q. Is KU proposing to offer any new types of lights?

A. Yes. KU wants to be proactive in encouraging energy efficiency by offering light emitting diode ("LED") lights. The lights being offered correspond to the size and style of the most popular conventional lights offered by the Company. The new lights to be offered are: (1) 50 Watt Open Bottom Overhead Yard Light; (2) 80 Watt Overhead Cobra Head Light; (3) 134 Watt Overhead Cobra Head Light; (4) 228 Watt Overhead Cobra Head Light; (5) 80 Watt Underground Cobra Head Light; (6) 134 Watt Underground Cobra Head Light; (7) 228 Watt Underground Cobra Head Light; and (8) 68 Watt Underground Colonial Light. While LED lights are more energy efficient than traditional lighting fixtures, the cost of an LED fixture tends to be higher than the cost of a conventional fixture, and the average service life ("ASL") for an LED fixture is expected to be lower. This could ultimately result in higher depreciation expenses for all lights.

Q. How did KU develop the proposed charges for these new lights?

A. The rates for these lights were determined using a standard revenue requirement approach, with carrying charges, distribution energy costs, and operation and maintenance expenses included as revenue requirements for the monthly rates. The carrying charges include depreciation expenses, return on investment, income taxes and property taxes. The support for the proposed rates for LED lights is included in Exhibit WSS-5.

I. REDUNDANT CAPACITY (RC)

Q. Please describe KU's Redundant Capacity rider.

A. The Redundant Capacity rider allows customers that have one or more redundant distribution feeds to reserve back-up capacity on the distribution system. This rider would typically be used by customers who want greater assurance that their service will not be interrupted because of an outage on a distribution line. These customers would want a redundant feed along with automatic relay equipment capable of switching from a principal circuit to a backup circuit if electric service from the primary feed is lost. With the greater use of technology, some customers are finding it increasingly difficult to tolerate electrical outages for even short periods of time.

Q. How is a customer charged for redundant capacity?

A. A customer who wants a second feed must pay the cost of the customer-specific facilities required to provide the feed, including the second distribution line, automatic relay equipment, or other customer-specific facilities that may be required. Customers can pay for the customer-specific facilities by either making a contribution-in-aid-of-construction or by taking service under the Company's Excess Facilities rider. If the customer wants to have full backup capacity on the second feed, there are additional costs incurred by KU of ensuring that there is sufficient network distribution capacity to provide full backup if a relay occurs on the automatic switchgear. To ensure that there is sufficient capacity on the redundant feed to serve the load if the primary feed goes down, the utility must plan the distribution facility as if there were two customers placing demands on the system. For this reason, KU assesses a demand charge to cover the distribution demand-related cost of providing backup service for new customers with redundant feeds. The demand charge is applied to the customer's monthly billing demand determined under the standard rate schedule under which the customer receives service. Rider RC includes a charge for customers taking service at primary voltages and a charge for customers taking service at secondary voltages.

Q. What changes is KU proposing to the Redundant Capacity charges?

A. KU is proposing to decrease the demand charge for primary voltage customers from \$1.11 to \$0.90 per kW per month and from \$1.12 to \$1.09 per kW per month for secondary voltage customers. The cost support for the proposed redundant capacity charges is included in Exhibit WSS-6.

IV. MISCELLANEOUS SERVICE CHARGES

A. POLE AND STRUCTURE ATTACHMENTS (RATE PSA)

Q. Is the Company proposing to adjust the pole attachment charge?

A. Yes. Changes to the tariff language are discussed in Mr. Conroy's testimony. As described in Mr. Conroy's testimony, the Company is broadening the tariff to include not only charges for cable television attachments but also charges for telecommunication wireline and wireless facilities that are attached to KU's poles and cable television and telecommunications wireline facilities utilizing the Company's underground infrastructure. In the proposed schedule, the Company is proposing three charges: (1) an annual charge per standard pole attachment which is based on one foot of the usable space on the pole; (2) an annual charge per attachment for wireless telecommunication facilities such as antennas, risers, transmitters, and receivers when they are attached to the Company's poles; (3) an annual charge per linear foot of duct that will be applicable when the Company's underground infrastructure is utilized for cable television or telecommunication wireline facilities. Cable television companies are currently covered by the Company's rate schedule, but other telecommunication attachments are billed pursuant to individual contracts with the companies or organizations that attach to KU's poles. KU is proposing that as these individual contracts expire then the attachments would be transitioned to and covered by Rate PSA. I will address the derivation of the charges for the rate schedule in my testimony below.

Q. Is KU proposing any increases to the attachment charges that would be applicable to cable television companies?

A. No. The Company is proposing to maintain the pole attachment charge applicable to cable television companies at the current level of $7.25 per attachment. When I calculated the attachment charges using forecasted costs based on a revenue requirements reflecting net cost plant (net cost rate base), the analysis resulted in a unit cost for KU and LG&E of $7.45 per attachment. Because the current charge reasonably reflects the updated cost based on forecasted net plant, the Company decided not to propose a change in the rate at this time.

Q. Is the Company proposing to apply this same rate to other wireline attachments?

A. Yes.

Q. Please describe the methodology used to calculate the charges.

A. In its Order in Administrative Case No. 251, the Commission prescribed a methodology for determining the attachment charges. The calculations set forth in Exhibit WSS-7 follow the guidelines established in Administrative Case No. 251. In this exhibit, the weighted average carrying costs are calculated for 35, 40 and 45 foot poles. The charge is calculated by multiplying a usage factor of 0.0759 by the annual carrying costs of a bare pole. The 0.0759 usage factor was the prescribed percentage for a three-user pole set forth in the Commission's Order in Administrative Case No. 251 dated September 17, 1982, and assumes that a cable television attachment would utilize one foot of the usable space on the pole. In calculating bare pole costs, 15% of the pole costs have been removed from plant in service costs for 35, 40 and 45 foot poles to reflect the elimination of appurtenances.

The calculations set forth in Exhibit WSS-8 for the duct attachment charge follow the same carrying charge methodology except the cost of conduit investment is utilized. In calculating the cost per foot of duct, the methodology for determining the applicable linear feet of duct is consistent with the methodology described in the *Report and Order* issued in CS Docket No. 97-98 by the Federal Communications

Commission on April 3, 2000.

Q. How are the carrying charges calculated?

A. They are calculated using a standard revenue requirement (cost of service) methodology. The carrying charges include the following cost-of-service components: (1) return on net investment (rate base), (2) income taxes, (3) depreciation expenses, (4) O&M expenses, and (5) property taxes. These are the standard items included in a utility's revenue requirements.

Q. Are the charges based on net depreciated plant?

A. Yes. Net depreciated plant (or rate base), along with straight line depreciation, is used in the carrying charge calculation. This approach is consistent with the way that all other revenue requirements are determined in this proceeding. Therefore, the charges shown in Exhibits WSS-7 and WSS-8 are reflective of current revenue requirements associated with the cost of providing attachment service.

Q. What is the proposed charge for attaching wireless facilities to a pole?

A. The proposed charge for attaching a wireless facility is $84.00 per year per attachment. This charge was determined by multiplying the annual charge for a standard attachment by 11.585 feet, which corresponds to the average space currently used for each wireless facility.

Q. What is the proposed duct attachment charge?

A. The proposed charge for a duct attachment is $0.81 per year per linear foot of duct.

Q. Is there a revenue impact for these changes?

A. Yes. There is a small revenue impact. While KU is not proposing to change the rate applicable to cable television companies, the Company will apply the rate to all other wireline attachments as the contracts that are currently in place for such attachments expire. For purposes of calculating the impact on miscellaneous revenues in this proceeding, the Company assumes that all wireline contracts will expire during the test year, resulting in an increase in miscellaneous revenue of $19,720. (For LG&E, there is a revenue decrease that is approximately equal to this amount.) The support for the change in miscellaneous revenues is shown in Exhibit WSS-9.

B. UNAUTHORIZED RECONNECTION CHARGE

Q. Is KU proposing an Unauthorized Reconnection Charge and what is it?

A. Yes. KU is proposing to add an Unauthorized Reconnection Charge to its tariffs that will allow the Company to recover the cost of addressing theft of service in excess of any back-billing of energy and/or demand charges for stolen service. Specifically, the Unauthorized Reconnection Charge is a set of charges that would apply when a customer either connects or reconnects to the Company's service without authorization. Because these reconnects will typically involve some type of meter tampering, the charge will vary depending on whether the Company's metering equipment has been damaged and needs to be replaced. The need for the charge is discussed in Mr. Conroy's testimony. I will discuss the calculation of the standard charges that would apply.

Q. Please describe the various Unauthorized Reconnection Charges that KU is proposing and how they are calculated?

A. The Company is proposing the following charges: (1) an Unauthorized Reconnection Charge of $70.00 for an unauthorized connection or reconnection that does not require the replacement of the meter; (2) an Unauthorized Reconnection Charge of $90.00 for an unauthorized connection or reconnection that requires the replacement of a single-phase standard meter; (3) an Unauthorized Reconnection Charge of $110.00 for an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Meter Reading ("AMR") meter; (4) an Unauthorized Reconnection Charge of $174.00 for an unauthorized connection or reconnection that requires the replacement of a single-phase Automatic Metering System ("AMS") meter; and (5) an Unauthorized Reconnection Charge of $177.00 for an unauthorized connection or reconnection that requires the replacement of a three-phase meter. The cost support for these charges is included in Exhibit WSS-10. The charge includes the labor cost of a field investigator and back-office support, transportation costs, cost associated with the installation of a locking device to prevent future meter tampering, and the cost of replacing the meter if necessary.

Q. Will implementing this rate result in increased miscellaneous revenues?

A. No. The Company has been recovering the costs from customers who have tampered with their meter based on the out-of-pocket expenses incurred by the Company. Since the proposed rate is determined on the same basis (i.e., on the basis of average out-of-pocket expenses), there will be no difference between the forecasted charges reflected in the determination of revenue requirements and the revenues that would be collected from the implementation of a standard charge in the tariff.

V. COST OF SERVICE STUDY

Q. Did The Prime Group prepare a cost of service study for KU's operations based on forecasted financial and operating results for the 12 months beginning July 1, 2017?

A. Yes. The Prime Group prepared a fully allocated embedded cost of service study based on a forecasted test year beginning July 1, 2017. The cost of service study corresponds to the pro-forma financial exhibits that the Company has provided to meet the requirements of Section 16(8). The objective in performing the cost of service study is to allocate KU's revenue requirement as fairly as possible to all of the classes of customers that KU serves, to determine the rate of return on rate base that KU is earning from each customer class, and to provide the data necessary to develop rate components that more accurately reflect cost causation.

The Prime Group prepared two versions of the cost of service study using alternative methodologies to time-differentiate and allocate fixed production costs. In the first version of the cost of service study, the modified Base-Intermediate-Peak ("BIP") methodology used in prior KU and LG&E cost of service studies was utilized. In the second version of the study, a Loss-of-Load-Probability ("LOLP") methodology was utilized. I will describe the two methodologies later in my testimony. All other costs, including variable production costs, transmission costs, and general plant are handled the same way in both versions of the study.

Q. What model was used to perform the cost of service study?

A. The cost of service study was performed using an EXCEL™ spreadsheet model that was developed by The Prime Group and that has been utilized in previous filings by KU to support requests for adjustments in its rates.

Q. What procedure was used in performing the cost of service study?

A. Regardless of whether a historic test year or a forecasted test year is used to develop a cost of service study, the methodology for developing a cost of service study is basically the same. However, because KU operates in multiple jurisdictions, it is necessary to identify costs for the Kentucky jurisdiction prior to developing a cost of service study. Therefore, the spreadsheet model used to perform the cost of service study also includes a jurisdictional separation analysis. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods which time differentiates the costs. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then finally (4) costs were allocated to the rate classes. These steps are depicted in the following diagram (Figure 1).

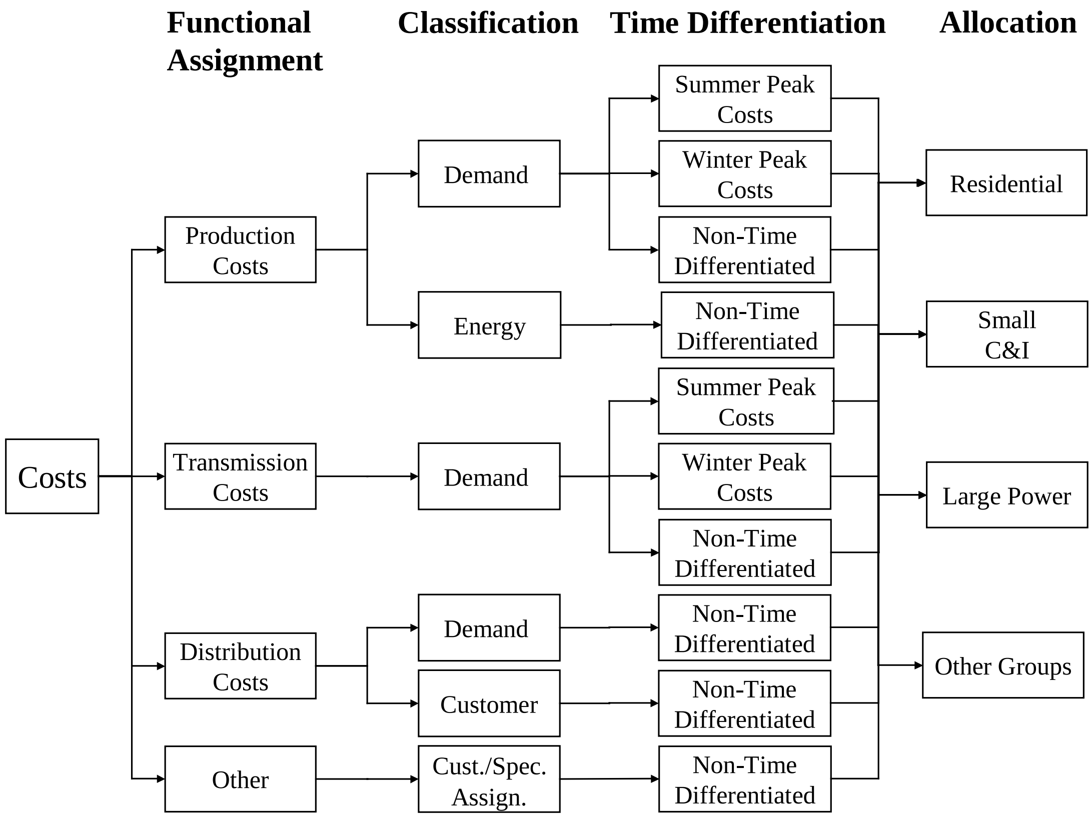


Figure 1

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. How were costs time differentiated and allocated in the version of the study that utilized the BIP methodology?

A. The BIP method is used to assign production costs to the relevant costing periods.[1] Using this methodology, production demand-related costs (fixed costs) were assigned to three categories of capacity – base, intermediate, and peak. The percentages of production fixed cost that were assigned to the base period were determined by dividing the minimum system demand by the maximum demand. The percentages of production fixed cost that were assigned to the intermediate period were calculated by dividing the winter peak demand by the summer peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer or winter peak periods or assigned as non-time-differentiated. Base costs were assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. In applying the modified BIP methodology, what demands were used?

A Demands for the combined KU and LG&E systems were used to determine the costing periods and in determining the percentages of production fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly, developing costing periods and assigning costs to the costing periods based on the

[1] In Case No. 90-158, the Commission found LG&E's cost of service study, which utilized the modified BIP methodology, to be "acceptable and suitable for use as a starting point for electric rate design." (Order in Case No. 90-158, dated December 21, 1990, at 58.)

combined loads for KU and LG&E accurately reflects cost causation. Developing the costing periods and allocation factors in the cost of service study based on the combined loads for KU and LG&E does not result in any shifting of booked expenses from one utility to the other. LG&E's cost of service study relied on LG&E's accounting costs, and KU's cost of service study relied on KU's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the KU and LG&E cost of service studies.

Q. What percentages were assigned to the costing periods using the BIP methodology?

A. Exhibit WSS-11 shows the application of the BIP methodology. Using this methodology 34.38% of KU's production and transmission fixed costs were assigned to the winter peak period, 36.02% to the summer peak period, and 29.60% as base period costs that are non-time-differentiated.

Q. How were costs time differentiated and allocated in the version of the study that utilized the LOLP?

A. LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour. Loss of load probability therefore takes into consideration the magnitude of the load, installed generation capacity, forced outage rates, maintenance schedules, and ramp-up rates of generating units. LOLP can be calculated for any period – an hour, a day, a week, etc. LOLP is a critical measurement used by KU and LG&E in planning its generation resources. Specifically, it is used to evaluate the level of reserve margins that the Companies target. Therefore, LOLP can serve as a foundation for allocating fixed production costs to the classes of customers. In other words, allocating fixed production costs on the basis of LOLP links the cost-of-service allocation methodology to a key measurement used by KU and LG&E to plan the system.

For the cost of service study, LOLP was calculated for each hour of the test year based on the hourly loads for the test year and the characteristics of KU and LG&E's generating facilities, including capacity, forced outage rates, and maintenance schedules. Hourly loads for each rate class were then weighted by the LOLP for each hour to determine LOLP weighted hourly load for each rate class. The weighted loads for each rate class are then summed for the test year to determine a production fixed cost allocator. Mathematically, this is equivalent to calculating an allocation vector for fixed production costs using the following formula:

$$\overline{PROD\ ALLOCATOR} = \sum_{i=1}^{8760} LOLP_i * \overline{LOAD_i}$$

Where: $\overline{PROD\ ALLOCATOR}$ is the allocation vector for production fixed costs in the cost of service study;

$LOLP_i$ is the Loss of Load Probability for hour i;

$\overline{LOAD_i}$ is a vector of hourly load (in kW) for each rate class at hour i; for example, $\overline{LOAD_i} =$ (load for Rate RS at hour i, load for Rate GS for hour i, load for Rate PS at hour i, …);

i is the hour of the year;

The allocation vector $\overline{PROD\ ALLOCATOR}$ is then used to allocate fixed production costs to the customer classes in the cost of service study.

Q. But is the LOLP approach a time-differentiated methodology?

A. Yes, and at a fine level of granularity. With the LOLP methodology, costs are differentiated for each hour of the test year. The approach can also be adapted to calculate costs for any set of time periods during the test year, including the base, intermediate and off-peak periods used in the BIP, or the approach can be adapted to calculate costs for other time periods that may be more appropriate for rate design. Exhibit WSS-12 is a summary of the production fixed cost allocators used in the LOLP version of the study.

Q. Why are you presenting an alternative methodology for allocating fixed production costs?

A. While the BIP methodology has been accepted by the Commission as a basis of developing rates in prior rate cases, the LOLP methodology more closely reflects how KU and LG&E's generation resources have been planned over the past 30 years or so and how the Companies' generation resources are currently planned. Therefore, the LOLP version of the study provides useful information for the development of rates.

Q. How were costs classified as energy-related, demand-related or customer-related?

A. Classification involves utilizing the appropriate cost driver for each functionally assigned cost which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. For costs classified as *energy-related*, the appropriate cost driver is the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand-related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. The costs of production plant and transmission lines are examples of costs typically classified as demand-related costs. Costs classified as *customer-related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, a portion of the costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related because these costs do not vary with customers' capacity or energy usage.

Q. What methodologies are commonly used to classify distribution plant between customer-related and demand-related components?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of the minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the average number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is preferred over the minimum system methodology when the necessary data is available. Additionally, KU has utilized the zero-intercept methodology in determining customer-related costs in prior rate case filings before this Commission. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer-related component of distribution costs. In the zero-intercept methodology, the estimated cost of a zero-size conductor or line transformer is the absolute minimum system for determining customer-related costs.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost of conductor ($/ft) or line transformers ($/kVA of transformer size) and the load flow capability of the plant measured as the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero-intercept. The zero-intercept is essentially the cost component of conductor or transformers that is invariant to the size and load carrying capability of the plant.

Like most electric utilities, the feet of conductor and the number of transformers on KU's system are not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted linear regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted linear regression analysis all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

Using a weighted linear regression analysis, the cost and size of each type of conductor or transformer is weighted by the number of feet of installed conductor or the number of transformers. In a weighted linear regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

Q. Has the Commission accepted the use of the zero-intercept methodology?

A. Yes. The Commission found LG&E's cost of service studies submitted in Case No. Case No. 90-158 to be reasonable, thus providing a means of measuring class rates of return that are suitable for use as a guide in developing appropriate revenue allocations and rate design. The cost of service studies in both proceedings utilized a zero-intercept methodology to calculate the splits between demand-related and customer-related distribution costs. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2014-00371 and 2014-00372, the Companies' last general rate case filings.

Q. Have you prepared exhibits showing the results of the zero-intercept analysis?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Exhibits WSS-13, WSS-14 and WSS-15, respectively.

Q. Have you prepared an exhibit showing summarizing the results of the functional assignment, time-differentiation and classification steps of the cost of service study?

A. Yes. Exhibit WSS-16 shows the results of the first three steps of the cost of service study for the BIP version of the study, namely functional assignment, classification, and time differentiation. Exhibit WSS-17 shows the same three steps for the LOLP version of the study. The first column of numbers in these two exhibits reflect plant costs and expenses for KU's Kentucky retail jurisdiction. In the cost of service model used in this study, the calculations for functionally assigning, classifying and time differentiating KU's accounting costs are made using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*[2]) by the dollar amount in the various accounts to simultaneously functionally assign, classify and time differentiate KU's accounting costs. These calculations are made in the portion of the cost of service model included in Exhibits WSS-16 and WSS-17. In these exhibits, KU's accounting costs are functionally assigned, classified and time differentiated using explicitly determined functional vectors and using internally generated functional vectors. The explicitly determined

[2] "Scalar multiplication" is the multiplication of each element of a vector by a constant (scalar). Scalar multiplication is different from "vector multiplication," in which one vector is multiplied by another vector either as a dot product (whose product is a scalar) or as a cross product (whose product is another vector).

functional vectors, which are primarily used to direct where costs are functionally assigned, classified, and time differentiated, are shown on pages 49 through 52 of Exhibits WSS-16 and WSS-17. Internally generated functional vectors are utilized throughout the study to functionally assign, classify and time differentiate costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 49 through 52 of Exhibits WSS-16 and WSS-17. An example of this process is the use of total O&M expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign, classify and time differentiate these costs on the same basis. (See Exhibits WSS-16 and WSS-17, pages 9 through 12, for the functional assignment, classification and time differentiation of cash working capital on the basis of OMLPP shown on pages 25 through 28.) The functional vector used to allocate a specific cost is identified in the column of the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Q. Please describe how the functionally assigned, classified and time differentiated costs were allocated to the various classes of customers that KU serves.

A. Exhibits WSS-18 and WSS-19 show the allocation of the functionally assigned, classified and time differentiated costs to the various classes of customers that KU serves using the BIP methodology and the LOLP methodology, respectively. For a forecasted test year, the average number of customers is used for allocating customer-related costs rather than the year end number of customers that is used for a historic test year. The following allocation factors were used in the cost of service study to allocate the functionally assigned, classified and time differentiated costs:

- **E01 –** The energy cost component of purchased power costs was allocated on the basis of the loss adjusted kWh sales to each class of customers during the test year.
- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPT –** The demand cost component is allocated based on the maximum class demands for transmission, primary and secondary voltage customers. This allocation vector is used to allocate transmission costs.
- **NCPP –** The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers. This allocation vector is used to allocate distribution substations and primary distribution demand-related costs.
- **SICD –** The demand cost component is allocated on the

basis of the sum of individual customer demands for secondary voltage customers.

- **C02 –** The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03 –** Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **Cust04 –** Customer-related costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05 and Cust06 –** Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor calculated using the average number of customers for the test year based on discussions with KU's meter reading, billing and customer service departments.
- **Cust07 –** Customer-related costs are allocated on the basis of the average number of customers using line transformers and secondary voltage conductor.
- **Cust08 –** Customer-related costs are allocated on the

basis of the average number of customers using primary voltage conductor.

Q. Once costs are functionally assigned, classified and time differentiated, what calculations are used to allocate these costs to the various customer classes that KU serves?

A. Once costs for all of the major accounts are functionally assigned, classified, and time differentiated, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, O&M Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". A transpose of a matrix is formed by turning all the rows of a given matrix into columns and vice-versa. This process results in the columns of functionally assigned, classified and time differentiated costs becoming rows in the transposed matrix which then can be allocated to the various classes of customers that KU serves. This process is illustrated in Figure 2 below.

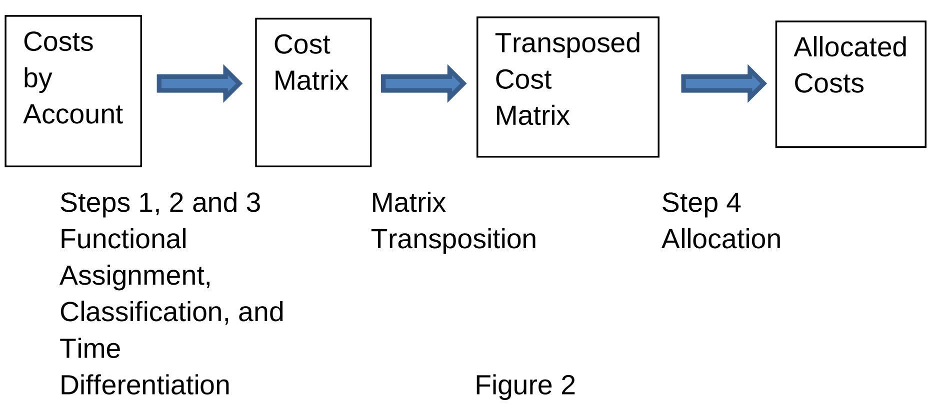


Figure 2

The results of the class allocation step of the cost of service study are included in Exhibits WSS-18 and WSS-19. The costs shown in the column labeled "Total System" in Exhibits WSS-18 and WSS-19 were carried forward from the functionally assigned, classified and time differentiated costs shown in Exhibits WSS-16 and WSS-17, respectively. The column labeled "Ref" in Exhibits WSS-18 and WSS-19 provides a reference to the results included in Exhibits WSS-16 and WSS-17.

Q. Please summarize the results of the cost of service study.

A. The following table (Table 14) summarizes the rates of return for each customer class after reflecting the rate adjustments proposed by KU under the BIP version of the study and the LOLP version of the study. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the rate base, income and expenses discussed in the testimony of Mr. Garrett. The Proposed Rates of Return were calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

	Rate of Return on Rate Base at Current Rates		Rate of Return on Rate Base at Proposed Rates	
Rate Class	BIP Version	LOLP Version	BIP Version	LOLP Version
Residential Service	4.16%	4.36%	5.64%	5.85%
General Service	9.10%	9.20%	10.95%	11.05%
All Electric Schools	5.27%	6.77%	7.07%	8.75%
Primary Service-Secondary	9.61%	9.26%	11.51%	11.12%
Primary Service-Primary	11.83%	10.70%	13.77%	12.55%
Time-of-Day Secondary Service	6.42%	6.06%	8.30%	7.91%
Time-of-Day Primary Service	4.48%	4.05%	6.57%	6.10%
Retail Transmission Service	4.55%	4.50%	6.76%	6.72%
Fluctuating Load Service	1.50%	1.24%	3.44%	3.14%
Lighting Energy Service	9.83%	18.57%	9.82%	18.56%
Traffic Energy Service	10.02%	11.34%	11.66%	13.11%
Lighting Service & Restricted Lighting Service	7.67%	8.44%	8.83%	9.66%
Total All Classes	5.56%	5.56%	7.29%	7.29%

Table 14

The determination of the actual adjusted and proposed rates of return are detailed on pages 29 and 30 and pages 33 through 34, respectively, of Exhibits WSS-18 and WSS-19.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is the Managing Partner with The Prime Group, LLC, and that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

W Seelye

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 1st day of November 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Exhibit WSS-1

Qualifications

WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Principal and Managing Partner
The Prime Group, LLC
(1996 to 2012) (2015-Present)
(Associate Member 2012-2015)

Provides consulting services in the areas of tariff development, regulatory analysis, revenue requirements, cost of service studies, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic resource and marketing plans. Assist with resource planning and cost benefit analyses for generation investment projects. Performs economic analyses evaluating the costs and benefits of an electric generation projects; performs business practice audits for electric utilities, gas utilities, and independent transmission organizations, including audits of production cost modeling, fuel procurement practices and controls, and wholesale marketing procedures. Assists investor-owned utilities in the development of testimony regarding the prudence of power supply decisions and of investments in specific generation and distribution assets.

Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus

	of rate alternatives for use with customers; performance-based rate development. Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.
Instructor in Mathematics Walden School and Private Instruction (2012-2015)	Taught advanced placement calculus, linear algebra, pre-calculus, college algebra and differential equations.
Manager of Rates and Other Positions Louisville Gas & Electric Co. (May 1979 to July 1996)	Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
66 Hours of Graduate Level Course Work in Electrical and Industrial Engineering and Physics.

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

Submitted expert report in No. 14-CV-30031 before District Court, Prowers County, State of Colorado, on behalf of Arkansas River Power Authority in the *City of Lamar et al v. Arkansas River Power Authority* regarding power planning and operations.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER11-2127-000 concerning transmission rates proposed by Terra-Gen Dixie Valley, LLC.

Submitted testimony in Docket No. ER11-2779 on behalf of Southern Illinois Power Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Submitted testimony in Docket No. ER11-2786 on behalf of Norris Electric Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric

	Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.
	Submitted testimony in Case No. 2010-00116 on behalf of Delta Natural Gas Company concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.
	Submitted testimony in Case No. 2011-00036 on behalf of Big Rivers Electric Cooperative concerning cost of service, rate design, pro-forma TIER adjustments, temperature normalization, and support of MISO Attachment O.
	Submitted testimony in Case No. 2016-00107 on behalf of Columbia Gas Company of Kentucky regarding a tariff application to the continue its energy efficiency and conservation rider and programs.
	Submitted testimony in Case No. 2016-00274 on behalf of Kentucky Utilities Company and Louisville Gas and Electric Company in support of community solar rates.
Maryland	Submitted direct testimony in PSC Case No. 9234 on behalf of Southern Maryland Electric Cooperative regarding a class cost of service study.
Nevada:	Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.
	Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.
	Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.
	Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.
	Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 10-06001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate cases.

Submitted direct testimony in Case No. Docket No. 11-06006 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

New Mexico Submitted testimony in support of filing of Advice Notice No. 60 on behalf of Kit Carson Electric Cooperative, Inc.

Submitted direct testimony in Case No. 15-00375-UT on behalf of Kit Carson Electric Cooperative, Inc. regarding revenue requirements, the need for a rate increase, class cost of service study, apportionment of the revenue increase to the classes of service, and rate design.

Submitted testimony in Advice Notices in Case No. 15-00087-UT on behalf of Jemez Mountain Electric Cooperative in support of tribal right of way cost recovery surcharge mechanisms.

Submitted direct testimony in Case. No. 16-00065-UT on behalf of Kit Carson Electric Cooperative in support of an application for continuation of its fuel and purchased power cost adjustment clause.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company’s application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2011-00013 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, and rate design.

Exhibit WSS-2

Cost Components for Residential Service Rate RS

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2018

Rate RS

		Production		Transmission	Distribution		Cust Service Expenses	
Description	**Reference Total**	**Demand-Related**	**Energy-Related**	**Demand-Related**	**Demand-Related**	**Customer-Related**	**Customer-Related**	**Total**
(1) Rate Base	$ 1,666,639,443	$ 791,919,086	$ 24,137,273	$ 220,794,890	$ 229,433,648	$ 395,881,330	$ 4,473,217	$ 1,666,639,443
(2) Rate Base Adjustments	$ -	-	-	-	-	-	-	$ -
(3) Rate Base as Adjusted	$ 1,666,639,443	$ 791,919,086	$ 24,137,273	$ 220,794,890	$ 229,433,648	$ 395,881,330	$ 4,473,217	$ 1,666,639,443
(4) Rate of Return	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	
(5) Return	$ 93,978,376	$ 44,654,691	$ 1,361,051	$ 12,450,170	$ 12,937,292	$ 22,322,935	$ 252,236	$ 93,978,376
(6) Interest Expenses	$ 39,274,989	$ 18,661,873	$ 568,804	$ 5,203,115	$ 5,406,691	$ 9,329,093	$ 105,413	$ 39,274,989
(7) Net Income	$ 54,703,387	$ 25,992,818	$ 792,247	$ 7,247,055	$ 7,530,602	$ 12,993,842	$ 146,822	$ 54,703,387
(8) Income Taxes	$ 37,450,706	$ 17,795,048	$ 542,384	$ 4,961,436	$ 5,155,555	$ 8,895,766	$ 100,517	$ 37,450,706
(9) Operation and Maintenance Expenses	$ 367,458,386	$ 41,725,441	$ 214,989,646	$ 18,726,398	$ 17,939,245	$ 36,930,529	$ 37,147,127	$ 367,458,386
(10) Depreciation Expenses	$ 101,410,555	$ 58,850,232	$ -	$ 10,232,822	$ 11,870,817	$ 20,456,684	$ -	$ 101,410,555
(11) Other Taxes	$ 17,253,162	$ 8,768,731	$ -	$ 2,160,223	$ 2,322,280	$ 4,001,928	$ -	$ 17,253,162
(12) Curtailable Service Credit	$ -	$ -						$ -
(13) Expense Adjustments - Prod. Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(14) Expense Adjustments - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(15) Expense Adjustments - Trans. Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(16) Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(17) Expense Adjustments - Other	$ 552,393	$ 262,475	$ 8,000	$ 73,181	$ 76,044	$ 131,211	$ 1,483	$ 552,393
(18) Revenue Adjustments	$ (3,559,496)	$ (3,549,839.02)	$ (266.49)	$ (2,437.71)	$ (2,533.09)	$ (4,370.77)	$ (49.39)	$ (3,559,496)
(19) Expense Adjustments - Total	$ (3,007,103)	$ (3,287,364)	$ 7,734	$ 70,743	$ 73,511	$ 126,841	$ 1,433	$ (3,007,103)
(20) Total Cost of Service	$ 614,544,081	$ 168,506,780	$ 216,900,814	$ 48,601,791	$ 50,298,700	$ 92,734,683	$ 37,501,312	$ 614,544,081
(21) Less: Misc Revenue - Prod Demand	$ 7,089,946	$ 7,089,946	$ -	$ -	$ -	$ -	$ -	$ 7,089,946
(22) Less: Misc Revenue - Energy	$ (2,827,720)	$ -	$ (2,827,720)	$ -	$ -	$ -	$ -	$ (2,827,720)
(23) Less: Misc Revenue - Other	$ (27,263,056)	$ (12,954,292)	$ (394,840)	$ (3,611,785)	$ (3,753,099)	$ (6,475,867)	$ (73,173)	$ (27,263,056)
(24) Less: Misc Revenue - Total	$ (23,000,830)	$ (5,864,346)	$ (3,222,560)	$ (3,611,785)	$ (3,753,099)	$ (6,475,867)	$ (73,173)	$ (23,000,830)
(25) Net Cost of Service	$ 591,543,251	$ 162,642,434	$ 213,678,254	$ 44,990,006	$ 46,545,601	$ 86,258,817	$ 37,428,139	$ 591,543,251
(26) Billing Units		6,091,971,051	6,091,971,051	6,091,971,051	6,091,971,051	5,168,140	5,168,140	
(27) Unit Costs		0.026697834	0.035075389	0.007385131	0.007640483	$ 16.69	$ 7.24	$ 23.93

Customer Cost	23.93
Infrastructure Energy Cost	0.041723
ECR Base Rates	0.006770
Total Infrastructure Energy	0.048493
Variable Energy Cost	0.035075

Exhibit WSS-3

Cost Support for CSR Credits

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
Plant		$ 285,515,838	$ 248,172,766	$ 39,574,165	$ 573,262,768
Accumulated Depreciation		$ 162,922,503	$ 111,210,802	$ 15,526,405	$ 289,659,711
Net Plant		$ 122,593,334	$ 136,961,964	$ 24,047,759	$ 283,603,057
Accumulated Deferred Income Taxes		37,916,634	45,143,182	8,170,625	$ 91,230,442
Net Cost Rate Base		$ 84,676,700	$ 91,818,782	$ 15,877,134	$ 192,372,616
Rate of Return		7.29%	7.29%	7.29%	7.29%
Return		$ 6,172,826	$ 6,693,475	$ 1,157,423	$ 14,023,725
Depreciation Expenses		$ 13,397,159	$ 10,663,309	$ 1,886,537	$ 25,947,005
Non-Burdened Non-Fuel Operation and Maintenance Expenses		$ 3,417,067	$ 1,560,485	$ 358,517	$ 5,336,069
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
Property Taxes		$ 197,748	$ 216,317	$ 38,727	$ 452,792
Revenue Requirement		$ 26,190,393	$ 22,712,135	$ 4,113,203	$ 53,015,730
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
Net Peak Demand on Plant (Form 7, Pages 402-403, line 6)		726,140	626,460	69,090	1,421,690
Cost per kW per Month (Net Peak Demand on Plant)		$ 3.01	$ 3.02	$ 4.96	$ 3.11
Loss Factor (Transmission)		0.0281	0.0281	0.0281	0.0281
Cost per kW per Month (Transmission)		$ 3.09	$ 3.11	$ 5.10	**$ 3.20**
Loss Factor (Primary)		0.0613	0.0613	0.0613	0.0613
Cost per kW per Month (Primary)		$ 3.20	$ 3.22	$ 5.28	**$ 3.31**

Exhibit WSS-4

Cost Support for
Lighting Rates LS and RLS

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	Carry Charge	RLS	RLS	RLS	RLS
		413 Decorative Smooth Coach 117 9,500 hps	412 Decorative Smooth Coach 83 5,800 hps	466 Decorative Smooth Colonial 60 4,000 hps	410 Historic Fluted Acorn 60 4,000 hps
Estimated Investment per Unit ($)		$2,819.92	$2,819.25	$1,553.34	$3,157.57
Fixed Charges ($ / yr)	16.27%	$458.80	$458.69	$252.73	$513.74
Distribution Energy per kWh ($ / yr)	$0.07328	$34.30	$24.33	$24.33	$24.33
Operation and Maintenance ($ / yr)		$8.23	$8.15	$8.15	$8.15
Monthly Unit Cost ($ / mo)		$41.78	$40.93	$23.77	$45.52

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	RLS	RLS	RLS	RLS	RLS
	440 Decorative Smooth Acorn 60 4,000 hps	470 Decorative Smooth Directional 1,080 107,800 metal halide	469 Decorative Smooth Directional 350 32,000 metal halide	460 Decorative Smooth Directional 150 12,000 metal halide	404 Fixture Only Open Bottom 207 7,000 mv
Estimated Investment per Unit ($)	$1,772.75	$2,728.47	$2,589.38	$2,577.62	$462.74
Fixed Charges ($ / yr)	$288.43	$443.92	$421.29	$419.38	$75.29
Distribution Energy per kWh ($ / yr)	$24.33	$316.57	$102.59	$43.97	$60.68
Operation and Maintenance ($ / yr)	$8.15	$8.48	$8.23	$8.15	$7.89
Monthly Unit Cost ($ / mo)	$26.74	$64.08	$44.34	$39.29	$11.99

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	RLS	RLS	RLS	RLS	RLS
	458 Fixture and Pole Cobra Head 453 20,000 mv	448 Fixture Only Cobra Head 453 20,000 mv	457 Fixture and Pole Cobra Head 294 10,000 mv	447 Fixture Only Cobra Head 294 10,000 mv	456 Fixture and Pole Cobra Head 207 7,000 mv
Estimated Investment per Unit ($)	$4,038.99	$548.66	$4,036.15	$545.81	$3,982.86
Fixed Charges ($ / yr)	$657.14	$89.27	$656.68	$88.80	$648.01
Distribution Energy per kWh ($ / yr)	$132.78	$132.78	$86.18	$86.18	$60.68
Operation and Maintenance ($ / yr)	$8.19	$8.19	$8.03	$8.03	$7.89
Monthly Unit Cost ($ / mo)	$66.51	$19.19	$62.57	$15.25	$59.71

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	RLS	RLS	RLS	RLS	RLS
	446 Fixture Only Cobra Head 207 7,000 mv	459 Fixture and Pole Directional 1,080 107,800 metal halide	455 Fixture and Pole Directional 350 32,000 metal halide	454 Fixture and Pole Directional 150 12,000 metal halide	426 Fixture Only Open Bottom 83 5,800 hps
Estimated Investment per Unit ($)	$492.52	$1,400.34	$1,261.24	$1,249.49	$447.79
Fixed Charges ($ / yr)	$80.13	$227.84	$205.20	$203.29	$72.86
Distribution Energy per kWh ($ / yr)	$60.68	$316.57	$102.59	$43.97	$24.33
Operation and Maintenance ($ / yr)	$7.89	$8.48	$8.23	$8.15	$8.15
Monthly Unit Cost ($ / mo)	$12.39	$46.07	$26.34	$21.28	$8.78

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	RLS	RLS	RLS	RLS	LS
	409 Fixture Only Cobra Head 471 50,000 hps	471 Fixture and Pole Cobra Head 60 4,000 hps	461 Fixture Only Cobra Head 60 4,000 hps	360 Decorative Smooth Granville 181 16,000 hps	496 Decorative Smooth Contemporary 1,080 107,800 Metal Halide
Estimated Investment per Unit ($)	$725.39	$1,203.28	$669.76	$2,829.19	$2,580.60
Fixed Charges ($ / yr)	$118.02	$195.77	$108.97	$460.31	$419.86
Distribution Energy per kWh ($ / yr)	$138.06	$17.59	$17.59	$53.05	$316.57
Operation and Maintenance ($ / yr)	$8.37	$8.23	$8.23	$8.95	$8.48
Monthly Unit Cost ($ / mo)	$22.04	$18.47	$11.23	$43.53	$62.08

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	493 Fixture Only Contemporary 1,080 107,800 Metal Halide	495 Decorative Smooth Contemporary 350 32,000 Metal Halide	491 Fixture Only Contemporary 350 32,000 Metal Halide	494 Decorative Smooth Contemporary 150 12,000 Metal Halide	490 Fixture Only Contemporary 150 12,000 Metal Halide
Estimated Investment per Unit ($)	$662.56	$2,695.74	$777.70	$2,192.00	$689.18
Fixed Charges ($ / yr)	$107.80	$438.60	$126.53	$356.64	$112.13
Distribution Energy per kWh ($ / yr)	$316.57	$102.59	$102.59	$43.97	$43.97
Operation and Maintenance ($ / yr)	$8.48	$8.23	$8.23	$8.15	$8.15
Monthly Unit Cost ($ / mo)	$36.07	$45.78	$19.78	$34.06	$13.69

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	301 Decorative Smooth Dark Sky 117 9,500 hps	300 Decorative Smooth Dark Sky 60 4,000 hps	479 Decorative Smooth Contemporary 471 50,000 hps	499 Fixture Only Contemporary 471 50,000 hps	478 Decorative Smooth Contemporary 242 22,000 hps
Estimated Investment per Unit ($)	$1,817.14	$1,793.41	$2,599.74	$681.71	$2,580.60
Fixed Charges ($ / yr)	$295.65	$291.79	$422.98	$110.91	$419.86
Distribution Energy per kWh ($ / yr)	$34.30	$17.59	$138.06	$138.06	$70.94
Operation and Maintenance ($ / yr)	$8.23	$8.15	$8.37	$8.37	$8.48
Monthly Unit Cost ($ / mo)	$28.18	$26.46	$47.45	$21.45	$41.61

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	498 Fixture Only Contemporary 242 22,000 hps	477 Decorative Smooth Contemporary 117 9,500 hps	497 Fixture Only Contemporary 117 9,500 hps	476 Decorative Smooth Contemporary 83 5,800 hps	492 Fixture Only Contemporary 83 5,800 hps
Estimated Investment per Unit ($)	$662.56	$2,585.14	$667.10	$2,169.25	$666.43
Fixed Charges ($ / yr)	$107.80	$420.60	$108.54	$352.94	$108.43
Distribution Energy per kWh ($ / yr)	$70.94	$34.30	$34.30	$24.33	$24.33
Operation and Maintenance ($ / yr)	$8.48	$8.23	$8.23	$8.15	$8.15
Monthly Unit Cost ($ / mo)	$15.60	$38.59	$12.59	$32.12	$11.74

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	415 Historic Fluted Victorian 117 9,500 hps	414 Historic Fluted Victorian 83 5,800 hps	430 Historic Fluted Acorn 117 9,500 hps	420 Decorative Smooth Acorn 117 9,500 hps	411 Historic Fluted Acorn 83 5,800 hps
Estimated Investment per Unit ($)	$2,819.92	$2,819.25	$3,197.11	$1,707.81	$3,157.57
Fixed Charges ($ / yr)	$458.80	$458.69	$520.17	$277.86	$513.74
Distribution Energy per kWh ($ / yr)	$34.30	$24.33	$34.30	$34.30	$24.33
Operation and Maintenance ($ / yr)	$8.23	$8.15	$8.23	$8.23	$8.15
Monthly Unit Cost ($ / mo)	$41.78	$40.93	$46.89	$26.70	$45.52

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	401 Decorative Smooth Acorn 83 5,800 hps	468 Decorative Smooth Colonial 117 9,500 hps	467 Decorative Smooth Colonial 83 5,800 hps	452 Fixture Only Directional 1,080 107,800 metal halide	451 Fixture Only Directional 350 32,000 metal halide
Estimated Investment per Unit ($)	$1,772.75	$1,508.77	$1,553.34	$798.68	$659.58
Fixed Charges ($ / yr)	$288.43	$245.48	$252.73	$129.94	$107.31
Distribution Energy per kWh ($ / yr)	$24.33	$34.30	$24.33	$316.57	$102.59
Operation and Maintenance ($ / yr)	$8.15	$8.23	$8.15	$8.48	$8.23
Monthly Unit Cost ($ / mo)	$26.74	$24.00	$23.77	$37.92	$18.18

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	450 Fixture Only Directional 150 12,000 metal halide	428 Fixture Only Open Bottom 117 9,500 hps	489 Fixture Only Directional 471 50,000 hps	488 Fixture Only Directional 242 22,000 hps	487 Fixture Only Directional 117 9,500 hps
Estimated Investment per Unit ($)	$647.83	$456.91	$629.93	$633.81	$597.66
Fixed Charges ($ / yr)	$105.40	$74.34	$102.49	$103.12	$97.24
Distribution Energy per kWh ($ / yr)	$43.97	$34.30	$138.06	$70.94	$34.30
Operation and Maintenance ($ / yr)	$8.15	$8.23	$8.37	$8.48	$8.23
Monthly Unit Cost ($ / mo)	$13.13	$9.74	$20.74	$15.21	$11.65

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS	LS	LS
	475 Ornamental Cobra Head 471 50,000 hps	465 Fixture Only Cobra Head 471 50,000 hps	474 Ornamental Cobra Head 242 22,000 hps	464 Fixture Only Cobra Head 242 22,000 hps	473 Ornamental Cobra Head 117 9,500 hps
Estimated Investment per Unit ($)	$2,148.08	$725.39	$2,088.52	$665.90	$2,048.97
Fixed Charges ($ / yr)	$349.49	$118.02	$339.80	$108.34	$333.37
Distribution Energy per kWh ($ / yr)	$138.06	$138.06	$70.94	$70.94	$34.30
Operation and Maintenance ($ / yr)	$8.37	$8.37	$8.48	$8.48	$8.23
Monthly Unit Cost ($ / mo)	$41.33	$22.04	$34.93	$15.65	$31.32

KENTUCKY UTILITIES COMPANY

Estimated Unit Cost of Lighting Fixtures
Rate LS and Rate RLS

Description	LS	LS	LS
	463 Fixture Only Cobra Head 117 9,500 hps	472 Ornamental Cobra Head 83 5,800 hps	462 Fixture Only Cobra Head 83 5,800 hps
Estimated Investment per Unit ($)	$626.25	$1,830.06	$623.38
Fixed Charges ($ / yr)	$101.89	$297.75	$101.42
Distribution Energy per kWh ($ / yr)	$34.30	$24.33	$24.33
Operation and Maintenance ($ / yr)	$8.23	$8.15	$8.15
Monthly Unit Cost ($ / mo)	$12.03	$27.52	$11.16

Exhibit WSS-5

Cost Support for LED Lighting Rates

KENTUCKY UTILITIES COMPANY

Cost Support for LED Lighting Charges

Description	Carry Charge	LED	LED	LED	LED
		Overhead			
		Open Bottom Yard Light 50 WATT 5,007 Lumen 393 Fixture, Arm & Wire	Cobra 80 WATT 8,179 Lumen 390 Fixture, Arm & Wire	Cobra 134 WATT 14,166 Lumen 391 Fixture, Arm & Wire	Cobra 228 WATT 23,214 lumen 392 Fixture, Arm & Wire
Estimated Investment per Unit ($)		$550.60	$830.36	$932.84	$1,334.01
Fixed Charges ($ / yr)	**16.27%**	$89.61	$135.14	$151.82	$217.11
Distribution Energy per kWh ($ / yr)	**$0.07328**	$14.66	$23.45	$39.28	$66.83
Operation and Maintenance ($ / yr)		$17.29	$23.94	$29.89	$53.18
Monthly Unit Cost ($ / mo)		**$10.13**	**$15.21**	**$18.42**	**$28.09**

KENTUCKY UTILITIES COMPANY

Cost Support for LED Lighting Charges

Description	LED	LED	LED	LED
	Underground			Underground Decorative
	Cobra 80 WATT 8,179 Lumen 396 Pole, Fixture, Arm & Wire	**Cobra** 134 WATT 14,166 Lumen 397 Pole, Fixture, Arm & Wire	**Cobra** 228 WATT 23,214 lumen 398 Pole, Fixture, Arm & Wire	**Colonial** 68 WATT 5,665 Lumen 399 Fixture, Pole & Wire
Estimated Investment per Unit ($)	$2,383.01	$2,485.50	$2,886.67	$2,329.56
Fixed Charges ($ / yr)	$387.83	$404.51	$469.80	$379.13
Distribution Energy per kWh ($ / yr)	$23.45	$39.28	$66.83	$19.93
Operation and Maintenance ($ / yr)	$23.94	$29.89	$53.18	$60.83
Monthly Unit Cost ($ / mo)	**$36.27**	**$39.47**	**$49.15**	**$38.32**

Exhibit WSS-6

Cost Support for Redundant Capacity Charge

Kentucky Utilities Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2018

Secondary Service

Distribution Demand Costs				
PSS	$ 4,415,062			
TODS	$ 3,395,528			
Total Cost	$ 7,810,590			
Billing Demand				
PSS	6,098,096			
TODS	5,210,823			
Total Cost	11,308,919			
Unit Cost		$	0.69	
Rate Base				
PSS	$ 35,016,143			
TODS	$ 26,444,079			
Total Cost	$ 61,460,222			
Return	$ 4,480,450			
Unit Return		$	0.40	
Capacity Charge		$	1.09	/ KW

Kentucky Utilities Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2018

Primary Service

Distribution Demand Costs				
PSP	$	281,809		
TODP	$	6,417,729		
Total Cost	$	6,699,539		
Billing Demand				
PSP		486,738		
TODP		10,909,236		
Total Cost		11,395,974		
Unit Cost			$	0.59
Rate Base				
PSP	$	2,049,422		
TODP	$	46,666,872		
Total Cost	$	48,716,294		
Return	$	3,551,418		
Unit Return			$	0.31
Capacity Charge			$	0.90 / KW

Exhibit WSS-7

Cost Support for
Pole Attachment Charge

Kentucky Utilities Company and Louisvillle Gas & Electric Company
Cost Support for Attachment Charges for Wireline Pole Attachments
Based on 12 Months Ended June 30, 2018

Pole Description		**35'**	**40'**	**45'**	**Total**
Gross Plant		$ 36,350,278	$ 128,380,719	$ 112,705,295	$ 277,436,291
Remove Appurtenances		15%	15%	15%	
Gross Plant less Appurtenances		$ 30,897,736	$ 109,123,611	$ 95,799,500	$ 235,820,847
Accumulated Depreciation		(14,287,553)	(50,460,312)	(44,299,054)	(109,046,920)
Remove Appurtenances		15%	15%	15%	
Accumulated Depreciation less Appurtenances		$ (12,144,420)	$ (42,891,266)	$ (37,654,196)	$ (92,689,882)
Net Plant		$ 18,753,316	$ 66,232,345	$ 58,145,305	$ 143,130,966
Accumulated Deferred Income Taxes		$ (4,870,028)	$ (17,199,804)	$ (15,099,689)	$ (37,169,520)
Cash Working Capital		284,427	1,004,530	881,876	2,170,833
Common Plant		1,053,963	3,722,352	3,267,849	8,044,164
Net Cost Rate Base		$ 15,221,678	$ 53,759,424	$ 47,195,340	$ 116,176,442
Rate of Return		7.27%	7.27%	7.27%	
Return		$ 1,106,082	$ 3,906,424	$ 3,429,445	$ 8,441,951
Income Taxes	38.59%	$ 521,284	$ 1,841,055	$ 1,616,260	$ 3,978,599
Property Taxes		$ 213,257	$ 753,175	$ 661,212	$ 1,627,644
Depreciation Expenses		$ 857,942	$ 3,030,050	$ 2,660,078	$ 6,548,069
Maintenance of Poles		$ 458,229	$ 1,618,358	$ 1,420,754	$ 3,497,341
Tree Trimming of Poles		1,497,833	5,289,996	4,644,082	$ 11,431,911
A&G Expense Allocation to Poles		297,181	1,049,573	921,419	$ 2,268,173
Revenue Requirement		$ 4,951,807	$ 17,488,631	$ 15,353,250	$ 37,793,688
Quantity		103,454	192,111	89,471	385,036
Average Installed Cost		$ 47.86	$ 91.03	$ 171.60	$ 98.16
Space Usage Factor		0.0759	0.0759	0.0759	0.0759
Pole Attachment Rate		$ 3.63	$ 6.91	$ 13.02	**$ 7.45**

Exhibit WSS-8

Cost Support for
Duct Attachment Charge

Kentucky Utilities Company and Louisvillle Gas & Electric Company
Calculation Of Attachment Charges for Underground Conduit
Based on 12 Months Ended June 30, 2018

Pole Description			**Total**
Gross Plant		$	79,957,770
Remove Appurtenances			15%
Gross Plant less Appurtenances		$	67,964,105
Accumulated Depreciation			(23,190,169)
Remove Appurtenances			15%
Accumulated Depreciation less Appurtenances		$	(19,711,644)
Net Plant		$	48,252,461
Accumulated Deferred Income Taxes		$	(11,956,770)
Cash Working Capital			673,647
Common Plant			5,747,707
Net Cost Rate Base		$	42,717,045
Rate of Return			7.27%
Return		$	3,104,030
Income Taxes	38.59%	$	1,462,896
Property Taxes		$	498,222
Depreciation Expenses		$	1,061,872
Maintenance of UG Lines		$	694,791
A&G Expense Allocation to UG Lines			580,351
Revenue Requirement		$	7,402,163
Quantity			4,557,311
Average Installed Cost		$	1.62
Space Usage Factor			0.50
Underground Conduit Attachment Rate		**$**	**0.81**

Exhibit WSS-9

Change in Miscellaneous Revenues
for Attachment Charges

Kentucky Utilities Company and Louisville Gas and Electric Company
Forecasted Miscellaneous Revenue at Proposed Attachment Charges
For the 12 Months Ended June 30, 2018

Attachment Type	Total Attachments	Annual Revenue	Current Rate	Proposed Rate	Annual Revenue at Proposed Rate	Increase (Decrease) in Revenue
Telecom Wireline						
Telecom Wireline (KU)	11,067	$ 61,750.83	$ 5.58	$ 7.25	$ 80,236	$ 18,485
Telecom Wireline (LG&E)	4,344	$ 54,201.15	$ 12.48	$ 7.25	$ 31,494	$ (22,707)
	$ 15,411.00	$ 115,951.98				
Total CATV						
CATV (KU)	149,547	$ 1,083,117.44	$ 7.25	$ 7.25		
CATV (LG&E)	88,362	$ 639,921.25	$ 7.25	$ 7.25		
	$ 237,909.00	$ 1,723,038.69				
Wireless						
Telecom Wireless (KU)				$ 84.00	$ 1,235	$ 1,235
Telecom Wireless (LG&E)				$ 84.00	$ 317	$ 317
Total KU						**$ 19,720**
Total LG&E						**$ (22,391)**

Exhibit WSS-10

Cost Support for
Unauthorized Reconnection Charge

Kentucky Utilities Company
Unauthorized Meter Reconnect Charges
Cost Justification

Charge Description	Cost
Field Investigator - (1/2 hour)	$ 34.39
Transportation - (1/2 hour)	3.15
Back Office Admin Labor - (1/2 hour)	21.04
Lock Costs	11.82
Total Charge without meter replacement at August 31, 2016	$ 70.41
Total Charge if meter replacement necessary:	
UAR Charge for 1/0 Standard Meter Replacement	
Charge without meter replacement	$ 70.41
Charge for 1/0 Standard Meter Replacement	19.18
	$ 89.59
UAR Charge for 1/0 AMR Meter Replacement	
Charge without meter replacement	$ 70.41
Charge for 1/0 AMR Meter Replacement	40.01
	$ 110.41
UAR Charge for 1/0 AMS Meter Replacement	
Charge without meter replacement	$ 70.41
Charge for 1/0 AMS Meter Replacement	103.70
	$ 174.10
UAR Charge for 3/0 Standard Meter Replacement	
Charge without meter replacement	$ 70.41
Charge for 3/0 Standard Meter Replacement	106.73
	$ 177.13

Exhibit WSS-11

BIP Analysis
for Electric Cost of Service Study

LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES
Assignment of Production and Transmission Demand-Related Costs
Based on Forecasted 12 Months Ended June 30, 2018

Minimum System Demand	2,303
Winter System Peak Demand	6,021
Summer System Peak Demand	6,698

Assignment of Production and Transmission
Demand-Related Costs to the Costing Periods

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	2,303	
2. Maximum System Demand	6,698	
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.3438	
4. Non-Time-Differentiated Cost (Line 3)		34.38%

Winter Peak Period Costs

5. Maximum Winter System Demand	6,021	
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.5551	
7. Winter Peak Period Hours	2,416	
8. Summer Peak Period Hours	1,308	
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,724	
10. Winter Peak Period Costs (Line 8/Line 9 x Line 6)		36.02%

Summer Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.1011	
12. Summer Peak Period Costs (Line 11 + Line 7/Line 9 x Line 6)		29.60%

Exhibit WSS-12

LOLP Analysis
for Electric Cost of Service Study

Kentucky Utilities Company
LOLP Fixed Production Cost Allocation Factor
For the 12 Months Ended June 30, 2018

Rate Class	Weighted LOLP
	$\sum_{i=1}^{8760} LOLP_i * \overline{LOAD_i}$
Residential	16,742.80
General Service	4,922.40
All Electric Schools	321.46
TOD Secondary	3,942.05
TOD Primary	9,204.19
PS Secondary	5,377.62
PS Primary	407.89
RTS	3,150.82
FLS	1,222.99
Unmetered Lighting	6.02
Traffic Energy Service	2.31
Lighting Energy Service	0.02
Total	45,300.58

Exhibit WSS-13

Zero Intercept
Overhead Conductor

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

Weighted Linear Regression Statistics

	Estimate	Standard Error	LINEST ARRAY	
Size Coefficient ($ per MCM)	0.0042381	0.0007242	0.004238076	1.148169
Zero Intercept ($ per Unit)	1.1481694	0.2165379	0.000724158	0.216538
			0.8382354	1682.393
R-Square	0.8382354		82.90915541	32
			469339999.2	90574315

Plant Classification

Total Number of Units		98,977,688
Zero Intercept		1.1481694
Zero Intercept Cost	$	113,643,149
Total Cost of Sample	$	191,986,396
Percentage of Total		0.591933343
Percentage Classified as Customer-Related		59.19%
Percentage Classified as Demand-Related		40.81%

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

Description	Size	Cost	Quantity	Avg Cost
#2 Triplex	66.369	12,049,980.44	9,444,024.00	1.275937
#4 Aluminum Poly	41.74	107,147.80	24,198.00	4.427961
1 CONDUCTOR	83.69	1,411,598.65	182,059.00	7.753523
1/0 CONDUCTOR	105.6	4,290,230.09	690,429.00	6.213861
1/0 Triplex	105.6	4,992.80	1,000.00	4.9928
1/0 Aluminum	105.6	19,519.07	5,787.00	3.372917
123,270 ACAR WIRE	123.27	16,001,355.25	9,030,733.00	1.771878
195,700 ACAR WIRE	195.7	2,350,342.57	1,867,358.00	1.258646
2/0 COPPER CONDUCTOR	133.1	814,744.67	619,229.00	1.31574
20 M.A.W. MESSENGER WIRE	20	2,835,873.99	1,331,916.00	2.129169
336,400 19 STR. ALL ALUMINUM	336.4	8,877,286.87	5,632,629.00	1.576047
350 MCM COPPER CONDUCTOR	350	1,343,426.45	74,915.00	17.93268
392,500 24/13 ACAR WIRE	392.5	1,018,369.50	863,538.00	1.179299
4 COPPER CONDUCTOR	41.74	17,171,210.51	11,636,815.00	1.475594
4A COPPER CONDUCTOR	41.74	619,277.91	70,532.00	8.780099
6 COPPER CONDUCTOR	26.25	9,672,518.55	15,184,951.00	0.636981
6A COPPER CONDUCTOR	26.25	752,935.77	101,691.00	7.404153
750 MCM COPPER CONDUCTOR	750	854,930.69	26,529.00	32.22627
795 MCM ALUMINUM CONDUCTOR	795	50,420,186.86	10,820,405.00	4.659732
8 COPPER CONDUCTOR	16.51	692,062.17	334,246.00	2.070517
840,200 24/13 ACAR WIRE	840.2	580,130.00	211,997.00	2.736501
1/0 CABLE	105.6	40,927,306.48	22,040,786.00	1.85689
101 MCM ACSR CONDUCTOR	101	1,181.18	250.00	4.72472
1272 MCM ACSR CONDUCTOR	1272	80,155.38	31,063.00	2.580413
200 MCM CABLE	200	3,238.76	500.00	6.47752
3/0 CONDUCTOR	167.8	5,943,955.85	2,037,913.00	2.916688
300 MCM COPPER CONDUCTOR	300	3,564.60	260.00	13.71
4/0 CONDUCTOR	211.6	12,422,874.97	6,559,680.00	1.893823
520 MCM CONDUCTOR	520	688.25	112.00	6.145089
600 MCM CONDUCTOR	600	105,138.81	15,810.00	6.650146
636 MCM ALUMINUM CONDUCTOR	636	21,911.09	3,040.00	7.207595
7/C CONDUCTOR	20.92	18,059.98	4,050.00	4.459254
80 MCM ACSR CONDUCTOR	80	16,623.99	7,500.00	2.216532
954 MCM ACSR CONDUCTOR	954	553,575.80	121,743.00	4.547085

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

n	y	x	est y	y*n^.5	n^.5	xn^.5
9,444,024	1.27594	66.37	1.429	3921.09894	3,073.11	203959.4
24,198	4.42796	41.74	1.325	688.8006086	155.56	6492.952
182,059	7.75352	83.69	1.503	3308.302079	426.68	35709.16
690,429	6.21386	105.60	1.596	5163.225253	830.92	87745.21
1,000	4.99280	105.60	1.596	157.886199	31.62	3339.365
5,787	3.37292	105.60	1.596	256.5856596	76.07	8033.238
9,030,733	1.77188	123.27	1.671	5324.701495	3,005.12	370440.9
1,867,358	1.25865	195.70	1.978	1719.956145	1,366.51	267426.6
619,229	1.31574	133.10	1.712	1035.370733	786.91	104737.9
1,331,916	2.12917	20.00	1.233	2457.24529	1,154.09	23081.73
5,632,629	1.57605	336.40	2.574	3740.457124	2,373.32	798383.5
74,915	17.93268	350.00	2.631	4908.281955	273.71	95797.12
863,538	1.17930	392.50	2.812	1095.884179	929.27	364737.5
11,636,815	1.47559	41.74	1.325	5033.65965	3,411.28	142386.7
70,532	8.78010	41.74	1.325	2331.806397	265.58	11085.25
15,184,951	0.63698	26.25	1.259	2482.177725	3,896.79	102290.7
101,691	7.40415	26.25	1.259	2361.112448	318.89	8370.869
26,529	32.22627	750.00	4.327	5248.926212	162.88	122157.9
10,820,405	4.65973	795.00	4.517	15327.90121	3,289.44	2615104
334,246	2.07052	16.51	1.218	1197.0492	578.14	9545.093
211,997	2.73650	840.20	4.709	1259.970761	460.43	386854.4
22,040,786	1.85689	105.60	1.596	8717.653933	4,694.76	495766.8
250	4.72472	101.00	1.576	74.70438253	15.81	1596.95
31,063	2.58041	1,272.00	6.539	454.7900756	176.25	224186.2
500	6.47752	200.00	1.996	144.8417505	22.36	4472.136
2,037,913	2.91669	167.80	1.859	4163.731874	1,427.55	239543.7
260	13.71000	300.00	2.420	221.0671075	16.12	4837.355
6,559,680	1.89382	211.60	2.045	4850.436099	2,561.19	541947.2
112	6.14509	520.00	3.352	65.03351214	10.58	5503.163
15,810	6.65015	600.00	3.691	836.174891	125.74	75442.69
3,040	7.20760	636.00	3.844	397.3993852	55.14	35066.62
4,050	4.45925	20.92	1.237	283.7852072	63.64	1331.341
7,500	2.21653	80.00	1.487	191.957302	86.60	6928.203
121,743	4.54709	954.00	5.191	1586.55487	348.92	332866.7

Kentucky Utilities Company
Pri/Sec Splits for Overhead Conductor

		Customer	Demand
Overhead		59.19%	40.81%
Primary	65.21%	0.3860	0.2661
Secondary	34.79%	0.2059	0.1420

Exhibit WSS-14

Zero Intercept
Underground Conductor

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

Weighted Linear Regression Statistics

	Estimate	Standard Error	LINEST ARRAY	
Size Coefficient ($ per MCM)	0.0102572	0.0030099	0.010257168	4.674835997
Zero Intercept ($ per Unit)	4.6748360	0.5168983	0.003009929	0.516898278
			0.906339753	2008.459481
R-Square	0.9063398		125.7995482	26
			1014927981	104881646.6

Plant Classification

Total Number of Units	28,072,832
Zero Intercept	4.6748360
Zero Intercept Cost	$131,235,886
Total Cost of Sample	164,853,919
Percentage of Total	0.796073799
Percentage Classified as Customer-Related	79.61%
Percentage Classified as Demand-Related	20.39%

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

Description	Size	Cost	Quantity	Avg Cost
#12 CABLE	13.12	89,006.20	39,823.00	2.235045074
#2 Triplex	66.36	79,989,007.18	15,404,958.00	5.192419686
1 CONDUCTOR	83.69	1,250,374.51	120,419.00	10.38353175
1/0 CABLE	105.6	9,840,505.50	773,491.00	12.7221978
1/0 CONDUCTOR	105.6	4,118,279.86	207,683.00	19.82964354
1/0 Triplex	105.6	44,974.14	7,912.00	5.684294742
1000 MCM CONDUCTOR	1000	4,879,316.51	366,565.00	13.3109176
1500 MCM UGAL CABLE	1500	44,861.19	4,026.00	11.14286885
2/0 COPPER CONDUCTOR	133.1	34,766,450.69	6,361,132.00	5.465450283
20 M.A.W. MESSENGER WIRE	20	1,880.60	2,834.00	0.663585039
200 MCM CABLE	200	44,255.13	5,194.00	8.520433192
2000 MCM 1/C 1000V CABLE	2000	501.81	578.00	0.868183391
266 MCM ACSR CONDUCTOR	266	7,717.86	400.00	19.29465
3/0 CONDUCTOR	167.8	994,247.11	224,357.00	4.431540402
300 MCM COPPER CONDUCTOR	300	8,963.91	126.00	71.14214286
350 MCM COPPER CONDUCTOR	350	3,544,244.42	403,573.00	8.782164367
397 MCM ACSR CONDUCTOR	397	117,135.66	9,339.00	12.54263412
4 COPPER CONDUCTOR	41.74	374,991.52	45,767.00	8.19349138
4/0 CONDUCTOR	211.6	21,298,803.39	2,820,181.00	7.552282421
4A COPPER CONDUCTOR	41.74	9,810.69	4,140.00	2.369731884
500 MCM COPPER CONDUCTOR	500	725,216.67	62,790.00	11.5498753
520 MCM CONDUCTOR	520	451.53	75.00	6.0204
6 COPPER CONDUCTOR	26.25	1,037,863.57	770,088.00	1.347720741
600 MCM CONDUCTOR	600	76,600.45	3,983.00	19.23184785
6A COPPER CONDUCTOR	26.25	377,669.81	334,569.00	1.128824876
750 MCM COPPER CONDUCTOR	750	1,171,289.16	95,550.00	12.25838995
795 MCM ALUMINUM CONDUCTOR	795	38,247.86	2,606.00	14.67684574
8 COPPER CONDUCTOR	795	1,252.12	673.00	1.860505201

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

n	y	x	est y	y*n^.5	n^.5	xn^.5
39,823	2.23505	13.12	4.809	446.0189109	199.56	2618.187963
15,404,958	5.19242	66.36	5.356	20379.80607	3,924.92	260457.3615
120,419	10.38353	83.69	5.533	3603.235133	347.01	29041.63588
773,491	12.72220	105.60	5.758	11188.96141	879.48	92873.44399
207,683	19.82964	105.60	5.758	9036.814795	455.72	48124.29635
7,912	5.68429	105.60	5.758	505.6147422	88.95	9393.059157
366,565	13.31092	1,000.00	14.932	8059.043368	605.45	605446.1165
4,026	11.14287	1,500.00	20.061	707.0235899	63.45	95176.15248
6,361,132	5.46545	133.10	6.040	13784.56774	2,522.13	335695.2989
2,834	0.66359	20.00	4.880	35.32616628	53.24	1064.706532
5,194	8.52043	200.00	6.726	614.0626015	72.07	14413.8822
578	0.86818	2,000.00	25.189	20.87254435	24.04	48083.26112
400	19.29465	266.00	7.403	385.893	20.00	5320
224,357	4.43154	167.80	6.396	2099.058417	473.66	79480.7156
126	71.14214	300.00	7.752	798.568573	11.22	3367.491648
403,573	8.78216	350.00	8.265	5579.080305	635.27	222345.8848
9,339	12.54263	397.00	8.747	1212.101368	96.64	38365.48515
45,767	8.19349	41.74	5.103	1752.851901	213.93	8929.531375
2,820,181	7.55228	211.60	6.845	12682.84583	1,679.34	355348.2284
4,140	2.36973	41.74	5.103	152.47526	64.34	2685.669798
62,790	11.54988	500.00	9.803	2894.16	250.58	125289.6644
75	6.02040	520.00	10.009	52.13819341	8.66	4503.3321
770,088	1.34772	26.25	4.944	1182.687727	877.55	23035.59772
3,983	19.23185	600.00	10.829	1213.741406	63.11	37866.60798
334,569	1.12882	26.25	4.944	652.9342053	578.42	15183.5092
95,550	12.25839	750.00	12.368	3789.210903	309.11	231833.7227
2,606	14.67685	795.00	12.829	749.2382406	51.05	40583.95188
673	1.86051	795.00	12.829	48.26567903	25.94	20624.08362

Kentucky Utilities Company
Pri/Sec Splits for Underground Conductor

		Customer	Demand
Underground		79.61%	20.39%
Primary	91.81%	0.7309	0.1872
Secondary	8.19%	0.0652	0.0167

Exhibit WSS-15

Zero Intercept
Line Transformers

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

Weighted Linear Regression Statistics

	Estimate	Standard Error	LINEST Array	
			11.05450218	426.2180274
Size Coefficient ($ per kVA)	11.0545022	0.4496801	0.449680101	55.55395735
Zero Intercept ($ per Unit)	426.22	55.5539573	0.948747147	26299.78697
			453.5221726	49
R-Square	0.9487471		6.27383E+11	33892260941

Plant Classification

Total Number of Units		255,549
Zero Intercept	$	426.22
Zero Intercept Cost	$	108,919,591
Total Cost of Sample	$	231,317,736
Percentage of Total		0.470865713
Percentage Classified as Customer-Related		47.09%
Percentage Classified as Demand-Related		52.91%

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

	Size	Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - .6 KVA	0.6	6,350.91	5	1270.18
TRANSFORMERS - OH 1P - 1 KVA	1	7,213.02	17	424.30
TRANSFORMERS - OH 1P - 1.5 KVA	1.5	1,516.80	22	68.95
TRANSFORMERS - OH 1P - 10 KVA	10	9,385,213.20	27,058	346.86
TRANSFORMERS - OH 1P - 100 KVA	100	6,031,328.08	4,248	1419.80
TRANSFORMERS - OH 1P - 1250 KVA	1250	148,540.75	14	10610.05
TRANSFORMERS - OH 1P - 15 KVA	15	27,800,803.47	54,618	509.00
TRANSFORMERS - OH 1P - 150 KVA	150	8,633.26	5	1726.65
TRANSFORMERS - OH 1P - 167 KVA	167	4,105,405.83	2,250	1824.62
TRANSFORMERS - OH 1P - 25 KVA	25	39,922,144.76	62,932	634.37
TRANSFORMERS - OH 1P - 250 KVA	250	995,942.04	297	3353.34
TRANSFORMERS - OH 1P - 3 KVA	3	97,135.32	793	122.49
TRANSFORMERS - OH 1P - 333 KVA	333	498,154.29	134	3717.57
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	23,229,188.04	30,639	758.16
TRANSFORMERS - OH 1P - 5 KVA	5	804,677.62	5,314	151.43
TRANSFORMERS - OH 1P - 50 KVA	50	22,526,634.76	18,853	1194.86
TRANSFORMERS - OH 1P - 500 KVA	500	1,079,113.11	230	4691.80
TRANSFORMERS - OH 1P - 667 KVA	667	92,692.95	17	5452.53
TRANSFORMERS - OH 1P - 7.5 KVA	7.5	4,794.01	14	342.43
TRANSFORMERS - OH 1P - 75 KVA	75	7,792,123.39	6,654	1171.04
TRANSFORMERS - OH 1P - 833 KVA	833	255,840.52	25	10233.62
TRANSFORMERS - PM 1P - 10 KVA	10	119,797.83	156	767.93
TRANSFORMERS - PM 1P - 100 KVA	100	2,620,877.58	1,410	1858.78
TRANSFORMERS - PM 1P - 15 KVA	15	2,512,954.32	2,860	878.66
TRANSFORMERS - PM 1P - 150 KVA	150	70,726.30	15	4715.09
TRANSFORMERS - PM 1P - 167 KVA	167	2,208,351.44	972	2271.97
TRANSFORMERS - PM 1P - 225 KVA	225	24,046.73	7	3435.25
TRANSFORMERS - PM 1P - 25 KVA	25	9,557,478.42	9,683	987.04
TRANSFORMERS - PM 1P - 250 KVA	250	1,850,305.59	485	3815.06
TRANSFORMERS - PM 1P - 333 KVA	333	3,901.90	2	1950.95
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	10,048,725.05	9,363	1073.24
TRANSFORMERS - PM 1P - 50 KVA	50	8,556,238.09	7,415	1153.91
TRANSFORMERS - PM 1P - 500 KVA	500	6,978.58	1	6978.58
TRANSFORMERS - PM 1P - 75 KVA	75	4,419,304.21	3,062	1443.27
TRANSFORMERS - PM 3P - 1000 KVA	1000	4,303,893.22	359	11988.56
TRANSFORMERS - PM 3P - 112 KVA	112	79,190.82	29	2730.72
TRANSFORMERS - PM 3P - 112.5 KVA	112.5	801,067.83	224	3576.20
TRANSFORMERS - PM 3P - 1250 KVA	1250	14,355.37	2	7177.69
TRANSFORMERS - PM 3P - 150 KVA	150	3,688,490.25	872	4229.92
TRANSFORMERS - PM 3P - 1500 KVA	1500	4,766,436.89	279	17084.00
TRANSFORMERS - PM 3P - 2000 KVA	2000	2,812,618.87	120	23438.49
TRANSFORMERS - PM 3P - 225 KVA	225	2,660,782.26	574	4635.51
TRANSFORMERS - PM 3P - 2500 KVA	2500	3,483,061.89	167	20856.66
TRANSFORMERS - PM 3P - 300 KVA	300	5,565,402.43	1,007	5526.72
TRANSFORMERS - PM 3P - 3000 KVA	3000	573,153.95	15	38210.26
TRANSFORMERS - PM 3P - 333 KVA	333	117,861.40	33	3571.56
TRANSFORMERS - PM 3P - 45 KVA	45	374,141.61	117	3197.79
TRANSFORMERS - PM 3P - 500 KVA	500	7,621,986.26	1,012	7531.61
TRANSFORMERS - PM 3P - 75 KVA	75	2,300,583.50	645	3566.80
TRANSFORMERS - PM 3P - 750 KVA	750	5,345,163.66	521	10259.43
TRANSFORMERS - PM 3P - 833 KVA	833	16,413.78	3	5471.26

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

n	y	x	est y	y*n^.5	n^.5	xn^.5
5	1,270	0.60	267	2840.213296	2.24	1.341640786
17	424	1.00	437	1749.414314	4.12	4.123105626
22	69	1.50	650	323.3828466	4.69	7.03562364
27,058	347	10.00	4,273	57055.33984	164.49	1644.93161
4,248	1,420	100.00	42,633	92538.12571	65.18	6517.668295
14	10,610	1,250.00	532,784	39699.18532	3.74	4677.071733
54,618	509	15.00	6,404	118956.8488	233.70	3505.574133
5	1,727	150.00	63,944	3860.911245	2.24	335.4101966
2,250	1,825	167.00	71,189	86549.55428	47.43	7921.505539
62,932	634	25.00	10,667	159139.5399	250.86	6271.562804
297	3,353	250.00	106,566	57790.4186	17.23	4308.421985
793	122	3.00	1,290	3449.376352	28.16	84.48076704
134	3,718	333.00	141,942	43033.97622	11.58	3854.753689
30,639	758	37.50	15,994	132707.8876	175.04	6563.999829
5,314	151	5.00	2,142	11038.5276	72.90	364.4859394
18,853	1,195	50.00	21,322	164061.2756	137.31	6865.311355
230	4,692	500.00	213,120	71154.61133	15.17	7582.875444
17	5,453	667.00	284,298	22481.34256	4.12	2750.111452
14	342	7.50	3,208	1281.253066	3.74	28.0624304
6,654	1,171	75.00	31,977	95524.42294	81.57	6117.904053
25	10,234	833.00	355,051	51168.104	5.00	4165
156	768	10.00	4,273	9591.502674	12.49	124.89996
1,410	1,859	100.00	42,633	69797.068	37.55	3754.996671
2,860	879	15.00	6,404	46989.58155	53.48	802.1845174
15	4,715	150.00	63,944	18261.45214	3.87	580.9475019
972	2,272	167.00	71,189	70832.90546	31.18	5206.544728
7	3,435	225.00	95,910	9088.809632	2.65	595.294045
9,683	987	25.00	10,667	97126.63892	98.40	2460.055894
485	3,815	250.00	106,566	84018.04883	22.02	5505.678886
2	1,951	333.00	141,942	2759.05995	1.41	470.9331163
9,363	1,073	37.50	15,994	103849.2709	96.76	3628.597353
7,415	1,154	50.00	21,322	99363.59209	86.11	4305.519713
1	6,979	500.00	213,120	6978.58	1.00	500
3,062	1,443	75.00	31,977	79864.04536	55.34	4150.1506
359	11,989	1,000.00	426,229	227150.7963	18.95	18947.29532
29	2,731	112.00	47,747	14705.3661	5.39	603.1384584
224	3,576	112.50	47,961	53523.59578	14.97	1683.745824
2	7,178	1,250.00	532,784	10150.77947	1.41	1767.766953
872	4,230	150.00	63,944	124908.0411	29.53	4429.446918
279	17,084	1,500.00	639,338	285359.1124	16.70	25054.93963
120	23,438	2,000.00	852,447	256755.8001	10.95	21908.9023
574	4,636	225.00	95,910	111058.9058	23.96	5390.616848
167	20,857	2,500.00	1,065,556	269527.4211	12.92	32307.11996
1,007	5,527	300.00	127,876	175380.7157	31.73	9519.978992
15	38,210	3,000.00	1,278,665	147987.7135	3.87	11618.95004
33	3,572	333.00	141,942	20517.03624	5.74	1912.939361
117	3,198	45.00	19,191	34589.40408	10.82	486.7494222
1,012	7,532	500.00	213,120	239595.0853	31.81	15905.97372
645	3,567	75.00	31,977	90585.38685	25.40	1904.763765
521	10,259	750.00	319,675	234175.8717	22.83	17119.06832
3	5,471	833.00	355,051	9476.500301	1.73	1442.798323

Exhibit WSS-16

Electric Cost of Service Study
Functional Assignment and Classification
BIP Methodology

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	$ 39,493	8,275	8,668	7,125	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	55,919	11,716	12,273	10,089	-	-	-
303.00 SOFTWARE	P302	PT&D	102,982,045	21,576,997	22,603,270	18,579,812	-	-	-
Total Intangible Plant	PINT		$ 103,077,457	$ 21,596,988	$ 22,624,212	$ 18,597,026	$ -	$ -	$ -
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	$ 3,145,206,425	1,081,326,073	1,132,757,504	931,122,848	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	$ 36,962,631	12,707,801	13,312,226	10,942,605	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	$ 894,751,299	307,616,664	322,247,926	264,886,709	-	-	-
Total Production Plant	PPRTL		$ 4,076,920,355	$ 1,401,650,538	$ 1,468,317,655	$ 1,206,952,162	$ -	$ -	$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	$ 873,007,848	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	8,230,400	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 881,238,248	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	$ 209,650,161	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	717,117,865	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	200,924,821	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	5,414,628	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	303,128,639	-	-	-	-	-	-
369-SERVICES	P369	F006	97,262,577	-	-	-	-	-	-
370-METERS	P370	F007	82,987,729	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	282,792	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	114,827,799	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 1,731,597,011	$ -	$ -	$ -	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 6,689,755,615	$ 1,401,650,538	$ 1,468,317,655	$ 1,206,952,162	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Demand**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Plant in Service								
Intangible Plant								
301.00 ORGANIZATION	P301	PT&D	5,202	-	1,238	-	1,349	2,501
302.00 FRANCHISE AND CONSENTS	P301	PT&D	7,366	-	1,752	-	1,910	3,541
303.00 SOFTWARE	P302	PT&D	13,565,775	-	3,227,353	-	3,516,821	6,521,627
Total Intangible Plant	PINT		$ 13,578,343	$ -	$ 3,230,343	$ -	$ 3,520,079	$ 6,527,669
Steam Production Plant								
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-
Hydraulic Production Plant								
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-
Other Production Plant								
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -		$ -	$ -	
Transmission								
KENTUCKY SYSTEM PROPERTY	P350	F011	873,007,848	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	8,230,400	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 881,238,248	$ -	$ -	$ -	$ -	$ -
Distribution								
TOTAL ACCTS 360-362	P362	F001	-	-	209,650,161	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	190,840,848	276,791,712
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	37,613,245	146,855,833
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	-	-	-	-
370-METERS	P370	F007	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ 209,650,161	$ -	$ 228,454,093	$ 423,647,545
Total Prod, Trans, and Dist Plant	PT&D		$ 881,238,248	$ -	$ 209,650,161	$ -	$ 228,454,093	$ 423,647,545

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	621	949	964	858	574	490	680
302.00 FRANCHISE AND CONSENTS	P301	PT&D	879	1,344	1,365	1,214	813	694	962
303.00 SOFTWARE	P302	PT&D	1,618,990	2,474,904	2,513,236	2,236,477	1,497,259	1,277,512	1,772,012
Total Intangible Plant	PINT		$ 1,620,490	$ 2,477,197	$ 2,515,564	$ 2,238,549	$ 1,498,647	$ 1,278,696	$ 1,773,653
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-
Total Production Plant	PPRTL				$ -	$ -			$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	101,814,953	147,670,352	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	3,355,326	13,100,417	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	2,865,065	2,549,563	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	160,395,756	142,732,883	-	-	-
369-SERVICES	P369	F006	-	-	-	-	97,262,577	-	-
370-METERS	P370	F007	-	-	-	-	-	82,987,729	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	282,792
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	114,827,799
Total Distribution Plant	PDIST		$ 105,170,279	$ 160,770,769	$ 163,260,822	$ 145,282,445	$ 97,262,577	$ 82,987,729	$ 115,110,592
Total Prod, Trans, and Dist Plant	PT&D		$ 105,170,279	$ 160,770,769	$ 163,260,822	$ 145,282,445	$ 97,262,577	$ 82,987,729	$ 115,110,592

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service					
Intangible Plant					
301.00 ORGANIZATION	P301	PT&D	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	-	-	-
303.00 SOFTWARE	P302	PT&D	-	-	-
Total Intangible Plant	PINT		$ -	$ -	$ -
Steam Production Plant					
Total Steam Production Plant	PSTPR	F017	-	-	-
Hydraulic Production Plant					
Total Hydraulic Production Plant	PHDPR	F017	-	-	-
Other Production Plant					
Total Other Production Plant	POTPR	F017	-	-	-
Total Production Plant	PPRTL		$ -	$ -	$ -
Transmission					
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -
Distribution					
TOTAL ACCTS 360-362	P362	F001	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-
369-SERVICES	P369	F006	-	-	-
370-METERS	P370	F007	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	$ 177,535,196	37,197,518	38,966,754	32,030,541	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	$ -	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$ -	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	$ 271,089	93,201	97,634	80,255	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	$ 113,882	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 6,970,753,239	$ 1,460,538,245	$ 1,530,006,255	$ 1,257,659,983	$ -	$ -	$ -
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	$ 28,153,069	9,679,062	10,139,430	8,334,577	-	-	-
CWIP Transmission	CWIP2	F011	30,190,923	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	32,868,652	-	-	-	-	-	-
CWIP General Plant	CWIP4	PT&D	27,491,296	5,760,029	6,033,995	4,959,924	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 118,703,941	$ 15,439,091	$ 16,173,426	$ 13,294,501	$ -	$ -	$ -
Total Utility Plant			$ 7,089,457,179	$ 1,475,977,336	$ 1,546,179,681	$ 1,270,954,484	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Plant in Service (Continued)								
General Plant								
Total General Plant	PGP	PT&D	23,386,625	-	5,563,773	-	6,062,799	11,242,914
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	-	-	13,788	-	15,025	27,862
OTHER		PDIST	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 918,203,216	$ -	$ 218,458,065	$ -	$ 238,051,995	$ 441,445,991
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	F017	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	30,190,923	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	3,979,516	-	4,336,447	8,041,550
CWIP General Plant	CWIP4	PT&D	3,621,415	-	861,549	-	938,823	1,740,963
RWIP	CWIP5	F004	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 33,812,338	$ -	$ 4,841,066	$ -	$ 5,275,270	$ 9,782,513
Total Utility Plant			$ 952,015,555	$ -	$ 223,299,131	$ -	$ 243,327,265	$ 451,228,504

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	2,791,048	4,266,594	4,332,676	3,855,559	2,581,190	2,202,359	3,054,847
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	6,917	10,573	10,737	9,555	6,397	5,458	7,570
OTHER		PDIST	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 109,588,734	$ 167,525,133	$ 170,119,799	$ 151,386,108	$ 101,348,810	$ 86,474,242	$ 119,946,663
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	1,996,311	3,051,702	3,098,968	2,757,708	1,846,209	1,575,248	2,184,995
CWIP General Plant	CWIP4	PT&D	432,193	660,681	670,914	597,033	399,697	341,035	473,043
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 2,428,504	$ 3,712,384	$ 3,769,882	$ 3,354,740	$ 2,245,906	$ 1,916,283	$ 2,658,037
Total Utility Plant			$ 112,017,238	$ 171,237,517	$ 173,889,681	$ 154,740,848	$ 103,594,716	$ 88,390,525	$ 122,604,700

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)					
General Plant					
Total General Plant	PGP	PT&D	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	-	-	-
OTHER		PDIST	-	-	-
Total Plant in Service	TPIS		$ -	$ -	$ -
Construction Work in Progress (CWIP)					
CWIP Production	CWIP1	F017	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	-
CWIP General Plant	CWIP4	PT&D	-	-	-
RWIP	CWIP5	F004	-	-	-
Total Construction Work in Progress	TCWIP		$ -	$ -	$ -
Total Utility Plant			$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand			Production Energy		
				Base	Inter.	Peak	Base	Inter.	Peak
Rate Base									
Utility Plant									
Plant in Service			$ 6,970,753,239	$ 1,460,538,245	$ 1,530,006,255	$ 1,257,659,983	$ -	$ -	$ -
Construction Work in Progress (CWIP)			118,703,941	15,439,091.47	16,173,425.52	13,294,501.24	-	-	-
Total Utility Plant	TUP		$ 7,089,457,179	$ 1,475,977,336	$ 1,546,179,681	$ 1,270,954,484	$ -	$ -	$ -
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	$ 1,351,527,013	464,656,751	486,757,357	400,112,906	-	-	-
Hydraulic Production	RWIP	F017	11,357,150	3,904,603	4,090,319	3,362,228	-	-	-
Other Production		F017	279,457,486	96,077,848	100,647,627	82,732,010	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	303,777,627	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	4,014,978	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	637,170,341	-	-	-	-	-	-
General Plant	ADEPRD12	PT&D	60,263,984	12,626,626	13,227,190	10,872,706	-	-	-
Intangible Plant	ADEPRGP	PT&D	51,974,185	10,889,732	11,407,683	9,377,077	-	-	-
Total Accumulated Depreciation	TADEPR		$ 2,699,542,764	$ 588,155,561	$ 616,130,177	$ 506,456,928	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 4,389,914,415	$ 887,821,776	$ 930,049,504	$ 764,497,556	$ -	$ -	$ -
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 106,348,560	4,228,864	4,012,925	4,067,104	71,897,457	-	-
Materials and Supplies	M&S	TPIS	119,808,344	25,102,692	26,296,658	21,615,764	-	-	-
Prepayments	PREPAY	TPIS	16,171,254	3,388,261	3,549,418	2,917,610	-	-	-
Total Working Capital	TWC		$ 242,328,157	$ 32,719,817	$ 33,859,002	$ 28,600,478	$ 71,897,457	$ -	$ -
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	511,060,465	175,703,255	184,060,280	151,296,930	-	-	-
Total Transmission Plant	ADITTP	F011	129,909,095	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	241,830,055	-	-	-	-	-	-
Total General Plant	ADITGP	PT&D	27,628,083	5,788,689	6,064,018	4,984,603	-	-	-
Total Accumulated Deferred Income Tax	ADITT		910,427,698	181,491,944	190,124,299	156,281,533	-	-	-
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	$ 81,185,411	27,911,650	29,239,220	24,034,541	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		81,185,411	27,911,650	29,239,220	24,034,541	-	-	-
Total Deferred Debits			$ 991,613,109	$ 209,403,594	$ 219,363,519	$ 180,316,073	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	$ 1,549,704	-	-	-	-	-	-
Less: Asset Retirement Obligations		F017		-	-	-	-	-	-
Net Rate Base	RB		$ 3,639,079,759	$ 711,137,998	$ 744,544,987	$ 612,781,961	$ 71,897,457	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Demand**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Rate Base								
Utility Plant								
Plant in Service			$ 918,203,216	$ -	$ 218,458,065	$ -	$ 238,051,995	$ 441,445,991
Construction Work in Progress (CWIP)			33,812,338.16	-	4,841,065.50	-	5,275,270.10	9,782,513.43
Total Utility Plant	TUP		$ 952,015,555	$ -	$ 223,299,131	$ -	$ 243,327,265	$ 451,228,504
Less: Acummulated Provision for Depreciation								
Steam Production	ADEPREPA	F017	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	303,777,627	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	4,014,978	-	-	-	-	-
Distribution	ADEPRD11	PDIST	-	-	77,144,315	-	84,063,539	155,888,263
General Plant	ADEPRD12	PT&D	7,938,545	-	1,888,612	-	2,058,005	3,816,386
Intangible Plant	ADEPRGP	PT&D	6,846,534	-	1,628,818	-	1,774,910	3,291,411
Total Accumulated Depreciation	TADEPR		$ 322,577,684	$ -	$ 80,661,745	$ -	$ 87,896,454	$ 162,996,060
Net Utility Plant	NTPLANT		$ 629,437,870	$ -	$ 142,637,386	$ -	$ 155,430,811	$ 288,232,444
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	5,301,675	-	894,425	-	1,652,866	2,645,269
Materials and Supplies	M&S	TPIS	15,781,423	-	3,754,702	-	4,091,468	7,587,259
Prepayments	PREPAY	TPIS	2,130,114	-	506,795	-	552,250	1,024,098
Total Working Capital	TWC		$ 23,213,212	$ -	$ 5,155,922	$ -	$ 6,296,585	$ 11,256,626
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-
Deferred Debits								
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-
Accumulated Deferred Income Tax								
Total Production Plant	ADITPP	F017	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	129,909,095	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	29,279,162	-	31,905,267	59,165,446
Total General Plant	ADITGP	PT&D	3,639,434	-	865,836	-	943,495	1,749,626
Total Accumulated Deferred Income Tax	ADITT		133,548,529	-	30,144,998	-	32,848,762	60,915,072
Accumulated Deferred Investment Tax Credits								
Production	ADITCP	F017	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-
Total Deferred Debits			$ 133,548,529	$ -	$ 30,144,998	$ -	$ 32,848,762	$ 60,915,072
Less: Customer Advances	CSTDEP	F027	-	-	-	-	385,642	715,139
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-
Net Rate Base	RB		$ 519,102,553	$ -	$ 117,648,309	$ -	$ 128,492,991	$ 237,858,860

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Rate Base									
Utility Plant									
Plant in Service			$ 109,588,734	$ 167,525,133	$ 170,119,799	$ 151,386,108	$ 101,348,810	$ 86,474,242	$ 119,946,663
Construction Work in Progress (CWIP)			2,428,503.78	3,712,383.62	3,769,881.82	3,354,740.25	2,245,905.76	1,916,282.97	2,658,037.14
Total Utility Plant	TUP		$ 112,017,238	$ 171,237,517	$ 173,889,681	$ 154,740,848	$ 103,594,716	$ 88,390,525	$ 122,604,700
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	38,699,179	59,158,317	60,074,574	53,459,127	35,789,406	30,536,735	42,356,885
General Plant	ADEPRD12	PT&D	947,416	1,448,287	1,470,719	1,308,762	876,180	747,587	1,036,962
Intangible Plant	ADEPRGP	PT&D	817,091	1,249,064	1,268,409	1,128,731	755,654	644,750	894,320
Total Accumulated Depreciation	TADEPR		$ 40,463,686	$ 61,855,668	$ 62,813,702	$ 55,896,621	$ 37,421,241	$ 31,929,072	$ 44,288,166
Net Utility Plant	NTPLANT		$ 71,553,552	$ 109,381,849	$ 111,075,979	$ 98,844,227	$ 66,173,475	$ 56,461,453	$ 78,316,533
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	836,918	1,235,970	367,121	326,693	215,040	1,485,823	237,305
Materials and Supplies	M&S	TPIS	1,883,533	2,879,303	2,923,898	2,601,917	1,741,911	1,486,258	2,061,558
Prepayments	PREPAY	TPIS	254,232	388,637	394,656	351,196	235,116	200,609	278,261
Total Working Capital	TWC		$ 2,974,683	$ 4,503,910	$ 3,685,675	$ 3,279,806	$ 2,192,067	$ 3,172,689	$ 2,577,123
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	14,687,791	22,452,801	22,800,555	20,289,745	13,583,423	11,589,837	16,076,027
Total General Plant	ADITGP	PT&D	434,344	663,969	674,252	600,003	401,686	342,732	475,396
Total Accumulated Deferred Income Tax	ADITT		15,122,134	23,116,770	23,474,808	20,889,748	13,985,108	11,932,569	16,551,424
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-	-
Total Deferred Debits			$ 15,122,134	$ 23,116,770	$ 23,474,808	$ 20,889,748	$ 13,985,108	$ 11,932,569	$ 16,551,424
Less: Customer Advances	CSTDEP	F027	177,533	271,389	-	-	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-	-
Net Rate Base	RB		$ 59,228,567	$ 90,497,599	$ 91,286,846	$ 81,234,285	$ 54,380,434	$ 47,701,574	$ 64,342,233

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base					
Utility Plant					
Plant in Service			$ -	$ -	$ -
Construction Work in Progress (CWIP)			-	-	-
Total Utility Plant	TUP		$ -	$ -	$ -
Less: Acummulated Provision for Depreciation					
Steam Production	ADEPREPA	F017	-	-	-
Hydraulic Production	RWIP	F017	-	-	-
Other Production		F017	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-
Distribution	ADEPRD11	PDIST	-	-	-
General Plant	ADEPRD12	PT&D	-	-	-
Intangible Plant	ADEPRGP	PT&D	-	-	-
Total Accumulated Depreciation	TADEPR		$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ -	$ -	$ -
Working Capital					
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	6,169,535	773,569	-
Materials and Supplies	M&S	TPIS	-	-	-
Prepayments	PREPAY	TPIS	-	-	-
Total Working Capital	TWC		$ 6,169,535	$ 773,569	$ -
Emission Allowance	EMALL	PROFIX	-	-	-
Deferred Debits					
Service Pension Cost	PENSCOST	TLB	-	-	-
Accumulated Deferred Income Tax					
Total Production Plant	ADITPP	F017	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	-
Total General Plant	ADITGP	PT&D	-	-	-
Total Accumulated Deferred Income Tax	ADITT		-	-	-
Accumulated Deferred Investment Tax Credits					
Production	ADITCP	F017	-	-	-
Transmission	ADITCT	F011	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-
General	ADITCG	PT&D	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-
Total Deferred Debits			$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-
Net Rate Base	RB		$ 6,169,535	$ 773,569	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 9,442,701	2,799,391	2,638,923	2,710,193	1,294,194	-	-
501 FUEL	OM501	Energy	372,621,659	-	-	-	372,621,659	-	-
502 STEAM EXPENSES	OM502		15,516,429	2,836,708	2,674,102	2,746,321	7,259,297	-	-
505 ELECTRIC EXPENSES	OM505		7,214,388	2,023,579	1,907,583	1,959,101	1,324,124	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	14,444,590	4,962,388	4,677,933	4,804,269	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ 419,239,766	$ 12,622,067	$ 11,898,541	$ 12,219,884	$ 382,499,274	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 10,261,750	340,085	320,591	329,249	9,271,825	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	5,959,887	2,047,498	1,930,131	1,982,258	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	40,186,142	-	-	-	40,186,142	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	8,270,033	-	-	-	8,270,033	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	2,439,522	-	-	-	2,439,522	-	-
Total Steam Power Generation Maintenance Expense			$ 67,117,335	$ 2,387,584	$ 2,250,722	$ 2,311,507	$ 60,167,522	$ -	$ -
Total Steam Power Generation Expense			$ 486,357,101	$ 15,009,650	$ 14,149,263	$ 14,531,391	$ 442,666,797	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ -	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	8,523	2,928	2,760	2,835	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 8,523	$ 2,928	$ 2,760	$ 2,835	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 186,494	64,069	60,397	62,028	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	116,901	40,161	37,859	38,881	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	22,497	7,729	7,286	7,482	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	33,030	-	-	-	33,030	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	9,592	-	-	-	9,592	-	-
Total Hydraulic Power Generation Maint. Expense			$ 368,513	$ 111,959	$ 105,541	$ 108,392	$ 42,622	$ -	$ -
Total Hydraulic Power Generation Expense			$ 377,036	$ 114,887	$ 108,301	$ 111,226	$ 42,622	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 1,071,395	368,074	346,975	356,346	-	-	-
547 FUEL	OM547	Energy	130,769,641	-	-	-	130,769,641	-	-
548 GENERATION EXPENSE	OM548	PROFIX	611,306	210,012	197,974	203,320	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	3,639,052	1,250,183	1,178,520	1,210,348	-	-	-
550 RENTS	OM550	PROFIX	4,421	1,519	1,432	1,470	-	-	-
Total Other Power Generation Expenses			$ 136,095,816	$ 1,829,789	$ 1,724,901	$ 1,771,485	$ 130,769,641	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses								
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses								
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-
501 FUEL	OM501	Energy	-	-	-
502 STEAM EXPENSES	OM502		-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-
507 RENTS	OM507	PROFIX	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-
540 RENTS		PROFIX	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-
547 FUEL	OM547	Energy	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-
550 RENTS	OM550	PROFIX	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

				Production Demand			Production Energy		
Description	**Name**	**Functional Vector**	**Total System**	**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 257,199	88,360	83,295	85,544	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	1,680,721	577,406	544,308	559,008	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	4,895,395	1,681,796	1,585,391	1,628,208	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	5,139,215	1,765,559	1,664,353	1,709,302	-	-	-
Total Other Power Generation Maintenance Expense			$ 11,972,530	$ 4,113,121	$ 3,877,347	$ 3,982,062	$ -	$ -	$ -
Total Other Power Generation Expense			$ 148,068,346	$ 5,942,909	$ 5,602,248	$ 5,753,548	$ 130,769,641	$ -	$ -
Total Station Expense			$ 634,802,484	$ 21,067,446	$ 19,859,813	$ 20,396,165	$ 573,479,060	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	$ 50,619,307	2,507,314	2,626,570	2,159,032	43,326,391	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP		-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP		-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP		-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	1,864,717	640,617	603,895	620,205	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	10,369	3,562	3,358	3,449	-	-	-
Total Other Power Supply Expenses	TPP		$ 52,494,393	$ 3,151,493	$ 3,233,823	$ 2,782,685	$ 43,326,391	$ -	$ -
Total Electric Power Generation Expenses			$ 687,296,876	$ 24,218,939	$ 23,093,636	$ 23,178,850	$ 616,805,451	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 1,804,305	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	3,644,052	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	1,303,298	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	1,058,993	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	2,940,449	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	11,948,572	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	112,005	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,986,407	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	10,570,832	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	337,099	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ 35,706,011	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 1,510,424	-	-	-	-	-	-
581 LOAD DISPATCHING	OM581	P362	341,053	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	1,798,545	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	4,706,317	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	8,749,183	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	(142,800)	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	6,743,173	-	-	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 23,705,895	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses								
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	1,804,305	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	3,644,052	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	1,303,298	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	1,058,993	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	2,940,449	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	11,948,572	-	-	-	-	-
567 RENTS	OM567	PTRAN	112,005	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,986,407	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	10,570,832	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	337,099	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-
Total Transmission Expenses			$ 35,706,011	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	196,412	-	123,632	200,942
581 LOAD DISPATCHING	OM581	P362	-	-	341,053	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	1,798,545	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	1,252,454	1,816,535
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	816,418	-	889,644	1,649,765
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ 3,152,429	$ -	$ 2,265,731	$ 3,667,242

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	62,043	91,915	38,256	34,044	22,791	713,416	26,974
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	668,193	969,134	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	8,749,183	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	(142,800)
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	409,553	626,072	635,769	565,758	378,759	323,170	448,263
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 1,139,789	$ 1,687,121	$ 674,026	$ 599,802	$ 401,551	$ 9,785,769	$ 332,436

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -
Other Power Supply Expenses					
555 PURCHASED POWER	OM555	OMPP	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -
Transmission Expenses					
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-
567 RENTS	OM567	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-
Total Transmission Expenses			$ -	$ -	$ -
Distribution Operation Expense					
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-
589 RENTS	OM589	PDIST	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 57,449	-	-	-	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	1,286,692	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	30,239,215	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	790,500	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	96,331	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	1,371,953	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	550,314	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 34,392,454	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			58,098,349	-	-	-	-	-	-
Transmission and Distribution Expenses			93,804,360	-	-	-	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 781,101,237	$ 24,218,939	$ 23,093,636	$ 23,178,850	$ 616,805,451	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 3,631,554	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	5,301,482	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	20,167,471	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	5,566,157	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 34,666,664	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	$ 651,425	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	450,051	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	389,845	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	1,861,027	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	794,217	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 4,146,565	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		819,914,466	24,218,939	23,093,636	23,178,850	616,805,451	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses (Continued)								
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	4,810	-	13,640	21,294
591 STRUCTURES	OM591	P362	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	1,286,692	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	8,047,321	11,671,671
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	147,982	577,776
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	66,628	-	72,604	134,638
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ 1,358,130	$ -	$ 8,281,547	$ 12,405,380
Total Distribution Operation and Maintenance Expenses			-	-	4,510,559	-	10,547,278	16,072,622
Transmission and Distribution Expenses			35,706,011	-	4,510,559	-	10,547,278	16,072,622
Production, Transmission and Distribution Expenses	OMSUB		$ 35,706,011	$ -	$ 4,510,559	$ -	$ 10,547,278	$ 16,072,622
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	OM907	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		35,706,011	-	4,510,559	-	10,547,278	16,072,622

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	7,004	10,293	216	192	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	4,293,303	6,226,920	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	13,201	51,541	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	50,972	45,359	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	1,371,953	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	33,424	51,094	51,885	46,172	30,911	26,374	36,583
Total Distribution Maintenance Expense	OMDM		$ 4,346,931	$ 6,339,848	$ 103,074	$ 91,723	$ 30,911	$ 1,398,327	$ 36,583
Total Distribution Operation and Maintenance Expenses			5,486,721	8,026,969	777,099	691,525	432,461	11,184,096	369,019
Transmission and Distribution Expenses			5,486,721	8,026,969	777,099	691,525	432,461	11,184,096	369,019
Production, Transmission and Distribution Expenses	OMSUB		$ 5,486,721	$ 8,026,969	$ 777,099	$ 691,525	$ 432,461	$ 11,184,096	$ 369,019
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		5,486,721	8,026,969	777,099	691,525	432,461	11,184,096	369,019

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Distribution Maintenance Expense					
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-
591 STRUCTURES	OM591	P362	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-
Transmission and Distribution Expenses			-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ -	$ -	$ -
Customer Accounts Expense					
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	3,631,554	-	-
902 METER READING EXPENSES	OM902	F025	5,301,482	-	-
903 RECORDS AND COLLECTION	OM903	F025	20,167,471	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	5,566,157	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-
Total Customer Accounts Expense	OMCA		$ 34,666,664	$ -	$ -
Customer Service Expense					
907 SUPERVISION	OM907	F026	-	651,425	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	450,051	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	389,845	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	1,861,027	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	794,217	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-
Total Customer Service Expense	OMCS		$ -	$ 4,146,565	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		34,666,664	4,146,565	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 33,809,232	3,683,645	3,472,490	3,566,271	7,680,251	-	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	7,269,104	791,997	746,598	766,761	1,651,281	-	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(4,414,266)	(480,951)	(453,382)	(465,626)	(1,002,764)	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	19,133,213	2,084,637	1,965,141	2,018,213	4,346,383	-	-
924 PROPERTY INSURANCE	OM924	TUP	5,543,869	1,154,196	1,209,094	993,871	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	3,904,092	425,366	400,983	411,812	886,870	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	38,912,106	4,239,622	3,996,598	4,104,533	8,839,442	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	1,800,307	374,812	392,639	322,748	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	5,197,262	566,262	533,802	548,218	1,180,632	-	-
931 RENTS AND LEASES	OM931	PGP	1,831,134	383,663	401,911	330,369	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	873,720	183,064	191,771	157,635	-	-	-
Total Administrative and General Expense	OMAG		$ 113,859,773	$ 13,406,311	$ 12,857,643	$ 12,754,806	$ 23,582,096	$ -	$ -
Total Operation and Maintenance Expenses	TOM		$ 933,774,239	$ 37,625,250	$ 35,951,279	$ 35,933,656	$ 640,387,547	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 883,154,932	$ 35,117,936	$ 33,324,709	$ 33,774,624	$ 597,061,156	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	2,272,732	-	847,086	-	923,063	1,711,738
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	488,645	-	182,127	-	198,462	368,030
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(296,737)	-	(110,599)	-	(120,519)	(223,491)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	1,286,177	-	479,380	-	522,377	968,701
924 PROPERTY INSURANCE	OM924	TUP	744,465	-	174,617	-	190,279	352,855
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	262,442	-	97,817	-	106,590	197,661
926 EMPLOYEE BENEFITS	OM926	LBSUB7	2,615,758	-	974,938	-	1,062,382	1,970,093
928 REGULATORY COMMISSION FEES	OM928	TUP	241,756	-	56,705	-	61,791	114,586
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	349,371	-	130,217	-	141,896	263,134
931 RENTS AND LEASES	OM931	PGP	241,214	-	57,386	-	62,533	115,962
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	115,095	-	27,382	-	29,837	55,331
Total Administrative and General Expense	OMAG		$ 8,320,918	$ -	$ 2,917,056	$ -	$ 3,178,692	$ 5,894,598
Total Operation and Maintenance Expenses	TOM		$ 44,026,929	$ -	$ 7,427,615	$ -	$ 13,725,970	$ 21,967,220
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 44,026,929	$ -	$ 7,427,615	$ -	$ 13,725,970	$ 21,967,220

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	424,938	649,590	659,651	587,010	392,987	335,310	465,102
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	91,363	139,664	141,827	126,209	84,494	72,093	99,998
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(55,482)	(84,813)	(86,127)	(76,642)	(51,310)	(43,779)	(60,725)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	240,480	367,614	373,308	332,199	222,398	189,758	263,209
924 PROPERTY INSURANCE	OM924	TUP	87,596	133,906	135,980	121,005	81,010	69,120	95,875
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	49,069	75,011	76,173	67,785	45,380	38,720	53,707
926 EMPLOYEE BENEFITS	OM926	LBSUB7	489,074	747,634	759,213	675,608	452,301	385,919	535,300
928 REGULATORY COMMISSION FEES	OM928	TUP	28,446	43,484	44,158	39,295	26,307	22,446	31,134
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	65,323	99,857	101,404	90,237	60,411	51,545	71,497
931 RENTS AND LEASES	OM931	PGP	28,787	44,007	44,688	39,767	26,623	22,716	31,508
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	13,736	20,998	21,323	18,975	12,703	10,839	15,034
Total Administrative and General Expense	OMAG		$ 1,463,331	$ 2,236,952	$ 2,271,598	$ 2,021,448	$ 1,353,304	$ 1,154,685	$ 1,601,640
Total Operation and Maintenance Expenses	TOM		$ 6,950,051	$ 10,263,921	$ 3,048,697	$ 2,712,973	$ 1,785,765	$ 12,338,781	$ 1,970,659
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 6,950,051	$ 10,263,921	$ 3,048,697	$ 2,712,973	$ 1,785,765	$ 12,338,781	$ 1,970,659

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	5,395,654	741,714	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	1,160,085	159,471	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(704,478)	(96,841)	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	3,053,491	419,748	-
924 PROPERTY INSURANCE	OM924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	623,059	85,649	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	6,210,028	853,662	-
928 REGULATORY COMMISSION FEES	OM928	TUP	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	829,437	114,019	-
931 RENTS AND LEASES	OM931	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	-	-	-
Total Administrative and General Expense	OMAG		$ 16,567,275	$ 2,277,421	$ -
Total Operation and Maintenance Expenses	TOM		$ 51,233,939	$ 6,423,986	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 51,233,939	$ 6,423,986	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 7,176,311	2,127,495	2,005,542	2,059,705	983,568	-	-
501 FUEL	LB501	Energy	2,518,295	-	-	-	2,518,295	-	-
502 STEAM EXPENSES	LB502	PROFIX	8,257,131	2,836,708	2,674,102	2,746,321	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	5,890,264	2,023,579	1,907,583	1,959,101	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	1,708,296	586,879	553,238	568,179	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 25,550,297	$ 7,574,662	$ 7,140,465	$ 7,333,307	$ 3,501,864	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 8,497,622	281,620	265,477	272,647	7,677,878	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	1,238,874	425,611	401,214	412,049	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	9,213,874	-	-	-	9,213,874	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	1,992,105	-	-	-	1,992,105	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	397,544	-	-	-	397,544	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 21,340,020	$ 707,231	$ 666,691	$ 684,696	$ 19,281,401	$ -	$ -
Total Steam Power Generation Expense			$ 46,890,316	$ 8,281,893	$ 7,807,156	$ 8,018,003	$ 22,783,265	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ -	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 166,692	57,266	53,984	55,442	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	47,185	16,210	15,281	15,694	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 213,877	$ 73,477	$ 69,265	$ 71,135	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 213,877	$ 73,477	$ 69,265	$ 71,135	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 848,268	291,419	274,715	282,134	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	327,051	112,357	105,917	108,777	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	1,662,761	571,236	538,491	553,034	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 2,838,080	$ 975,012	$ 919,122	$ 943,945	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Labor Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses								
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses								
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-
501 FUEL	LB501	Energy	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-
507 RENTS	LB507	PROFIX	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-
540 RENTS	LB540	PROFIX	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-
547 FUEL	LB547	Energy	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-
550 RENTS	LB550	PROFIX	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector		Total System	Production Demand Base	Inter.	Peak	Production Energy Base	Inter.	Peak
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	201,322	69,163	65,199	66,960	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX		-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX		1,017,670	349,617	329,576	338,477	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX		1,600,551	549,864	518,344	532,343	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$	2,819,543	$ 968,644	$ 913,119	$ 937,780	$ -	$ -	$ -
Total Other Power Generation Expense			$	5,657,623	$ 1,943,656	$ 1,832,242	$ 1,881,725	$ -	$ -	$ -
Total Production Expense	LPREX		$	52,761,816	$ 10,299,026	$ 9,708,662	$ 9,970,863	$ 22,783,265	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	$	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	1,829,189	628,411	592,389	608,388	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$	1,829,189	$ 628,411	$ 592,389	$ 608,388	$ -	$ -	$ -
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	1,648,654	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN		3,065,460	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN		505,135	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN		-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN		118,042	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN		-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN		937,915	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN		466,793	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN		-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN		-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$	6,741,999	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$	1,081,711	-	-	-	-	-	-
581 LOAD DISPATCHING	LB581	P362		342,506	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362		870,967	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365		2,170,209	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367		-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371		-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370		5,717,580	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012		-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371		-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST		3,343,041	-	-	-	-	-	-
589 RENTS	LB589	PDIST		-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$	13,526,014	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	1,648,654	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	3,065,460	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	505,135	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	118,042	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	937,915	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	466,793	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 6,741,999	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	140,663	-	88,541	143,907
581 LOAD DISPATCHING	LB581	P362	-	-	342,506	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	870,967	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	577,540	837,653
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	404,753	-	441,056	817,899
589 RENTS	LB589	PDIST	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ 1,758,889	$ -	$ 1,107,137	$ 1,799,459

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	44,433	65,826	27,398	24,381	16,322	510,923	19,317
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	308,122	446,894	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	5,717,580	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	203,043	310,386	315,193	280,484	187,776	160,217	222,234
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 555,597	$ 823,106	$ 342,591	$ 304,865	$ 204,099	$ 6,388,720	$ 241,551

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -
Purchased Power					
555 PURCHASED POWER	LB555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -
Transmission Labor Expenses					
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -
Distribution Operation Labor Expense					
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-
589 RENTS	LB589	PDIST	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	605,269	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	6,158,359	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	413,802	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	51,420	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 7,228,850	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	20,754,864	-	-	-	-	-	-
Transmission and Distribution Labor Expenses			27,496,863	-	-	-	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 82,087,867	$ 10,927,437	$ 10,301,052	$ 10,579,251	$ 22,783,265	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 3,259,518	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	754,379	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	11,992,171	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 16,006,068	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	LB907	F026	$ 614,307	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	1,585,968	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 2,200,275	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		100,294,210	10,927,437	10,301,052	10,579,251	22,783,265	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	605,269	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	1,638,875	2,376,991
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	77,464	302,447
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ 605,269	$ -	$ 1,716,339	$ 2,679,438
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	2,512,860	-	2,738,243	5,077,825
Transmission and Distribution Labor Expenses			6,741,999	-	2,512,860	-	2,738,243	5,077,825
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 6,741,999	$ -	$ 2,512,860	$ -	$ 2,738,243	$ 5,077,825
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	LB907	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		6,741,999	-	2,512,860	-	2,738,243	5,077,825

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	874,351	1,268,142	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	6,910	26,980	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	27,208	24,212	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 881,262	$ 1,295,122	$ 27,208	$ 24,212	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	1,260,567	1,926,993	1,956,839	1,741,351	1,165,786	994,688	1,379,712
Transmission and Distribution Labor Expenses			1,260,567	1,926,993	1,956,839	1,741,351	1,165,786	994,688	1,379,712
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 1,260,567	$ 1,926,993	$ 1,956,839	$ 1,741,351	$ 1,165,786	$ 994,688	$ 1,379,712
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		1,260,567	1,926,993	1,956,839	1,741,351	1,165,786	994,688	1,379,712

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector		Customer Accounts Expense		Customer Service & Info.		Sales Expense
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024		-		-		-
591 MAINTENANCE OF STRUCTURES	LB591	P362		-		-		-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362		-		-		-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365		-		-		-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367		-		-		-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368		-		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373		-		-		-
597 MAINTENANCE OF METERS	LB597	P370		-		-		-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST		-		-		-
Total Distribution Maintenance Labor Expense	LBDM		$	-	$	-	$	-
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-		-		-
Transmission and Distribution Labor Expenses				-		-		-
Production, Transmission and Distribution Labor Expenses	LBSUB		$	-	$	-	$	-
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025		3,259,518		-		-
902 METER READING EXPENSES	LB902	F025		754,379		-		-
903 RECORDS AND COLLECTION	LB903	F025		11,992,171		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025		-		-		-
905 MISC CUST ACCOUNTS	LB903	F025		-		-		-
Total Customer Accounts Labor Expense	LBCA		$	16,006,068	$	-	$	-
Customer Service Expense								
907 SUPERVISION	LB907	F026		-		614,307		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026		-		1,585,968		-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026		-		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	F026		-		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	F026		-		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026		-		-		-
916 MISC SALES EXPENSE	LB916	F026		-		-		-
Total Customer Service Labor Expense	LBCS		$	-	$	2,200,275	$	-
Sub-Total Labor Exp	LBSUB7			16,006,068		2,200,275		-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector		Total System		Production Demand Base		Production Demand Inter.		Production Demand Peak		Production Energy Base		Production Energy Inter.		Production Energy Peak
Labor Expenses (Continued)																
Administrative and General Expense																
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$	33,809,236		3,683,645		3,472,490		3,566,272		7,680,252		-		-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7		-		-		-		-		-		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7		(3,161,163)		(344,421)		(324,678)		(333,446)		(718,104)		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7		-		-		-		-		-		-		-
924 PROPERTY INSURANCE	LB924	TUP		-		-		-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7		560,277		61,044		57,545		59,099		127,275		-		-
926 EMPLOYEE BENEFITS	LB926	LBSUB7		39,380,962		4,290,706		4,044,753		4,153,989		8,945,949		-		-
928 REGULATORY COMMISSION FEES	LB928	TUP		-		-		-		-		-		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7		-		-		-		-		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7		-		-		-		-		-		-		-
931 RENTS AND LEASES	LB931	PGP		-		-		-		-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP		593,047		124,256		130,166		106,996		-		-		-
Total Administrative and General Expense	LBAG		$	71,182,359	$	7,815,231	$	7,380,277	$	7,552,910	$	16,035,372	$	-	$	-
Total Operation and Maintenance Expenses	TLB		$	171,476,569	$	18,742,668	$	17,681,329	$	18,132,162	$	38,818,637	$	-	$	-
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	171,476,569	$	18,742,668	$	17,681,329	$	18,132,162	$	38,818,637	$	-	$	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	2,272,732	-	847,086	-	923,063	1,711,738
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(212,500)	-	(79,203)	-	(86,306)	(160,047)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	37,663	-	14,038	-	15,297	28,366
926 EMPLOYEE BENEFITS	LB926	LBSUB7	2,647,276	-	986,685	-	1,075,183	1,993,830
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	78,122	-	18,586	-	20,252	37,556
Total Administrative and General Expense	LBAG		$ 4,823,292	$ -	$ 1,787,193	$ -	$ 1,947,489	$ 3,611,444
Total Operation and Maintenance Expenses	TLB		$ 11,565,291	$ -	$ 4,300,052	$ -	$ 4,685,732	$ 8,689,269
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 11,565,291	$ -	$ 4,300,052	$ -	$ 4,685,732	$ 8,689,269

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	424,938	649,590	659,651	587,010	392,987	335,310	465,102
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(39,732)	(60,737)	(61,677)	(54,885)	(36,744)	(31,351)	(43,487)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	7,042	10,765	10,932	9,728	6,512	5,557	7,708
926 EMPLOYEE BENEFITS	LB926	LBSUB7	494,967	756,642	768,361	683,749	457,751	390,569	541,750
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	9,323	14,252	14,473	12,879	8,622	7,357	10,205
Total Administrative and General Expense	LBAG		$ 896,539	$ 1,370,513	$ 1,391,740	$ 1,238,481	$ 829,129	$ 707,441	$ 981,277
Total Operation and Maintenance Expenses	TLB		$ 2,157,106	$ 3,297,506	$ 3,348,579	$ 2,979,831	$ 1,994,915	$ 1,702,129	$ 2,360,988
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 2,157,106	$ 3,297,506	$ 3,348,579	$ 2,979,831	$ 1,994,915	$ 1,702,129	$ 2,360,988

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	5,395,655	741,714	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(504,494)	(69,350)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	89,415	12,291	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	6,284,853	863,947	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-
Total Administrative and General Expense	LBAG		$ 11,265,429	$ 1,548,603	$ -
Total Operation and Maintenance Expenses	TLB		$ 27,271,497	$ 3,748,877	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 27,271,497	$ 3,748,877	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector		Total System	Production Demand Base		Inter.		Peak		Production Energy Base		Inter.		Peak
Other Expenses															
Depreciation Expenses															
Steam Production	DEPRTP	PPRTL	$	99,900,146	34,345,801		35,979,400		29,574,946		-		-		-
Hydraulic Production	DEPRDP1	PPRTL		1,118,831	384,656		402,951		331,224		-		-		-
Other Production	DEPRDP2	PPRTL		35,620,454	12,246,359		12,828,836		10,545,260		-		-		-
Transmission - Kentucky System Property	DEPRDP3	PTRAN		20,185,930	-		-		-		-		-		-
Transmission - Virginia Property	DEPRDP4	PTRAN		182,214	-		-		-		-		-		-
Distribution	DEPRDP5	PDIST		43,044,393	-		-		-		-		-		-
General Plant	DEPRDP6	PGP		11,631,105	2,436,972		2,552,882		2,098,460		-		-		-
Intangible Plant	DEPRAADJ	PINT		16,379,764	3,431,920		3,595,153		2,955,204		-		-		-
Total Depreciation Expense	TDEPR		$	228,062,837	52,845,706		55,359,222		45,505,094		-		-		-
Regulatory Credits and Accretion Expenses															
Production Plant	ACRTPP	PPRTL	$	-	-		-		-		-		-		-
Transmission Plant	ACRTTP	PTRAN		-	-		-		-		-		-		-
Distribution Plant		PDIST		-	-		-		-		-		-		-
Total Regulatory Credits and Accretion Expenses	TACRT		$	-	$ -	$	-	$	-	$	-	$	-	$	-
Property Taxes	PTAX	TUP	$	24,894,101	5,182,784		5,429,295		4,462,862		-		-		-
Other Taxes	OTAX	TUP	$	12,926,774	2,691,268		2,819,273		2,317,433		-		-		-
Gain Disposition of Allowances	GAIN	F013	$	-	-		-		-		-		-		-
Interest	INTLTD	TUP	$	86,095,200	17,924,442		18,776,988		15,434,620		-		-		-
Other Expenses	OT	TUP	$	-	-		-		-		-		-		-
Total Other Expenses	TOE		$	351,978,912	$ 78,644,200	$	82,384,778	$	67,720,009	$	-	$	-	$	-
Total Cost of Service (O&M + Other Expenses)			$	1,285,753,151	$ 116,269,450	$	118,336,057	$	103,653,665	$	640,387,547	$	-	$	-
Non-Operating Items															
Non-Operating Margins - Interest				-											
AFUDC				-											
Income (Loss) from Equity Investments				-											
Non-Operating Margins - Other				-											
Generation and Transmission Capital Credits				-											
Other Capital Credits and Patronage Dividends				-											
Extraordinary Items				-											
Long Term Debt Service Requirements				-											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Other Expenses								
Depreciation Expenses								
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	20,185,930	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	182,214	-	-	-	-	-
Distribution	DEPRDP5	PDIST	-	-	5,211,527	-	5,678,959	10,531,117
General Plant	DEPRDP6	PGP	1,532,160	-	364,507	-	397,200	736,572
Intangible Plant	DEPRAADJ	PINT	2,157,698	-	513,325	-	559,366	1,037,295
Total Depreciation Expense	TDEPR		24,058,002	-	6,089,359	-	6,635,525	12,304,984
Regulatory Credits and Accretion Expenses								
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	3,342,932	-	784,098	-	854,426	1,584,455
Other Taxes	OTAX	TUP	1,735,886	-	407,159	-	443,678	822,761
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-
Interest	INTLTD	TUP	11,561,389	-	2,711,771	-	2,954,995	5,479,772
Other Expenses	OT	TUP	-	-	-	-	-	-
Total Other Expenses	TOE		$ 40,698,209	$ -	$ 9,992,387	$ -	$ 10,888,624	$ 20,191,972
Total Cost of Service (O&M + Other Expenses)			$ 84,725,138	$ -	$ 17,420,002	$ -	$ 24,614,594	$ 42,159,192
Non-Operating Items								
Non-Operating Margins - Interest								
AFUDC								
Income (Loss) from Equity Investments								
Non-Operating Margins - Other								
Generation and Transmission Capital Credits								
Other Capital Credits and Patronage Dividends								
Extraordinary Items								
Long Term Debt Service Requirements								

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Expenses									
Depreciation Expenses									
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	2,614,344	3,996,473	4,058,371	3,611,461	2,417,773	2,062,926	2,861,443
General Plant	DEPRDP6	PGP	182,854	279,523	283,852	252,594	169,105	144,286	200,136
Intangible Plant	DEPRAADJ	PINT	257,508	393,645	399,742	355,722	238,146	203,194	281,847
Total Depreciation Expense	TDEPR		3,054,706	4,669,641	4,741,965	4,219,777	2,825,024	2,410,406	3,343,426
Regulatory Credits and Accretion Expenses									
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	393,340	601,288	610,601	543,361	363,765	310,377	430,517
Other Taxes	OTAX	TUP	204,250	312,231	317,067	282,151	188,893	161,170	223,555
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-
Interest	INTLTD	TUP	1,360,350	2,079,529	2,111,737	1,879,191	1,258,066	1,073,425	1,488,926
Other Expenses	OT	TUP	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 5,012,646	$ 7,662,688	$ 7,781,369	$ 6,924,480	$ 4,635,748	$ 3,955,377	$ 5,486,424
Total Cost of Service (O&M + Other Expenses)			$ 11,962,698	$ 17,926,608	$ 10,830,067	$ 9,637,453	$ 6,421,513	$ 16,294,158	$ 7,457,083
Non-Operating Items									
Non-Operating Margins - Interest									
AFUDC									
Income (Loss) from Equity Investments									
Non-Operating Margins - Other									
Generation and Transmission Capital Credits									
Other Capital Credits and Patronage Dividends									
Extraordinary Items									
Long Term Debt Service Requirements									

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses					
Depreciation Expenses					
Steam Production	DEPRTP	PPRTL	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-
Distribution	DEPRDP5	PDIST	-	-	-
General Plant	DEPRDP6	PGP	-	-	-
Intangible Plant	DEPRAADJ	PINT	-	-	-
Total Depreciation Expense	TDEPR		-	-	-
Regulatory Credits and Accretion Expenses					
Production Plant	ACRTPP	PPRTL	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-
Distribution Plant		PDIST	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -
Property Taxes	PTAX	TUP	-	-	-
Other Taxes	OTAX	TUP	-	-	-
Gain Disposition of Allowances	GAIN	F013	-	-	-
Interest	INTLTD	TUP	-	-	-
Other Expenses	OT	TUP	-	-	-
Total Other Expenses	TOE		$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 51,233,939	$ 6,423,986	$ -
Non-Operating Items					
Non-Operating Margins - Interest					
AFUDC					
Income (Loss) from Equity Investments					
Non-Operating Margins - Other					
Generation and Transmission Capital Credits					
Other Capital Credits and Patronage Dividends					
Extraordinary Items					
Long Term Debt Service Requirements					

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Functional Vectors									
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	0.343801	0.360154	0.296045	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		18,373,986	5,447,167	5,134,923	5,273,601	2,518,295	-	-
PROFIX	PROFIX		1.000000	0.343546	0.323854	0.332600	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		12,842,398	425,611	401,214	412,049	11,603,523	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		47,185	16,210	15,281	15,694	-	-	-
Distribution Operation Labor	F023		12,444,303	-	-	-	-	-	-
Distribution Maintenance Labor	F024		7,228,850	-	-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		918,042,686	-	-	-	-	-	-
Purchase Power Demand		F017	7,312,226	2,513,953	2,633,525	2,164,748	-	-	-
Purchase Power Energy		F018	43,441,113	-	-	-	43,441,113	-	-
Purchased Power Expenses	OMPP	F017	50,753,339	2,513,953	2,633,525	2,164,748	43,441,113	-	-
Gain Disposition of Allowances	F013		1.00000	-	-	-	1.000000	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
	Energy		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.209522	0.219487	0.180418	-	-	-
Total Distribution Plant		PDIST	1.000000	-	-	-	-	-	-
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.039764	0.037734	0.038243	0.676055	-	-
Total Plant in Service		TPIS	1.000000	0.209524	0.219489	0.180420	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.109302	0.103112	0.105741	0.226379	-	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.029538	0.028166	0.028270	0.752280	-	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.296461	0.279467	0.287015	0.137058	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.033141	0.031241	0.032085	0.903532	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	-	-	-
Sub-Total Labor Exp		LBSUB7	1.000000	0.108954	0.102708	0.105482	0.227164	-	-
Total General Plant		PGP	1.000000	0.209522	0.219487	0.180418	-	-	-
Total Production Plant		PPRTL	1.000000	0.343801	0.360154	0.296045	-	-	-
Total Intangible Plant		PINT	1.000000	0.209522	0.219487	0.180418	-	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Functional Vectors								
Station Equipment	F001		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.266122	0.385978
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.266122	0.385978
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.187201	0.730899
Line Transformers	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-
Distribution Operation Labor	F023		-	-	1,618,226	-	1,018,596	1,655,552
Distribution Maintenance Labor	F024		-	-	605,269	-	1,716,339	2,679,438
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		-	-	-	-	228,454,093	423,647,545
Purchase Power Demand		F017	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors								
Total Prod, Trans, and Dist Plant		PT&D	0.131730	-	0.031339	-	0.034150	0.063328
Total Distribution Plant		PDIST	-	-	0.121073	-	0.131933	0.244657
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.049852	-	0.008410	-	0.015542	0.024874
Total Plant in Service		TPIS	0.131722	-	0.031339	-	0.034150	0.063328
Total Operation and Maintenance Expenses (Labor)		TLB	0.067445	-	0.025077	-	0.027326	0.050673
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.043548	-	0.005501	-	0.012864	0.019603
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.0000000	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	0.130037	-	0.081852	0.133037
Total Distribution Maintenance Labor Expense		LBDM	-	-	0.083730	-	0.237429	0.370659
Sub-Total Labor Exp		LBSUB7	0.067222	-	0.025055	-	0.027302	0.050629
Total General Plant		PGP	0.131730	-	0.031339	-	0.034150	0.063328
Total Production Plant		PPRTL	-	-	-	-	-	-
Total Intangible Plant		PINT	0.131730	-	0.031339	-	0.034150	0.063328

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Functional Vectors									
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.141978	0.205922	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.141978	0.205922	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.016699	0.065201	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.529134	0.470866	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-
Distribution Operation Labor	F023		511,165	757,280	315,193	280,484	187,776	5,877,797	222,234
Distribution Maintenance Labor	F024		881,262	1,295,122	27,208	24,212	-	-	-
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		105,170,279	160,770,769	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	0.015721	0.024032	0.024405	0.021717	0.014539	0.012405	0.017207
Total Distribution Plant		PDIST	0.060736	0.092845	0.094283	0.083901	0.056169	0.047926	0.066477
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.007870	0.011622	0.003452	0.003072	0.002022	0.013971	0.002231
Total Plant in Service		TPIS	0.015721	0.024033	0.024405	0.021717	0.014539	0.012405	0.017207
Total Operation and Maintenance Expenses (Labor)		TLB	0.012580	0.019230	0.019528	0.017377	0.011634	0.009926	0.013769
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.006692	0.009790	0.000948	0.000843	0.000527	0.013641	0.000450
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.041076	0.060854	0.025328	0.022539	0.015089	0.472328	0.017858
Total Distribution Maintenance Labor Expense		LBDM	0.121909	0.179160	0.003764	0.003349	-	-	-
Sub-Total Labor Exp		LBSUB7	0.012569	0.019213	0.019511	0.017362	0.011624	0.009918	0.013757
Total General Plant		PGP	0.015721	0.024032	0.024405	0.021717	0.014539	0.012405	0.017207
Total Production Plant		PPRTL	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.015721	0.024032	0.024405	0.021717	0.014539	0.012405	0.017207

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

BIP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Functional Vectors					
Station Equipment	F001		0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	1.000000	0.000000
Billing	F010		0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-
Distribution Operation Labor	F023		-	-	-
Distribution Maintenance Labor	F024		-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-
Purchase Power Demand		F017	-	-	-
Purchase Power Energy		F018	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-
Gain Disposition of Allowances	F013		-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000
Internally Generated Functional Vectors					
Total Prod, Trans, and Dist Plant		PT&D	-	-	-
Total Distribution Plant		PDIST	-	-	-
Total Transmission Plant		PTRAN	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.058012	0.007274	-
Total Plant in Service		TPIS	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.159039	0.021862	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.042281	0.005057	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	-	-	-
Sub-Total Labor Exp		LBSUB7	0.159591	0.021938	-
Total General Plant		PGP	-	-	-
Total Production Plant		PPRTL	-	-	-
Total Intangible Plant		PINT	-	-	-

Exhibit WSS-17

Electric Cost of Service Study
Functional Assignment and Classification
LOLP Methodology

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	$ 39,493	8,275	8,668	7,125	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	55,919	11,716	12,273	10,089	-	-	-
303.00 SOFTWARE	P302	PT&D	102,982,045	21,576,997	22,603,270	18,579,812	-	-	-
Total Intangible Plant	PINT		$ 103,077,457	$ 21,596,988	$ 22,624,212	$ 18,597,026	$ -	$ -	$ -
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	$ 3,145,206,425	1,081,326,073	1,132,757,504	931,122,848	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	$ 36,962,631	12,707,801	13,312,226	10,942,605	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	$ 894,751,299	307,616,664	322,247,926	264,886,709	-	-	-
Total Production Plant	PPRTL		$ 4,076,920,355	$ 1,401,650,538	$ 1,468,317,655	$ 1,206,952,162	$ -	$ -	$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	$ 873,007,848	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	8,230,400	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 881,238,248	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	$ 209,650,161	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	717,117,865	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	200,924,821	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	5,414,628	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	303,128,639	-	-	-	-	-	-
369-SERVICES	P369	F006	97,262,577	-	-	-	-	-	-
370-METERS	P370	F007	82,987,729	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	282,792	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	114,827,799	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 1,731,597,011	$ -	$ -	$ -	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 6,689,755,615	$ 1,401,650,538	$ 1,468,317,655	$ 1,206,952,162	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Plant in Service								
Intangible Plant								
301.00 ORGANIZATION	P301	PT&D	5,202	-	1,238	-	1,349	2,501
302.00 FRANCHISE AND CONSENTS	P301	PT&D	7,366	-	1,752	-	1,910	3,541
303.00 SOFTWARE	P302	PT&D	13,565,775	-	3,227,353	-	3,516,821	6,521,627
Total Intangible Plant	PINT		$ 13,578,343	$ -	$ 3,230,343	$ -	$ 3,520,079	$ 6,527,669
Steam Production Plant								
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-
Hydraulic Production Plant								
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-
Other Production Plant								
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -		$ -	$ -	
Transmission								
KENTUCKY SYSTEM PROPERTY	P350	F011	873,007,848	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	8,230,400	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 881,238,248	$ -	$ -	$ -	$ -	$ -
Distribution								
TOTAL ACCTS 360-362	P362	F001	-	-	209,650,161	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	190,840,848	276,791,712
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	37,613,245	146,855,833
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	-	-	-	-
370-METERS	P370	F007	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ 209,650,161	$ -	$ 228,454,093	$ 423,647,545
Total Prod, Trans, and Dist Plant	PT&D		$ 881,238,248	$ -	$ 209,650,161	$ -	$ 228,454,093	$ 423,647,545

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

			Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
Description	**Name**	**Functional Vector**	**Demand**	**Customer**	**Demand**	**Customer**	**Customer**		
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	621	949	964	858	574	490	680
302.00 FRANCHISE AND CONSENTS	P301	PT&D	879	1,344	1,365	1,214	813	694	962
303.00 SOFTWARE	P302	PT&D	1,618,990	2,474,904	2,513,236	2,236,477	1,497,259	1,277,512	1,772,012
Total Intangible Plant	PINT		$ 1,620,490	$ 2,477,197	$ 2,515,564	$ 2,238,549	$ 1,498,647	$ 1,278,696	$ 1,773,653
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-
Total Production Plant	PPRTL				$ -	$ -			$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	101,814,953	147,670,352	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	3,355,326	13,100,417	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	2,865,065	2,549,563	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	160,395,756	142,732,883	-	-	-
369-SERVICES	P369	F006	-	-	-	-	97,262,577	-	-
370-METERS	P370	F007	-	-	-	-	-	82,987,729	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	282,792
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	114,827,799
Total Distribution Plant	PDIST		$ 105,170,279	$ 160,770,769	$ 163,260,822	$ 145,282,445	$ 97,262,577	$ 82,987,729	$ 115,110,592
Total Prod, Trans, and Dist Plant	PT&D		$ 105,170,279	$ 160,770,769	$ 163,260,822	$ 145,282,445	$ 97,262,577	$ 82,987,729	$ 115,110,592

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service					
Intangible Plant					
301.00 ORGANIZATION	P301	PT&D	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	-	-	-
303.00 SOFTWARE	P302	PT&D	-	-	-
Total Intangible Plant	PINT		$ -	$ -	$ -
Steam Production Plant					
Total Steam Production Plant	PSTPR	F017	-	-	-
Hydraulic Production Plant					
Total Hydraulic Production Plant	PHDPR	F017	-	-	-
Other Production Plant					
Total Other Production Plant	POTPR	F017	-	-	-
Total Production Plant	PPRTL		$ -	$ -	$ -
Transmission					
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -
Distribution					
TOTAL ACCTS 360-362	P362	F001	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-
369-SERVICES	P369	F006	-	-	-
370-METERS	P370	F007	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	$ 177,535,196	37,197,518	38,966,754	32,030,541	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	$ -	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$ -	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	$ 271,089	93,201	97,634	80,255	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	$ 113,882	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 6,970,753,239	$ 1,460,538,245	$ 1,530,006,255	$ 1,257,659,983	$ -	$ -	$ -
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	$ 28,153,069	9,679,062	10,139,430	8,334,577	-	-	-
CWIP Transmission	CWIP2	F011	30,190,923	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	32,868,652	-	-	-	-	-	-
CWIP General Plant	CWIP4	PT&D	27,491,296	5,760,029	6,033,995	4,959,924	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 118,703,941	$ 15,439,091	$ 16,173,426	$ 13,294,501	$ -	$ -	$ -
Total Utility Plant			$ 7,089,457,179	$ 1,475,977,336	$ 1,546,179,681	$ 1,270,954,484	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Plant in Service (Continued)								
General Plant								
Total General Plant	PGP	PT&D	23,386,625	-	5,563,773	-	6,062,799	11,242,914
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	-	-	13,788	-	15,025	27,862
OTHER		PDIST	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 918,203,216	$ -	$ 218,458,065	$ -	$ 238,051,995	$ 441,445,991
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	F017	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	30,190,923	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	3,979,516	-	4,336,447	8,041,550
CWIP General Plant	CWIP4	PT&D	3,621,415	-	861,549	-	938,823	1,740,963
RWIP	CWIP5	F004	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 33,812,338	$ -	$ 4,841,066	$ -	$ 5,275,270	$ 9,782,513
Total Utility Plant			$ 952,015,555	$ -	$ 223,299,131	$ -	$ 243,327,265	$ 451,228,504

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	2,791,048	4,266,594	4,332,676	3,855,559	2,581,190	2,202,359	3,054,847
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	6,917	10,573	10,737	9,555	6,397	5,458	7,570
OTHER		PDIST	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 109,588,734	$ 167,525,133	$ 170,119,799	$ 151,386,108	$ 101,348,810	$ 86,474,242	$ 119,946,663
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	1,996,311	3,051,702	3,098,968	2,757,708	1,846,209	1,575,248	2,184,995
CWIP General Plant	CWIP4	PT&D	432,193	660,681	670,914	597,033	399,697	341,035	473,043
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 2,428,504	$ 3,712,384	$ 3,769,882	$ 3,354,740	$ 2,245,906	$ 1,916,283	$ 2,658,037
Total Utility Plant			$ 112,017,238	$ 171,237,517	$ 173,889,681	$ 154,740,848	$ 103,594,716	$ 88,390,525	$ 122,604,700

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)					
General Plant					
Total General Plant	PGP	PT&D	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	P105	PPRTL	-	-	-
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	P105	PDIST	-	-	-
OTHER		PDIST	-	-	-
Total Plant in Service	TPIS		$ -	$ -	$ -
Construction Work in Progress (CWIP)					
CWIP Production	CWIP1	F017	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	-
CWIP General Plant	CWIP4	PT&D	-	-	-
RWIP	CWIP5	F004	-	-	-
Total Construction Work in Progress	TCWIP		$ -	$ -	$ -
Total Utility Plant			$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Rate Base									
Utility Plant									
Plant in Service			$ 6,970,753,239	$ 1,460,538,245	$ 1,530,006,255	$ 1,257,659,983	$ -	$ -	$ -
Construction Work in Progress (CWIP)			118,703,941	15,439,091.47	16,173,425.52	13,294,501.24	-	-	-
Total Utility Plant	TUP		$ 7,089,457,179	$ 1,475,977,336	$ 1,546,179,681	$ 1,270,954,484	$ -	$ -	$ -
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	$ 1,351,527,013	464,656,751	486,757,357	400,112,906	-	-	-
Hydraulic Production	RWIP	F017	11,357,150	3,904,603	4,090,319	3,362,228	-	-	-
Other Production		F017	279,457,486	96,077,848	100,647,627	82,732,010	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	303,777,627	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	4,014,978	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	637,170,341	-	-	-	-	-	-
General Plant	ADEPRD12	PT&D	60,263,984	12,626,626	13,227,190	10,872,706	-	-	-
Intangible Plant	ADEPRGP	PT&D	51,974,185	10,889,732	11,407,683	9,377,077	-	-	-
Total Accumulated Depreciation	TADEPR		$ 2,699,542,764	$ 588,155,561	$ 616,130,177	$ 506,456,928	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 4,389,914,415	$ 887,821,776	$ 930,049,504	$ 764,497,556	$ -	$ -	$ -
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 106,348,560	4,228,864	4,012,925	4,067,104	71,897,457	-	-
Materials and Supplies	M&S	TPIS	119,808,344	25,102,692	26,296,658	21,615,764	-	-	-
Prepayments	PREPAY	TPIS	16,171,254	3,388,261	3,549,418	2,917,610	-	-	-
Total Working Capital	TWC		$ 242,328,157	$ 32,719,817	$ 33,859,002	$ 28,600,478	$ 71,897,457	$ -	$ -
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	511,060,465	175,703,255	184,060,280	151,296,930	-	-	-
Total Transmission Plant	ADITTP	F011	129,909,095	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	241,830,055	-	-	-	-	-	-
Total General Plant	ADITGP	PT&D	27,628,083	5,788,689	6,064,018	4,984,603	-	-	-
Total Accumulated Deferred Income Tax	ADITT		910,427,698	181,491,944	190,124,299	156,281,533	-	-	-
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	$ 81,185,411	27,911,650	29,239,220	24,034,541	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		81,185,411	27,911,650	29,239,220	24,034,541	-	-	-
Total Deferred Debits			$ 991,613,109	$ 209,403,594	$ 219,363,519	$ 180,316,073	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	$ 1,549,704	-	-	-	-	-	-
Less: Asset Retirement Obligations		F017		-	-	-	-	-	-
Net Rate Base	RB		$ 3,639,079,759	$ 711,137,998	$ 744,544,987	$ 612,781,961	$ 71,897,457	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Rate Base								
Utility Plant								
Plant in Service			$ 918,203,216	$ -	$ 218,458,065	$ -	$ 238,051,995	$ 441,445,991
Construction Work in Progress (CWIP)			33,812,338.16	-	4,841,065.50	-	5,275,270.10	9,782,513.43
Total Utility Plant	TUP		$ 952,015,555	$ -	$ 223,299,131	$ -	$ 243,327,265	$ 451,228,504
Less: Acummulated Provision for Depreciation								
Steam Production	ADEPREPA	F017	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	303,777,627	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	4,014,978	-	-	-	-	-
Distribution	ADEPRD11	PDIST	-	-	77,144,315	-	84,063,539	155,888,263
General Plant	ADEPRD12	PT&D	7,938,545	-	1,888,612	-	2,058,005	3,816,386
Intangible Plant	ADEPRGP	PT&D	6,846,534	-	1,628,818	-	1,774,910	3,291,411
Total Accumulated Depreciation	TADEPR		$ 322,577,684	$ -	$ 80,661,745	$ -	$ 87,896,454	$ 162,996,060
Net Utility Plant	NTPLANT		$ 629,437,870	$ -	$ 142,637,386	$ -	$ 155,430,811	$ 288,232,444
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	5,301,675	-	894,425	-	1,652,866	2,645,269
Materials and Supplies	M&S	TPIS	15,781,423	-	3,754,702	-	4,091,468	7,587,259
Prepayments	PREPAY	TPIS	2,130,114	-	506,795	-	552,250	1,024,098
Total Working Capital	TWC		$ 23,213,212	$ -	$ 5,155,922	$ -	$ 6,296,585	$ 11,256,626
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-
Deferred Debits								
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-
Accumulated Deferred Income Tax								
Total Production Plant	ADITPP	F017	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	129,909,095	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	29,279,162	-	31,905,267	59,165,446
Total General Plant	ADITGP	PT&D	3,639,434	-	865,836	-	943,495	1,749,626
Total Accumulated Deferred Income Tax	ADITT		133,548,529	-	30,144,998	-	32,848,762	60,915,072
Accumulated Deferred Investment Tax Credits								
Production	ADITCP	F017	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-
Total Deferred Debits			$ 133,548,529	$ -	$ 30,144,998	$ -	$ 32,848,762	$ 60,915,072
Less: Customer Advances	CSTDEP	F027	-	-	-	-	385,642	715,139
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-
Net Rate Base	RB		$ 519,102,553	$ -	$ 117,648,309	$ -	$ 128,492,991	$ 237,858,860

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Rate Base									
Utility Plant									
Plant in Service			$ 109,588,734	$ 167,525,133	$ 170,119,799	$ 151,386,108	$ 101,348,810	$ 86,474,242	$ 119,946,663
Construction Work in Progress (CWIP)			2,428,503.78	3,712,383.62	3,769,881.82	3,354,740.25	2,245,905.76	1,916,282.97	2,658,037.14
Total Utility Plant	TUP		$ 112,017,238	$ 171,237,517	$ 173,889,681	$ 154,740,848	$ 103,594,716	$ 88,390,525	$ 122,604,700
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	38,699,179	59,158,317	60,074,574	53,459,127	35,789,406	30,536,735	42,356,885
General Plant	ADEPRD12	PT&D	947,416	1,448,287	1,470,719	1,308,762	876,180	747,587	1,036,962
Intangible Plant	ADEPRGP	PT&D	817,091	1,249,064	1,268,409	1,128,731	755,654	644,750	894,320
Total Accumulated Depreciation	TADEPR		$ 40,463,686	$ 61,855,668	$ 62,813,702	$ 55,896,621	$ 37,421,241	$ 31,929,072	$ 44,288,166
Net Utility Plant	NTPLANT		$ 71,553,552	$ 109,381,849	$ 111,075,979	$ 98,844,227	$ 66,173,475	$ 56,461,453	$ 78,316,533
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	836,918	1,235,970	367,121	326,693	215,040	1,485,823	237,305
Materials and Supplies	M&S	TPIS	1,883,533	2,879,303	2,923,898	2,601,917	1,741,911	1,486,258	2,061,558
Prepayments	PREPAY	TPIS	254,232	388,637	394,656	351,196	235,116	200,609	278,261
Total Working Capital	TWC		$ 2,974,683	$ 4,503,910	$ 3,685,675	$ 3,279,806	$ 2,192,067	$ 3,172,689	$ 2,577,123
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	14,687,791	22,452,801	22,800,555	20,289,745	13,583,423	11,589,837	16,076,027
Total General Plant	ADITGP	PT&D	434,344	663,969	674,252	600,003	401,686	342,732	475,396
Total Accumulated Deferred Income Tax	ADITT		15,122,134	23,116,770	23,474,808	20,889,748	13,985,108	11,932,569	16,551,424
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-	-
Total Deferred Debits			$ 15,122,134	$ 23,116,770	$ 23,474,808	$ 20,889,748	$ 13,985,108	$ 11,932,569	$ 16,551,424
Less: Customer Advances	CSTDEP	F027	177,533	271,389	-	-	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-	-
Net Rate Base	RB		$ 59,228,567	$ 90,497,599	$ 91,286,846	$ 81,234,285	$ 54,380,434	$ 47,701,574	$ 64,342,233

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base					
Utility Plant					
Plant in Service			$ -	$ -	$ -
Construction Work in Progress (CWIP)			-	-	-
Total Utility Plant	TUP		$ -	$ -	$ -
Less: Acummulated Provision for Depreciation					
Steam Production	ADEPREPA	F017	-	-	-
Hydraulic Production	RWIP	F017	-	-	-
Other Production		F017	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-
Distribution	ADEPRD11	PDIST	-	-	-
General Plant	ADEPRD12	PT&D	-	-	-
Intangible Plant	ADEPRGP	PT&D	-	-	-
Total Accumulated Depreciation	TADEPR		$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ -	$ -	$ -
Working Capital					
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	6,169,535	773,569	-
Materials and Supplies	M&S	TPIS	-	-	-
Prepayments	PREPAY	TPIS	-	-	-
Total Working Capital	TWC		$ 6,169,535	$ 773,569	$ -
Emission Allowance	EMALL	PROFIX	-	-	-
Deferred Debits					
Service Pension Cost	PENSCOST	TLB	-	-	-
Accumulated Deferred Income Tax					
Total Production Plant	ADITPP	F017	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	-
Total General Plant	ADITGP	PT&D	-	-	-
Total Accumulated Deferred Income Tax	ADITT		-	-	-
Accumulated Deferred Investment Tax Credits					
Production	ADITCP	F017	-	-	-
Transmission	ADITCT	F011	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-
General	ADITCG	PT&D	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-
Total Deferred Debits			$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-
Net Rate Base	RB		$ 6,169,535	$ 773,569	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 9,442,701	2,799,391	2,638,923	2,710,193	1,294,194	-	-
501 FUEL	OM501	Energy	372,621,659	-	-	-	372,621,659	-	-
502 STEAM EXPENSES	OM502		15,516,429	2,836,708	2,674,102	2,746,321	7,259,297	-	-
505 ELECTRIC EXPENSES	OM505		7,214,388	2,023,579	1,907,583	1,959,101	1,324,124	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	14,444,590	4,962,388	4,677,933	4,804,269	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ 419,239,766	$ 12,622,067	$ 11,898,541	$ 12,219,884	$ 382,499,274	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 10,261,750	340,085	320,591	329,249	9,271,825	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	5,959,887	2,047,498	1,930,131	1,982,258	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	40,186,142	-	-	-	40,186,142	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	8,270,033	-	-	-	8,270,033	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	2,439,522	-	-	-	2,439,522	-	-
Total Steam Power Generation Maintenance Expense			$ 67,117,335	$ 2,387,584	$ 2,250,722	$ 2,311,507	$ 60,167,522	$ -	$ -
Total Steam Power Generation Expense			$ 486,357,101	$ 15,009,650	$ 14,149,263	$ 14,531,391	$ 442,666,797	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ -	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	8,523	2,928	2,760	2,835	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 8,523	$ 2,928	$ 2,760	$ 2,835	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 186,494	64,069	60,397	62,028	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	116,901	40,161	37,859	38,881	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	22,497	7,729	7,286	7,482	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	33,030	-	-	-	33,030	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	9,592	-	-	-	9,592	-	-
Total Hydraulic Power Generation Maint. Expense			$ 368,513	$ 111,959	$ 105,541	$ 108,392	$ 42,622	$ -	$ -
Total Hydraulic Power Generation Expense			$ 377,036	$ 114,887	$ 108,301	$ 111,226	$ 42,622	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 1,071,395	368,074	346,975	356,346	-	-	-
547 FUEL	OM547	Energy	130,769,641	-	-	-	130,769,641	-	-
548 GENERATION EXPENSE	OM548	PROFIX	611,306	210,012	197,974	203,320	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	3,639,052	1,250,183	1,178,520	1,210,348	-	-	-
550 RENTS	OM550	PROFIX	4,421	1,519	1,432	1,470	-	-	-
Total Other Power Generation Expenses			$ 136,095,816	$ 1,829,789	$ 1,724,901	$ 1,771,485	$ 130,769,641	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Operation and Maintenance Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses								
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses								
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-
501 FUEL	OM501	Energy	-	-	-
502 STEAM EXPENSES	OM502		-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-
507 RENTS	OM507	PROFIX	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-
540 RENTS		PROFIX	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-
547 FUEL	OM547	Energy	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-
550 RENTS	OM550	PROFIX	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 257,199	88,360	83,295	85,544	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	1,680,721	577,406	544,308	559,008	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	4,895,395	1,681,796	1,585,391	1,628,208	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	5,139,215	1,765,559	1,664,353	1,709,302	-	-	-
Total Other Power Generation Maintenance Expense			$ 11,972,530	$ 4,113,121	$ 3,877,347	$ 3,982,062	$ -	$ -	$ -
Total Other Power Generation Expense			$ 148,068,346	$ 5,942,909	$ 5,602,248	$ 5,753,548	$ 130,769,641	$ -	$ -
Total Station Expense			$ 634,802,484	$ 21,067,446	$ 19,859,813	$ 20,396,165	$ 573,479,060	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	$ 50,619,307	2,507,314	2,626,570	2,159,032	43,326,391	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP		-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP		-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP		-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	1,864,717	640,617	603,895	620,205	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	10,369	3,562	3,358	3,449	-	-	-
Total Other Power Supply Expenses	TPP		$ 52,494,393	$ 3,151,493	$ 3,233,823	$ 2,782,685	$ 43,326,391	$ -	$ -
Total Electric Power Generation Expenses			$ 687,296,876	$ 24,218,939	$ 23,093,636	$ 23,178,850	$ 616,805,451	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 1,804,305	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	3,644,052	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	1,303,298	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	1,058,993	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	2,940,449	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	11,948,572	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	112,005	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,986,407	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	10,570,832	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	337,099	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ 35,706,011	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 1,510,424	-	-	-	-	-	-
581 LOAD DISPATCHING	OM581	P362	341,053	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	1,798,545	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	4,706,317	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	8,749,183	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	(142,800)	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	6,743,173	-	-	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 23,705,895	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Demand**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses								
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	1,804,305	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	3,644,052	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	1,303,298	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	1,058,993	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	2,940,449	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	11,948,572	-	-	-	-	-
567 RENTS	OM567	PTRAN	112,005	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,986,407	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	10,570,832	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	337,099	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-
Total Transmission Expenses			$ 35,706,011	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	196,412	-	123,632	200,942
581 LOAD DISPATCHING	OM581	P362	-	-	341,053	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	1,798,545	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	1,252,454	1,816,535
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	816,418	-	889,644	1,649,765
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ 3,152,429	$ -	$ 2,265,731	$ 3,667,242

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	62,043	91,915	38,256	34,044	22,791	713,416	26,974
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	668,193	969,134	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	8,749,183	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	(142,800)
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	409,553	626,072	635,769	565,758	378,759	323,170	448,263
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 1,139,789	$ 1,687,121	$ 674,026	$ 599,802	$ 401,551	$ 9,785,769	$ 332,436

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -
Other Power Supply Expenses					
555 PURCHASED POWER	OM555	OMPP	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -
Transmission Expenses					
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-
567 RENTS	OM567	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-
Total Transmission Expenses			$ -	$ -	$ -
Distribution Operation Expense					
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-
589 RENTS	OM589	PDIST	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 57,449	-	-	-	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	1,286,692	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	30,239,215	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	790,500	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	96,331	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	1,371,953	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	550,314	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 34,392,454	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			58,098,349	-	-	-	-	-	-
Transmission and Distribution Expenses			93,804,360	-	-	-	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 781,101,237	$ 24,218,939	$ 23,093,636	$ 23,178,850	$ 616,805,451	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 3,631,554	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	5,301,482	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	20,167,471	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	5,566,157	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 34,666,664	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	$ 651,425	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	450,051	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	389,845	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	1,861,027	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	794,217	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 4,146,565	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		819,914,466	24,218,939	23,093,636	23,178,850	616,805,451	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses (Continued)								
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	4,810	-	13,640	21,294
591 STRUCTURES	OM591	P362	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	1,286,692	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	8,047,321	11,671,671
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	147,982	577,776
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	66,628	-	72,604	134,638
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ 1,358,130	$ -	$ 8,281,547	$ 12,405,380
Total Distribution Operation and Maintenance Expenses			-	-	4,510,559	-	10,547,278	16,072,622
Transmission and Distribution Expenses			35,706,011	-	4,510,559	-	10,547,278	16,072,622
Production, Transmission and Distribution Expenses	OMSUB		$ 35,706,011	$ -	$ 4,510,559	$ -	$ 10,547,278	$ 16,072,622
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	OM907	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		35,706,011	-	4,510,559	-	10,547,278	16,072,622

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	7,004	10,293	216	192	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	4,293,303	6,226,920	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	13,201	51,541	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	50,972	45,359	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	1,371,953	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	33,424	51,094	51,885	46,172	30,911	26,374	36,583
Total Distribution Maintenance Expense	OMDM		$ 4,346,931	$ 6,339,848	$ 103,074	$ 91,723	$ 30,911	$ 1,398,327	$ 36,583
Total Distribution Operation and Maintenance Expenses			5,486,721	8,026,969	777,099	691,525	432,461	11,184,096	369,019
Transmission and Distribution Expenses			5,486,721	8,026,969	777,099	691,525	432,461	11,184,096	369,019
Production, Transmission and Distribution Expenses	OMSUB		$ 5,486,721	$ 8,026,969	$ 777,099	$ 691,525	$ 432,461	$ 11,184,096	$ 369,019
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		5,486,721	8,026,969	777,099	691,525	432,461	11,184,096	369,019

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Distribution Maintenance Expense					
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-
591 STRUCTURES	OM591	P362	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-
Transmission and Distribution Expenses			-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ -	$ -	$ -
Customer Accounts Expense					
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	3,631,554	-	-
902 METER READING EXPENSES	OM902	F025	5,301,482	-	-
903 RECORDS AND COLLECTION	OM903	F025	20,167,471	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	5,566,157	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-
Total Customer Accounts Expense	OMCA		$ 34,666,664	$ -	$ -
Customer Service Expense					
907 SUPERVISION	OM907	F026	-	651,425	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	450,051	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	389,845	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	1,861,027	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	794,217	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-
Total Customer Service Expense	OMCS		$ -	$ 4,146,565	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		34,666,664	4,146,565	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 33,809,232	3,683,645	3,472,490	3,566,271	7,680,251	-	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	7,269,104	791,997	746,598	766,761	1,651,281	-	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(4,414,266)	(480,951)	(453,382)	(465,626)	(1,002,764)	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	19,133,213	2,084,637	1,965,141	2,018,213	4,346,383	-	-
924 PROPERTY INSURANCE	OM924	TUP	5,543,869	1,154,196	1,209,094	993,871	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	3,904,092	425,366	400,983	411,812	886,870	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	38,912,106	4,239,622	3,996,598	4,104,533	8,839,442	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	1,800,307	374,812	392,639	322,748	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	5,197,262	566,262	533,802	548,218	1,180,632	-	-
931 RENTS AND LEASES	OM931	PGP	1,831,134	383,663	401,911	330,369	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	873,720	183,064	191,771	157,635	-	-	-
Total Administrative and General Expense	OMAG		$ 113,859,773	$ 13,406,311	$ 12,857,643	$ 12,754,806	$ 23,582,096	$ -	$ -
Total Operation and Maintenance Expenses	TOM		$ 933,774,239	$ 37,625,250	$ 35,951,279	$ 35,933,656	$ 640,387,547	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 883,154,932	$ 35,117,936	$ 33,324,709	$ 33,774,624	$ 597,061,156	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	2,272,732	-	847,086	-	923,063	1,711,738
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	488,645	-	182,127	-	198,462	368,030
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(296,737)	-	(110,599)	-	(120,519)	(223,491)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	1,286,177	-	479,380	-	522,377	968,701
924 PROPERTY INSURANCE	OM924	TUP	744,465	-	174,617	-	190,279	352,855
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	262,442	-	97,817	-	106,590	197,661
926 EMPLOYEE BENEFITS	OM926	LBSUB7	2,615,758	-	974,938	-	1,062,382	1,970,093
928 REGULATORY COMMISSION FEES	OM928	TUP	241,756	-	56,705	-	61,791	114,586
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	349,371	-	130,217	-	141,896	263,134
931 RENTS AND LEASES	OM931	PGP	241,214	-	57,386	-	62,533	115,962
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	115,095	-	27,382	-	29,837	55,331
Total Administrative and General Expense	OMAG		$ 8,320,918	$ -	$ 2,917,056	$ -	$ 3,178,692	$ 5,894,598
Total Operation and Maintenance Expenses	TOM		$ 44,026,929	$ -	$ 7,427,615	$ -	$ 13,725,970	$ 21,967,220
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 44,026,929	$ -	$ 7,427,615	$ -	$ 13,725,970	$ 21,967,220

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	424,938	649,590	659,651	587,010	392,987	335,310	465,102
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	91,363	139,664	141,827	126,209	84,494	72,093	99,998
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(55,482)	(84,813)	(86,127)	(76,642)	(51,310)	(43,779)	(60,725)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	240,480	367,614	373,308	332,199	222,398	189,758	263,209
924 PROPERTY INSURANCE	OM924	TUP	87,596	133,906	135,980	121,005	81,010	69,120	95,875
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	49,069	75,011	76,173	67,785	45,380	38,720	53,707
926 EMPLOYEE BENEFITS	OM926	LBSUB7	489,074	747,634	759,213	675,608	452,301	385,919	535,300
928 REGULATORY COMMISSION FEES	OM928	TUP	28,446	43,484	44,158	39,295	26,307	22,446	31,134
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	65,323	99,857	101,404	90,237	60,411	51,545	71,497
931 RENTS AND LEASES	OM931	PGP	28,787	44,007	44,688	39,767	26,623	22,716	31,508
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	13,736	20,998	21,323	18,975	12,703	10,839	15,034
Total Administrative and General Expense	OMAG		$ 1,463,331	$ 2,236,952	$ 2,271,598	$ 2,021,448	$ 1,353,304	$ 1,154,685	$ 1,601,640
Total Operation and Maintenance Expenses	TOM		$ 6,950,051	$ 10,263,921	$ 3,048,697	$ 2,712,973	$ 1,785,765	$ 12,338,781	$ 1,970,659
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 6,950,051	$ 10,263,921	$ 3,048,697	$ 2,712,973	$ 1,785,765	$ 12,338,781	$ 1,970,659

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector		Customer Accounts Expense		Customer Service & Info.		Sales Expense
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7		5,395,654		741,714		-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7		1,160,085		159,471		-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7		(704,478)		(96,841)		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7		3,053,491		419,748		-
924 PROPERTY INSURANCE	OM924	TUP		-		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7		623,059		85,649		-
926 EMPLOYEE BENEFITS	OM926	LBSUB7		6,210,028		853,662		-
928 REGULATORY COMMISSION FEES	OM928	TUP		-		-		-
929 DUPLICATE CHARGES	OM929	LBSUB7		-		-		-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7		829,437		114,019		-
931 RENTS AND LEASES	OM931	PGP		-		-		-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP		-		-		-
Total Administrative and General Expense	OMAG		$	16,567,275	$	2,277,421	$	-
Total Operation and Maintenance Expenses	TOM		$	51,233,939	$	6,423,986	$	-
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$	51,233,939	$	6,423,986	$	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 7,176,311	2,127,495	2,005,542	2,059,705	983,568	-	-
501 FUEL	LB501	Energy	2,518,295	-	-	-	2,518,295	-	-
502 STEAM EXPENSES	LB502	PROFIX	8,257,131	2,836,708	2,674,102	2,746,321	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	5,890,264	2,023,579	1,907,583	1,959,101	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	1,708,296	586,879	553,238	568,179	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 25,550,297	$ 7,574,662	$ 7,140,465	$ 7,333,307	$ 3,501,864	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 8,497,622	281,620	265,477	272,647	7,677,878	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	1,238,874	425,611	401,214	412,049	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	9,213,874	-	-	-	9,213,874	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	1,992,105	-	-	-	1,992,105	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	397,544	-	-	-	397,544	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 21,340,020	$ 707,231	$ 666,691	$ 684,696	$ 19,281,401	$ -	$ -
Total Steam Power Generation Expense			$ 46,890,316	$ 8,281,893	$ 7,807,156	$ 8,018,003	$ 22,783,265	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ -	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 166,692	57,266	53,984	55,442	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	47,185	16,210	15,281	15,694	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 213,877	$ 73,477	$ 69,265	$ 71,135	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 213,877	$ 73,477	$ 69,265	$ 71,135	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 848,268	291,419	274,715	282,134	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	327,051	112,357	105,917	108,777	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	1,662,761	571,236	538,491	553,034	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 2,838,080	$ 975,012	$ 919,122	$ 943,945	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses								
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses								
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
			Demand	Customer	Demand	Customer	Customer		
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-
501 FUEL	LB501	Energy	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-
507 RENTS	LB507	PROFIX	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-
540 RENTS	LB540	PROFIX	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-
547 FUEL	LB547	Energy	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-
550 RENTS	LB550	PROFIX	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector		Total System		Production Demand Base		Production Demand Inter.		Production Demand Peak		Production Energy Base		Production Energy Inter.		Production Energy Peak
Other Power Generation Maintenance Expense																
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	201,322		69,163		65,199		66,960		-		-		-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX		-		-		-		-		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX		1,017,670		349,617		329,576		338,477		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX		1,600,551		549,864		518,344		532,343		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB6		$	2,819,543	$	968,644	$	913,119	$	937,780	$	-	$	-	$	-
Total Other Power Generation Expense			$	5,657,623	$	1,943,656	$	1,832,242	$	1,881,725	$	-	$	-	$	-
Total Production Expense	LPREX		$	52,761,816	$	10,299,026	$	9,708,662	$	9,970,863	$	22,783,265	$	-	$	-
Purchased Power																
555 PURCHASED POWER	LB555	OMPP	$	-		-		-		-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$	1,829,189		628,411		592,389		608,388		-		-		-
557 OTHER EXPENSES	LB557	PROFIX	$	-		-		-		-		-		-		-
Total Purchased Power Labor	LBPP		$	1,829,189	$	628,411	$	592,389	$	608,388	$	-	$	-	$	-
Transmission Labor Expenses																
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$	1,648,654		-		-		-		-		-		-
561 LOAD DISPATCHING	LB561	PTRAN		3,065,460		-		-		-		-		-		-
562 STATION EXPENSES	LB562	PTRAN		505,135		-		-		-		-		-		-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN		-		-		-		-		-		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN		118,042		-		-		-		-		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN		-		-		-		-		-		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN		937,915		-		-		-		-		-		-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN		466,793		-		-		-		-		-		-
572 UNDERGROUND LINES	LB572	PTRAN		-		-		-		-		-		-		-
573 MISC PLANT	LB573	PTRAN		-		-		-		-		-		-		-
Total Transmission Labor Expenses	LBTRAN		$	6,741,999	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Operation Labor Expense																
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$	1,081,711		-		-		-		-		-		-
581 LOAD DISPATCHING	LB581	P362		342,506		-		-		-		-		-		-
582 STATION EXPENSES	LB582	P362		870,967		-		-		-		-		-		-
583 OVERHEAD LINE EXPENSES	LB583	P365		2,170,209		-		-		-		-		-		-
584 UNDERGROUND LINE EXPENSES	LB584	P367		-		-		-		-		-		-		-
585 STREET LIGHTING EXPENSE	LB585	P371		-		-		-		-		-		-		-
586 METER EXPENSES	LB586	P370		5,717,580		-		-		-		-		-		-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012		-		-		-		-		-		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371		-		-		-		-		-		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST		3,343,041		-		-		-		-		-		-
589 RENTS	LB589	PDIST		-		-		-		-		-		-		-
Total Distribution Operation Labor Expense	LBDO		$	13,526,014	$	-	$	-	$	-	$	-	$	-	$	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Demand**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	1,648,654	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	3,065,460	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	505,135	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	118,042	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	937,915	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	466,793	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 6,741,999	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	140,663	-	88,541	143,907
581 LOAD DISPATCHING	LB581	P362	-	-	342,506	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	870,967	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	577,540	837,653
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	404,753	-	441,056	817,899
589 RENTS	LB589	PDIST	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ 1,758,889	$ -	$ 1,107,137	$ 1,799,459

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	44,433	65,826	27,398	24,381	16,322	510,923	19,317
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	308,122	446,894	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	5,717,580	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	203,043	310,386	315,193	280,484	187,776	160,217	222,234
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 555,597	$ 823,106	$ 342,591	$ 304,865	$ 204,099	$ 6,388,720	$ 241,551

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -
Purchased Power					
555 PURCHASED POWER	LB555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -
Transmission Labor Expenses					
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -
Distribution Operation Labor Expense					
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-
589 RENTS	LB589	PDIST	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	605,269	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	6,158,359	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	413,802	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	51,420	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 7,228,850	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	20,754,864	-	-	-	-	-	-
Transmission and Distribution Labor Expenses			27,496,863	-	-	-	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 82,087,867	$ 10,927,437	$ 10,301,052	$ 10,579,251	$ 22,783,265	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 3,259,518	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	754,379	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	11,992,171	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 16,006,068	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	LB907	F026	$ 614,307	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	1,585,968	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 2,200,275	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		100,294,210	10,927,437	10,301,052	10,579,251	22,783,265	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	605,269	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	1,638,875	2,376,991
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	77,464	302,447
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ 605,269	$ -	$ 1,716,339	$ 2,679,438
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	2,512,860	-	2,738,243	5,077,825
Transmission and Distribution Labor Expenses			6,741,999	-	2,512,860	-	2,738,243	5,077,825
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 6,741,999	$ -	$ 2,512,860	$ -	$ 2,738,243	$ 5,077,825
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	LB907	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		6,741,999	-	2,512,860	-	2,738,243	5,077,825

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	874,351	1,268,142	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	6,910	26,980	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	27,208	24,212	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 881,262	$ 1,295,122	$ 27,208	$ 24,212	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	1,260,567	1,926,993	1,956,839	1,741,351	1,165,786	994,688	1,379,712
Transmission and Distribution Labor Expenses			1,260,567	1,926,993	1,956,839	1,741,351	1,165,786	994,688	1,379,712
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 1,260,567	$ 1,926,993	$ 1,956,839	$ 1,741,351	$ 1,165,786	$ 994,688	$ 1,379,712
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		1,260,567	1,926,993	1,956,839	1,741,351	1,165,786	994,688	1,379,712

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Distribution Maintenance Labor Expense					
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-
Transmission and Distribution Labor Expenses			-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ -	$ -	$ -
Customer Accounts Expense					
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	3,259,518	-	-
902 METER READING EXPENSES	LB902	F025	754,379	-	-
903 RECORDS AND COLLECTION	LB903	F025	11,992,171	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 16,006,068	$ -	$ -
Customer Service Expense					
907 SUPERVISION	LB907	F026	-	614,307	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	1,585,968	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ 2,200,275	$ -
Sub-Total Labor Exp	LBSUB7		16,006,068	2,200,275	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$ 33,809,236	3,683,645	3,472,490	3,566,272	7,680,252	-	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(3,161,163)	(344,421)	(324,678)	(333,446)	(718,104)	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	560,277	61,044	57,545	59,099	127,275	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	39,380,962	4,290,706	4,044,753	4,153,989	8,945,949	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	593,047	124,256	130,166	106,996	-	-	-
Total Administrative and General Expense	LBAG		$ 71,182,359	$ 7,815,231	$ 7,380,277	$ 7,552,910	$ 16,035,372	$ -	$ -
Total Operation and Maintenance Expenses	TLB		$ 171,476,569	$ 18,742,668	$ 17,681,329	$ 18,132,162	$ 38,818,637	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 171,476,569	$ 18,742,668	$ 17,681,329	$ 18,132,162	$ 38,818,637	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	2,272,732	-	847,086	-	923,063	1,711,738
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(212,500)	-	(79,203)	-	(86,306)	(160,047)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	37,663	-	14,038	-	15,297	28,366
926 EMPLOYEE BENEFITS	LB926	LBSUB7	2,647,276	-	986,685	-	1,075,183	1,993,830
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	78,122	-	18,586	-	20,252	37,556
Total Administrative and General Expense	LBAG		$ 4,823,292	$ -	$ 1,787,193	$ -	$ 1,947,489	$ 3,611,444
Total Operation and Maintenance Expenses	TLB		$ 11,565,291	$ -	$ 4,300,052	$ -	$ 4,685,732	$ 8,689,269
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 11,565,291	$ -	$ 4,300,052	$ -	$ 4,685,732	$ 8,689,269

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	424,938	649,590	659,651	587,010	392,987	335,310	465,102
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(39,732)	(60,737)	(61,677)	(54,885)	(36,744)	(31,351)	(43,487)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	7,042	10,765	10,932	9,728	6,512	5,557	7,708
926 EMPLOYEE BENEFITS	LB926	LBSUB7	494,967	756,642	768,361	683,749	457,751	390,569	541,750
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	9,323	14,252	14,473	12,879	8,622	7,357	10,205
Total Administrative and General Expense	LBAG		$ 896,539	$ 1,370,513	$ 1,391,740	$ 1,238,481	$ 829,129	$ 707,441	$ 981,277
Total Operation and Maintenance Expenses	TLB		$ 2,157,106	$ 3,297,506	$ 3,348,579	$ 2,979,831	$ 1,994,915	$ 1,702,129	$ 2,360,988
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 2,157,106	$ 3,297,506	$ 3,348,579	$ 2,979,831	$ 1,994,915	$ 1,702,129	$ 2,360,988

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	5,395,655	741,714	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(504,494)	(69,350)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	89,415	12,291	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	6,284,853	863,947	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-
Total Administrative and General Expense	LBAG		$ 11,265,429	$ 1,548,603	$ -
Total Operation and Maintenance Expenses	TLB		$ 27,271,497	$ 3,748,877	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 27,271,497	$ 3,748,877	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Other Expenses									
Depreciation Expenses									
Steam Production	DEPRTP	PPRTL	$ 99,900,146	34,345,801	35,979,400	29,574,946	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	1,118,831	384,656	402,951	331,224	-	-	-
Other Production	DEPRDP2	PPRTL	35,620,454	12,246,359	12,828,836	10,545,260	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	20,185,930	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	182,214	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	43,044,393	-	-	-	-	-	-
General Plant	DEPRDP6	PGP	11,631,105	2,436,972	2,552,882	2,098,460	-	-	-
Intangible Plant	DEPRAADJ	PINT	16,379,764	3,431,920	3,595,153	2,955,204	-	-	-
Total Depreciation Expense	TDEPR		$ 228,062,837	52,845,706	55,359,222	45,505,094	-	-	-
Regulatory Credits and Accretion Expenses									
Production Plant	ACRTPP	PPRTL	$ -	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	$ 24,894,101	5,182,784	5,429,295	4,462,862	-	-	-
Other Taxes	OTAX	TUP	$ 12,926,774	2,691,268	2,819,273	2,317,433	-	-	-
Gain Disposition of Allowances	GAIN	F013	$ -	-	-	-	-	-	-
Interest	INTLTD	TUP	$ 86,095,200	17,924,442	18,776,988	15,434,620	-	-	-
Other Expenses	OT	TUP	$ -	-	-	-	-	-	-
Total Other Expenses	TOE		$ 351,978,912	$ 78,644,200	$ 82,384,778	$ 67,720,009	$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 1,285,753,151	$ 116,269,450	$ 118,336,057	$ 103,653,665	$ 640,387,547	$ -	$ -
Non-Operating Items									
Non-Operating Margins - Interest			-						
AFUDC			-						
Income (Loss) from Equity Investments			-						
Non-Operating Margins - Other			-						
Generation and Transmission Capital Credits			-						
Other Capital Credits and Patronage Dividends			-						
Extraordinary Items			-						
Long Term Debt Service Requirements			-						

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Other Expenses								
Depreciation Expenses								
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	20,185,930	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	182,214	-	-	-	-	-
Distribution	DEPRDP5	PDIST	-	-	5,211,527	-	5,678,959	10,531,117
General Plant	DEPRDP6	PGP	1,532,160	-	364,507	-	397,200	736,572
Intangible Plant	DEPRAADJ	PINT	2,157,698	-	513,325	-	559,366	1,037,295
Total Depreciation Expense	TDEPR		24,058,002	-	6,089,359	-	6,635,525	12,304,984
Regulatory Credits and Accretion Expenses								
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	3,342,932	-	784,098	-	854,426	1,584,455
Other Taxes	OTAX	TUP	1,735,886	-	407,159	-	443,678	822,761
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-
Interest	INTLTD	TUP	11,561,389	-	2,711,771	-	2,954,995	5,479,772
Other Expenses	OT	TUP	-	-	-	-	-	-
Total Other Expenses	TOE		$ 40,698,209	$ -	$ 9,992,387	$ -	$ 10,888,624	$ 20,191,972
Total Cost of Service (O&M + Other Expenses)			$ 84,725,138	$ -	$ 17,420,002	$ -	$ 24,614,594	$ 42,159,192
Non-Operating Items								
Non-Operating Margins - Interest								
AFUDC								
Income (Loss) from Equity Investments								
Non-Operating Margins - Other								
Generation and Transmission Capital Credits								
Other Capital Credits and Patronage Dividends								
Extraordinary Items								
Long Term Debt Service Requirements								

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Expenses									
Depreciation Expenses									
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	2,614,344	3,996,473	4,058,371	3,611,461	2,417,773	2,062,926	2,861,443
General Plant	DEPRDP6	PGP	182,854	279,523	283,852	252,594	169,105	144,286	200,136
Intangible Plant	DEPRAADJ	PINT	257,508	393,645	399,742	355,722	238,146	203,194	281,847
Total Depreciation Expense	TDEPR		3,054,706	4,669,641	4,741,965	4,219,777	2,825,024	2,410,406	3,343,426
Regulatory Credits and Accretion Expenses									
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	PTAX	TUP	393,340	601,288	610,601	543,361	363,765	310,377	430,517
Other Taxes	OTAX	TUP	204,250	312,231	317,067	282,151	188,893	161,170	223,555
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-
Interest	INTLTD	TUP	1,360,350	2,079,529	2,111,737	1,879,191	1,258,066	1,073,425	1,488,926
Other Expenses	OT	TUP	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 5,012,646	$ 7,662,688	$ 7,781,369	$ 6,924,480	$ 4,635,748	$ 3,955,377	$ 5,486,424
Total Cost of Service (O&M + Other Expenses)			$ 11,962,698	$ 17,926,608	$ 10,830,067	$ 9,637,453	$ 6,421,513	$ 16,294,158	$ 7,457,083

Non-Operating Items
Non-Operating Margins - Interest
AFUDC
Income (Loss) from Equity Investments
Non-Operating Margins - Other
Generation and Transmission Capital Credits
Other Capital Credits and Patronage Dividends
Extraordinary Items

Long Term Debt Service Requirements

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses					
Depreciation Expenses					
Steam Production	DEPRTP	PPRTL	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-
Distribution	DEPRDP5	PDIST	-	-	-
General Plant	DEPRDP6	PGP	-	-	-
Intangible Plant	DEPRAADJ	PINT	-	-	-
Total Depreciation Expense	TDEPR		-	-	-
Regulatory Credits and Accretion Expenses					
Production Plant	ACRTPP	PPRTL	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-
Distribution Plant		PDIST	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -
Property Taxes	PTAX	TUP	-	-	-
Other Taxes	OTAX	TUP	-	-	-
Gain Disposition of Allowances	GAIN	F013	-	-	-
Interest	INTLTD	TUP	-	-	-
Other Expenses	OT	TUP	-	-	-
Total Other Expenses	TOE		$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 51,233,939	$ 6,423,986	$ -
Non-Operating Items					
Non-Operating Margins - Interest					
AFUDC					
Income (Loss) from Equity Investments					
Non-Operating Margins - Other					
Generation and Transmission Capital Credits					
Other Capital Credits and Patronage Dividends					
Extraordinary Items					
Long Term Debt Service Requirements					

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Functional Vectors									
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	0.343801	0.360154	0.296045	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		18,373,986	5,447,167	5,134,923	5,273,601	2,518,295	-	-
PROFIX	PROFIX		1.000000	0.343546	0.323854	0.332600	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		12,842,398	425,611	401,214	412,049	11,603,523	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		47,185	16,210	15,281	15,694	-	-	-
Distribution Operation Labor	F023		12,444,303	-	-	-	-	-	-
Distribution Maintenance Labor	F024		7,228,850	-	-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		918,042,686	-	-	-	-	-	-
Purchase Power Demand		F017	7,312,226	2,513,953	2,633,525	2,164,748	-	-	-
Purchase Power Energy		F018	43,441,113	-	-	-	43,441,113	-	-
Purchased Power Expenses	OMPP	F017	50,753,339	2,513,953	2,633,525	2,164,748	43,441,113	-	-
Gain Disposition of Allowances	F013		1.00000	-	-	-	1.000000	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
	Energy		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.209522	0.219487	0.180418	-	-	-
Total Distribution Plant		PDIST	1.000000	-	-	-	-	-	-
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.039764	0.037734	0.038243	0.676055	-	-
Total Plant in Service		TPIS	1.000000	0.209524	0.219489	0.180420	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.109302	0.103112	0.105741	0.226379	-	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.029538	0.028166	0.028270	0.752280	-	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.296461	0.279467	0.287015	0.137058	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.033141	0.031241	0.032085	0.903532	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	-	-	-
Sub-Total Labor Exp		LBSUB7	1.000000	0.108954	0.102708	0.105482	0.227164	-	-
Total General Plant		PGP	1.000000	0.209522	0.219487	0.180418	-	-	-
Total Production Plant		PPRTL	1.000000	0.343801	0.360154	0.296045	-	-	-
Total Intangible Plant		PINT	1.000000	0.209522	0.219487	0.180418	-	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	Customer
Functional Vectors								
Station Equipment	F001		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.266122	0.385978
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.266122	0.385978
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.187201	0.730899
Line Transformers	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-
Distribution Operation Labor	F023		-	-	1,618,226	-	1,018,596	1,655,552
Distribution Maintenance Labor	F024		-	-	605,269	-	1,716,339	2,679,438
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		-	-	-	-	228,454,093	423,647,545
Purchase Power Demand		F017	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors								
Total Prod, Trans, and Dist Plant		PT&D	0.131730	-	0.031339	-	0.034150	0.063328
Total Distribution Plant		PDIST	-	-	0.121073	-	0.131933	0.244657
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.049852	-	0.008410	-	0.015542	0.024874
Total Plant in Service		TPIS	0.131722	-	0.031339	-	0.034150	0.063328
Total Operation and Maintenance Expenses (Labor)		TLB	0.067445	-	0.025077	-	0.027326	0.050673
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.043548	-	0.005501	-	0.012864	0.019603
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.0000000	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	0.130037	-	0.081852	0.133037
Total Distribution Maintenance Labor Expense		LBDM	-	-	0.083730	-	0.237429	0.370659
Sub-Total Labor Exp		LBSUB7	0.067222	-	0.025055	-	0.027302	0.050629
Total General Plant		PGP	0.131730	-	0.031339	-	0.034150	0.063328
Total Production Plant		PPRTL	-	-	-	-	-	-
Total Intangible Plant		PINT	0.131730	-	0.031339	-	0.034150	0.063328

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Functional Vectors									
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.141978	0.205922	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.141978	0.205922	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.016699	0.065201	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.529134	0.470866	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-
Distribution Operation Labor	F023		511,165	757,280	315,193	280,484	187,776	5,877,797	222,234
Distribution Maintenance Labor	F024		881,262	1,295,122	27,208	24,212	-	-	-
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		105,170,279	160,770,769	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	0.015721	0.024032	0.024405	0.021717	0.014539	0.012405	0.017207
Total Distribution Plant		PDIST	0.060736	0.092845	0.094283	0.083901	0.056169	0.047926	0.066477
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.007870	0.011622	0.003452	0.003072	0.002022	0.013971	0.002231
Total Plant in Service		TPIS	0.015721	0.024033	0.024405	0.021717	0.014539	0.012405	0.017207
Total Operation and Maintenance Expenses (Labor)		TLB	0.012580	0.019230	0.019528	0.017377	0.011634	0.009926	0.013769
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.006692	0.009790	0.000948	0.000843	0.000527	0.013641	0.000450
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.041076	0.060854	0.025328	0.022539	0.015089	0.472328	0.017858
Total Distribution Maintenance Labor Expense		LBDM	0.121909	0.179160	0.003764	0.003349	-	-	-
Sub-Total Labor Exp		LBSUB7	0.012569	0.019213	0.019511	0.017362	0.011624	0.009918	0.013757
Total General Plant		PGP	0.015721	0.024032	0.024405	0.021717	0.014539	0.012405	0.017207
Total Production Plant		PPRTL	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.015721	0.024032	0.024405	0.021717	0.014539	0.012405	0.017207

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2018

LOLP METHODOLOGY

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Functional Vectors					
Station Equipment	F001		0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	1.000000	0.000000
Billing	F010		0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-
Distribution Operation Labor	F023		-	-	-
Distribution Maintenance Labor	F024		-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-
Purchase Power Demand		F017	-	-	-
Purchase Power Energy		F018	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-
Gain Disposition of Allowances	F013		-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000
Internally Generated Functional Vectors					
Total Prod, Trans, and Dist Plant		PT&D	-	-	-
Total Distribution Plant		PDIST	-	-	-
Total Transmission Plant		PTRAN	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.058012	0.007274	-
Total Plant in Service		TPIS	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.159039	0.021862	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.042281	0.005057	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	-	-	-
Sub-Total Labor Exp		LBSUB7	0.159591	0.021938	-
Total General Plant		PGP	-	-	-
Total Production Plant		PPRTL	-	-	-
Total Intangible Plant		PINT	-	-	-

Exhibit WSS-18

Electric Cost of Service Study
Class Allocation
BIP Methodology

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Plant in Service									
Power Production Plant									
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 1,460,538,245	$ 490,329,023	$ 146,286,933	$ 12,222,948	$ 172,774,529	$ 13,332,939
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	1,530,006,255	663,775,884	178,431,715	14,727,201	167,434,520	10,597,394
Production Demand - Peak	TPIS	PLPPDP	PPSDA	1,257,659,983	472,385,143	141,460,866	9,496,956	149,181,911	11,190,242
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 4,248,204,483	$ 1,626,490,050	$ 466,179,515	$ 36,447,104	$ 489,390,960	$ 35,120,575
					38.3%	11.0%	0.9%	11.5%	0.8%
Transmission Plant									
Transmission Demand	TPIS	PLTRB	NCPT	$ 918,203,216	$ 390,548,219	$ 98,875,137	$ 9,545,370	$ 87,167,957	$ 6,854,993
Distribution Poles									
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TPIS	PLDSG	NCPP	$ 218,458,065	$ 103,629,304	$ 26,235,842	$ 2,532,799	$ 23,129,422	$ 1,818,926
Distribution Primary & Secondary Lines									
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	238,051,995	112,924,018	28,588,986	2,759,971	25,203,945	1,982,069
Primary Customer	TPIS	PLDPLC	Cust08	441,445,991	352,743,595	68,249,994	485,692	3,688,148	141,694
Secondary Demand	TPIS	PLDSLD	SICD	109,588,734	91,289,586	16,440,796	1,154,842	-	-
Secondary Customer	TPIS	PLDSLC	Cust07	167,525,133	135,261,394	26,170,821	186,241	-	-
Total Distribution Primary & Secondary Lines		PLDLT		$ 956,611,853	$ 692,218,593	$ 139,450,598	$ 4,586,746	$ 28,892,094	$ 2,123,763
Distribution Line Transformers									
Demand	TPIS	PLDLTD	SICDT	$ 170,119,799	$ 118,027,154	$ 21,256,098	$ 1,493,081	$ 16,689,677	$ -
Customer	TPIS	PLDLTC	Cust09	151,386,108	121,068,269	23,424,688	166,699	1,265,842	-
Total Line Transformers		PLDLTT		$ 321,505,907	$ 239,095,423	$ 44,680,786	$ 1,659,779	$ 17,955,519	$ -
Distribution Services									
Customer	TPIS	PLDSC	C02	$ 101,348,810	$ 71,077,561	$ 27,841,199	$ 263,669	$ 1,891,563	$ -
Distribution Meters									
Customer	TPIS	PLDMC	C03	$ 86,474,242	$ 53,740,504	$ 20,028,963	$ 424,846	$ 5,428,842	$ 1,196,946
Distribution Street & Customer Lighting									
Customer	TPIS	PLDSCL	C04	$ 119,946,663	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TPIS	PLCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TPIS	PLCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TPIS	PLSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 6,970,753,239	$ 3,176,799,654	$ 823,292,040	$ 55,460,314	$ 653,856,358	$ 47,115,202

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Plant in Service										
Power Production Plant										
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 134,505,560	$ 323,323,806	$ 115,146,494	$ 42,509,126	$ 9,951,076	$ 35,955	$ 119,856
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	112,088,409	259,436,606	89,705,805	33,727,891	-	-	80,831
Production Demand - Peak	TPIS	PLPPDP	PPSDA	109,966,670	240,641,820	89,457,702	33,818,923	-	-	59,749
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 356,560,639	$ 823,402,232	$ 294,310,001	$ 110,055,940	$ 9,951,076	$ 35,955	$ 260,436
				8.4%						
Transmission Plant										
Transmission Demand	TPIS	PLTRB	NCPT	$ 67,372,105	$ 156,093,339	$ 57,127,325	$ 37,772,005	$ 6,774,443	$ 28,376	$ 43,947
Distribution Poles										
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TPIS	PLDSG	NCPP	$ 17,876,728	$ 41,418,302	$ -	$ -	$ 1,797,552	$ 7,529	$ 11,661
Distribution Primary & Secondary Lines										
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	19,480,127	45,133,190	-	-	1,958,778	8,205	12,707
Primary Customer	TPIS	PLDPLC	Cust08	506,168	226,875	-	-	15,332,840	364	70,620
Secondary Demand	TPIS	PLDSLD	SICD	-	-	-	-	696,083	2,916	4,511
Secondary Customer	TPIS	PLDSLC	Cust07	-	-	-	-	5,879,458	140	27,079
Total Distribution Primary & Secondary Lines		PLDLT		$ 19,986,295	$ 45,360,065	$ -	$ -	$ 23,867,160	$ 11,624	$ 114,917
Distribution Line Transformers										
Demand	TPIS	PLDLTD	SICDT	$ 11,744,231	$ -	$ -	$ -	$ 899,957	$ 3,770	$ 5,832
Customer	TPIS	PLDLTC	Cust09	173,727	-	-	-	5,262,520	125	24,238
Total Line Transformers		PLDLTT		$ 11,917,957	$ -	$ -	$ -	$ 6,162,477	$ 3,895	$ 30,070
Distribution Services										
Customer	TPIS	PLDSC	C02	$ 274,819	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TPIS	PLDMC	C03	$ 1,006,794	$ 2,659,464	$ 1,813,785	$ 76,767	$ -	$ 499	$ 96,830
Distribution Street & Customer Lighting										
Customer	TPIS	PLDSCL	C04	$ -	$ -	$ -	$ -	$ 119,946,663	$ -	$ -
Customer Accounts Expense										
Customer	TPIS	PLCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TPIS	PLCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TPIS	PLSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 474,995,337	$ 1,068,933,401	$ 353,251,111	$ 147,904,713	$ 168,499,371	$ 87,878	$ 557,860

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Net Utility Plant									
Power Production Plant									
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 887,821,776	$ 298,057,778	$ 88,923,878	$ 7,430,000	$ 105,024,973	$ 8,104,734
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	930,049,504	403,491,443	108,463,824	8,952,268	101,778,926	6,441,870
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	764,497,556	287,150,177	85,990,242	5,772,943	90,683,657	6,802,246
Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 2,582,368,836	$ 988,699,399	$ 283,377,944	$ 22,155,211	$ 297,487,555	$ 21,348,850
Transmission Plant									
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 629,437,870	$ 267,724,873	$ 67,779,936	$ 6,543,451	$ 59,754,543	$ 4,699,169
Distribution Poles									
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	NTPLANT	UPDSG	NCPP	$ 142,637,386	$ 67,662,473	$ 17,130,116	$ 1,653,735	$ 15,101,847	$ 1,187,627
Distribution Primary & Secondary Lines									
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	155,430,811	73,731,252	18,666,549	1,802,062	16,456,361	1,294,148
Primary Customer	NTPLANT	UPDPLC	Cust08	288,232,444	230,316,167	44,562,332	317,122	2,408,095	92,516
Secondary Demand	NTPLANT	UPDSLD	SICD	71,553,552	59,605,526	10,734,656	754,029	-	-
Secondary Customer	NTPLANT	UPDSLC	Cust07	109,381,849	88,315,950	17,087,661	121,602	-	-
Total Distribution Primary & Secondary Lines		UPDLT		$ 624,598,655	$ 451,968,895	$ 91,051,199	$ 2,994,815	$ 18,864,457	$ 1,386,664
Distribution Line Transformers									
Demand	NTPLANT	UPDLTD	SICDT	$ 111,075,979	$ 77,063,233	$ 13,878,702	$ 974,874	$ 10,897,157	$ -
Customer	NTPLANT	UPDLTC	Cust09	98,844,227	79,048,862	15,294,634	108,842	826,504	-
Total Line Transformers		UPDLTT		$ 209,920,206	$ 156,112,094	$ 29,173,336	$ 1,083,716	$ 11,723,661	$ -
Distribution Services									
Customer	NTPLANT	UPDSC	C02	$ 66,173,475	$ 46,408,529	$ 18,178,298	$ 172,157	$ 1,235,054	$ -
Distribution Meters									
Customer	NTPLANT	UPDMC	C03	$ 56,461,453	$ 35,088,680	$ 13,077,471	$ 277,394	$ 3,544,643	$ 781,519
Distribution Street & Customer Lighting									
Customer	NTPLANT	UPDSCL	C04	$ 78,316,533	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	NTPLANT	UPCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	NTPLANT	UPCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	NTPLANT	UPSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 4,389,914,415	$ 2,013,664,943	$ 519,768,299	$ 34,880,479	$ 407,711,760	$ 29,403,830

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Net Utility Plant										
Power Production Plant										
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 81,762,299	$ 196,539,814	$ 69,994,446	$ 25,840,151	$ 6,048,991	$ 21,856	$ 72,857
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	68,135,518	157,704,510	54,529,737	20,502,274	-	-	49,135
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	66,845,771	146,279,667	54,378,922	20,557,611	-	-	36,320
Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 216,743,588	$ 500,523,991	$ 178,903,106	$ 66,900,035	$ 6,048,991	$ 21,856	$ 158,312
Transmission Plant										
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 46,184,280	$ 107,003,610	$ 39,161,376	$ 25,893,103	$ 4,643,951	$ 19,452	$ 30,126
Distribution Poles										
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	NTPLANT	UPDSG	NCPP	$ 11,672,216	$ 27,043,169	$ -	$ -	$ 1,173,672	$ 4,916	$ 7,614
Distribution Primary & Secondary Lines										
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	12,719,120	29,468,723	-	-	1,278,941	5,357	8,297
Primary Customer	NTPLANT	UPDPLC	Cust08	330,491	148,133	-	-	10,011,240	238	46,110
Secondary Demand	NTPLANT	UPDSLD	SICD	-	-	-	-	454,492	1,904	2,945
Secondary Customer	NTPLANT	UPDSLC	Cust07	-	-	-	-	3,838,863	91	17,681
Total Distribution Primary & Secondary Lines		UPDLT		$ 13,049,611	$ 29,616,856	$ -	$ -	$ 15,583,537	$ 7,590	$ 75,032
Distribution Line Transformers										
Demand	NTPLANT	UPDLTD	SICDT	$ 7,668,137	$ -	$ -	$ -	$ 587,607	$ 2,461	$ 3,808
Customer	NTPLANT	UPDLTC	Cust09	113,431	-	-	-	3,436,047	82	15,826
Total Line Transformers		UPDLTT		$ 7,781,568	$ -	$ -	$ -	$ 4,023,654	$ 2,543	$ 19,633
Distribution Services										
Customer	NTPLANT	UPDSC	C02	$ 179,437	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	NTPLANT	UPDMC	C03	$ 657,364	$ 1,736,438	$ 1,184,271	$ 50,124	$ -	$ 326	$ 63,223
Distribution Street & Customer Lighting										
Customer	NTPLANT	UPDSCL	C04	$ -	$ -	$ -	$ -	$ 78,316,533	$ -	$ -
Customer Accounts Expense										
Customer	NTPLANT	UPCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	NTPLANT	UPCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	NTPLANT	UPSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 296,268,064	$ 665,924,064	$ 219,248,753	$ 92,843,262	$ 109,790,338	$ 56,682	$ 353,940

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Net Cost Rate Base									
Power Production Plant									
Production Demand - Base	RB	RBPPDB	PPBDA	$ 711,137,998	$ 238,741,848	$ 71,227,301	$ 5,951,369	$ 84,124,146	$ 6,491,826
Production Demand - Inter.	RB	RBPPDI	PPWDA	744,544,987	323,012,409	86,829,997	7,166,679	81,478,446	5,156,996
Production Demand - Peak	RB	RBPPDP	PPSDA	612,781,961	230,164,828	68,925,360	4,627,295	72,687,360	5,452,331
Production Energy - Base	RB	RBPPEB	E01	71,897,457	24,137,273	7,201,221	601,695	8,505,117	656,336
Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		RBPPT		$ 2,140,362,403	$ 816,056,359	$ 234,183,879	$ 18,347,038	$ 246,795,070	$ 17,757,489
Transmission Plant									
Transmission Demand	RB	RBTRB	NCPT	$ 519,102,553	$ 220,794,890	$ 55,898,667	$ 5,396,437	$ 49,280,060	$ 3,875,443
Distribution Poles									
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	RB	RBDSG	NCPP	$ 117,648,309	$ 55,808,479	$ 14,129,039	$ 1,364,012	$ 12,456,109	$ 979,563
Distribution Primary & Secondary Lines									
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	128,492,991	60,952,839	15,431,437	1,489,745	13,604,298	1,069,858
Primary Customer	RB	RBDPLC	Cust08	237,858,860	190,064,449	36,774,297	261,700	1,987,239	76,347
Secondary Demand	RB	RBDSLD	SICD	59,228,567	49,338,570	8,885,629	624,148	-	-
Secondary Customer	RB	RBDSLC	Cust07	90,497,599	73,068,626	14,137,559	100,608	-	-
Total Distribution Primary & Secondary Lines		RBDLT		$ 516,078,017	$ 373,424,484	$ 75,228,921	$ 2,476,201	$ 15,591,537	$ 1,146,206
Distribution Line Transformers									
Demand	RB	RBDLTD	SICDT	$ 91,286,846	$ 63,333,761	$ 11,406,093	$ 801,192	$ 8,955,736	$ -
Customer	RB	RBDLTC	Cust09	81,234,285	64,965,633	12,569,765	89,451	679,255	-
Total Line Transformers		RBDLTT		$ 172,521,131	$ 128,299,393	$ 23,975,857	$ 890,643	$ 9,634,991	$ -
Distribution Services									
Customer	RB	RBDSC	C02	$ 54,380,434	$ 38,137,879	$ 14,938,670	$ 141,476	$ 1,014,950	$ -
Distribution Meters									
Customer	RB	RBDMC	C03	$ 47,701,574	$ 29,644,742	$ 11,048,528	$ 234,357	$ 2,994,699	$ 660,268
Distribution Street & Customer Lighting									
Customer	RB	RBDSCL	C04	$ 64,342,233	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	RB	RBCAE	C05	$ 6,169,535	$ 3,974,831	$ 1,538,127	$ 54,729	$ 207,796	$ 7,983
Customer Service & Info.									
Customer	RB	RBCSI	C05	$ 773,569	$ 498,386	$ 192,859	$ 6,862	$ 26,055	$ 1,001
Sales Expense									
Customer	RB	RBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 3,639,079,759	$ 1,666,639,443	$ 431,134,547	$ 28,911,757	$ 338,001,267	$ 24,427,954

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Net Cost Rate Base										
Power Production Plant										
Production Demand - Base	RB	RBPPDB	PPBDA	$ 65,490,934	$ 157,426,788	$ 56,064,980	$ 20,697,750	$ 4,845,192	$ 17,506	$ 58,358
Production Demand - Inter.	RB	RBPPDI	PPWDA	54,545,439	126,249,303	43,653,421	16,412,960	-	-	39,334
Production Demand - Peak	RB	RBPPDP	PPSDA	53,580,135	117,250,265	43,587,350	16,477,924	-	-	29,112
Production Energy - Base	RB	RBPPEB	E01	6,621,263	15,916,159	5,668,280	2,092,583	489,858	1,770	5,900
Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		RBPPT		$ 180,237,772	$ 416,842,516	$ 148,974,032	$ 55,681,218	$ 5,335,050	$ 19,276	$ 132,705
Transmission Plant										
Transmission Demand	RB	RBTRB	NCPT	$ 38,088,553	$ 88,246,751	$ 32,296,707	$ 21,354,254	$ 3,829,904	$ 16,042	$ 24,845
Distribution Poles										
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	RB	RBDSG	NCPP	$ 9,627,325	$ 22,305,394	$ -	$ -	$ 968,053	$ 4,055	$ 6,280
Distribution Primary & Secondary Lines										
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	10,514,761	24,361,479	-	-	1,057,287	4,429	6,859
Primary Customer	RB	RBDPLC	Cust08	272,732	122,244	-	-	8,261,604	196	38,051
Secondary Demand	RB	RBDSLD	SICD	-	-	-	-	376,207	1,576	2,438
Secondary Customer	RB	RBDSLC	Cust07	-	-	-	-	3,176,102	75	14,628
Total Distribution Primary & Secondary Lines		RBDLT		$ 10,787,493	$ 24,483,723	$ -	$ -	$ 12,871,199	$ 6,276	$ 61,976
Distribution Line Transformers										
Demand	RB	RBDLTD	SICDT	$ 6,301,993	$ -	$ -	$ -	$ 482,920	$ 2,023	$ 3,129
Customer	RB	RBDLTC	Cust09	93,222	-	-	-	2,823,886	67	13,006
Total Line Transformers		RBDLTT		$ 6,395,215	$ -	$ -	$ -	$ 3,306,806	$ 2,090	$ 16,135
Distribution Services										
Customer	RB	RBDSC	C02	$ 147,459	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	RB	RBDMC	C03	$ 555,375	$ 1,467,034	$ 1,000,534	$ 42,347	$ -	$ 275	$ 53,414
Distribution Street & Customer Lighting										
Customer	RB	RBDSCL	C04	$ -	$ -	$ -	$ -	$ 64,342,233	$ -	$ -
Customer Accounts Expense										
Customer	RB	RBCAE	C05	$ 142,592	$ 63,912	$ 5,538	$ 461	$ 172,771	$ -	$ 794
Customer Service & Info.										
Customer	RB	RBCSI	C05	$ 17,879	$ 8,014	$ 694	$ 58	$ 21,663	$ -	$ 100
Sales Expense										
Customer	RB	RBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 245,999,663	$ 553,417,343	$ 182,277,504	$ 77,078,338	$ 90,847,680	$ 48,015	$ 296,249

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
			Allocation	Total	Residential	General Service	All Electric Schools	Power Service	Power Service
Description	Ref	Name	Vector	System	Rate RS	GS	AES	PS-Secondary	PS-Primary
Operation and Maintenance Expenses									
Power Production Plant									
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 37,625,250	$ 12,631,475	$ 3,768,530	$ 314,878	$ 4,450,883	$ 343,473
Production Demand - Inter.	TOM	OMPPDI	PPWDA	35,951,279	15,597,055	4,192,694	346,052	3,934,288	249,012
Production Demand - Peak	TOM	OMPPDP	PPSDA	35,933,656	13,496,911	4,041,797	271,345	4,262,401	319,726
Production Energy - Base	TOM	OMPPEB	E01	640,387,547	214,989,646	64,140,963	5,359,274	75,754,712	5,845,961
Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		OMPPT		$ 749,897,732	$ 256,715,087	$ 76,143,984	$ 6,291,550	$ 88,402,284	$ 6,758,171
					34.2%	10.2%	0.8%	11.8%	0.9%
Transmission Plant									
Transmission Demand	TOM	OMTRB	NCPT	$ 44,026,929	$ 18,726,398	$ 4,740,964	$ 457,691	$ 4,179,617	$ 328,690
Distribution Poles									
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TOM	OMDSG	NCPP	$ 7,427,615	$ 3,523,416	$ 892,024	$ 86,116	$ 786,405	$ 61,844
Distribution Primary & Secondary Lines									
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	13,725,970	6,511,148	1,648,428	159,139	1,453,248	114,285
Primary Customer	TOM	OMDPLC	Cust08	21,967,220	17,553,214	3,396,254	24,169	183,530	7,051
Secondary Demand	TOM	OMDSLD	SICD	6,950,051	5,789,530	1,042,665	73,239	-	-
Secondary Customer	TOM	OMDSLC	Cust07	10,263,921	8,287,188	1,603,432	11,411	-	-
Total Distribution Primary & Secondary Lines		OMDLT		$ 52,907,162	$ 38,141,080	$ 7,690,780	$ 267,958	$ 1,636,778	$ 121,336
Distribution Line Transformers									
Demand	TOM	OMDLTD	SICDT	$ 3,048,697	$ 2,115,151	$ 380,928	$ 26,757	$ 299,094	$ -
Customer	TOM	OMDLTC	Cust09	2,712,973	2,169,651	419,791	2,987	22,685	-
Total Line Transformers		OMDLTT		$ 5,761,670	$ 4,284,802	$ 800,719	$ 29,745	$ 321,779	$ -
Distribution Services									
Customer	TOM	OMDSC	C02	$ 1,785,765	$ 1,252,386	$ 490,562	$ 4,646	$ 33,329	$ -
Distribution Meters									
Customer	TOM	OMDMC	C03	$ 12,338,781	$ 7,668,090	$ 2,857,880	$ 60,620	$ 774,627	$ 170,789
Distribution Street & Customer Lighting									
Customer	TOM	OMDSCL	C04	$ 1,970,659	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TOM	OMCAE	C05	$ 51,233,939	$ 33,008,361	$ 12,773,133	$ 454,492	$ 1,725,612	$ 66,296
Customer Service & Info.									
Customer	TOM	OMCSI	C05	$ 6,423,986	$ 4,138,766	$ 1,601,564	$ 56,987	$ 216,367	$ 8,313
Sales Expense									
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 933,774,239	$ 367,458,386	$ 107,991,610	$ 7,709,803	$ 98,076,797	$ 7,515,439

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Operation and Maintenance Expenses										
Power Production Plant										
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 3,465,028	$ 8,329,216	$ 2,966,314	$ 1,095,087	$ 256,352	$ 926	$ 3,088
Production Demand - Inter.	TOM	OMPPDI	PPWDA	2,633,794	6,096,104	2,107,860	792,520	-	-	1,899
Production Demand - Peak	TOM	OMPPDP	PPSDA	3,141,950	6,875,579	2,555,971	966,269	-	-	1,707
Production Energy - Base	TOM	OMPPEB	E01	58,975,304	141,764,544	50,487,128	18,638,549	4,363,148	15,765	52,552
Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OMPPT		$ 68,216,075	$ 163,065,444	$ 58,117,273	$ 21,492,425	$ 4,619,500	$ 16,691	$ 59,247
				9.1%	21.7%	7.8%	2.9%			
Transmission Plant										
Transmission Demand	TOM	OMTRB	NCPT	$ 3,230,425	$ 7,484,520	$ 2,739,198	$ 1,811,130	$ 324,828	$ 1,361	$ 2,107
Distribution Poles										
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TOM	OMDSG	NCPP	$ 607,812	$ 1,408,230	$ -	$ -	$ 61,117	$ 256	$ 396
Distribution Primary & Secondary Lines										
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	1,123,215	2,602,359	-	-	112,942	473	733
Primary Customer	TOM	OMDPLC	Cust08	25,188	11,290	-	-	762,992	18	3,514
Secondary Demand	TOM	OMDSLD	SICD	-	-	-	-	44,145	185	286
Secondary Customer	TOM	OMDSLC	Cust07	-	-	-	-	360,222	9	1,659
Total Distribution Primary & Secondary Lines		OMDLT		$ 1,148,403	$ 2,613,649	$ -	$ -	$ 1,280,302	$ 685	$ 6,192
Distribution Line Transformers										
Demand	TOM	OMDLTD	SICDT	$ 210,467	$ -	$ -	$ -	$ 16,128	$ 68	$ 105
Customer	TOM	OMDLTC	Cust09	3,113	-	-	-	94,309	2	434
Total Line Transformers		OMDLTT		$ 213,580	$ -	$ -	$ -	$ 110,437	$ 70	$ 539
Distribution Services										
Customer	TOM	OMDSC	C02	$ 4,842	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TOM	OMDMC	C03	$ 143,657	$ 379,472	$ 258,804	$ 10,954	$ -	$ 71	$ 13,816
Distribution Street & Customer Lighting										
Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ 1,970,659	$ -	$ -
Customer Accounts Expense										
Customer	TOM	OMCAE	C05	$ 1,184,131	$ 530,751	$ 45,986	$ 3,832	$ 1,434,753	$ -	$ 6,591
Customer Service & Info.										
Customer	TOM	OMCSI	C05	$ 148,473	$ 66,548	$ 5,766	$ 480	$ 179,897	$ -	$ 826
Sales Expense										
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 74,897,399	$ 175,548,614	$ 61,167,027	$ 23,318,822	$ 9,981,493	$ 19,134	$ 89,715

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Labor Expenses									
Power Production Plant									
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 18,742,668	$ 6,292,252	$ 1,877,258	$ 156,854	$ 2,217,166	$ 171,098
Production Demand - Inter.	TLB	LBPPDI	PPWDA	17,681,329	7,670,844	2,062,024	170,193	1,934,936	122,467
Production Demand - Peak	TLB	LBPPDP	PPSDA	18,132,162	6,810,556	2,039,495	136,921	2,150,812	161,334
Production Energy - Base	TLB	LBPPEB	E01	38,818,637	13,032,116	3,888,059	324,865	4,592,055	354,367
Production Energy - Inter.	TLB	LBPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TLB	LBPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		LBPPT		$ 93,374,796	$ 33,805,768	$ 9,866,837	$ 788,833	$ 10,894,969	$ 809,266
Transmission Plant									
Transmission Demand	TLB	LBTRB	NCPT	$ 11,565,291	$ 4,919,177	$ 1,245,389	$ 120,229	$ 1,097,930	$ 86,343
Distribution Poles									
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TLB	LBDSG	NCPP	$ 4,300,052	$ 2,039,803	$ 516,417	$ 49,855	$ 455,271	$ 35,803
Distribution Primary & Secondary Lines									
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	4,685,732	2,222,757	562,736	54,326	496,106	39,014
Primary Customer	TLB	LBDPLC	Cust08	8,689,269	6,943,282	1,343,409	9,560	72,596	2,789
Secondary Demand	TLB	LBDSLD	SICD	2,157,106	1,796,912	323,615	22,732	-	-
Secondary Customer	TLB	LBDSLC	Cust07	3,297,506	2,662,438	515,137	3,666	-	-
Total Distribution Primary & Secondary Lines		LBDLT		$ 18,829,614	$ 13,625,389	$ 2,744,897	$ 90,284	$ 568,702	$ 41,803
Distribution Line Transformers									
Demand	TLB	LBDLTD	SICDT	$ 3,348,579	$ 2,323,205	$ 418,398	$ 29,389	$ 328,514	$ -
Customer	TLB	LBDLTC	Cust09	2,979,831	2,383,066	461,083	3,281	24,916	-
Total Line Transformers		LBDLTT		$ 6,328,410	$ 4,706,271	$ 879,481	$ 32,671	$ 353,430	$ -
Distribution Services									
Customer	TLB	LBDSC	C02	$ 1,994,915	$ 1,399,066	$ 548,016	$ 5,190	$ 37,233	$ -
Distribution Meters									
Customer	TLB	LBDMC	C03	$ 1,702,129	$ 1,057,809	$ 394,243	$ 8,363	$ 106,859	$ 23,560
Distribution Street & Customer Lighting									
Customer	TLB	LBDSCL	C04	$ 2,360,988	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TLB	LBCAE	C05	$ 27,271,497	$ 17,570,139	$ 6,799,057	$ 241,923	$ 918,532	$ 35,289
Customer Service & Info.									
Customer	TLB	LBCSI	C05	$ 3,748,877	$ 2,415,280	$ 934,633	$ 33,256	$ 126,266	$ 4,851
Sales Expense									
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 171,476,569	$ 81,538,702	$ 23,928,969	$ 1,370,603	$ 14,559,194	$ 1,036,915

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Labor Expenses										
Power Production Plant										
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 1,726,071	$ 4,149,122	$ 1,477,642	$ 545,507	$ 127,699	$ 461	$ 1,538
Production Demand - Inter.	TLB	LBPPDI	PPWDA	1,295,336	2,998,147	1,036,674	389,772	-	-	934
Production Demand - Peak	TLB	LBPPDP	PPSDA	1,585,431	3,469,425	1,289,746	487,580	-	-	861
Production Energy - Base	TLB	LBPPEB	E01	3,574,930	8,593,400	3,060,399	1,129,821	264,483	956	3,186
Production Energy - Inter.	TLB	LBPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TLB	LBPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		LBPPT		$ 8,181,769	$ 19,210,093	$ 6,864,461	$ 2,552,681	$ 392,182	$ 1,417	$ 6,519
Transmission Plant										
Transmission Demand	TLB	LBTRB	NCPT	$ 848,590	$ 1,966,084	$ 719,551	$ 475,760	$ 85,328	$ 357	$ 554
Distribution Poles										
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TLB	LBDSG	NCPP	$ 351,879	$ 815,263	$ -	$ -	$ 35,382	$ 148	$ 230
Distribution Primary & Secondary Lines										
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	383,440	888,386	-	-	38,556	161	250
Primary Customer	TLB	LBDPLC	Cust08	9,963	4,466	-	-	301,806	7	1,390
Secondary Demand	TLB	LBDSLD	SICD	-	-	-	-	13,701	57	89
Secondary Customer	TLB	LBDSLC	Cust07	-	-	-	-	115,729	3	533
Total Distribution Primary & Secondary Lines		LBDLT		$ 393,403	$ 892,852	$ -	$ -	$ 469,793	$ 229	$ 2,262
Distribution Line Transformers										
Demand	TLB	LBDLTD	SICDT	$ 231,169	$ -	$ -	$ -	$ 17,714	$ 74	$ 115
Customer	TLB	LBDLTC	Cust09	3,420	-	-	-	103,586	2	477
Total Line Transformers		LBDLTT		$ 234,589	$ -	$ -	$ -	$ 121,300	$ 77	$ 592
Distribution Services										
Customer	TLB	LBDSC	C02	$ 5,409	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TLB	LBDMC	C03	$ 19,817	$ 52,348	$ 35,702	$ 1,511	$ -	$ 10	$ 1,906
Distribution Street & Customer Lighting										
Customer	TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ 2,360,988	$ -	$ -
Customer Accounts Expense										
Customer	TLB	LBCAE	C05	$ 630,305	$ 282,516	$ 24,478	$ 2,040	$ 763,710	$ -	$ 3,508
Customer Service & Info.										
Customer	TLB	LBCSI	C05	$ 86,645	$ 38,836	$ 3,365	$ 280	$ 104,983	$ -	$ 482
Sales Expense										
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 10,752,407	$ 23,257,992	$ 7,647,557	$ 3,032,272	$ 4,333,667	$ 2,238	$ 16,053

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector		3 Total System		4 Residential Rate RS		5 General Service GS		7 All Electric Schools AES		9 Power Service PS-Secondary		10 Power Service PS-Primary
Depreciation Expenses															
Power Production Plant															
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$	52,845,706	$	17,741,256	$	5,293,005	$	442,255	$	6,251,389	$	482,417
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA		55,359,222		24,016,971		6,456,079		532,865		6,058,174		383,439
Production Demand - Peak	TDEPR	DEPPDP	PPSDA		45,505,094		17,092,005		5,118,387		343,622		5,397,752		404,889
Production Energy - Base	TDEPR	DEPPEB	E01		-		-		-		-		-		-
Production Energy - Inter.	TDEPR	DEPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	TDEPR	DEPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		DEPPT		$	153,710,022	$	58,850,232	$	16,867,470	$	1,318,742	$	17,707,315	$	1,270,745
Transmission Plant															
Transmission Demand	TDEPR	DETRB	NCPT	$	24,058,002	$	10,232,822	$	2,590,645	$	250,100	$	2,283,903	$	179,609
Distribution Poles															
Specific	TDEPR	DEDPS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	TDEPR	DEDSG	NCPP	$	6,089,359	$	2,888,591	$	731,305	$	70,600	$	644,716	$	50,701
Distribution Primary & Secondary Lines															
Primary Specific	TDEPR	DEDPLS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	TDEPR	DEDPLD	NCPP		6,635,525		3,147,674		796,897		76,932		702,542		55,249
Primary Customer	TDEPR	DEDPLC	Cust08		12,304,984		9,832,470		1,902,419		13,538		102,804		3,950
Secondary Demand	TDEPR	DEDSLD	SICD		3,054,706		2,544,630		458,275		32,190		-		-
Secondary Customer	TDEPR	DEDSLC	Cust07		4,669,641		3,770,312		729,492		5,191		-		-
Total Distribution Primary & Secondary Lines		DEDLT		$	26,664,856	$	19,295,087	$	3,887,083	$	127,852	$	805,346	$	59,198
Distribution Line Transformers															
Demand	TDEPR	DEDLTD	SICDT	$	4,741,965	$	3,289,921	$	592,498	$	41,619	$	465,213	$	-
Customer	TDEPR	DEDLTC	Cust09		4,219,777		3,374,689		652,946		4,647		35,284		-
Total Line Transformers		DEDLTT		$	8,961,742	$	6,664,610	$	1,245,444	$	46,265	$	500,497	$	-
Distribution Services															
Customer	TDEPR	DEDSC	C02	$	2,825,024	$	1,981,235	$	776,053	$	7,350	$	52,726	$	-
Distribution Meters															
Customer	TDEPR	DEDMC	C03	$	2,410,406	$	1,497,977	$	558,293	$	11,842	$	151,325	$	33,364
Distribution Street & Customer Lighting															
Customer	TDEPR	DEDSCL	C04	$	3,343,426	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	TDEPR	DECAE	C05	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service & Info.															
Customer	TDEPR	DECSI	C05	$	-	$	-	$	-	$	-	$	-	$	-
Sales Expense															
Customer	TDEPR	DESEC	C06	$	-	$	-	$	-	$	-	$	-	$	-
Total		DET		$	228,062,837	$	101,410,555	$	26,656,293	$	1,832,751	$	22,145,827	$	1,593,617

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Depreciation Expenses										
Power Production Plant										
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 4,866,727	$ 11,698,615	$ 4,166,271	$ 1,538,080	$ 360,053	$ 1,301	$ 4,337
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	4,055,622	9,387,026	3,245,767	1,220,354	-	-	2,925
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	3,978,853	8,706,987	3,236,790	1,223,648	-	-	2,162
Production Energy - Base	TDEPR	DEPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TDEPR	DEPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TDEPR	DEPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		DEPPT		$ 12,901,202	$ 29,792,628	$ 10,648,828	$ 3,982,083	$ 360,053	$ 1,301	$ 9,423
Transmission Plant										
Transmission Demand	TDEPR	DETRB	NCPT	$ 1,765,228	$ 4,089,829	$ 1,496,803	$ 989,671	$ 177,498	$ 743	$ 1,151
Distribution Poles										
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TDEPR	DEDSG	NCPP	$ 498,301	$ 1,154,505	$ -	$ -	$ 50,105	$ 210	$ 325
Distribution Primary & Secondary Lines										
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	542,994	1,258,055	-	-	54,600	229	354
Primary Customer	TDEPR	DEDPLC	Cust08	14,109	6,324	-	-	427,392	10	1,968
Secondary Demand	TDEPR	DEDSLD	SICD	-	-	-	-	19,403	81	126
Secondary Customer	TDEPR	DEDSLC	Cust07	-	-	-	-	163,886	4	755
Total Distribution Primary & Secondary Lines		DEDLT		$ 557,103	$ 1,264,379	$ -	$ -	$ 665,280	$ 324	$ 3,203
Distribution Line Transformers										
Demand	TDEPR	DEDLTD	SICDT	$ 327,362	$ -	$ -	$ -	$ 25,086	$ 105	$ 163
Customer	TDEPR	DEDLTC	Cust09	4,842	-	-	-	146,689	3	676
Total Line Transformers		DEDLTT		$ 332,204	$ -	$ -	$ -	$ 171,775	$ 109	$ 838
Distribution Services										
Customer	TDEPR	DEDSC	C02	$ 7,660	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TDEPR	DEDMC	C03	$ 28,064	$ 74,131	$ 50,558	$ 2,140	$ -	$ 14	$ 2,699
Distribution Street & Customer Lighting										
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ 3,343,426	$ -	$ -
Customer Accounts Expense										
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 16,089,763	$ 36,375,471	$ 12,196,188	$ 4,973,893	$ 4,768,137	$ 2,701	$ 17,640

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Accretion Expenses									
Power Production Plant									
Production Demand - Base	TACRT	ACPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	-	-	-	-	-	-
Production Demand - Peak	TACRT	ACPPDP	PPSDA	-	-	-	-	-	-
Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
Transmission Demand	TACRT	ACTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles									
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TACRT	ACDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines									
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	-	-	-	-	-	-
Primary Customer	TACRT	ACDPLC	Cust08	-	-	-	-	-	-
Secondary Demand	TACRT	ACDSLD	SICD	-	-	-	-	-	-
Secondary Customer	TACRT	ACDSLC	Cust07	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers									
Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust09	-	-	-	-	-	-
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services									
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters									
Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting									
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
<u>Accretion Expenses</u>										
Power Production Plant										
Production Demand - Base	TACRT	ACPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	-	-	-	-	-	-	-
Production Demand - Peak	TACRT	ACPPDP	PPSDA	-	-	-	-	-	-	-
Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	TACRT	ACTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TACRT	ACDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	TACRT	ACDPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	TACRT	ACDSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	TACRT	ACDSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust09	-	-	-	-	-	-	-
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Property Taxes									
Power Production Plant									
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 5,182,784	$ 1,739,954	$ 519,106	$ 43,374	$ 613,098	$ 47,313
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	5,429,295	2,355,438	633,173	52,260	594,149	37,605
Production Demand - Peak	PTAX	PTPPDP	PPSDA	4,462,862	1,676,280	501,980	33,700	529,379	39,709
Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 15,074,941	$ 5,771,672	$ 1,654,259	$ 129,334	$ 1,736,625	$ 124,627
Transmission Plant									
Transmission Demand	PTAX	PTTRB	NCPT	$ 3,342,932	$ 1,421,881	$ 359,978	$ 34,752	$ 317,355	$ 24,957
Distribution Poles									
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	PTAX	PTDSG	NCPP	$ 784,098	$ 371,950	$ 94,167	$ 9,091	$ 83,017	$ 6,529
Distribution Primary & Secondary Lines									
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	854,426	405,311	102,613	9,906	90,463	7,114
Primary Customer	PTAX	PTDPLC	Cust08	1,584,455	1,266,081	244,966	1,743	13,238	509
Secondary Demand	PTAX	PTDSLD	SICD	393,340	327,660	59,010	4,145	-	-
Secondary Customer	PTAX	PTDSLC	Cust07	601,288	485,486	93,933	668	-	-
Total Distribution Primary & Secondary Lines		PTDLT		$ 3,433,509	$ 2,484,538	$ 500,522	$ 16,463	$ 103,701	$ 7,623
Distribution Line Transformers									
Demand	PTAX	PTDLTD	SICDT	$ 610,601	$ 423,628	$ 76,293	$ 5,359	$ 59,903	$ -
Customer	PTAX	PTDLTC	Cust09	543,361	434,543	84,077	598	4,543	-
Total Line Transformers		PTDLTT		$ 1,153,962	$ 858,171	$ 160,370	$ 5,957	$ 64,447	$ -
Distribution Services									
Customer	PTAX	PTDSC	C02	$ 363,765	$ 255,114	$ 99,929	$ 946	$ 6,789	$ -
Distribution Meters									
Customer	PTAX	PTDMC	C03	$ 310,377	$ 192,888	$ 71,889	$ 1,525	$ 19,485	$ 4,296
Distribution Street & Customer Lighting									
Customer	PTAX	PTDSCL	C04	$ 430,517	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 24,894,101	$ 11,356,214	$ 2,941,112	$ 198,069	$ 2,331,420	$ 168,031

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	Time of Day	Time of Day	Service	Service	Outdoor Lighting	Lighting Energy	Traffic Energy
Description	Ref	Name	Vector	TOD-Secondary	TOD-Primary	RTS	FLS - Transmission	ST & POL	LE	TE
Property Taxes										
Power Production Plant										
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 477,299	$ 1,147,329	$ 408,602	$ 150,846	$ 35,312	$ 128	$ 425
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	397,751	920,622	318,325	119,685	-	-	287
Production Demand - Peak	PTAX	PTPPDP	PPSDA	390,222	853,928	317,445	120,008	-	-	212
Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 1,265,271	$ 2,921,879	$ 1,044,372	$ 390,538	$ 35,312	$ 128	$ 924
Transmission Plant										
Transmission Demand	PTAX	PTTRB	NCPT	$ 245,284	$ 568,294	$ 207,985	$ 137,518	$ 24,664	$ 103	$ 160
Distribution Poles										
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	PTAX	PTDSG	NCPP	$ 64,164	$ 148,660	$ -	$ -	$ 6,452	$ 27	$ 42
Distribution Primary & Secondary Lines										
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	69,919	161,994	-	-	7,031	29	46
Primary Customer	PTAX	PTDPLC	Cust08	1,817	814	-	-	55,033	1	253
Secondary Demand	PTAX	PTDSLD	SICD	-	-	-	-	2,498	10	16
Secondary Customer	PTAX	PTDSLC	Cust07	-	-	-	-	21,103	1	97
Total Distribution Primary & Secondary Lines		PTDLT		$ 71,736	$ 162,808	$ -	$ -	$ 85,665	$ 42	$ 412
Distribution Line Transformers										
Demand	PTAX	PTDLTD	SICDT	$ 42,153	$ -	$ -	$ -	$ 3,230	$ 14	$ 21
Customer	PTAX	PTDLTC	Cust09	624	-	-	-	18,888	0	87
Total Line Transformers		PTDLTT		$ 42,776	$ -	$ -	$ -	$ 22,119	$ 14	$ 108
Distribution Services										
Customer	PTAX	PTDSC	C02	$ 986	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	PTAX	PTDMC	C03	$ 3,614	$ 9,545	$ 6,510	$ 276	$ -	$ 2	$ 348
Distribution Street & Customer Lighting										
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ 430,517	$ -	$ -
Customer Accounts Expense										
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 1,693,831	$ 3,811,187	$ 1,258,867	$ 528,332	$ 604,728	$ 315	$ 1,994

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector		3 Total System		4 Residential Rate RS		5 General Service GS		7 All Electric Schools AES		9 Power Service PS-Secondary		10 Power Service PS-Primary
Other Taxes															
Power Production Plant															
Production Demand - Base	OTAX	OTPPDB	PPBDA	$	2,691,268	$	903,507	$	269,556	$	22,523	$	318,364	$	24,568
Production Demand - Inter.	OTAX	OTPPDI	PPWDA		2,819,273		1,223,110		328,788		27,137		308,524		19,527
Production Demand - Peak	OTAX	OTPPDP	PPSDA		2,317,433		870,443		260,664		17,500		274,891		20,620
Production Energy - Base	OTAX	OTPPEB	E01		-		-		-		-		-		-
Production Energy - Inter.	OTAX	OTPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	OTAX	OTPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		OTPPT		$	7,827,974	$	2,997,059	$	859,008	$	67,159	$	901,779	$	64,715
Transmission Plant															
Transmission Demand	OTAX	OTTRB	NCPT	$	1,735,886	$	738,341	$	186,926	$	18,046	$	164,793	$	12,960
Distribution Poles															
Specific	OTAX	OTDPS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	OTAX	OTDSG	NCPP	$	407,159	$	193,143	$	48,898	$	4,721	$	43,108	$	3,390
Distribution Primary & Secondary Lines															
Primary Specific	OTAX	OTDPLS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	OTAX	OTDPLD	NCPP		443,678		210,466		53,284		5,144		46,975		3,694
Primary Customer	OTAX	OTDPLC	Cust08		822,761		657,439		127,203		905		6,874		264
Secondary Demand	OTAX	OTDSLD	SICD		204,250		170,144		30,642		2,152		-		-
Secondary Customer	OTAX	OTDSLC	Cust07		312,231		252,098		48,777		347		-		-
Total Distribution Primary & Secondary Lines		OTDLT		$	1,782,920	$	1,290,148	$	259,906	$	8,549	$	53,849	$	3,958
Distribution Line Transformers															
Demand	OTAX	OTDLTD	SICDT	$	317,067	$	219,977	$	39,617	$	2,783	$	31,106	$	-
Customer	OTAX	OTDLTC	Cust09		282,151		225,645		43,659		311		2,359		-
Total Line Transformers		OTDLTT		$	599,218	$	445,623	$	83,275	$	3,093	$	33,465	$	-
Distribution Services															
Customer	OTAX	OTDSC	C02	$	188,893	$	132,473	$	51,890	$	491	$	3,525	$	-
Distribution Meters															
Customer	OTAX	OTDMC	C03	$	161,170	$	100,161	$	37,330	$	792	$	10,118	$	2,231
Distribution Street & Customer Lighting															
Customer	OTAX	OTDSCL	C04	$	223,555	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	OTAX	OTCAE	C05	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service & Info.															
Customer	OTAX	OTCSI	C05	$	-	$	-	$	-	$	-	$	-	$	-
Sales Expense															
Customer	OTAX	OTSEC	C06	$	-	$	-	$	-	$	-	$	-	$	-
Total		OTT		$	12,926,774	$	5,896,948	$	1,527,233	$	102,851	$	1,210,638	$	87,254

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Other Taxes										
Power Production Plant										
Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 247,847	$ 595,774	$ 212,175	$ 78,330	$ 18,336	$ 66	$ 221
Production Demand - Inter.	OTAX	OTPPDI	PPWDA	206,540	478,052	165,297	62,149	-	-	149
Production Demand - Peak	OTAX	OTPPDP	PPSDA	202,631	443,420	164,840	62,317	-	-	110
Production Energy - Base	OTAX	OTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	OTAX	OTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	OTAX	OTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ 657,018	$ 1,517,246	$ 542,312	$ 202,795	$ 18,336	$ 66	$ 480
Transmission Plant										
Transmission Demand	OTAX	OTTRB	NCPT	$ 127,369	$ 295,098	$ 108,001	$ 71,409	$ 12,807	$ 54	$ 83
Distribution Poles										
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	OTAX	OTDSG	NCPP	$ 33,318	$ 77,195	$ -	$ -	$ 3,350	$ 14	$ 22
Distribution Primary & Secondary Lines										
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	36,307	84,119	-	-	3,651	15	24
Primary Customer	OTAX	OTDPLC	Cust08	943	423	-	-	28,577	1	132
Secondary Demand	OTAX	OTDSLD	SICD	-	-	-	-	1,297	5	8
Secondary Customer	OTAX	OTDSLC	Cust07	-	-	-	-	10,958	0	50
Total Distribution Primary & Secondary Lines		OTDLT		$ 37,250	$ 84,541	$ -	$ -	$ 44,483	$ 22	$ 214
Distribution Line Transformers										
Demand	OTAX	OTDLTD	SICDT	$ 21,889	$ -	$ -	$ -	$ 1,677	$ 7	$ 11
Customer	OTAX	OTDLTC	Cust09	324	-	-	-	9,808	0	45
Total Line Transformers		OTDLTT		$ 22,213	$ -	$ -	$ -	$ 11,486	$ 7	$ 56
Distribution Services										
Customer	OTAX	OTDSC	C02	$ 512	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	OTAX	OTDMC	C03	$ 1,876	$ 4,957	$ 3,381	$ 143	$ -	$ 1	$ 180
Distribution Street & Customer Lighting										
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ 223,555	$ -	$ -
Customer Accounts Expense										
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 879,557	$ 1,979,037	$ 653,693	$ 274,347	$ 314,018	$ 164	$ 1,035

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Gain Disposition of Allowances									
Power Production Plant									
Production Demand - Base	GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	-	-	-	-	-	-
Production Demand - Peak	GAIN	OTPPDP	PPSDA	-	-	-	-	-	-
Production Energy - Base	GAIN	OTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	GAIN	OTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	GAIN	OTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
Transmission Demand	GAIN	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles									
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines									
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	-	-	-	-	-	-
Primary Customer	GAIN	OTDPLC	Cust08	-	-	-	-	-	-
Secondary Demand	GAIN	OTDSLD	SICD	-	-	-	-	-	-
Secondary Customer	GAIN	OTDSLC	Cust07	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers									
Demand	GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust09	-	-	-	-	-	-
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services									
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters									
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting									
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Gain Disposition of Allowances										
Power Production Plant										
Production Demand - Base	GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	-	-	-	-	-	-	-
Production Demand - Peak	GAIN	OTPPDP	PPSDA	-	-	-	-	-	-	-
Production Energy - Base	GAIN	OTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	GAIN	OTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	GAIN	OTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	GAIN	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	GAIN	OTDPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	GAIN	OTDSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	GAIN	OTDSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust09	-	-	-	-	-	-	-
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Interest									
Power Production Plant									
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 17,924,442	$ 6,017,558	$ 1,795,305	$ 150,006	$ 2,120,374	$ 163,628
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	18,776,988	8,146,183	2,189,802	180,739	2,054,839	130,056
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	15,434,620	5,797,342	1,736,077	116,551	1,830,834	137,332
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 52,136,050	$ 19,961,084	$ 5,721,184	$ 447,297	$ 6,006,046	$ 431,017
Transmission Plant									
Transmission Demand	INTLTD	INTTRB	NCPT	$ 11,561,389	$ 4,917,517	$ 1,244,968	$ 120,189	$ 1,097,559	$ 86,313
Distribution Poles									
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	INTLTD	INTDSG	NCPP	$ 2,711,771	$ 1,286,375	$ 325,672	$ 31,440	$ 287,111	$ 22,579
Distribution Primary & Secondary Lines									
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	2,954,995	1,401,752	354,882	34,260	312,862	24,604
Primary Customer	INTLTD	INTDPLC	Cust08	5,479,772	4,378,688	847,203	6,029	45,782	1,759
Secondary Demand	INTLTD	INTDSLD	SICD	1,360,350	1,133,199	204,083	14,335	-	-
Secondary Customer	INTLTD	INTDSLC	Cust07	2,079,529	1,679,031	324,864	2,312	-	-
Total Distribution Primary & Secondary Lines		INTDLT		$ 11,874,646	$ 8,592,671	$ 1,731,033	$ 56,936	$ 358,644	$ 26,363
Distribution Line Transformers									
Demand	INTLTD	INTDLTD	SICDT	$ 2,111,737	$ 1,465,099	$ 263,857	$ 18,534	$ 207,173	$ -
Customer	INTLTD	INTDLTC	Cust09	1,879,191	1,502,849	290,776	2,069	15,713	-
Total Line Transformers		INTDLTT		$ 3,990,928	$ 2,967,947	$ 554,633	$ 20,603	$ 222,886	$ -
Distribution Services									
Customer	INTLTD	INTDSC	C02	$ 1,258,066	$ 882,302	$ 345,599	$ 3,273	$ 23,480	$ -
Distribution Meters									
Customer	INTLTD	INTDMC	C03	$ 1,073,425	$ 667,093	$ 248,624	$ 5,274	$ 67,389	$ 14,858
Distribution Street & Customer Lighting									
Customer	INTLTD	INTDSCL	C04	$ 1,488,926	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 86,095,200	$ 39,274,989	$ 10,171,713	$ 685,012	$ 8,063,117	$ 581,130

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	Time of Day	Time of Day	Service	Service	Outdoor Lighting	Lighting Energy	Traffic Energy
Description	Ref	Name	Vector	TOD-Secondary	TOD-Primary	RTS	FLS - Transmission	ST & POL	LE	TE
Interest										
Power Production Plant										
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 1,650,718	$ 3,967,988	$ 1,413,134	$ 521,693	$ 122,124	$ 441	$ 1,471
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	1,375,604	3,183,933	1,100,914	413,925	-	-	992
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	1,349,565	2,953,275	1,097,869	415,042	-	-	733
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 4,375,887	$ 10,105,196	$ 3,611,917	$ 1,350,661	$ 122,124	$ 441	$ 3,196
Transmission Plant										
Transmission Demand	INTLTD	INTTRB	NCPT	$ 848,304	$ 1,965,421	$ 719,308	$ 475,599	$ 85,299	$ 357	$ 553
Distribution Poles										
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	INTLTD	INTDSG	NCPP	$ 221,908	$ 514,135	$ -	$ -	$ 22,313	$ 93	$ 145
Distribution Primary & Secondary Lines										
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	241,811	560,249	-	-	24,315	102	158
Primary Customer	INTLTD	INTDPLC	Cust08	6,283	2,816	-	-	190,330	5	877
Secondary Demand	INTLTD	INTDSLD	SICD	-	-	-	-	8,641	36	56
Secondary Customer	INTLTD	INTDSLC	Cust07	-	-	-	-	72,983	2	336
Total Distribution Primary & Secondary Lines		INTDLT		$ 248,095	$ 563,065	$ -	$ -	$ 296,269	$ 144	$ 1,426
Distribution Line Transformers										
Demand	INTLTD	INTDLTD	SICDT	$ 145,784	$ -	$ -	$ -	$ 11,171	$ 47	$ 72
Customer	INTLTD	INTDLTC	Cust09	2,157	-	-	-	65,325	2	301
Total Line Transformers		INTDLTT		$ 147,940	$ -	$ -	$ -	$ 76,496	$ 48	$ 373
Distribution Services										
Customer	INTLTD	INTDSC	C02	$ 3,411	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	INTLTD	INTDMC	C03	$ 12,498	$ 33,013	$ 22,515	$ 953	$ -	$ 6	$ 1,202
Distribution Street & Customer Lighting										
Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ -	$ -	$ 1,488,926	$ -	$ -
Customer Accounts Expense										
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 5,858,043	$ 13,180,830	$ 4,353,740	$ 1,827,213	$ 2,091,428	$ 1,091	$ 6,896

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Cost of Service Summary -- Unadjusted									
Operating Revenues									
Sales		REVUC	R01	$ 1,464,489,053	$ 554,543,189	$ 198,233,994	$ 12,037,991	$ 174,459,441	$ 13,950,651
Intercompany Sales		SFRS	E01	8,422,903	2,827,720	843,635	70,490	996,388	76,891
Curtailable Service Rider			INTCRE	(17,395,776)	(7,089,946)	(1,996,214)	(151,165)	(1,975,770)	(135,961)
LATE PAYMENT CHARGES			LPAY	3,857,505	3,012,898	568,302	3,750	98,651	5,535
OTHER SERVICE CHARGES			MISCSERV	2,108,282	1,967,237	136,875	853	1,335	51
RENT FROM ELEC PROPERTY			RBT	3,142,645	1,439,280	372,320	24,968	291,892	21,096
OTHER MISC REVENUES			MISCSERV	22,338,060	20,843,640	1,450,249	9,036	14,148	542
Total Operating Revenues		TOR		$ 1,486,962,672	$ 577,544,019	$ 199,609,161	$ 11,995,923	$ 173,886,086	$ 13,918,805
Operating Expenses									
Operation and Maintenance Expenses				$ 933,774,239	$ 367,458,386	$ 107,991,610	$ 7,709,803	$ 98,076,797	$ 7,515,439
Depreciation and Amortization Expenses				228,062,837	101,410,555	26,656,293	1,832,751	22,145,827	1,593,617
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	24,894,101	11,356,214	2,941,112	198,069	2,331,420	168,031
Other Taxes				12,926,774	5,896,948	1,527,233	102,851	1,210,638	87,254
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	84,161,734	$ 21,811,969	$ 21,048,305	$ 613,798	$ 17,592,102	$ 1,661,962
Total Operating Expenses		TOE		$ 1,283,819,685	$ 507,934,072	$ 160,164,554	$ 10,457,272	$ 141,356,784	$ 11,026,304
Net Operating Income (Unadjusted)		TOM		$ 203,142,987	$ 69,609,947	$ 39,444,607	$ 1,538,651	$ 32,529,302	$ 2,892,501
Net Cost Rate Base				$ 3,639,079,759	$ 1,666,639,443	$ 431,134,547	$ 28,911,757	$ 338,001,267	$ 24,427,954

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Cost of Service Summary -- Unadjusted										
Operating Revenues										
Sales		REVUC	R01	$ 116,879,945	$ 251,561,897	$ 86,711,460	$ 29,892,107	$ 26,032,396	$ 29,470	$ 156,512
Intercompany Sales		SFRS	E01	775,692	1,864,604	664,048	245,150	57,388	207	691
Curtailable Service Rider			INTCRE	(1,385,683)	(3,120,622)	(1,118,028)	(421,510)	-	-	(877)
LATE PAYMENT CHARGES			LPAY	41,764	107,885	18,686	-	33	-	-
OTHER SERVICE CHARGES			MISCSERV	982	439	48	-	461	-	-
RENT FROM ELEC PROPERTY			RBT	212,441	477,921	157,412	66,563	78,454	41	256
OTHER MISC REVENUES			MISCSERV	10,403	4,653	505	-	4,883	-	-
Total Operating Revenues		TOR		$ 116,535,544	$ 250,896,778	$ 86,434,130	$ 29,782,310	$ 26,173,616	$ 29,719	$ 156,582
Operating Expenses										
Operation and Maintenance Expenses				$ 74,897,399	$ 175,548,614	$ 61,167,027	$ 23,318,822	$ 9,981,493	$ 19,134	$ 89,715
Depreciation and Amortization Expenses				16,089,763	36,375,471	12,196,188	4,973,893	4,768,137	2,701	17,640
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,693,831	3,811,187	1,258,867	528,332	604,728	315	1,994
Other Taxes				879,557	1,979,037	653,693	274,347	314,018	164	1,035
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 7,159,663	$ 8,366,267	$ 2,846,228	$ (476,962)	$ 3,519,322	$ 2,641	$ 16,439
Total Operating Expenses		TOE		$ 100,720,212	$ 226,080,576	$ 78,122,004	$ 28,618,432	$ 19,187,697	$ 24,955	$ 126,824
Net Operating Income (Unadjusted)		TOM		$ 15,815,332	$ 24,816,201	$ 8,312,127	$ 1,163,878	$ 6,985,918	$ 4,764	$ 29,758
Net Cost Rate Base				$ 245,999,663	$ 553,417,343	$ 182,277,504	$ 77,078,338	$ 90,847,680	$ 48,015	$ 296,249

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
			Allocation	Total	Residential	General Service	All Electric Schools	Power Service	Power Service
Description	Ref	Name	Vector	System	Rate RS	GS	AES	PS-Secondary	PS-Primary
Taxable Income Unadjusted									
Total Operating Revenue				$ 1,486,962,672	$ 577,544,019	$ 199,609,161	$ 11,995,923	$ 173,886,086	$ 13,918,805
Operating Expenses				$ 1,199,657,950	$ 486,122,103	$ 139,116,248	$ 9,843,474	$ 123,764,682	$ 9,364,341
Interest Expense		INTEXP		$ 86,095,200	$ 39,274,989	$ 10,171,713	$ 685,012	$ 8,063,117	$ 581,130
Taxable Income		TAXINC		$ 201,209,521	$ 52,146,927	$ 50,321,200	$ 1,467,437	$ 42,058,287	$ 3,973,334

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Taxable Income Unadjusted										
Total Operating Revenue				$ 116,535,544	$ 250,896,778	$ 86,434,130	$ 29,782,310	$ 26,173,616	$ 29,719	$ 156,582
Operating Expenses				$ 93,560,549	$ 217,714,309	$ 75,275,776	$ 29,095,394	$ 15,668,375	$ 22,314	$ 110,385
Interest Expense		INTEXP		$ 5,858,043	$ 13,180,830	$ 4,353,740	$ 1,827,213	$ 2,091,428	$ 1,091	$ 6,896
Taxable Income		TAXINC		$ 17,116,953	$ 20,001,639	$ 6,804,614	$ (1,140,297)	$ 8,413,812	$ 6,314	$ 39,301

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 1,486,962,672	$ 577,544,019	$ 199,609,161	$ 11,995,923	$ 173,886,086	$ 13,918,805
Pro-Forma Adjustments:									
Adj to eliminate Off System ECR revenues			ECRREV	(1,635,232)	$ (609,965)	$ (368,766)	$ (23,373)	$ (168,730)	$ (13,653)
Total Pro-Forma Operating Revenue				$ 1,485,327,440	$ 576,934,054	$ 199,240,395	$ 11,972,550	$ 173,717,356	$ 13,905,151

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 116,535,544	$ 250,896,778	$ 86,434,130	$ 29,782,310	$ 26,173,616	$ 29,719	$ 156,582
Pro-Forma Adjustments:										
Adj to eliminate Off System ECR revenues			ECRREV	$ (105,682)	$ (210,279)	$ (68,614)	$ (23,719)	$ (42,194)	$ (66)	$ (192)
Total Pro-Forma Operating Revenue				$ 116,429,863	$ 250,686,499	$ 86,365,516	$ 29,758,591	$ 26,131,422	$ 29,653	$ 156,390

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Operating Expenses									
Operation and Maintenance Expenses				$ 933,774,239	$ 367,458,386	$ 107,991,610	$ 7,709,803	$ 98,076,797	$ 7,515,439
Depreciation and Amortization Expenses				228,062,837	101,410,555	26,656,293	1,832,751	22,145,827	1,593,617
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	24,894,101	11,356,214	2,941,112	198,069	2,331,420	168,031
Other Taxes				12,926,774	5,896,948	1,527,233	102,851	1,210,638	87,254
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	84,161,734	$ 21,811,969	$ 21,048,305	$ 613,798	$ 17,592,102	$ 1,661,962
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ -	$ -	$ -	$ -	$ -	$ -
Adjustments to Operating Expenses:									
Eliminate advertising expenses			REVUC	(838,116)	(317,361)	(113,448)	(6,889)	(99,842)	(7,984)
Federal & State Income Tax Adjustment			TAXINC	(164,668)	(42,677)	(41,182)	(1,201)	(34,420)	(3,252)
Total Expense Adjustments				$ (1,002,784)	$ (360,037)	$ (154,630)	$ (8,090)	$ (134,262)	$ (11,236)
Total Operating Expenses		TOE		$ 1,282,816,901	$ 507,574,035	$ 160,009,923	$ 10,449,182	$ 141,222,522	$ 11,015,068
Net Operating Income (Adjusted)				$ 202,510,539	$ 69,360,019	$ 39,230,472	$ 1,523,368	$ 32,494,834	$ 2,890,083
Net Cost Rate Base				$ 3,639,079,759	$ 1,666,639,443	$ 431,134,547	$ 28,911,757	$ 338,001,267	$ 24,427,954
Rate of Return				**5.56%**	**4.16%**	**9.10%**	**5.27%**	**9.61%**	**11.83%**

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Operating Expenses										
Operation and Maintenance Expenses				$ 74,897,399	$ 175,548,614	$ 61,167,027	$ 23,318,822	$ 9,981,493	$ 19,134	$ 89,715
Depreciation and Amortization Expenses				16,089,763	36,375,471	12,196,188	4,973,893	4,768,137	2,701	17,640
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,693,831	3,811,187	1,258,867	528,332	604,728	315	1,994
Other Taxes				879,557	1,979,037	653,693	274,347	314,018	164	1,035
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 7,159,663	$ 8,366,267	$ 2,846,228	$ (476,962)	$ 3,519,322	$ 2,641	$ 16,439
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustments to Operating Expenses:										
Eliminate advertising expenses			REVUC	(66,890)	(143,967)	(49,624)	(17,107)	(14,898)	(17)	(90)
Federal & State Income Tax Adjustment			TAXINC	(14,008)	(16,369)	(5,569)	933	(6,886)	(5)	(32)
Total Expense Adjustments				$ (80,898)	$ (160,336)	$ (55,193)	$ (16,174)	$ (21,784)	$ (22)	$ (122)
Total Operating Expenses		TOE		$ 100,639,315	$ 225,920,240	$ 78,066,811	$ 28,602,258	$ 19,165,913	$ 24,933	$ 126,702
Net Operating Income (Adjusted)				$ 15,790,548	$ 24,766,259	$ 8,298,706	$ 1,156,333	$ 6,965,509	$ 4,720	$ 29,688
Net Cost Rate Base				$ 245,999,663	$ 553,417,343	$ 182,277,504	$ 77,078,338	$ 90,847,680	$ 48,015	$ 296,249
Rate of Return				**6.42%**	**4.48%**	**4.55%**	**1.50%**	**7.67%**	**9.83%**	**10.02%**

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Taxable Income Pro-Forma									
Total Operating Revenue				$ 1,485,327,440	$ 576,934,054	$ 199,240,395	$ 11,972,550	$ 173,717,356	$ 13,905,151
Operating Expenses				$ 1,198,655,166	$ 485,762,065	$ 138,961,618	$ 9,835,384	$ 123,630,420	$ 9,353,106
Interest Expense		INTEXP		$ 86,095,200	$ 39,274,989	$ 10,171,713	$ 685,012	$ 8,063,117	$ 581,130
Interest Syncronization Adjustment			INTEXP	$ 7,411,055	$ 3,380,782	$ 875,579	$ 58,966	$ 694,071	$ 50,024
Taxable Income		TXINCPF		$ 193,166,018	$ 48,516,217	$ 49,231,485	$ 1,393,189	$ 41,329,748	$ 3,920,892

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Taxable Income Pro-Forma										
Total Operating Revenue				$ 116,429,863	$ 250,686,499	$ 86,365,516	$ 29,758,591	$ 26,131,422	$ 29,653	$ 156,390
Operating Expenses				$ 93,479,651	$ 217,553,973	$ 75,220,583	$ 29,079,220	$ 15,646,592	$ 22,291	$ 110,263
Interest Expense		INTEXP		$ 5,858,043	$ 13,180,830	$ 4,353,740	$ 1,827,213	$ 2,091,428	$ 1,091	$ 6,896
Interest Syncronization Adjustment			INTEXP	$ 504,259	$ 1,134,603	$ 374,769	$ 157,286	$ 180,030	$ 94	$ 594
Taxable Income		TXINCPF		$ 16,587,910	$ 18,817,093	$ 6,416,425	$ (1,305,128)	$ 8,213,373	$ 6,177	$ 38,637

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Cost of Service Summary -- Adjusted for Proposed Increase									
Operating Revenue									
Total Operating Revenue				$ 1,485,327,440	$ 576,934,054	$ 199,240,395	$ 11,972,550	$ 173,717,356	$ 13,905,151
Proposed Increase				$ 94,389,823	$ 37,000,062	$ 12,094,455	$ 777,151	$ 9,478,307	$ 705,851
Proposed Reduction to CSR Credit			INTCRE	$ 8,688,375	$ 3,541,096	$ 997,016	$ 75,500	$ 986,805	$ 67,906
Increase in Miscellaneous Charges			MISCSERV	$ 19,720	$ 18,401	$ 1,280	$ 8	$ 12	$ 0
					$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 1,588,425,358	$ 617,493,613	$ 212,333,146	$ 12,825,209	$ 184,182,480	$ 14,678,909
Operating Expenses									
Total Operating Expenses				$ 1,283,819,685	$ 507,934,072	$ 160,164,554	$ 10,457,272	$ 141,356,784	$ 11,026,304
Pro-Forma Adjustments				$ (1,002,784)	$ (360,037)	$ (154,630)	$ (8,090)	$ (134,262)	$ (11,236)
Increase in Uncollectible Expense			Cust01	$ 362,905	$ 226,690	$ 43,861	$ 312	$ 2,370	$ 91
Increase in PSC Fees			R01	$ 200,113	$ 75,775	$ 27,087	$ 1,645	$ 23,839	$ 1,906
Incremental Income Taxes			0.385574631	$ 39,751,942	$ 15,638,737	$ 5,048,233	$ 328,764	$ 4,035,086	$ 298,341
Total Pro-Forma Operating Expenses				$ 1,323,131,860	$ 523,515,236	$ 165,129,104	$ 10,779,902	$ 145,283,817	$ 11,315,407
Net Operating Income				$ 265,293,498	$ 93,978,376	$ 47,204,042	$ 2,045,306	$ 38,898,663	$ 3,363,502
Net Cost Rate Base				$ 3,639,079,759	$ 1,666,639,443	$ 431,134,547	$ 28,911,757	$ 338,001,267	$ 24,427,954
Rate of Return				7.29%	5.64%	10.95%	7.07%	11.51%	13.77%

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Cost of Service Summary -- Adjusted for Proposed Increase										
Operating Revenue										
Total Operating Revenue				$ 116,429,863	$ 250,686,499	$ 86,365,516	$ 29,758,591	$ 26,131,422	$ 29,653	$ 156,390
Proposed Increase				$ 6,865,949	$ 17,335,551	$ 6,022,823	$ 2,235,015	$ 1,866,484	$ -	$ 8,175
Proposed Reduction to CSR Credit			INTCRE	$ 692,083	$ 1,558,604	$ 558,402	$ 210,525	$ -	$ -	$ 438
Increase in Miscellaneous Charges			MISCSERV	$ 9	$ 4	$ 0	$ -	$ 4	$ -	$ -
				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 123,987,904	$ 269,580,658	$ 92,946,742	$ 32,204,131	$ 27,997,910	$ 29,653	$ 165,003
Operating Expenses										
Total Operating Expenses				$ 100,720,212	$ 226,080,576	$ 78,122,004	$ 28,618,432	$ 19,187,697	$ 24,955	$ 126,824
Pro-Forma Adjustments				$ (80,898)	$ (160,336)	$ (55,193)	$ (16,174)	$ (21,784)	$ (22)	$ (122)
Increase in Uncollectible Expense			Cust01	$ 325	$ 146	$ 16	$ 1	$ 88,683	$ 2	$ 408
Increase in PSC Fees			R01	$ 15,971	$ 34,374	$ 11,849	$ 4,085	$ 3,557	$ 4	$ 21
Incremental Income Taxes			0.385574631	$ 2,914,189	$ 7,285,109	$ 2,537,554	$ 942,938	$ 719,671	$ -	$ 3,321
Total Pro-Forma Operating Expenses				$ 103,569,800	$ 233,239,869	$ 80,616,229	$ 29,549,281	$ 19,977,824	$ 24,939	$ 130,453
Net Operating Income				$ 20,418,104	$ 36,340,789	$ 12,330,513	$ 2,654,850	$ 8,020,087	$ 4,714	$ 34,550
Net Cost Rate Base				$ 245,999,663	$ 553,417,343	$ 182,277,504	$ 77,078,338	$ 90,847,680	$ 48,015	$ 296,249
Rate of Return				**8.30%**	**6.57%**	**6.76%**	**3.44%**	**8.83%**	**9.82%**	**11.66%**

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

BIP METHODOLOGY

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Allocation Factors									
Energy Allocation Factors									
Energy Usage by Class		E01	Energy	1.000000	0.335718	0.100160	0.008369	0.118295	0.009129
Customer Allocation Factors									
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	1.000000	0.79906	0.15461	0.00110	0.00835	0.00032
Customer Services -- Weighted cost of Services		C02		1.000000	0.701316	0.274707	0.002602	0.018664	-
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.621463	0.231618	0.004913	0.062780	0.013842
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.64427	0.24931	0.00887	0.03368	0.00129
Marketing/Economic Development		C06	Cust06	1.000000	0.79902	0.15460	0.00110	0.00835	0.00032
Total billed revenue per Billing Determinants		R01		1,464,489,053	554,543,189	198,233,994	12,037,991	174,459,441	13,950,651
Energy (at the Meter)				18,343,080,487	6,091,971,051	1,817,505,619	151,861,000	2,146,594,132	169,814,471
Energy (Loss Adjusted)(at Source)		Energy		19,428,782,556	6,522,592,615	1,945,979,163	162,595,559	2,298,329,870	177,361,189
O&M Customer Allocators									
Customers (Monthly Bills)				8,273,588	5,168,140	999,948	7,118	54,034	2,070
Average Customers (Bills/12)				689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = Lights)				689,466	430,678	83,329	593	4,503	173
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		668,477	430,678	166,658	5,930	22,515	865
Street Lighting		Cust04		114,827,799	-	-	-	-	-
Average Customers		Cust01		689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = 9 Lights per Cust)		Cust06		539,008	430,678	83,329	593	4,503	173
Average Secondary Customers		Cust07		533,407	430,678	83,329	593	-	-
Average Primary Customers		Cust08		538,978	430,678	83,329	593	4,503	173
Average Transformer Customers		Cust09		538,528	430,678	83,329	593	4,503	-
Plant Customer Allocators									
Customers (Monthly Bills)				8,273,588	5,168,140	999,948	7,118	54,034	2,070
Average Customers (Bills/12)				689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = Lights)				689,466	430,678	83,329	593	4,503	173
Weighted Average Customers (Lighting =9 Lights per Cust)				668,477	430,678	166,658	5,930	22,515	865
Street Lighting				114,827,799	-	-	-	-	-
Average Customers				689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = 9 Lights per Cust)				539,008	430,678	83,329	593	4,503	173
Average Secondary Customers				533,407	430,678	83,329	593	-	-
Average Primary Customers				538,978	430,678	83,329	593	4,503	173
Average Transformer Customers				538,528	430,678	83,329	593	4,503	-
Demand Allocators									
Maximum Class Non-Coincident Peak Demands (Transm		NCPT		5,021,135	2,135,688	540,692	52,198	476,672	37,486
Maximum Class Non-Coincident Peak Demands (Primary		NCPP		4,502,184	2,135,688	540,692	52,198	476,672	37,486
Sum of the Individual Customer Demands (Transformer)		SICDT		6,459,671	4,481,645	807,122	56,694	633,729	-
Sum of the Individual Customer Demands (Secondary)		SICD		5,379,998	4,481,645	807,122	56,694	-	-
Summer Peak Period Demand Allocator		SCP		3,586,335	1,347,051	403,389	27,081	425,406	31,910
Winter Peak Period Demand Allocator		WCP		3,808,066	1,652,086	444,103	36,655	416,731	26,376
Base Demand Allocator		BDEM		2,211,838	742,554	221,537	18,510	261,650	20,191

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Allocation Factors										
Energy Allocation Factors										
Energy Usage by Class		E01	Energy	0.092093	0.221373	0.078838	0.029105	0.006813	0.000025	0.000082
Customer Allocation Factors										
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	0.00115	0.00051	-	-	0.03473	0.00000	0.00016
Customer Services -- Weighted cost of Services		C02		0.002712	-	-	-	-	-	-
Meter Costs -- Weighted Cost of Meters		C03		0.011643	0.030754	0.020975	0.000888	-	0.000006	0.001120
Lighting Systems -- Lighting Customers		C04	Cust04	-	-	-	-	1.00000	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.02311	0.01036	0.00090	0.00007	0.02800	-	0.00013
Marketing/Economic Development		C06	Cust06	0.00115	0.00051	0.00006	0.00000	0.03473	-	0.00016
Total billed revenue per Billing Determinants		R01		116,879,945	251,561,897	86,711,460	29,892,107	26,032,396	29,470	156,512
Energy (at the Meter)				1,671,130,915	4,118,000,917	1,497,714,279	552,917,598	123,634,653	446,721	1,489,131
Energy (Loss Adjusted)(at Source)		Energy		1,789,257,708	4,301,008,844	1,531,734,094	565,476,838	132,373,983	478,298	1,594,393
O&M Customer Allocators										
Customers (Monthly Bills)				7,419	3,318	360	12	2,021,809	48	9,312
Average Customers (Bills/12)				618	277	30	1	168,484	4	776
Average Customers (Lighting = Lights)				618	277	30	1	168,484	4	776
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		15,450	6,925	600	50	18,720	-	86
Street Lighting		Cust04		-	-	-	-	114,827,799	-	-
Average Customers		Cust01		618	277	30	1	168,484	4	776
Average Customers (Lighting = 9 Lights per Cust)		Cust06		618	277	30	1	18,720	-	86
Average Secondary Customers		Cust07		-	-	-	-	18,720	0	86
Average Primary Customers		Cust08		618	277	-	-	18,720	0	86
Average Transformer Customers		Cust09		618	-	-	-	18,720	0	86
Plant Customer Allocators									-	-
Customers (Monthly Bills)				7,419	3,318	360	12	2,021,809	48	9,312
Average Customers (Bills/12)				618	277	30	1	168,484	4	776
Average Customers (Lighting = Lights)				618	277	30	1	168,484	4	776
Weighted Average Customers (Lighting =9 Lights per Cust)				15,450	6,925	600	50	18,720	-	86
Street Lighting				-	-	-	-	114,827,799	-	-
Average Customers				618	277	30	1	168,484	4	776
Average Customers (Lighting = 9 Lights per Cust)				618	277	30	1	18,720	-	86
Average Secondary Customers				-	-	-	-	18,720	0	86
Average Primary Customers				618	277	-	-	18,720	0	86
Average Transformer Customers				618	-	-	-	18,720	0	86
Demand Allocators										
Maximum Class Non-Coincident Peak Demands (Transm		NCPT		368,420	853,586	312,397	206,554	37,046	155	240
Maximum Class Non-Coincident Peak Demands (Primary		NCPP		368,420	853,586	-	-	37,046	155	240
Sum of the Individual Customer Demands (Transformer)		SICDT		445,944	-	-	-	34,173	143	221
Sum of the Individual Customer Demands (Secondary)		SICD		-	-	-	-	34,173	143	221
Summer Peak Period Demand Allocator		SCP		313,580	686,213	255,097	96,438	-	-	170
Winter Peak Period Demand Allocator		WCP		278,979	645,717	223,271	83,946	-	-	201
Base Demand Allocator		BDEM		203,695	489,641	174,378	64,376	15,070	54	182

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

BIP METHODOLOGY

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Unadjusted Production Allocation									
Production Residual Winter Demand Allocator		PPWDRA		3,808,066	1,652,086	444,103	36,655	416,731	26,376
Production Winter Demand Costs				$ 35,951,279	$ 15,597,055	$ 4,192,694	$ 346,052	$ 3,934,288	$ 249,012
Customer Specific Assignment				$ -		-	0	-	-
Production Winter Demand Residual			PPWDRA	$ 35,951,279	$ 15,597,055	$ 4,192,694	$ 346,052	$ 3,934,288	$ 249,012
Production Winter Demand Total		PPWDT		$ 35,951,279	$ 15,597,055	$ 4,192,694	$ 346,052	$ 3,934,288	$ 249,012
Production Winter Demand Allocator		PPWDA	PPWDT	1.000000	0.43384	0.11662	0.00963	0.10943	0.00693
Production Residual Summer Demand Allocator		PPSDRA		3,586,335	1,347,051	403,389	27,081	425,406	31,910
Production Summer Demand Costs				$ 35,933,656	$ 13,496,911	$ 4,041,797	$ 271,345	$ 4,262,401	$ 319,726
Customer Specific Assignment				$ -		-	0	-	-
Production Summer Demand Residual			PPSDRA	$ 35,933,656	13,496,911	4,041,797	271,345	4,262,401	319,726
Production Summer Demand Total		PPSDT		$ 35,933,656	$ 13,496,911	$ 4,041,797	$ 271,345	$ 4,262,401	$ 319,726
Production Summer Demand Allocator		PPSDA	PPSDT	1.000000	0.37561	0.11248	0.00755	0.11862	0.00890
Production Residual Base Demand Allocator		PPBDRA		2,211,838	742,554	221,537	18,510	261,650	20,191
Production Base Demand Costs				$ 37,625,250					
Customer Specific Assignment				$ -	0	-	0	-	-
Production Base Demand Residual			PPBDRA	$ 37,625,250	12,631,475	3,768,530	314,878	4,450,883	343,473
Production Base Demand Total		PPBDT		$ 37,625,250	$ 12,631,475	$ 3,768,530	$ 314,878	$ 4,450,883	$ 343,473
Production Base Demand Allocator		PPBDA	PPBDT	1.000000	0.33572	0.10016	0.00837	0.11830	0.00913
Revenue Adjustment Allocators									
Remove ECR Revenues		ECRREV		183,699,328	68,522,534	41,426,529	2,625,661	18,954,821	1,533,784
Interruptible Credit Allocator		INTCRE		2,787,666,238	1,136,161,027	319,892,582	24,224,157	316,616,431	21,787,636
Base Rate Revenue				1,464,489,053	554,543,189	198,233,994	12,037,991	174,459,441	13,950,651
Late Payment Revenue		LPAY		3,719,777	2,905,326	548,011	3,616	95,129	5,337
Misc Service Revenue Allocator		MISCSERV		2,232,238	2,082,901	144,923	903	1,414	54
Operation and Maintenance Less Fuel		OMLF		293,386,691.81	152,468,739.91	43,850,646.58	2,350,528.91	22,322,085.22	1,669,478.16

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

BIP METHODOLOGY

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Unadjusted Production Allocation										
Production Residual Winter Demand Allocator		PPWDRA		278,979	645,717	223,271	83,946	-	-	201
Production Winter Demand Costs				$ 2,633,794	$ 6,096,104	$ 2,107,860	$ 792,520	$ -	$ -	$ 1,899
Customer Specific Assignment				-	-	-	-	-		
Production Winter Demand Residual			PPWDRA	$ 2,633,794	$ 6,096,104	$ 2,107,860	$ 792,520	$ -	$ -	$ 1,899
Production Winter Demand Total		PPWDT		$ 2,633,794	$ 6,096,104	$ 2,107,860	$ 792,520	$ -	$ -	$ 1,899
Production Winter Demand Allocator		PPWDA	PPWDT	0.07326	0.16957	0.05863	0.02204	-	-	0.00005
Production Residual Summer Demand Allocator		PPSDRA		313,580	686,213	255,097	96,438	-	-	170
Production Summer Demand Costs				$ 3,141,950	$ 6,875,579	$ 2,555,971	$ 966,269	$ -	$ -	$ 1,707
Customer Specific Assignment				-	-	-	-	-		
Production Summer Demand Residual			PPSDRA	3,141,950	6,875,579	2,555,971	966,269	-	-	1,707
Production Summer Demand Total		PPSDT		$ 3,141,950	$ 6,875,579	$ 2,555,971	$ 966,269	$ -	$ -	$ 1,707
Production Summer Demand Allocator		PPSDA	PPSDT	0.08744	0.19134	0.07113	0.02689	-	-	0.00005
Production Residual Base Demand Allocator		PPBDRA		203,695	489,641	174,378	64,376	15,070	54	182
Production Base Demand Costs										
Customer Specific Assignment				-	-	-	-	-	0	0
Production Base Demand Residual			PPBDRA	3,465,028	8,329,216	2,966,314	1,095,087	256,352	926	3,088
Production Base Demand Total		PPBDT		$ 3,465,028	$ 8,329,216	$ 2,966,314	$ 1,095,087	$ 256,352	$ 926	$ 3,088
Production Base Demand Allocator		PPBDA	PPBDT	0.09209	0.22137	0.07884	0.02911	0.00681	0.00002	0.00008
Revenue Adjustment Allocators										
Remove ECR Revenues		ECRREV		11,872,123	23,622,372	7,708,001	2,664,539	4,739,976	7,407	21,581
Interruptible Credit Allocator		INTCRE		222,055,079	500,078,426	179,163,507	67,546,814	-	-	140,580
Base Rate Revenue				116,879,945	251,561,897	86,711,460	29,892,107	26,032,396	29,470	156,512
Late Payment Revenue		LPAY		40,273	104,034	18,019	-	32	-	-
Misc Service Revenue Allocator		MISCSERV		1,040	465	50	-	488	-	-
Operation and Maintenance Less Fuel		OMLF		15,922,095.38	33,784,070.21	10,679,899.03	4,680,272.36	5,618,344.75	3,368.49	37,162.81

Exhibit WSS-19

Electric Cost of Service Study
Class Allocation
LOLP Methodology

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Plant in Service									
Power Production Plant									
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 1,460,538,245	$ 539,805,609	$ 158,703,502	$ 10,364,259	$ 173,380,230	$ 13,150,678
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	1,530,006,255	565,480,542	166,251,963	10,857,217	181,626,765	13,776,167
Production Demand - Peak	TPIS	PLPPDP	PPSDA	1,257,659,983	464,823,098	136,658,553	8,924,596	149,296,588	11,323,963
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 4,248,204,483	$ 1,570,109,248	$ 461,614,017	$ 30,146,073	$ 504,303,583	$ 38,250,808
					37.0%	10.9%	0.7%	11.9%	0.9%
Transmission Plant									
Transmission Demand	TPIS	PLTRB	NCPT	$ 918,203,216	$ 390,548,219	$ 98,875,137	$ 9,545,370	$ 87,167,957	$ 6,854,993
Distribution Poles									
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TPIS	PLDSG	NCPP	$ 218,458,065	$ 103,629,304	$ 26,235,842	$ 2,532,799	$ 23,129,422	$ 1,818,926
Distribution Primary & Secondary Lines									
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	238,051,995	112,924,018	28,588,986	2,759,971	25,203,945	1,982,069
Primary Customer	TPIS	PLDPLC	Cust08	441,445,991	352,743,595	68,249,994	485,692	3,688,148	141,694
Secondary Demand	TPIS	PLDSLD	SICD	109,588,734	91,289,586	16,440,796	1,154,842	-	-
Secondary Customer	TPIS	PLDSLC	Cust07	167,525,133	135,261,394	26,170,821	186,241	-	-
Total Distribution Primary & Secondary Lines		PLDLT		$ 956,611,853	$ 692,218,593	$ 139,450,598	$ 4,586,746	$ 28,892,094	$ 2,123,763
Distribution Line Transformers									
Demand	TPIS	PLDLTD	SICDT	$ 170,119,799	$ 118,027,154	$ 21,256,098	$ 1,493,081	$ 16,689,677	$ -
Customer	TPIS	PLDLTC	Cust09	151,386,108	121,068,269	23,424,688	166,699	1,265,842	-
Total Line Transformers		PLDLTT		$ 321,505,907	$ 239,095,423	$ 44,680,786	$ 1,659,779	$ 17,955,519	$ -
Distribution Services									
Customer	TPIS	PLDSC	C02	$ 101,348,810	$ 71,077,561	$ 27,841,199	$ 263,669	$ 1,891,563	$ -
Distribution Meters									
Customer	TPIS	PLDMC	C03	$ 86,474,242	$ 53,740,504	$ 20,028,963	$ 424,846	$ 5,428,842	$ 1,196,946
Distribution Street & Customer Lighting									
Customer	TPIS	PLDSCL	C04	$ 119,946,663	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TPIS	PLCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TPIS	PLCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TPIS	PLSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 6,970,753,239	$ 3,120,418,853	$ 818,726,543	$ 49,159,283	$ 668,768,981	$ 50,245,435

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Plant in Service										
Power Production Plant										
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 127,095,725	$ 296,752,782	$ 101,585,833	$ 39,430,413	$ 194,078	$ 740	$ 74,396
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	133,140,816	310,867,322	106,417,590	41,305,853	203,309	776	77,935
Production Demand - Peak	TPIS	PLPPDP	PPSDA	109,441,302	255,531,890	87,474,900	33,953,272	167,119	638	64,062
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 369,677,844 8.7%	$ 863,151,993	$ 295,478,323	$ 114,689,539	$ 564,507	$ 2,154	$ 216,393
Transmission Plant										
Transmission Demand	TPIS	PLTRB	NCPT	$ 67,372,105	$ 156,093,339	$ 57,127,325	$ 37,772,005	$ 6,774,443	$ 28,376	$ 43,947
Distribution Poles										
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TPIS	PLDSG	NCPP	$ 17,876,728	$ 41,418,302	$ -	$ -	$ 1,797,552	$ 7,529	$ 11,661
Distribution Primary & Secondary Lines										
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	19,480,127	45,133,190	-	-	1,958,778	8,205	12,707
Primary Customer	TPIS	PLDPLC	Cust08	506,168	226,875	-	-	15,332,840	364	70,620
Secondary Demand	TPIS	PLDSLD	SICD	-	-	-	-	696,083	2,916	4,511
Secondary Customer	TPIS	PLDSLC	Cust07	-	-	-	-	5,879,458	140	27,079
Total Distribution Primary & Secondary Lines		PLDLT		$ 19,986,295	$ 45,360,065	$ -	$ -	$ 23,867,160	$ 11,624	$ 114,917
Distribution Line Transformers										
Demand	TPIS	PLDLTD	SICDT	$ 11,744,231	$ -	$ -	$ -	$ 899,957	$ 3,770	$ 5,832
Customer	TPIS	PLDLTC	Cust09	173,727	-	-	-	5,262,520	125	24,238
Total Line Transformers		PLDLTT		$ 11,917,957	$ -	$ -	$ -	$ 6,162,477	$ 3,895	$ 30,070
Distribution Services										
Customer	TPIS	PLDSC	C02	$ 274,819	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TPIS	PLDMC	C03	$ 1,006,794	$ 2,659,464	$ 1,813,785	$ 76,767	$ -	$ 499	$ 96,830
Distribution Street & Customer Lighting										
Customer	TPIS	PLDSCL	C04	$ -	$ -	$ -	$ -	$ 119,946,663	$ -	$ -
Customer Accounts Expense										
Customer	TPIS	PLCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TPIS	PLCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TPIS	PLSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 488,112,542	$ 1,108,683,163	$ 354,419,433	$ 152,538,311	$ 159,112,801	$ 54,076	$ 513,817

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Net Utility Plant									
Power Production Plant									
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 887,821,776	$ 328,133,259	$ 96,471,575	$ 6,300,153	$ 105,393,162	$ 7,993,942
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	930,049,504	343,740,358	101,060,081	6,599,809	110,406,008	8,374,160
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	764,497,556	282,553,415	83,071,046	5,425,021	90,753,366	6,883,531
Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 2,582,368,836	$ 954,427,031	$ 280,602,701	$ 18,324,984	$ 306,552,536	$ 23,251,634
Transmission Plant									
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 629,437,870	$ 267,724,873	$ 67,779,936	$ 6,543,451	$ 59,754,543	$ 4,699,169
Distribution Poles									
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	NTPLANT	UPDSG	NCPP	$ 142,637,386	$ 67,662,473	$ 17,130,116	$ 1,653,735	$ 15,101,847	$ 1,187,627
Distribution Primary & Secondary Lines									
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	155,430,811	73,731,252	18,666,549	1,802,062	16,456,361	1,294,148
Primary Customer	NTPLANT	UPDPLC	Cust08	288,232,444	230,316,167	44,562,332	317,122	2,408,095	92,516
Secondary Demand	NTPLANT	UPDSLD	SICD	71,553,552	59,605,526	10,734,656	754,029	-	-
Secondary Customer	NTPLANT	UPDSLC	Cust07	109,381,849	88,315,950	17,087,661	121,602	-	-
Total Distribution Primary & Secondary Lines		UPDLT		$ 624,598,655	$ 451,968,895	$ 91,051,199	$ 2,994,815	$ 18,864,457	$ 1,386,664
Distribution Line Transformers									
Demand	NTPLANT	UPDLTD	SICDT	$ 111,075,979	$ 77,063,233	$ 13,878,702	$ 974,874	$ 10,897,157	$ -
Customer	NTPLANT	UPDLTC	Cust09	98,844,227	79,048,862	15,294,634	108,842	826,504	-
Total Line Transformers		UPDLTT		$ 209,920,206	$ 156,112,094	$ 29,173,336	$ 1,083,716	$ 11,723,661	$ -
Distribution Services									
Customer	NTPLANT	UPDSC	C02	$ 66,173,475	$ 46,408,529	$ 18,178,298	$ 172,157	$ 1,235,054	$ -
Distribution Meters									
Customer	NTPLANT	UPDMC	C03	$ 56,461,453	$ 35,088,680	$ 13,077,471	$ 277,394	$ 3,544,643	$ 781,519
Distribution Street & Customer Lighting									
Customer	NTPLANT	UPDSCL	C04	$ 78,316,533	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	NTPLANT	UPCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	NTPLANT	UPCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	NTPLANT	UPSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 4,389,914,415	$ 1,979,392,575	$ 516,993,057	$ 31,050,252	$ 416,776,741	$ 31,306,614

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Net Utility Plant										
Power Production Plant										
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 77,258,061	$ 180,388,006	$ 61,751,286	$ 23,968,684	$ 117,975	$ 450	$ 45,223
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	80,932,709	188,967,854	64,688,381	25,108,713	123,586	472	47,374
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	66,526,414	155,330,939	53,173,631	20,639,278	101,587	388	38,942
Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 224,717,183	$ 524,686,798	$ 179,613,297	$ 69,716,675	$ 343,148	$ 1,309	$ 131,539
Transmission Plant										
Transmission Demand	NTPLANT	UPTRB	NCPT	$ 46,184,280	$ 107,003,610	$ 39,161,376	$ 25,893,103	$ 4,643,951	$ 19,452	$ 30,126
Distribution Poles										
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	NTPLANT	UPDSG	NCPP	$ 11,672,216	$ 27,043,169	$ -	$ -	$ 1,173,672	$ 4,916	$ 7,614
Distribution Primary & Secondary Lines										
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	12,719,120	29,468,723	-	-	1,278,941	5,357	8,297
Primary Customer	NTPLANT	UPDPLC	Cust08	330,491	148,133	-	-	10,011,240	238	46,110
Secondary Demand	NTPLANT	UPDSLD	SICD	-	-	-	-	454,492	1,904	2,945
Secondary Customer	NTPLANT	UPDSLC	Cust07	-	-	-	-	3,838,863	91	17,681
Total Distribution Primary & Secondary Lines		UPDLT		$ 13,049,611	$ 29,616,856	$ -	$ -	$ 15,583,537	$ 7,590	$ 75,032
Distribution Line Transformers										
Demand	NTPLANT	UPDLTD	SICDT	$ 7,668,137	$ -	$ -	$ -	$ 587,607	$ 2,461	$ 3,808
Customer	NTPLANT	UPDLTC	Cust09	113,431	-	-	-	3,436,047	82	15,826
Total Line Transformers		UPDLTT		$ 7,781,568	$ -	$ -	$ -	$ 4,023,654	$ 2,543	$ 19,633
Distribution Services										
Customer	NTPLANT	UPDSC	C02	$ 179,437	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	NTPLANT	UPDMC	C03	$ 657,364	$ 1,736,438	$ 1,184,271	$ 50,124	$ -	$ 326	$ 63,223
Distribution Street & Customer Lighting										
Customer	NTPLANT	UPDSCL	C04	$ -	$ -	$ -	$ -	$ 78,316,533	$ -	$ -
Customer Accounts Expense										
Customer	NTPLANT	UPCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	NTPLANT	UPCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	NTPLANT	UPSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 304,241,659	$ 690,086,871	$ 219,958,944	$ 95,659,902	$ 104,084,496	$ 36,136	$ 327,168

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Net Cost Rate Base									
Power Production Plant									
Production Demand - Base	RB	RBPPDB	PPBDA	$ 711,137,998	$ 262,832,063	$ 77,272,944	$ 5,046,371	$ 84,419,063	$ 6,403,082
Production Demand - Inter.	RB	RBPPDI	PPWDA	744,544,987	275,179,073	80,902,980	5,283,434	88,384,800	6,703,879
Production Demand - Peak	RB	RBPPDP	PPSDA	612,781,961	226,480,300	66,585,482	4,348,418	72,743,235	5,517,485
Production Energy - Base	RB	RBPPEB	E01	71,897,457	24,137,273	7,201,221	601,695	8,505,117	656,336
Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		RBPPT		$ 2,140,362,403	$ 788,628,708	$ 231,962,627	$ 15,279,919	$ 254,052,216	$ 19,280,783
Transmission Plant									
Transmission Demand	RB	RBTRB	NCPT	$ 519,102,553	$ 220,794,890	$ 55,898,667	$ 5,396,437	$ 49,280,060	$ 3,875,443
Distribution Poles									
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	RB	RBDSG	NCPP	$ 117,648,309	$ 55,808,479	$ 14,129,039	$ 1,364,012	$ 12,456,109	$ 979,563
Distribution Primary & Secondary Lines									
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	128,492,991	60,952,839	15,431,437	1,489,745	13,604,298	1,069,858
Primary Customer	RB	RBDPLC	Cust08	237,858,860	190,064,449	36,774,297	261,700	1,987,239	76,347
Secondary Demand	RB	RBDSLD	SICD	59,228,567	49,338,570	8,885,629	624,148	-	-
Secondary Customer	RB	RBDSLC	Cust07	90,497,599	73,068,626	14,137,559	100,608	-	-
Total Distribution Primary & Secondary Lines		RBDLT		$ 516,078,017	$ 373,424,484	$ 75,228,921	$ 2,476,201	$ 15,591,537	$ 1,146,206
Distribution Line Transformers									
Demand	RB	RBDLTD	SICDT	$ 91,286,846	$ 63,333,761	$ 11,406,093	$ 801,192	$ 8,955,736	$ -
Customer	RB	RBDLTC	Cust09	81,234,285	64,965,633	12,569,765	89,451	679,255	-
Total Line Transformers		RBDLTT		$ 172,521,131	$ 128,299,393	$ 23,975,857	$ 890,643	$ 9,634,991	$ -
Distribution Services									
Customer	RB	RBDSC	C02	$ 54,380,434	$ 38,137,879	$ 14,938,670	$ 141,476	$ 1,014,950	$ -
Distribution Meters									
Customer	RB	RBDMC	C03	$ 47,701,574	$ 29,644,742	$ 11,048,528	$ 234,357	$ 2,994,699	$ 660,268
Distribution Street & Customer Lighting									
Customer	RB	RBDSCL	C04	$ 64,342,233	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	RB	RBCAE	C05	$ 6,169,535	$ 3,974,831	$ 1,538,127	$ 54,729	$ 207,796	$ 7,983
Customer Service & Info.									
Customer	RB	RBCSI	C05	$ 773,569	$ 498,386	$ 192,859	$ 6,862	$ 26,055	$ 1,001
Sales Expense									
Customer	RB	RBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 3,639,079,759	$ 1,639,211,792	$ 428,913,296	$ 25,844,638	$ 345,258,413	$ 25,951,247

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Net Cost Rate Base										
Power Production Plant										
Production Demand - Base	RB	RBPPDB	PPBDA	$ 61,883,076	$ 144,489,321	$ 49,462,276	$ 19,198,720	$ 94,497	$ 361	$ 36,224
Production Demand - Inter.	RB	RBPPDI	PPWDA	64,790,145	151,276,967	51,785,856	20,100,615	98,936	377	37,925
Production Demand - Peak	RB	RBPPDP	PPSDA	53,324,155	124,505,299	42,621,250	16,543,385	81,427	311	31,214
Production Energy - Base	RB	RBPPEB	E01	6,621,263	15,916,159	5,668,280	2,092,583	489,858	1,770	5,900
Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		RBPPT		$ 186,618,639	$ 436,187,747	$ 149,537,662	$ 57,935,303	$ 764,719	$ 2,819	$ 111,263
Transmission Plant										
Transmission Demand	RB	RBTRB	NCPT	$ 38,088,553	$ 88,246,751	$ 32,296,707	$ 21,354,254	$ 3,829,904	$ 16,042	$ 24,845
Distribution Poles										
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	RB	RBDSG	NCPP	$ 9,627,325	$ 22,305,394	$ -	$ -	$ 968,053	$ 4,055	$ 6,280
Distribution Primary & Secondary Lines										
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	10,514,761	24,361,479	-	-	1,057,287	4,429	6,859
Primary Customer	RB	RBDPLC	Cust08	272,732	122,244	-	-	8,261,604	196	38,051
Secondary Demand	RB	RBDSLD	SICD	-	-	-	-	376,207	1,576	2,438
Secondary Customer	RB	RBDSLC	Cust07	-	-	-	-	3,176,102	75	14,628
Total Distribution Primary & Secondary Lines		RBDLT		$ 10,787,493	$ 24,483,723	$ -	$ -	$ 12,871,199	$ 6,276	$ 61,976
Distribution Line Transformers										
Demand	RB	RBDLTD	SICDT	$ 6,301,993	$ -	$ -	$ -	$ 482,920	$ 2,023	$ 3,129
Customer	RB	RBDLTC	Cust09	93,222	-	-	-	2,823,886	67	13,006
Total Line Transformers		RBDLTT		$ 6,395,215	$ -	$ -	$ -	$ 3,306,806	$ 2,090	$ 16,135
Distribution Services										
Customer	RB	RBDSC	C02	$ 147,459	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	RB	RBDMC	C03	$ 555,375	$ 1,467,034	$ 1,000,534	$ 42,347	$ -	$ 275	$ 53,414
Distribution Street & Customer Lighting										
Customer	RB	RBDSCL	C04	$ -	$ -	$ -	$ -	$ 64,342,233	$ -	$ -
Customer Accounts Expense										
Customer	RB	RBCAE	C05	$ 142,592	$ 63,912	$ 5,538	$ 461	$ 172,771	$ -	$ 794
Customer Service & Info.										
Customer	RB	RBCSI	C05	$ 17,879	$ 8,014	$ 694	$ 58	$ 21,663	$ -	$ 100
Sales Expense										
Customer	RB	RBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 252,380,530	$ 572,762,574	$ 182,841,135	$ 79,332,423	$ 86,277,348	$ 31,557	$ 274,806

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Operation and Maintenance Expenses									
Power Production Plant									
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 37,625,250	$ 13,906,052	$ 4,088,396	$ 266,996	$ 4,466,487	$ 338,778
Production Demand - Inter.	TOM	OMPPDI	PPWDA	35,951,279	13,287,363	3,906,501	255,117	4,267,770	323,705
Production Demand - Peak	TOM	OMPPDP	PPSDA	35,933,656	13,280,850	3,904,586	254,992	4,265,678	323,546
Production Energy - Base	TOM	OMPPEB	E01	640,387,547	214,989,646	64,140,963	5,359,274	75,754,712	5,845,961
Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		OMPPT		$ 749,897,732	$ 255,463,911	$ 76,040,446	$ 6,136,379	$ 88,754,646	$ 6,831,990
					34.1%	10.1%	0.8%	11.8%	0.9%
Transmission Plant									
Transmission Demand	TOM	OMTRB	NCPT	$ 44,026,929	$ 18,726,398	$ 4,740,964	$ 457,691	$ 4,179,617	$ 328,690
Distribution Poles									
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TOM	OMDSG	NCPP	$ 7,427,615	$ 3,523,416	$ 892,024	$ 86,116	$ 786,405	$ 61,844
Distribution Primary & Secondary Lines									
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	13,725,970	6,511,148	1,648,428	159,139	1,453,248	114,285
Primary Customer	TOM	OMDPLC	Cust08	21,967,220	17,553,214	3,396,254	24,169	183,530	7,051
Secondary Demand	TOM	OMDSLD	SICD	6,950,051	5,789,530	1,042,665	73,239	-	-
Secondary Customer	TOM	OMDSLC	Cust07	10,263,921	8,287,188	1,603,432	11,411	-	-
Total Distribution Primary & Secondary Lines		OMDLT		$ 52,907,162	$ 38,141,080	$ 7,690,780	$ 267,958	$ 1,636,778	$ 121,336
Distribution Line Transformers									
Demand	TOM	OMDLTD	SICDT	$ 3,048,697	$ 2,115,151	$ 380,928	$ 26,757	$ 299,094	$ -
Customer	TOM	OMDLTC	Cust09	2,712,973	2,169,651	419,791	2,987	22,685	-
Total Line Transformers		OMDLTT		$ 5,761,670	$ 4,284,802	$ 800,719	$ 29,745	$ 321,779	$ -
Distribution Services									
Customer	TOM	OMDSC	C02	$ 1,785,765	$ 1,252,386	$ 490,562	$ 4,646	$ 33,329	$ -
Distribution Meters									
Customer	TOM	OMDMC	C03	$ 12,338,781	$ 7,668,090	$ 2,857,880	$ 60,620	$ 774,627	$ 170,789
Distribution Street & Customer Lighting									
Customer	TOM	OMDSCL	C04	$ 1,970,659	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TOM	OMCAE	C05	$ 51,233,939	$ 33,008,361	$ 12,773,133	$ 454,492	$ 1,725,612	$ 66,296
Customer Service & Info.									
Customer	TOM	OMCSI	C05	$ 6,423,986	$ 4,138,766	$ 1,601,564	$ 56,987	$ 216,367	$ 8,313
Sales Expense									
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 933,774,239	$ 366,207,210	$ 107,888,071	$ 7,554,633	$ 98,429,159	$ 7,589,257

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Operation and Maintenance Expenses										
Power Production Plant										
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 3,274,141	$ 7,644,714	$ 2,616,975	$ 1,015,776	$ 5,000	$ 19	$ 1,917
Production Demand - Inter.	TOM	OMPPDI	PPWDA	3,128,473	7,304,596	2,500,544	970,583	4,777	18	1,831
Production Demand - Peak	TOM	OMPPDP	PPSDA	3,126,939	7,301,015	2,499,319	970,107	4,775	18	1,830
Production Energy - Base	TOM	OMPPEB	E01	58,975,304	141,764,544	50,487,128	18,638,549	4,363,148	15,765	52,552
Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OMPPT		$ 68,504,857	$ 164,014,870	$ 58,103,966	$ 21,595,016	$ 4,377,700	$ 15,821	$ 58,131
				9.1%	21.9%	7.7%	2.9%			
Transmission Plant										
Transmission Demand	TOM	OMTRB	NCPT	$ 3,230,425	$ 7,484,520	$ 2,739,198	$ 1,811,130	$ 324,828	$ 1,361	$ 2,107
Distribution Poles										
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TOM	OMDSG	NCPP	$ 607,812	$ 1,408,230	$ -	$ -	$ 61,117	$ 256	$ 396
Distribution Primary & Secondary Lines										
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	1,123,215	2,602,359	-	-	112,942	473	733
Primary Customer	TOM	OMDPLC	Cust08	25,188	11,290	-	-	762,992	18	3,514
Secondary Demand	TOM	OMDSLD	SICD	-	-	-	-	44,145	185	286
Secondary Customer	TOM	OMDSLC	Cust07	-	-	-	-	360,222	9	1,659
Total Distribution Primary & Secondary Lines		OMDLT		$ 1,148,403	$ 2,613,649	$ -	$ -	$ 1,280,302	$ 685	$ 6,192
Distribution Line Transformers										
Demand	TOM	OMDLTD	SICDT	$ 210,467	$ -	$ -	$ -	$ 16,128	$ 68	$ 105
Customer	TOM	OMDLTC	Cust09	3,113	-	-	-	94,309	2	434
Total Line Transformers		OMDLTT		$ 213,580	$ -	$ -	$ -	$ 110,437	$ 70	$ 539
Distribution Services										
Customer	TOM	OMDSC	C02	$ 4,842	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TOM	OMDMC	C03	$ 143,657	$ 379,472	$ 258,804	$ 10,954	$ -	$ 71	$ 13,816
Distribution Street & Customer Lighting										
Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ 1,970,659	$ -	$ -
Customer Accounts Expense										
Customer	TOM	OMCAE	C05	$ 1,184,131	$ 530,751	$ 45,986	$ 3,832	$ 1,434,753	$ -	$ 6,591
Customer Service & Info.										
Customer	TOM	OMCSI	C05	$ 148,473	$ 66,548	$ 5,766	$ 480	$ 179,897	$ -	$ 826
Sales Expense										
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 75,186,180	$ 176,498,041	$ 61,153,721	$ 23,421,412	$ 9,739,693	$ 18,263	$ 88,599

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector		3 Total System		4 Residential Rate RS		5 General Service GS		7 All Electric Schools AES		9 Power Service PS-Secondary		10 Power Service PS-Primary
Labor Expenses															
Power Production Plant															
Production Demand - Base	TLB	LBPPDB	PPBDA	$	18,742,668	$	6,927,171	$	2,036,597	$	133,002	$	2,224,939	$	168,759
Production Demand - Inter.	TLB	LBPPDI	PPWDA		17,681,329		6,534,906		1,921,270		125,470		2,098,947		159,203
Production Demand - Peak	TLB	LBPPDP	PPSDA		18,132,162		6,701,531		1,970,258		128,669		2,152,466		163,262
Production Energy - Base	TLB	LBPPEB	E01		38,818,637		13,032,116		3,888,059		324,865		4,592,055		354,367
Production Energy - Inter.	TLB	LBPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	TLB	LBPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		LBPPT		$	93,374,796	$	33,195,724	$	9,816,184	$	712,006	$	11,068,406	$	845,590
Transmission Plant															
Transmission Demand	TLB	LBTRB	NCPT	$	11,565,291	$	4,919,177	$	1,245,389	$	120,229	$	1,097,930	$	86,343
Distribution Poles															
Specific	TLB	LBDPS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	TLB	LBDSG	NCPP	$	4,300,052	$	2,039,803	$	516,417	$	49,855	$	455,271	$	35,803
Distribution Primary & Secondary Lines															
Primary Specific	TLB	LBDPLS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	TLB	LBDPLD	NCPP		4,685,732		2,222,757		562,736		54,326		496,106		39,014
Primary Customer	TLB	LBDPLC	Cust08		8,689,269		6,943,282		1,343,409		9,560		72,596		2,789
Secondary Demand	TLB	LBDSLD	SICD		2,157,106		1,796,912		323,615		22,732		-		-
Secondary Customer	TLB	LBDSLC	Cust07		3,297,506		2,662,438		515,137		3,666		-		-
Total Distribution Primary & Secondary Lines		LBDLT		$	18,829,614	$	13,625,389	$	2,744,897	$	90,284	$	568,702	$	41,803
Distribution Line Transformers															
Demand	TLB	LBDLTD	SICDT	$	3,348,579	$	2,323,205	$	418,398	$	29,389	$	328,514	$	-
Customer	TLB	LBDLTC	Cust09		2,979,831		2,383,066		461,083		3,281		24,916		-
Total Line Transformers		LBDLTT		$	6,328,410	$	4,706,271	$	879,481	$	32,671	$	353,430	$	-
Distribution Services															
Customer	TLB	LBDSC	C02	$	1,994,915	$	1,399,066	$	548,016	$	5,190	$	37,233	$	-
Distribution Meters															
Customer	TLB	LBDMC	C03	$	1,702,129	$	1,057,809	$	394,243	$	8,363	$	106,859	$	23,560
Distribution Street & Customer Lighting															
Customer	TLB	LBDSCL	C04	$	2,360,988	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	TLB	LBCAE	C05	$	27,271,497	$	17,570,139	$	6,799,057	$	241,923	$	918,532	$	35,289
Customer Service & Info.															
Customer	TLB	LBCSI	C05	$	3,748,877	$	2,415,280	$	934,633	$	33,256	$	126,266	$	4,851
Sales Expense															
Customer	TLB	LBSEC	C06	$	-	$	-	$	-	$	-	$	-	$	-
Total		LBT		$	171,476,569	$	80,928,658	$	23,878,317	$	1,293,776	$	14,732,631	$	1,073,240

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Labor Expenses										
Power Production Plant										
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 1,630,983	$ 3,808,143	$ 1,303,622	$ 505,999	$ 2,491	$ 10	$ 955
Production Demand - Inter.	TLB	LBPPDI	PPWDA	1,538,625	3,592,500	1,229,802	477,346	2,350	9	901
Production Demand - Peak	TLB	LBPPDP	PPSDA	1,577,857	3,684,100	1,261,159	489,517	2,409	9	924
Production Energy - Base	TLB	LBPPEB	E01	3,574,930	8,593,400	3,060,399	1,129,821	264,483	956	3,186
Production Energy - Inter.	TLB	LBPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TLB	LBPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		LBPPT		$ 8,322,396	$ 19,678,144	$ 6,854,982	$ 2,602,683	$ 271,732	$ 983	$ 5,965
Transmission Plant										
Transmission Demand	TLB	LBTRB	NCPT	$ 848,590	$ 1,966,084	$ 719,551	$ 475,760	$ 85,328	$ 357	$ 554
Distribution Poles										
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TLB	LBDSG	NCPP	$ 351,879	$ 815,263	$ -	$ -	$ 35,382	$ 148	$ 230
Distribution Primary & Secondary Lines										
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	383,440	888,386	-	-	38,556	161	250
Primary Customer	TLB	LBDPLC	Cust08	9,963	4,466	-	-	301,806	7	1,390
Secondary Demand	TLB	LBDSLD	SICD	-	-	-	-	13,701	57	89
Secondary Customer	TLB	LBDSLC	Cust07	-	-	-	-	115,729	3	533
Total Distribution Primary & Secondary Lines		LBDLT		$ 393,403	$ 892,852	$ -	$ -	$ 469,793	$ 229	$ 2,262
Distribution Line Transformers										
Demand	TLB	LBDLTD	SICDT	$ 231,169	$ -	$ -	$ -	$ 17,714	$ 74	$ 115
Customer	TLB	LBDLTC	Cust09	3,420	-	-	-	103,586	2	477
Total Line Transformers		LBDLTT		$ 234,589	$ -	$ -	$ -	$ 121,300	$ 77	$ 592
Distribution Services										
Customer	TLB	LBDSC	C02	$ 5,409	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TLB	LBDMC	C03	$ 19,817	$ 52,348	$ 35,702	$ 1,511	$ -	$ 10	$ 1,906
Distribution Street & Customer Lighting										
Customer	TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ 2,360,988	$ -	$ -
Customer Accounts Expense										
Customer	TLB	LBCAE	C05	$ 630,305	$ 282,516	$ 24,478	$ 2,040	$ 763,710	$ -	$ 3,508
Customer Service & Info.										
Customer	TLB	LBCSI	C05	$ 86,645	$ 38,836	$ 3,365	$ 280	$ 104,983	$ -	$ 482
Sales Expense										
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 10,893,034	$ 23,726,042	$ 7,638,077	$ 3,082,274	$ 4,213,217	$ 1,804	$ 15,498

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	Total	Residential	General Service	All Electric Schools	Power Service	Power Service
Description	Ref	Name	Vector	System	Rate RS	GS	AES	PS-Secondary	PS-Primary
Depreciation Expenses									
Power Production Plant									
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 52,845,706	$ 19,531,436	$ 5,742,266	$ 375,003	$ 6,273,304	$ 475,822
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	55,359,222	20,460,415	6,015,387	392,840	6,571,683	498,454
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	45,505,094	16,818,392	4,944,628	322,913	5,401,901	409,728
Production Energy - Base	TDEPR	DEPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TDEPR	DEPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TDEPR	DEPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		DEPPT		$ 153,710,022	$ 56,810,243	$ 16,702,280	$ 1,090,756	$ 18,246,889	$ 1,384,004
Transmission Plant									
Transmission Demand	TDEPR	DETRB	NCPT	$ 24,058,002	$ 10,232,822	$ 2,590,645	$ 250,100	$ 2,283,903	$ 179,609
Distribution Poles									
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TDEPR	DEDSG	NCPP	$ 6,089,359	$ 2,888,591	$ 731,305	$ 70,600	$ 644,716	$ 50,701
Distribution Primary & Secondary Lines									
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	6,635,525	3,147,674	796,897	76,932	702,542	55,249
Primary Customer	TDEPR	DEDPLC	Cust08	12,304,984	9,832,470	1,902,419	13,538	102,804	3,950
Secondary Demand	TDEPR	DEDSLD	SICD	3,054,706	2,544,630	458,275	32,190	-	-
Secondary Customer	TDEPR	DEDSLC	Cust07	4,669,641	3,770,312	729,492	5,191	-	-
Total Distribution Primary & Secondary Lines		DEDLT		$ 26,664,856	$ 19,295,087	$ 3,887,083	$ 127,852	$ 805,346	$ 59,198
Distribution Line Transformers									
Demand	TDEPR	DEDLTD	SICDT	$ 4,741,965	$ 3,289,921	$ 592,498	$ 41,619	$ 465,213	$ -
Customer	TDEPR	DEDLTC	Cust09	4,219,777	3,374,689	652,946	4,647	35,284	-
Total Line Transformers		DEDLTT		$ 8,961,742	$ 6,664,610	$ 1,245,444	$ 46,265	$ 500,497	$ -
Distribution Services									
Customer	TDEPR	DEDSC	C02	$ 2,825,024	$ 1,981,235	$ 776,053	$ 7,350	$ 52,726	$ -
Distribution Meters									
Customer	TDEPR	DEDMC	C03	$ 2,410,406	$ 1,497,977	$ 558,293	$ 11,842	$ 151,325	$ 33,364
Distribution Street & Customer Lighting									
Customer	TDEPR	DEDSCL	C04	$ 3,343,426	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 228,062,837	$ 99,370,565	$ 26,491,103	$ 1,604,765	$ 22,685,401	$ 1,706,877

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Depreciation Expenses										
Power Production Plant										
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 4,598,622	$ 10,737,213	$ 3,675,614	$ 1,426,685	$ 7,022	$ 27	$ 2,692
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	4,817,348	11,247,910	3,850,439	1,494,543	7,356	28	2,820
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	3,959,844	9,245,744	3,165,047	1,228,509	6,047	23	2,318
Production Energy - Base	TDEPR	DEPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TDEPR	DEPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TDEPR	DEPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		DEPPT		$ 13,375,813	$ 31,230,868	$ 10,691,100	$ 4,149,737	$ 20,425	$ 78	$ 7,830
Transmission Plant										
Transmission Demand	TDEPR	DETRB	NCPT	$ 1,765,228	$ 4,089,829	$ 1,496,803	$ 989,671	$ 177,498	$ 743	$ 1,151
Distribution Poles										
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TDEPR	DEDSG	NCPP	$ 498,301	$ 1,154,505	$ -	$ -	$ 50,105	$ 210	$ 325
Distribution Primary & Secondary Lines										
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	542,994	1,258,055	-	-	54,600	229	354
Primary Customer	TDEPR	DEDPLC	Cust08	14,109	6,324	-	-	427,392	10	1,968
Secondary Demand	TDEPR	DEDSLD	SICD	-	-	-	-	19,403	81	126
Secondary Customer	TDEPR	DEDSLC	Cust07	-	-	-	-	163,886	4	755
Total Distribution Primary & Secondary Lines		DEDLT		$ 557,103	$ 1,264,379	$ -	$ -	$ 665,280	$ 324	$ 3,203
Distribution Line Transformers										
Demand	TDEPR	DEDLTD	SICDT	$ 327,362	$ -	$ -	$ -	$ 25,086	$ 105	$ 163
Customer	TDEPR	DEDLTC	Cust09	4,842	-	-	-	146,689	3	676
Total Line Transformers		DEDLTT		$ 332,204	$ -	$ -	$ -	$ 171,775	$ 109	$ 838
Distribution Services										
Customer	TDEPR	DEDSC	C02	$ 7,660	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TDEPR	DEDMC	C03	$ 28,064	$ 74,131	$ 50,558	$ 2,140	$ -	$ 14	$ 2,699
Distribution Street & Customer Lighting										
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ 3,343,426	$ -	$ -
Customer Accounts Expense										
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 16,564,374	$ 37,813,710	$ 12,238,461	$ 5,141,548	$ 4,428,509	$ 1,478	$ 16,047

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Accretion Expenses									
Power Production Plant									
Production Demand - Base	TACRT	ACPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	-	-	-	-	-	-
Production Demand - Peak	TACRT	ACPPDP	PPSDA	-	-	-	-	-	-
Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
Transmission Demand	TACRT	ACTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles									
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TACRT	ACDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines									
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	-	-	-	-	-	-
Primary Customer	TACRT	ACDPLC	Cust08	-	-	-	-	-	-
Secondary Demand	TACRT	ACDSLD	SICD	-	-	-	-	-	-
Secondary Customer	TACRT	ACDSLC	Cust07	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers									
Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust09	-	-	-	-	-	-
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services									
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters									
Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting									
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Accretion Expenses										
Power Production Plant										
Production Demand - Base	TACRT	ACPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	-	-	-	-	-	-	-
Production Demand - Peak	TACRT	ACPPDP	PPSDA	-	-	-	-	-	-	-
Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	TACRT	ACTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	TACRT	ACDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TACRT	ACDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	TACRT	ACDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	TACRT	ACDPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	TACRT	ACDSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	TACRT	ACDSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	TACRT	ACDLTC	Cust09	-	-	-	-	-	-	-
Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

LOLP Methodology

Description	Ref	Name (1)	Allocation Vector (2)	Total System (3)	Residential Rate RS (4)	General Service GS (5)	All Electric Schools AES (7)	Power Service PS-Secondary (9)	Power Service PS-Primary (10)
Property Taxes									
Power Production Plant									
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 5,182,784	$ 1,915,524	$ 563,166	$ 36,778	$ 615,247	$ 46,666
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	5,429,295	2,006,633	589,952	38,527	644,511	48,885
Production Demand - Peak	PTAX	PTPPDP	PPSDA	4,462,862	1,649,445	484,939	31,669	529,786	40,184
Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 15,074,941	$ 5,571,602	$ 1,638,058	$ 106,975	$ 1,789,544	$ 135,735
Transmission Plant									
Transmission Demand	PTAX	PTTRB	NCPT	$ 3,342,932	$ 1,421,881	$ 359,978	$ 34,752	$ 317,355	$ 24,957
Distribution Poles									
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	PTAX	PTDSG	NCPP	$ 784,098	$ 371,950	$ 94,167	$ 9,091	$ 83,017	$ 6,529
Distribution Primary & Secondary Lines									
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	854,426	405,311	102,613	9,906	90,463	7,114
Primary Customer	PTAX	PTDPLC	Cust08	1,584,455	1,266,081	244,966	1,743	13,238	509
Secondary Demand	PTAX	PTDSLD	SICD	393,340	327,660	59,010	4,145	-	-
Secondary Customer	PTAX	PTDSLC	Cust07	601,288	485,486	93,933	668	-	-
Total Distribution Primary & Secondary Lines		PTDLT		$ 3,433,509	$ 2,484,538	$ 500,522	$ 16,463	$ 103,701	$ 7,623
Distribution Line Transformers									
Demand	PTAX	PTDLTD	SICDT	$ 610,601	$ 423,628	$ 76,293	$ 5,359	$ 59,903	$ -
Customer	PTAX	PTDLTC	Cust09	543,361	434,543	84,077	598	4,543	-
Total Line Transformers		PTDLTT		$ 1,153,962	$ 858,171	$ 160,370	$ 5,957	$ 64,447	$ -
Distribution Services									
Customer	PTAX	PTDSC	C02	$ 363,765	$ 255,114	$ 99,929	$ 946	$ 6,789	$ -
Distribution Meters									
Customer	PTAX	PTDMC	C03	$ 310,377	$ 192,888	$ 71,889	$ 1,525	$ 19,485	$ 4,296
Distribution Street & Customer Lighting									
Customer	PTAX	PTDSCL	C04	$ 430,517	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 24,894,101	$ 11,156,145	$ 2,924,911	$ 175,709	$ 2,384,338	$ 179,139

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Property Taxes										
Power Production Plant										
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 451,005	$ 1,053,040	$ 360,482	$ 139,921	$ 689	$ 3	$ 264
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	472,456	1,103,126	377,628	146,576	721	3	277
Production Demand - Peak	PTAX	PTPPDP	PPSDA	388,357	906,766	310,409	120,485	593	2	227
Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 1,311,818	$ 3,062,933	$ 1,048,518	$ 406,981	$ 2,003	$ 8	$ 768
Transmission Plant										
Transmission Demand	PTAX	PTTRB	NCPT	$ 245,284	$ 568,294	$ 207,985	$ 137,518	$ 24,664	$ 103	$ 160
Distribution Poles										
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	PTAX	PTDSG	NCPP	$ 64,164	$ 148,660	$ -	$ -	$ 6,452	$ 27	$ 42
Distribution Primary & Secondary Lines										
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	69,919	161,994	-	-	7,031	29	46
Primary Customer	PTAX	PTDPLC	Cust08	1,817	814	-	-	55,033	1	253
Secondary Demand	PTAX	PTDSLD	SICD	-	-	-	-	2,498	10	16
Secondary Customer	PTAX	PTDSLC	Cust07	-	-	-	-	21,103	1	97
Total Distribution Primary & Secondary Lines		PTDLT		$ 71,736	$ 162,808	$ -	$ -	$ 85,665	$ 42	$ 412
Distribution Line Transformers										
Demand	PTAX	PTDLTD	SICDT	$ 42,153	$ -	$ -	$ -	$ 3,230	$ 14	$ 21
Customer	PTAX	PTDLTC	Cust09	624	-	-	-	18,888	0	87
Total Line Transformers		PTDLTT		$ 42,776	$ -	$ -	$ -	$ 22,119	$ 14	$ 108
Distribution Services										
Customer	PTAX	PTDSC	C02	$ 986	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	PTAX	PTDMC	C03	$ 3,614	$ 9,545	$ 6,510	$ 276	$ -	$ 2	$ 348
Distribution Street & Customer Lighting										
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ 430,517	$ -	$ -
Customer Accounts Expense										
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 1,740,378	$ 3,952,241	$ 1,263,013	$ 544,774	$ 571,420	$ 195	$ 1,838

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector		3 Total System		4 Residential Rate RS		5 General Service GS		7 All Electric Schools AES		9 Power Service PS-Secondary		10 Power Service PS-Primary
Other Taxes															
Power Production Plant															
Production Demand - Base	OTAX	OTPPDB	PPBDA	$	2,691,268	$	994,675	$	292,436	$	19,098	$	319,480	$	24,232
Production Demand - Inter.	OTAX	OTPPDI	PPWDA		2,819,273		1,041,985		306,345		20,006		334,675		25,385
Production Demand - Peak	OTAX	OTPPDP	PPSDA		2,317,433		856,508		251,815		16,445		275,102		20,866
Production Energy - Base	OTAX	OTPPEB	E01		-		-		-		-		-		-
Production Energy - Inter.	OTAX	OTPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	OTAX	OTPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		OTPPT		$	7,827,974	$	2,893,169	$	850,595	$	55,549	$	929,257	$	70,483
Transmission Plant															
Transmission Demand	OTAX	OTTRB	NCPT	$	1,735,886	$	738,341	$	186,926	$	18,046	$	164,793	$	12,960
Distribution Poles															
Specific	OTAX	OTDPS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	OTAX	OTDSG	NCPP	$	407,159	$	193,143	$	48,898	$	4,721	$	43,108	$	3,390
Distribution Primary & Secondary Lines															
Primary Specific	OTAX	OTDPLS	NCPP	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	OTAX	OTDPLD	NCPP		443,678		210,466		53,284		5,144		46,975		3,694
Primary Customer	OTAX	OTDPLC	Cust08		822,761		657,439		127,203		905		6,874		264
Secondary Demand	OTAX	OTDSLD	SICD		204,250		170,144		30,642		2,152		-		-
Secondary Customer	OTAX	OTDSLC	Cust07		312,231		252,098		48,777		347		-		-
Total Distribution Primary & Secondary Lines		OTDLT		$	1,782,920	$	1,290,148	$	259,906	$	8,549	$	53,849	$	3,958
Distribution Line Transformers															
Demand	OTAX	OTDLTD	SICDT	$	317,067	$	219,977	$	39,617	$	2,783	$	31,106	$	-
Customer	OTAX	OTDLTC	Cust09		282,151		225,645		43,659		311		2,359		-
Total Line Transformers		OTDLTT		$	599,218	$	445,623	$	83,275	$	3,093	$	33,465	$	-
Distribution Services															
Customer	OTAX	OTDSC	C02	$	188,893	$	132,473	$	51,890	$	491	$	3,525	$	-
Distribution Meters															
Customer	OTAX	OTDMC	C03	$	161,170	$	100,161	$	37,330	$	792	$	10,118	$	2,231
Distribution Street & Customer Lighting															
Customer	OTAX	OTDSCL	C04	$	223,555	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	OTAX	OTCAE	C05	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service & Info.															
Customer	OTAX	OTCSI	C05	$	-	$	-	$	-	$	-	$	-	$	-
Sales Expense															
Customer	OTAX	OTSEC	C06	$	-	$	-	$	-	$	-	$	-	$	-
Total		OTT		$	12,926,774	$	5,793,058	$	1,518,820	$	91,241	$	1,238,116	$	93,022

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Other Taxes										
Power Production Plant										
Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 234,194	$ 546,813	$ 187,188	$ 72,657	$ 358	$ 1	$ 137
Production Demand - Inter.	OTAX	OTPPDI	PPWDA	245,333	572,821	196,091	76,112	375	1	144
Production Demand - Peak	OTAX	OTPPDP	PPSDA	201,663	470,857	161,186	62,564	308	1	118
Production Energy - Base	OTAX	OTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	OTAX	OTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	OTAX	OTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ 681,189	$ 1,590,491	$ 544,464	$ 211,333	$ 1,040	$ 4	$ 399
Transmission Plant										
Transmission Demand	OTAX	OTTRB	NCPT	$ 127,369	$ 295,098	$ 108,001	$ 71,409	$ 12,807	$ 54	$ 83
Distribution Poles										
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	OTAX	OTDSG	NCPP	$ 33,318	$ 77,195	$ -	$ -	$ 3,350	$ 14	$ 22
Distribution Primary & Secondary Lines										
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	36,307	84,119	-	-	3,651	15	24
Primary Customer	OTAX	OTDPLC	Cust08	943	423	-	-	28,577	1	132
Secondary Demand	OTAX	OTDSLD	SICD	-	-	-	-	1,297	5	8
Secondary Customer	OTAX	OTDSLC	Cust07	-	-	-	-	10,958	0	50
Total Distribution Primary & Secondary Lines		OTDLT		$ 37,250	$ 84,541	$ -	$ -	$ 44,483	$ 22	$ 214
Distribution Line Transformers										
Demand	OTAX	OTDLTD	SICDT	$ 21,889	$ -	$ -	$ -	$ 1,677	$ 7	$ 11
Customer	OTAX	OTDLTC	Cust09	324	-	-	-	9,808	0	45
Total Line Transformers		OTDLTT		$ 22,213	$ -	$ -	$ -	$ 11,486	$ 7	$ 56
Distribution Services										
Customer	OTAX	OTDSC	C02	$ 512	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	OTAX	OTDMC	C03	$ 1,876	$ 4,957	$ 3,381	$ 143	$ -	$ 1	$ 180
Distribution Street & Customer Lighting										
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ 223,555	$ -	$ -
Customer Accounts Expense										
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 903,727	$ 2,052,282	$ 655,846	$ 282,885	$ 296,721	$ 102	$ 954

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Gain Disposition of Allowances									
Power Production Plant									
Production Demand - Base	GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	-	-	-	-	-	-
Production Demand - Peak	GAIN	OTPPDP	PPSDA	-	-	-	-	-	-
Production Energy - Base	GAIN	OTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	GAIN	OTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	GAIN	OTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
Transmission Demand	GAIN	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles									
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines									
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	-	-	-	-	-	-
Primary Customer	GAIN	OTDPLC	Cust08	-	-	-	-	-	-
Secondary Demand	GAIN	OTDSLD	SICD	-	-	-	-	-	-
Secondary Customer	GAIN	OTDSLC	Cust07	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers									
Demand	GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust09	-	-	-	-	-	-
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services									
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters									
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting									
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	Time of Day	Time of Day	Service	Service	Outdoor Lighting	Lighting Energy	Traffic Energy
Description	Ref	Name	Vector	TOD-Secondary	TOD-Primary	RTS	FLS - Transmission	ST & POL	LE	TE
Gain Disposition of Allowances										
Power Production Plant										
Production Demand - Base	GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	-	-	-	-	-	-	-
Production Demand - Peak	GAIN	OTPPDP	PPSDA	-	-	-	-	-	-	-
Production Energy - Base	GAIN	OTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	GAIN	OTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	GAIN	OTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant										
Transmission Demand	GAIN	OTTRB	NCPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	GAIN	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	GAIN	OTDSG	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	GAIN	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPP	-	-	-	-	-	-	-
Primary Customer	GAIN	OTDPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	GAIN	OTDSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	GAIN	OTDSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust09	-	-	-	-	-	-	-
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Interest									
Power Production Plant									
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 17,924,442	$ 6,624,759	$ 1,947,687	$ 127,195	$ 2,127,807	$ 161,392
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	18,776,988	6,939,855	2,040,326	133,245	2,229,013	169,068
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	15,434,620	5,704,537	1,677,141	109,527	1,832,241	138,973
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 52,136,050	$ 19,269,151	$ 5,665,154	$ 369,967	$ 6,189,061	$ 469,433
Transmission Plant									
Transmission Demand	INTLTD	INTTRB	NCPT	$ 11,561,389	$ 4,917,517	$ 1,244,968	$ 120,189	$ 1,097,559	$ 86,313
Distribution Poles									
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	INTLTD	INTDSG	NCPP	$ 2,711,771	$ 1,286,375	$ 325,672	$ 31,440	$ 287,111	$ 22,579
Distribution Primary & Secondary Lines									
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	2,954,995	1,401,752	354,882	34,260	312,862	24,604
Primary Customer	INTLTD	INTDPLC	Cust08	5,479,772	4,378,688	847,203	6,029	45,782	1,759
Secondary Demand	INTLTD	INTDSLD	SICD	1,360,350	1,133,199	204,083	14,335	-	-
Secondary Customer	INTLTD	INTDSLC	Cust07	2,079,529	1,679,031	324,864	2,312	-	-
Total Distribution Primary & Secondary Lines		INTDLT		$ 11,874,646	$ 8,592,671	$ 1,731,033	$ 56,936	$ 358,644	$ 26,363
Distribution Line Transformers									
Demand	INTLTD	INTDLTD	SICDT	$ 2,111,737	$ 1,465,099	$ 263,857	$ 18,534	$ 207,173	$ -
Customer	INTLTD	INTDLTC	Cust09	1,879,191	1,502,849	290,776	2,069	15,713	-
Total Line Transformers		INTDLTT		$ 3,990,928	$ 2,967,947	$ 554,633	$ 20,603	$ 222,886	$ -
Distribution Services									
Customer	INTLTD	INTDSC	C02	$ 1,258,066	$ 882,302	$ 345,599	$ 3,273	$ 23,480	$ -
Distribution Meters									
Customer	INTLTD	INTDMC	C03	$ 1,073,425	$ 667,093	$ 248,624	$ 5,274	$ 67,389	$ 14,858
Distribution Street & Customer Lighting									
Customer	INTLTD	INTDSCL	C04	$ 1,488,926	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 86,095,200	$ 38,583,056	$ 10,115,683	$ 607,683	$ 8,246,132	$ 619,546

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Interest										
Power Production Plant										
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 1,559,781	$ 3,641,896	$ 1,246,711	$ 483,909	$ 2,382	$ 9	$ 913
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	1,633,969	3,815,116	1,306,009	506,926	2,495	10	956
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	1,343,117	3,136,013	1,073,535	416,691	2,051	8	786
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 4,536,868	$ 10,593,025	$ 3,626,255	$ 1,407,526	$ 6,928	$ 26	$ 2,656
Transmission Plant										
Transmission Demand	INTLTD	INTTRB	NCPT	$ 848,304	$ 1,965,421	$ 719,308	$ 475,599	$ 85,299	$ 357	$ 553
Distribution Poles										
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	INTLTD	INTDSG	NCPP	$ 221,908	$ 514,135	$ -	$ -	$ 22,313	$ 93	$ 145
Distribution Primary & Secondary Lines										
Primary Specific	INTLTD	INTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPP	241,811	560,249	-	-	24,315	102	158
Primary Customer	INTLTD	INTDPLC	Cust08	6,283	2,816	-	-	190,330	5	877
Secondary Demand	INTLTD	INTDSLD	SICD	-	-	-	-	8,641	36	56
Secondary Customer	INTLTD	INTDSLC	Cust07	-	-	-	-	72,983	2	336
Total Distribution Primary & Secondary Lines		INTDLT		$ 248,095	$ 563,065	$ -	$ -	$ 296,269	$ 144	$ 1,426
Distribution Line Transformers										
Demand	INTLTD	INTDLTD	SICDT	$ 145,784	$ -	$ -	$ -	$ 11,171	$ 47	$ 72
Customer	INTLTD	INTDLTC	Cust09	2,157	-	-	-	65,325	2	301
Total Line Transformers		INTDLTT		$ 147,940	$ -	$ -	$ -	$ 76,496	$ 48	$ 373
Distribution Services										
Customer	INTLTD	INTDSC	C02	$ 3,411	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	INTLTD	INTDMC	C03	$ 12,498	$ 33,013	$ 22,515	$ 953	$ -	$ 6	$ 1,202
Distribution Street & Customer Lighting										
Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ -	$ -	$ 1,488,926	$ -	$ -
Customer Accounts Expense										
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 6,019,023	$ 13,668,658	$ 4,368,078	$ 1,884,079	$ 1,976,231	$ 676	$ 6,355

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Cost of Service Summary -- Unadjusted									
Operating Revenues									
Sales		REVUC	R01	$ 1,464,489,053	$ 554,543,189	$ 198,233,994	$ 12,037,991	$ 174,459,441	$ 13,950,651
Intercompany Sales		SFRS	E01	8,422,903	2,827,720	843,635	70,490	996,388	76,891
Curtailable Service Rider			INTCRE	(17,395,776)	(6,429,368)	(1,890,242)	(123,444)	(2,065,049)	(156,631)
LATE PAYMENT CHARGES			LPAY	3,857,505	3,012,898	568,302	3,750	98,651	5,535
OTHER SERVICE CHARGES			MISCSERV	2,108,282	1,967,237	136,875	853	1,335	51
RENT FROM ELEC PROPERTY			RBT	3,142,645	1,415,594	370,402	22,319	298,159	22,411
OTHER MISC REVENUES			MISCSERV	22,338,060	20,843,640	1,450,249	9,036	14,148	542
Total Operating Revenues		TOR		$ 1,486,962,672	$ 578,180,912	$ 199,713,215	$ 12,020,995	$ 173,803,074	$ 13,899,449
Operating Expenses									
Operation and Maintenance Expenses				$ 933,774,239	$ 366,207,210	$ 107,888,071	$ 7,554,633	$ 98,429,159	$ 7,589,257
Depreciation and Amortization Expenses				228,062,837	99,370,565	26,491,103	1,604,765	22,685,401	1,706,877
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	24,894,101	11,156,145	2,924,911	175,709	2,384,338	179,139
Other Taxes				12,926,774	5,793,058	1,518,820	91,241	1,238,116	93,022
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	84,161,734	$ 23,871,555	$ 21,237,964	$ 831,106	$ 17,074,122	$ 1,552,488
Total Operating Expenses		TOE		$ 1,283,819,685	$ 506,398,532	$ 160,060,870	$ 10,257,453	$ 141,811,137	$ 11,120,783
Net Operating Income (Unadjusted)		TOM		$ 203,142,987	$ 71,782,380	$ 39,652,345	$ 1,763,542	$ 31,991,937	$ 2,778,666
Net Cost Rate Base				$ 3,639,079,759	$ 1,639,211,792	$ 428,913,296	$ 25,844,638	$ 345,258,413	$ 25,951,247

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Cost of Service Summary -- Unadjusted										
Operating Revenues										
Sales		REVUC	R01	$ 116,879,945	$ 251,561,897	$ 86,711,460	$ 29,892,107	$ 26,032,396	$ 29,470	$ 156,512
Intercompany Sales		SFRS	E01	775,692	1,864,604	664,048	245,150	57,388	207	691
Curtailable Service Rider			INTCRE	(1,513,777)	(3,534,481)	(1,209,941)	(469,637)	(2,312)	(9)	(886)
LATE PAYMENT CHARGES			LPAY	41,764	107,885	18,686	-	33	-	-
OTHER SERVICE CHARGES			MISCSERV	982	439	48	-	461	-	-
RENT FROM ELEC PROPERTY			RBT	217,951	494,628	157,898	68,510	74,508	27	237
OTHER MISC REVENUES			MISCSERV	10,403	4,653	505	-	4,883	-	-
Total Operating Revenues		TOR		$ 116,412,961	$ 250,499,625	$ 86,342,704	$ 29,736,130	$ 26,167,357	$ 29,696	$ 156,554
Operating Expenses										
Operation and Maintenance Expenses				$ 75,186,180	$ 176,498,041	$ 61,153,721	$ 23,421,412	$ 9,739,693	$ 18,263	$ 88,599
Depreciation and Amortization Expenses				16,564,374	37,813,710	12,238,461	5,141,548	4,428,509	1,478	16,047
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,740,378	3,952,241	1,263,013	544,774	571,420	195	1,838
Other Taxes				903,727	2,052,282	655,846	282,885	296,721	102	954
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 6,692,163	$ 6,907,750	$ 2,787,239	$ (643,551)	$ 3,829,254	$ 3,757	$ 17,886
Total Operating Expenses		TOE		$ 101,086,823	$ 227,224,025	$ 78,098,279	$ 28,747,068	$ 18,865,597	$ 23,795	$ 125,324
Net Operating Income (Unadjusted)		TOM		$ 15,326,138	$ 23,275,600	$ 8,244,425	$ 989,061	$ 7,301,760	$ 5,901	$ 31,231
Net Cost Rate Base				$ 252,380,530	$ 572,762,574	$ 182,841,135	$ 79,332,423	$ 86,277,348	$ 31,557	$ 274,806

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Taxable Income Unadjusted									
Total Operating Revenue				$ 1,486,962,672	$ 578,180,912	$ 199,713,215	$ 12,020,995	$ 173,803,074	$ 13,899,449
Operating Expenses				$ 1,199,657,950	$ 482,526,977	$ 138,822,906	$ 9,426,347	$ 124,737,015	$ 9,568,295
Interest Expense		INTEXP		$ 86,095,200	$ 38,583,056	$ 10,115,683	$ 607,683	$ 8,246,132	$ 619,546
Taxable Income		TAXINC		$ 201,209,521	$ 57,070,879	$ 50,774,626	$ 1,986,965	$ 40,819,927	$ 3,711,609

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Taxable Income Unadjusted										
Total Operating Revenue				$ 116,412,961	$ 250,499,625	$ 86,342,704	$ 29,736,130	$ 26,167,357	$ 29,696	$ 156,554
Operating Expenses				$ 94,394,659	$ 220,316,274	$ 75,311,041	$ 29,390,619	$ 15,036,342	$ 20,038	$ 107,438
Interest Expense		INTEXP		$ 6,019,023	$ 13,668,658	$ 4,368,078	$ 1,884,079	$ 1,976,231	$ 676	$ 6,355
Taxable Income		TAXINC		$ 15,999,278	$ 16,514,692	$ 6,663,586	$ (1,538,568)	$ 9,154,783	$ 8,982	$ 42,761

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 1,486,962,672	$ 578,180,912	$ 199,713,215	$ 12,020,995	$ 173,803,074	$ 13,899,449
Pro-Forma Adjustments:									
Adj to eliminate Off System ECR revenues			ECRREV	(1,635,232)	$ (609,965)	$ (368,766)	$ (23,373)	$ (168,730)	$ (13,653)
Total Pro-Forma Operating Revenue				$ 1,485,327,440	$ 577,570,946	$ 199,344,450	$ 11,997,623	$ 173,634,344	$ 13,885,796

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 116,412,961	$ 250,499,625	$ 86,342,704	$ 29,736,130	$ 26,167,357	$ 29,696	$ 156,554
Pro-Forma Adjustments:										
Adj to eliminate Off System ECR revenues			ECRREV	$ (105,682)	$ (210,279)	$ (68,614)	$ (23,719)	$ (42,194)	$ (66)	$ (192)
Total Pro-Forma Operating Revenue				$ 116,307,279	$ 250,289,346	$ 86,274,090	$ 29,712,411	$ 26,125,163	$ 29,630	$ 156,362

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Operating Expenses									
Operation and Maintenance Expenses				$ 933,774,239	$ 366,207,210	$ 107,888,071	$ 7,554,633	$ 98,429,159	$ 7,589,257
Depreciation and Amortization Expenses				228,062,837	99,370,565	26,491,103	1,604,765	22,685,401	1,706,877
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
Property Taxes			NPT	24,894,101	11,156,145	2,924,911	175,709	2,384,338	179,139
Other Taxes				12,926,774	5,793,058	1,518,820	91,241	1,238,116	93,022
Gain Disposition of Allowances				-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	84,161,734	$ 23,871,555	$ 21,237,964	$ 831,106	$ 17,074,122	$ 1,552,488
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ -	$ -	$ -	$ -	$ -	$ -
Adjustments to Operating Expenses:									
Eliminate advertising expenses			REVUC	(838,116)	(317,361)	(113,448)	(6,889)	(99,842)	(7,984)
Federal & State Income Tax Adjustment			TAXINC	(164,668)	(46,706)	(41,553)	(1,626)	(33,407)	(3,038)
Total Expense Adjustments				$ (1,002,784)	$ (364,067)	$ (155,001)	$ (8,515)	$ (133,248)	$ (11,021)
Total Operating Expenses		TOE		$ 1,282,816,901	$ 506,034,464	$ 159,905,869	$ 10,248,938	$ 141,677,888	$ 11,109,762
Net Operating Income (Adjusted)				$ 202,510,539	$ 71,536,482	$ 39,438,581	$ 1,748,685	$ 31,956,456	$ 2,776,034
Net Cost Rate Base				$ 3,639,079,759	$ 1,639,211,792	$ 428,913,296	$ 25,844,638	$ 345,258,413	$ 25,951,247
Rate of Return				**5.56%**	**4.36%**	**9.20%**	**6.77%**	**9.26%**	**10.70%**

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Operating Expenses										
Operation and Maintenance Expenses				$ 75,186,180	$ 176,498,041	$ 61,153,721	$ 23,421,412	$ 9,739,693	$ 18,263	$ 88,599
Depreciation and Amortization Expenses				16,564,374	37,813,710	12,238,461	5,141,548	4,428,509	1,478	16,047
Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
Property Taxes			NPT	1,740,378	3,952,241	1,263,013	544,774	571,420	195	1,838
Other Taxes				903,727	2,052,282	655,846	282,885	296,721	102	954
Gain Disposition of Allowances				-	-	-	-	-	-	-
State and Federal Income Taxes			TAXINC	$ 6,692,163	$ 6,907,750	$ 2,787,239	$ (643,551)	$ 3,829,254	$ 3,757	$ 17,886
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustments to Operating Expenses:										
Eliminate advertising expenses			REVUC	(66,890)	(143,967)	(49,624)	(17,107)	(14,898)	(17)	(90)
Federal & State Income Tax Adjustment			TAXINC	(13,094)	(13,515)	(5,453)	1,259	(7,492)	(7)	(35)
Total Expense Adjustments				$ (79,983)	$ (157,482)	$ (55,078)	$ (15,848)	$ (22,390)	$ (24)	$ (125)
Total Operating Expenses		TOE		$ 101,006,839	$ 227,066,542	$ 78,043,201	$ 28,731,220	$ 18,843,207	$ 23,770	$ 125,199
Net Operating Income (Adjusted)				$ 15,300,439	$ 23,222,804	$ 8,230,889	$ 981,190	$ 7,281,957	$ 5,859	$ 31,163
Net Cost Rate Base				$ 252,380,530	$ 572,762,574	$ 182,841,135	$ 79,332,423	$ 86,277,348	$ 31,557	$ 274,806
Rate of Return				**6.06%**	**4.05%**	**4.50%**	**1.24%**	**8.44%**	**18.57%**	**11.34%**

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

LOLP Methodology

		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Taxable Income Pro-Forma									
Total Operating Revenue				$ 1,485,327,440	$ 577,570,946	$ 199,344,450	$ 11,997,623	$ 173,634,344	$ 13,885,796
Operating Expenses				$ 1,198,655,166	$ 482,162,910	$ 138,667,905	$ 9,417,832	$ 124,603,766	$ 9,557,273
Interest Expense		INTEXP		$ 86,095,200	$ 38,583,056	$ 10,115,683	$ 607,683	$ 8,246,132	$ 619,546
Interest Syncronization Adjustment			INTEXP	$ 7,411,055	$ 3,321,221	$ 870,756	$ 52,309	$ 709,825	$ 53,330
Taxable Income		TXINCPF		$ 193,166,018	$ 53,503,760	$ 49,690,106	$ 1,919,799	$ 40,074,621	$ 3,655,647

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	Time of Day	Time of Day	Service	Service	Outdoor Lighting	Lighting Energy	Traffic Energy
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Taxable Income Pro-Forma										
Total Operating Revenue				$ 116,307,279	$ 250,289,346	$ 86,274,090	$ 29,712,411	$ 26,125,163	$ 29,630	$ 156,362
Operating Expenses				$ 94,314,676	$ 220,158,792	$ 75,255,963	$ 29,374,771	$ 15,013,952	$ 20,013	$ 107,313
Interest Expense		INTEXP		$ 6,019,023	$ 13,668,658	$ 4,368,078	$ 1,884,079	$ 1,976,231	$ 676	$ 6,355
Interest Syncronization Adjustment			INTEXP	$ 518,116	$ 1,176,595	$ 376,003	$ 162,181	$ 170,114	$ 58	$ 547
Taxable Income		TXINCPF		$ 15,455,463	$ 15,285,301	$ 6,274,046	$ (1,708,620)	$ 8,964,867	$ 8,882	$ 42,147

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Cost of Service Summary -- Adjusted for Proposed Increase									
Operating Revenue									
Total Operating Revenue				$ 1,485,327,440	$ 577,570,946	$ 199,344,450	$ 11,997,623	$ 173,634,344	$ 13,885,796
Proposed Increase				$ 94,389,823	$ 37,000,062	$ 12,094,455	$ 777,151	$ 9,478,307	$ 705,851
Proposed Reduction to CSR Credit			INTCRE	$ 8,688,375	$ 3,211,168	$ 944,087	$ 61,654	$ 1,031,395	$ 78,230
Increase in Miscellaneous Charges			MISCSERV	$ 19,720	$ 18,401	$ 1,280	$ 8	$ 12	$ 0
					$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 1,588,425,358	$ 617,800,577	$ 212,384,272	$ 12,836,436	$ 184,144,059	$ 14,669,878
Operating Expenses									
Total Operating Expenses				$ 1,283,819,685	$ 506,398,532	$ 160,060,870	$ 10,257,453	$ 141,811,137	$ 11,120,783
Pro-Forma Adjustments				$ (1,002,784)	$ (364,067)	$ (155,001)	$ (8,515)	$ (133,248)	$ (11,021)
Increase in Uncollectible Expense			Cust01	$ 362,905	$ 226,690	$ 43,861	$ 312	$ 2,370	$ 91
Increase in PSC Fees			R01	$ 200,113	$ 75,775	$ 27,087	$ 1,645	$ 23,839	$ 1,906
Incremental Income Taxes			0.385574631	$ 39,751,942	$ 15,511,525	$ 5,027,825	$ 323,425	$ 4,052,279	$ 302,322
Total Pro-Forma Operating Expenses				$ 1,323,131,860	$ 521,848,454	$ 165,004,642	$ 10,574,320	$ 145,756,376	$ 11,414,081
Net Operating Income				$ 265,293,498	$ 95,952,122	$ 47,379,630	$ 2,262,116	$ 38,387,683	$ 3,255,797
Net Cost Rate Base				$ 3,639,079,759	$ 1,639,211,792	$ 428,913,296	$ 25,844,638	$ 345,258,413	$ 25,951,247
Rate of Return				**7.29%**	**5.85%**	**11.05%**	**8.75%**	**11.12%**	**12.55%**

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

LOLP Methodology

		1	2	11	12	13	14	15	16	17
			Allocation	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
Description	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
Cost of Service Summary -- Adjusted for Proposed Increase										
Operating Revenue										
Total Operating Revenue				$ 116,307,279	$ 250,289,346	$ 86,274,090	$ 29,712,411	$ 26,125,163	$ 29,630	$ 156,362
Proposed Increase				$ 6,865,949	$ 17,335,551	$ 6,022,823	$ 2,235,015	$ 1,866,484	$ -	$ 8,175
Proposed Reduction to CSR Credit			INTCRE	$ 756,061	$ 1,765,308	$ 604,309	$ 234,562	$ 1,155	$ 4	$ 443
Increase in Miscellaneous Charges			MISCSERV	$ 9	$ 4	$ 0	$ -	$ 4	$ -	$ -
				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 123,929,298	$ 269,390,209	$ 92,901,222	$ 32,181,987	$ 27,992,806	$ 29,634	$ 164,980
Operating Expenses										
Total Operating Expenses				$ 101,086,823	$ 227,224,025	$ 78,098,279	$ 28,747,068	$ 18,865,597	$ 23,795	$ 125,324
Pro-Forma Adjustments				$ (79,983)	$ (157,482)	$ (55,078)	$ (15,848)	$ (22,390)	$ (24)	$ (125)
Increase in Uncollectible Expense			Cust01	$ 325	$ 146	$ 16	$ 1	$ 88,683	$ 2	$ 408
Increase in PSC Fees			R01	$ 15,971	$ 34,374	$ 11,849	$ 4,085	$ 3,557	$ 4	$ 21
Incremental Income Taxes			0.385574631	$ 2,938,857	$ 7,364,808	$ 2,555,254	$ 952,206	$ 720,116	$ 2	$ 3,323
Total Pro-Forma Operating Expenses				$ 103,961,993	$ 234,465,870	$ 80,610,320	$ 29,687,512	$ 19,655,562	$ 23,778	$ 128,952
Net Operating Income				$ 19,967,305	$ 34,924,338	$ 12,290,903	$ 2,494,476	$ 8,337,244	$ 5,856	$ 36,028
Net Cost Rate Base				$ 252,380,530	$ 572,762,574	$ 182,841,135	$ 79,332,423	$ 86,277,348	$ 31,557	$ 274,806
Rate of Return				**7.91%**	**6.10%**	**6.72%**	**3.14%**	**9.66%**	**18.56%**	**13.11%**

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	3 Total System	4 Residential Rate RS	5 General Service GS	7 All Electric Schools AES	9 Power Service PS-Secondary	10 Power Service PS-Primary
Allocation Factors									
Energy Allocation Factors									
Energy Usage by Class		E01	Energy	1.000000	0.335718	0.100160	0.008369	0.118295	0.009129
Customer Allocation Factors									
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	1.000000	0.79906	0.15461	0.00110	0.00835	0.00032
Customer Services -- Weighted cost of Services		C02		1.000000	0.701316	0.274707	0.002602	0.018664	-
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.621463	0.231618	0.004913	0.062780	0.013842
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.64427	0.24931	0.00887	0.03368	0.00129
Marketing/Economic Development		C06	Cust06	1.000000	0.79902	0.15460	0.00110	0.00835	0.00032
Total billed revenue per Billing Determinants		R01		1,464,489,053	554,543,189	198,233,994	12,037,991	174,459,441	13,950,651
Energy (at the Meter)				18,343,080,487	6,091,971,051	1,817,505,619	151,861,000	2,146,594,132	169,814,471
Energy (Loss Adjusted)(at Source)		Energy		19,428,782,556	6,522,592,615	1,945,979,163	162,595,559	2,298,329,870	177,361,189
O&M Customer Allocators									
Customers (Monthly Bills)				8,273,588	5,168,140	999,948	7,118	54,034	2,070
Average Customers (Bills/12)				689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = Lights)				689,466	430,678	83,329	593	4,503	173
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		668,477	430,678	166,658	5,930	22,515	865
Street Lighting		Cust04		114,827,799	-	-	-	-	-
Average Customers		Cust01		689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = 9 Lights per Cust)		Cust06		539,008	430,678	83,329	593	4,503	173
Average Secondary Customers		Cust07		533,407	430,678	83,329	593	-	-
Average Primary Customers		Cust08		538,978	430,678	83,329	593	4,503	173
Average Transformer Customers		Cust09		538,528	430,678	83,329	593	4,503	-
Plant Customer Allocators									
Customers (Monthly Bills)				8,273,588	5,168,140	999,948	7,118	54,034	2,070
Average Customers (Bills/12)				689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = Lights)				689,466	430,678	83,329	593	4,503	173
Weighted Average Customers (Lighting =9 Lights per Cust)				668,477	430,678	166,658	5,930	22,515	865
Street Lighting				114,827,799	-	-	-	-	-
Average Customers				689,466	430,678	83,329	593	4,503	173
Average Customers (Lighting = 9 Lights per Cust)				539,008	430,678	83,329	593	4,503	173
Average Secondary Customers				533,407	430,678	83,329	593	-	-
Average Primary Customers				538,978	430,678	83,329	593	4,503	173
Average Transformer Customers				538,528	430,678	83,329	593	4,503	-
Demand Allocators									
Maximum Class Non-Coincident Peak Demands (Transm		NCPT		5,021,135	2,135,688	540,692	52,198	476,672	37,486
Maximum Class Non-Coincident Peak Demands (Primary		NCPP		4,502,184	2,135,688	540,692	52,198	476,672	37,486
Sum of the Individual Customer Demands (Transformer)		SICDT		6,459,671	4,481,645	807,122	56,694	633,729	-
Sum of the Individual Customer Demands (Secondary)		SICD		5,379,998	4,481,645	807,122	56,694	-	-
Summer Peak Period Demand Allocator		SCP		45,301	16,743	4,922	321	5,378	408
Winter Peak Period Demand Allocator		WCP		45,301	16,743	4,922	321	5,378	408
Base Demand Allocator		BDEM		45,301	16,743	4,922	321	5,378	408

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Allocation Factors										
Energy Allocation Factors										
Energy Usage by Class		E01	Energy	0.092093	0.221373	0.078838	0.029105	0.006813	0.000025	0.000082
Customer Allocation Factors										
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	0.00115	0.00051	-	-	0.03473	0.00000	0.00016
Customer Services -- Weighted cost of Services		C02		0.002712	-	-	-	-	-	-
Meter Costs -- Weighted Cost of Meters		C03		0.011643	0.030754	0.020975	0.000888	-	0.000006	0.001120
Lighting Systems -- Lighting Customers		C04	Cust04	-	-	-	-	1.00000	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.02311	0.01036	0.00090	0.00007	0.02800	-	0.00013
Marketing/Economic Development		C06	Cust06	0.00115	0.00051	0.00006	0.00000	0.03473	-	0.00016
Total billed revenue per Billing Determinants		R01		116,879,945	251,561,897	86,711,460	29,892,107	26,032,396	29,470	156,512
Energy (at the Meter)				1,671,130,915	4,118,000,917	1,497,714,279	552,917,598	123,634,653	446,721	1,489,131
Energy (Loss Adjusted)(at Source)		Energy		1,789,257,708	4,301,008,844	1,531,734,094	565,476,838	132,373,983	478,298	1,594,393
O&M Customer Allocators										
Customers (Monthly Bills)				7,419	3,318	360	12	2,021,809	48	9,312
Average Customers (Bills/12)				618	277	30	1	168,484	4	776
Average Customers (Lighting = Lights)				618	277	30	1	168,484	4	776
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		15,450	6,925	600	50	18,720	-	86
Street Lighting		Cust04		-	-	-	-	114,827,799	-	-
Average Customers		Cust01		618	277	30	1	168,484	4	776
Average Customers (Lighting = 9 Lights per Cust)		Cust06		618	277	30	1	18,720	-	86
Average Secondary Customers		Cust07		-	-	-	-	18,720	0	86
Average Primary Customers		Cust08		618	277	-	-	18,720	0	86
Average Transformer Customers		Cust09		618	-	-	-	18,720	0	86
Plant Customer Allocators									-	-
Customers (Monthly Bills)				7,419	3,318	360	12	2,021,809	48	9,312
Average Customers (Bills/12)				618	277	30	1	168,484	4	776
Average Customers (Lighting = Lights)				618	277	30	1	168,484	4	776
Weighted Average Customers (Lighting =9 Lights per Cust)				15,450	6,925	600	50	18,720	-	86
Street Lighting				-	-	-	-	114,827,799	-	-
Average Customers				618	277	30	1	168,484	4	776
Average Customers (Lighting = 9 Lights per Cust)				618	277	30	1	18,720	-	86
Average Secondary Customers				-	-	-	-	18,720	0	86
Average Primary Customers				618	277	-	-	18,720	0	86
Average Transformer Customers				618	-	-	-	18,720	0	86
Demand Allocators										
Maximum Class Non-Coincident Peak Demands (Transm		NCPT		368,420	853,586	312,397	206,554	37,046	155	240
Maximum Class Non-Coincident Peak Demands (Primary		NCPP		368,420	853,586	-	-	37,046	155	240
Sum of the Individual Customer Demands (Transformer)		SICDT		445,944	-	-	-	34,173	143	221
Sum of the Individual Customer Demands (Secondary)		SICD		-	-	-	-	34,173	143	221
Summer Peak Period Demand Allocator		SCP		3,942	9,204	3,151	1,223	6	0	2
Winter Peak Period Demand Allocator		WCP		3,942	9,204	3,151	1,223	6	0	2
Base Demand Allocator		BDEM		3,942	9,204	3,151	1,223	6	0	2

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

LOLP Methodology

		1	2	3	4	5	7	9	10
			Allocation	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
Description	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
Unadjusted Production Allocation									
Production Residual Winter Demand Allocator		PPWDRA		45,301	16,743	4,922	321	5,378	408
Production Winter Demand Costs				$ 35,951,279	$ 13,287,363	$ 3,906,501	$ 255,117	$ 4,267,770	$ 323,705
Customer Specific Assignment				$ -	-	-	0	-	-
Production Winter Demand Residual			PPWDRA	$ 35,951,279	$ 13,287,363	$ 3,906,501	$ 255,117	$ 4,267,770	$ 323,705
Production Winter Demand Total		PPWDT		$ 35,951,279	$ 13,287,363	$ 3,906,501	$ 255,117	$ 4,267,770	$ 323,705
Production Winter Demand Allocator		PPWDA	PPWDT	1.000000	0.36959	0.10866	0.00710	0.11871	0.00900
Production Residual Summer Demand Allocator		PPSDRA		45,301	16,743	4,922	321	5,378	408
Production Summer Demand Costs				$ 35,933,656	$ 13,280,850	$ 3,904,586	$ 254,992	$ 4,265,678	$ 323,546
Customer Specific Assignment				$ -	-	-	0	-	-
Production Summer Demand Residual			PPSDRA	$ 35,933,656	13,280,850	3,904,586	254,992	4,265,678	323,546
Production Summer Demand Total		PPSDT		$ 35,933,656	$ 13,280,850	$ 3,904,586	$ 254,992	$ 4,265,678	$ 323,546
Production Summer Demand Allocator		PPSDA	PPSDT	1.000000	0.36959	0.10866	0.00710	0.11871	0.00900
Production Residual Base Demand Allocator		PPBDRA		45,301	16,743	4,922	321	5,378	408
Production Base Demand Costs				$ 37,625,250					
Customer Specific Assignment				$ -					
Production Base Demand Residual			PPBDRA	$ 37,625,250	13,906,052	4,088,396	266,996	4,466,487	338,778
Production Base Demand Total		PPBDT		$ 37,625,250	$ 13,906,052	$ 4,088,396	$ 266,996	$ 4,466,487	$ 338,778
Production Base Demand Allocator		PPBDA	PPBDT	1.000000	0.36959	0.10866	0.00710	0.11871	0.00900
Revenue Adjustment Allocators									
Remove ECR Revenues		ECRREV		183,699,328	68,522,534	41,426,529	2,625,661	18,954,821	1,533,784
Interruptible Credit Allocator		INTCRE		2,787,666,238	1,030,303,640	302,910,516	19,781,814	330,923,353	25,100,130
Base Rate Revenue				1,464,489,053	554,543,189	198,233,994	12,037,991	174,459,441	13,950,651
Late Payment Revenue		LPAY		3,719,777	2,905,326	548,011	3,616	95,129	5,337
Misc Service Revenue Allocator		MISCSERV		2,232,238	2,082,901	144,923	903	1,414	54
Operation and Maintenance Less Fuel		OMLF		293,386,691.81	151,217,563.65	43,747,108.26	2,195,358.63	22,674,447.24	1,743,296.68

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

LOLP Methodology

Description	Ref	1 Name	2 Allocation Vector	11 Time of Day TOD-Secondary	12 Time of Day TOD-Primary	13 Service RTS	14 Service FLS - Transmission	15 Outdoor Lighting ST & POL	16 Lighting Energy LE	17 Traffic Energy TE
Unadjusted Production Allocation										
Production Residual Winter Demand Allocator		PPWDRA		3,942	9,204	3,151	1,223	6	0	2
Production Winter Demand Costs				$ 3,128,473	$ 7,304,596	$ 2,500,544	$ 970,583	$ 4,777	$ 18	$ 1,831
Customer Specific Assignment				-	-	-	-	-		
Production Winter Demand Residual			PPWDRA	$ 3,128,473	$ 7,304,596	$ 2,500,544	$ 970,583	$ 4,777	$ 18	$ 1,831
Production Winter Demand Total		PPWDT		$ 3,128,473	$ 7,304,596	$ 2,500,544	$ 970,583	$ 4,777	$ 18	$ 1,831
Production Winter Demand Allocator		PPWDA	PPWDT	0.08702	0.20318	0.06955	0.02700	0.00013	0.00000	0.00005
Production Residual Summer Demand Allocator		PPSDRA		3,942	9,204	3,151	1,223	6	0	2
Production Summer Demand Costs				$ 3,126,939	$ 7,301,015	$ 2,499,319	$ 970,107	$ 4,775	$ 18	$ 1,830
Customer Specific Assignment				-	-	-	-	-		
Production Summer Demand Residual			PPSDRA	3,126,939	7,301,015	2,499,319	970,107	4,775	18	1,830
Production Summer Demand Total		PPSDT		$ 3,126,939	$ 7,301,015	$ 2,499,319	$ 970,107	$ 4,775	$ 18	$ 1,830
Production Summer Demand Allocator		PPSDA	PPSDT	0.08702	0.20318	0.06955	0.02700	0.00013	0.00000	0.00005
Production Residual Base Demand Allocator		PPBDRA		3,942	9,204	3,151	1,223	6	0	2
Production Base Demand Costs										
Customer Specific Assignment										
Production Base Demand Residual			PPBDRA	3,274,141	7,644,714	2,616,975	1,015,776	5,000	19	1,917
Production Base Demand Total		PPBDT		$ 3,274,141	$ 7,644,714	$ 2,616,975	$ 1,015,776	$ 5,000	$ 19	$ 1,917
Production Base Demand Allocator		PPBDA	PPBDT	0.08702	0.20318	0.06955	0.02700	0.00013	0.00000	0.00005
Revenue Adjustment Allocators										
Remove ECR Revenues		ECRREV		11,872,123	23,622,372	7,708,001	2,664,539	4,739,976	7,407	21,581
Interruptible Credit Allocator		INTCRE		242,582,119	566,399,212	193,892,490	75,259,126	370,429	1,413	141,997
Base Rate Revenue				116,879,945	251,561,897	86,711,460	29,892,107	26,032,396	29,470	156,512
Late Payment Revenue		LPAY		40,273	104,034	18,019	-	32	-	-
Misc Service Revenue Allocator		MISCSERV		1,040	465	50	-	488	-	-
Operation and Maintenance Less Fuel		OMLF		16,210,876.61	34,733,496.61	10,666,592.25	4,782,862.51	5,376,544.72	2,497.77	36,046.89