COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF SOUTH KENTUCKY RURAL	)	
ELECTRIC COOPERATIVE CORPORATION FOR	)	CASE NO.
APPROVAL OF MASTER POWER PURCHASE AND	)	2018-00050
SALE AGREEMENT AND TRANSACTIONS	)	
THEREUNDER	)	

ATTORNEY GENERAL'S NOTICE OF FILING- EXHIBIT LIST

Comes now the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and hereby provides the following exhibits he intends to introduce at the May 15 and 16 hearing in this matter.

Exhibit List

1. Direct Testimony and Exhibits of William Steven Seelye in Case No. 2007-00089.
2. Direct Testimony and Exhibits of William Steven Seelye in Case No. 2016-00370.
3. Direct Testimony and Exhibits of William Steven Seelye in Case No. 2008-00409.
4. Kentucky Utilities- OSL- Outdoor Sports Lighting Service Tariff.
5. Case No. 2016-00370 June 22, 2018 Final Order.
6. Duke Energy- Rate SP- Seasonal Sports Service Tariff.
7. Case No. 2017-00321 April 13, 2018 Final Order.

Respectfully submitted,

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AG Exhibit 1

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DELTA NATURAL GAS COMPANY, INC. FOR AN ADJUSTMENT OF RATES	)))	**CASE NO. 2007-00089**

DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT THE PRIME GROUP, LLC

AFFIDAVIT

The affiant, William Steven Seelye, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared direct testimony of this affiant in Case No. 2007-00089, in the Matter of: An Adjustment of the Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at the hearing in Case No. 2007-00089 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony in such case.

William Steven Seelye

STATE OF INDIANA)
)
COUNTY OF MARION)

Subscribed and sworn to before me by William Steven Seelye, this the 18th day of April, 2007.

My Commission Expires: 2/14/2015

Notary Public, State at Large, Indiana

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal 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. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor Delta Natural Gas Company Inc.'s ("Delta's") proposed rates for natural gas service; to describe the proposed allocation of the revenue increase; to sponsor the fully allocated class cost of service study based on Delta's embedded costs for the 12 months ended December 31, 2006; to sponsor the temperature normalization adjustment; and to sponsor Delta's depreciation study supporting the proposed depreciation rates and the pro-forma adjustment to depreciation expenses.

Q. Please summarize your testimony.

A. Delta is proposing to increase base rate revenues by $5,562,341. The Company has a large residential customer base, and, as a result, Delta is proposing to allocate $3,847,230 of the increase to the residential class. The Company is proposing to collect these revenues by increasing the residential customer charge. By recovering all of the residential increase through the customer charge, we are proposing to move in the direction of a "straight fixed variable" rate design, which is a methodology that has been adopted in other regulatory jurisdictions. More specifically, Delta is proposing to recover through the monthly customer charge most of the customer-related costs identified in the cost of service study. The Prime Group prepared a fully allocated, embedded cost of service study for Delta's test-year operations using a cost of service methodology that has been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to determine the contribution that each customer class is making towards Delta's overall rate of return. Rates of return are computed for each rate class. Delta was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service. Delta is also proposing to make a temperature normalization adjustment to sales and transportation volumes not covered by the Company's Weather Normalization Adjustment ("WNA") clause. In addition, Delta is proposing to change a number of its depreciation rates based on the depreciation study included as an exhibit to my testimony.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Rate Design and the Allocation of the Increase, (III) Cost of Service Study, (IV) Temperature Normalization Adjustment, (V) Revenue Adjustment to Reflect Year-End Customers, and (VI) Depreciation Study and Depreciation Expense Adjustment.

I. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

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 May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("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 cost of service and rate studies for over 100 investor-owned utilities, rural electric cooperatives, and municipal utilities. I have also developed or modified fuel and purchased power adjustment mechanisms for numerous electric and gas utilities, including integrated investor-owned utilities, integrated municipal utilities and distribution cooperatives. A more detailed description of my qualifications is included in Seelye Exhibit 1.

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

A. Yes, on many occasions. Concerning my background related to the subject matters addressed in this proceeding, I have testified in other proceedings regarding rate design, revenue requirements, cost of service studies, pro-forma adjustments and depreciation expenses. A listing of my testimony is included in Seelye Exhibit 1.

II. RATE DESIGN AND THE ALLOCATION OF THE INCREASE

Q. Is Delta proposing to change the relationship between the customer charge and volumetric charge for the residential rate class?

A. Yes. The Company is proposing a significant increase in its customer charge. Delta has a traditional residential base rate design consisting of a customer charge and a volumetric charge. This type of rate design is referred to as a "two-part" rate. Under this design, a portion of Delta's non-gas costs are collected through a monthly fixed customer charge, which does not vary with usage, and a volumetric charge applied to each Ccf used. Delta's residential customer charge is currently $9.80 per month and the non-gas volumetric charge is $0.41592 per Ccf (or $4.1592 per Mcf). Gas costs are recovered through the Gas Cost Recovery Rate (GCR), which is a volumetric charge.

Some regulatory jurisdictions have shifted from a traditional two-part rate design to a design in which all non-gas costs are recovered through a fixed monthly customer charge. This type of rate structure is referred to as a "straight fixed variable" rate design. This rate design evolved from pipeline rate designs that recovered all fixed costs through a fixed charge and all variable costs through a volumetric charge. Because non-gas costs are *fixed* for a gas distributor, and do not vary with the amount of gas purchased by its customers, all non-gas costs are recovered through a *fixed* monthly customer charge under a straight fixed variable rate structure.

The Missouri Public Service Commission ("Missouri Commission") recently adopted a straight fixed variable rate design for Atmos Energy Corporation (*Case No. GR-2006-0387*, Order dated February 22, 2007) and Missouri Gas Energy, a division of Southern Union Company (*Case No. GR-2006-0422*, Order dated March 22, 2007). The straight fixed variable rate design was proposed by the Missouri Commission Staff in the Atmos proceeding. A straight fixed variable rate design is also used by the Atlanta Gas Light Company in Georgia.

In the Atmos Proceeding, the Missouri Commission accepted the Staff's recommendation to eliminate the traditional two-part rate structure and to adopt instead a straight fixed variable design because collecting fixed costs through a volumetric charge:

- Creates unnecessary volatility in customer bills by collecting too much cost in the winter months;
- Sends incorrect price signals to residential customers;
- Forces residential customers whose usage is greater than the average to pay more than the cost of service, while allowing smaller customers to pay less than the cost of service;
- Provides no incentive for the utilities to promote conservation.

(*Atmos Energy Corporation, Case No. GR-2006-0387*, Order dated February 22, 2007, pp. 19-20.)

Q. Is Delta proposing a straight fixed variable rate design?

A. No. Although Delta is not recommending a straight fixed variable rate design, the Company is proposing to move significantly in that direction. Specifically, Delta is proposing to leave the volumetric charge at the current level and recover all of the residential revenue increase in the customer charge. Under a straight fixed variable design the non-gas volumetric charge would be eliminated and all of Delta's non-gas costs would be recovered through the monthly customer charge.

Although Delta's proposed residential rate will fall far short of recovering all fixed costs in the customer charge, it will come reasonably close to recovering the customer-related costs identified in the fully allocated class cost of service study submitted in this proceeding. In the cost of service study, Delta's non-gas fixed costs are classified as either customer-related or demand-related. With a straight fixed variable rate design adopted in Missouri and

Georgia all of these costs – both customer-related and demand-related fixed costs – would be recovered through the monthly customer charge. In this proceeding Delta is proposing to recover most – but not all – of its customer-related costs through the monthly customer charge. Delta's customer-related cost for residential customers is currently $24.16 per month. However, the Company is only charging $9.80 per month, or 41% of the customer-related costs that were identified in the cost of service study. In this proceeding, Delta is proposing to increase the monthly customer charge to $19.74, which represents 82% of the customer-related costs identified in the cost of service study. Although this increase in the customer charge is far less than it would be with straight fixed variable rate design, Delta's proposal is a significant shift in that direction.

Q. What would the customer charge be under a straight fixed variable design?

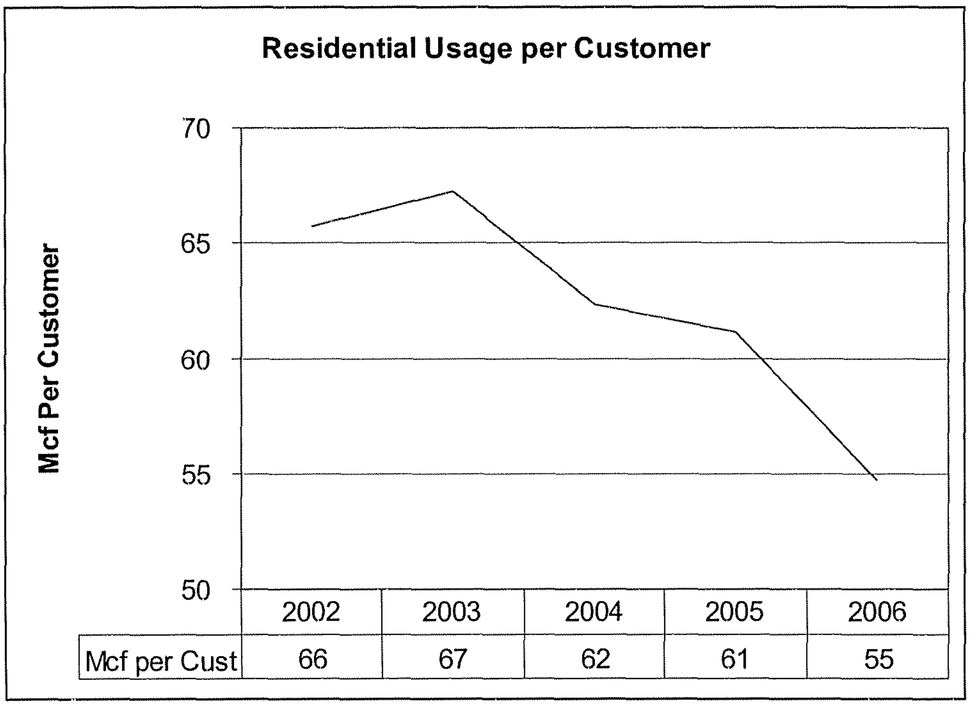
A. Under a straight fixed variable rate as was ordered by the Missouri Commission, the monthly customer charge would be $38.94, compared to the $19.74 charge proposed by Delta. Even with a $19.74 customer charge, approximately 50% of Delta's fixed costs will continue to be recovered through a volumetric charge.

Q. What are the benefits of recovering most of the customer-related costs through the customer charge?

A. Recovering more of Delta's customer-related costs through the fixed monthly customer charge will better reflect the actual cost of service through rates and will thus send a more accurate price signal to customers. In addition, Delta's proposed customer charge will reduce the volatility in customer bills by lowering the amount charged during the winter.

The Company's proposal will also eliminate rate subsidies within the residential customer class. Currently, customers with lower than average usage are being subsidized by customers with higher than average usage. Based on data that I have seen from other gas utilities, including a gas utility in the region, low income customers – contrary to a common misconception – tend to purchase more gas than the average customer. The likely reason for this is that low income customers often have poorly insulated homes, which causes their gas usage to be higher than the average even though their homes may have less square footage than the average. When customer-related costs are recovered through the volumetric charge, low income customers who use more than the average will subsidize customers who use less natural gas than the average.

Yet another advantage of Delta's proposal – and one which should be an important consideration for the Company – is that a higher customer charge should help mitigate the erosion in margins that Delta has been experiencing for a number of years. Delta's average Mcf per customer has been trending down for many years now. As shown in the following graph, in just four years the average residential usage has gone from 66 Mcf per customer in 2002 to 55 Mcf in 2006.



Because a large percentage of Delta's fixed costs have been recovered through a volumetric charge, the decline in customer usage has the effect of reducing the recovery of fixed costs and eroding the Company's earnings. Delta has not had an opportunity to earn the rate of return on equity authorized by the Commission in Delta's last three rate cases, and decreasing sales volumes have contributed heavily to this trend. Recovering more fixed costs through the customer charge should help mitigate this erosion in earnings. Furthermore, increasing the customer charge will work in tandem with the Experimental Customer Rate Stabilization ("CRS") Mechanism to provide Delta a reasonable opportunity to earn a fair, just and reasonable rate of return while preventing customers from being overcharged. Increasing the customer charge will in no way work at cross purposes with the CRS but, rather, will enhance the effectiveness of the proposed mechanism.

Q. Will the proposed rate design better position the Company to encourage conservation on the part of customers?

A. Yes it will, when considered in conjunction with the CRS and the proposed Conservation/ Efficiency Program (CEP) Cost Recovery Mechanism. Recovering a significant portion of fixed costs through a volumetric charge works to penalize the Company when customers conserve. Essentially all of Delta's non-gas costs are fixed and do not vary as customer volumes go up or down. With a significant portion of fixed costs recovered through volumetric charges, the Company's financial results are adversely affected from consumer conservation. Because Delta is not proposing to eliminate the volumetric charge for non-gas costs through the adoption a straight fixed variable rate design, the Company's non-gas revenues will continue to go down as a result of conservation, but not nearly as much as they would if Delta had proposed an increase in the volumetric charge. Furthermore, the adoption of the CRS and CEP Cost Recovery Mechanisms proposed by Delta will help position the Company so that it is not financially harmed by conservation on the part of customers. All three of these measures – increasing the customer charge, implementing the CRS Mechanism, and adopting the CEP Mechanism – work together as an integrated effort to help maintain Delta's financial integrity while encouraging customers to use less natural gas.

Q. Have you prepared an exhibit reconstructing Delta's test-year billing units?

A. Yes. In order to develop Delta's proposed rates it was necessary to reconstruct test-year billing units. The reconstruction of Delta's billing determinants is shown on Seelye Exhibit 2.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase apportioned to the individual customer classes?

A. Delta is proposing to increase its annual revenues by $5,641,650. As shown on Seelye Exhibit 3 , this amount would result in an increase of 9.2% in total operating revenue. In addition to requesting an increase in gas service rates, Delta is also proposing to increase the collection charge, reconnection charge, and bad check charge, all of which result in an increase in miscellaneous revenue of $79,309.

The proposed rates apportion the revenue increase among the customer classes as follows:

TABLE 1
Proposed Gas Increase

Customer Class	Proposed Increase	Percentage
Residential	$ 3,847,230	12.5%
Small Non-Residential	489,319	5.2%
Large Non-Residential	1,130,216	7.3%
Off-System Transportation	95,575	3.8%
Total Sales and Transportation	$ 5,562,341	9.2%

As shown on Seelye Exhibit 4, the effects on individual class revenues were determined by applying both the current and proposed charges to the adjusted billing determinants for each customer class.

Q. What was the basic underlying information that supported the proposed allocation among rate classes?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall return earned by the Company. The cost of service study indicated that the individual class rates of return ranged between 3.69%

and 19.11% as compared to an overall adjusted actual return on rate base of 5.71%, with residential being the lowest at 3.69%. This indicates a need to increase the revenues collected from the residential class more than the other classes. The rates of return for all of the rate classes except the special contracts were significantly higher than for residential. The cost of service study also showed that the earned return for the interruptible and off-system transportation rates were extremely high when compared to the other classes of service. Because the rate of return for the residential class is significantly below Delta's proposed overall rate of return of 8.82%, Delta is proposing to increase the residential rate by a larger percentage than the other classes in order to bring the residential rate of return more in line with the overall rate of return. The special contracts are served under fixed-price arrangements; therefore, none of the revenue increase will be allocated to these customers. Delta does not propose to increase the rates for the interruptible rate class because of the high rates of return for this rate class. With a rate of return of 19.11% for interruptible service, a rate increase for this rate class cannot be justified. Delta is proposing increases for the small and large non-residential rate classes that will result in a rate of return of around 10%, based on the results of the cost of service study, and the Company is proposing an increase in the off-system transportation rate that will produce a rate of return of approximately 9%.

Q. Is it important to consider competitive issues when designing rates?

A. Yes. It is extremely important to take into consideration the competitive pressures facing the utility when designing rates. Utility customers have many more options than they did in the past, and they are also becoming more sophisticated in how to utilize the various competitive products that are now available to them. However, the natural gas industry has always experienced keen competition from alternative fuels. When customers have alternatives (and the ability to substitute fuel oil for natural gas is only one example), gas distribution companies must be able to ensure that the revenues contributed by these customers are retained as long as they make some contribution to the utility's fixed costs. Industrial and commercial customers generally have more options than residential customers. Therefore, it is important not to charge rates to commercial and industrial customers that are uncompetitive and exceed the cost of providing service. Otherwise, large commercial and industrial customers will leave the system, forcing residential and small commercial customers, who have fewer options, to pay for fixed costs that are left stranded by the departing customers. Unlike volumetric costs, such as the cost of the gas commodity that a distribution company buys for its customers, a utility's fixed costs generally do not disappear if it sells less gas, but instead are spread over a lower volume of gas, thus causing the utility's rates to increase. Therefore, if a utility loses several large high-load factor industrial customers, then the utility's fixed costs do not suddenly disappear but are shifted to the remaining customers in future rate proceedings. On the other hand, if the utility can attract high-load factor customers or, even better, customers with off-peak usage, then the utility's fixed costs can be spread over a larger volume of gas thus causing gas rates to go down, benefiting all customers. Again, that is why it is important for Delta to keep the rates applicable to price sensitive customers as competitive as possible while considering the cost of serving these customers.

Q. What were the ratemaking objectives in developing the proposed gas rates?

A. As explained earlier, we tried to develop rates that more closely reflect the cost of providing service. Therefore, one of our key objectives was to bring the unit charges more in line with the unit costs derived from the cost of service study. Thus, we developed rates that moved the charges toward the unit costs indicated by the cost of service study.

Q. Have you analyzed the customer-related costs for Delta's rate classes?

A. Yes. Page 20 of Seelye Exhibit 6 shows the unit customer-related costs for each rate class based on the results of the cost of service study. The customer-related cost for each rate class was derived by calculating the customer-related cost of service, or "revenue requirement" and dividing this amount by the number of customers. Delta's cost of service includes (1) return on investment, (2) income taxes, (3) operation and maintenance expenses, (4) depreciation expenses, and (5) other taxes. The proposed overall rate of return of 8.82% was used to calculate the unit cost.

Q. What are the proposed unit charges for the small non-residential rate class?

A. Delta is proposing a customer charge of $25.00 per customer per month and a flat commodity charge of $0.4159 for all Ccf. The current rate consists of a customer charge of $20.00 and commodity charge of $0.3795 per Ccf.

Q. What are the proposed unit charges for the large non-residential rate class?

A. Delta is proposing a customer charge of $100.00 per customer per month and a commodity charge of $0.4159 for the first 2,000 Ccf, $0.2510 for the next 8,000 Ccf, $0.1714 for the next 40,000 Ccf, $0.1314 for the next 50,000 Ccf, and $0.1114 for all usage over 100,000 Ccf. The first block was set at the same level as the first block in the small non-residential rate, and the current charge differentials between the blocks were maintained.

Q. Is Delta proposing to modify the interruptible or off-system transportation rate schedules?

A. No. As indicated earlier, rate increases for these services cannot be justified in light of the high class rates of return.

Q. Is Delta proposing to increase the off-system transportation rate?

A. Yes. We are proposing to increase the off-system transportation rate from $0.26 to $0.27 per dekatherm.

III. GAS COST OF SERVICE

Q. Did you prepare a cost of service study for Delta's natural gas operations based on financial and operating results for the 12 months ended December 31, 2006?

A. Yes. I supervised and participated in the preparation of a fully allocated, embedded cost of service study for natural gas service based on Delta's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the 12 months ended December 31, 2006. The Commission in other rate case proceedings has accepted the methodology used in Delta's cost of service study. The objective in performing the cost of service study is to determine the rate of return on rate base that Delta is earning from each customer class, which provides an indication as to whether Delta's service rates reflect the cost of providing service to each customer class.

Q. Have you ever prepared an embedded cost of service study?

A. Yes, on many occasions. While employed at LG&E, I prepared numerous gas and electric cost of service studies, many of which were filed in rate cases before the Commission. Since leaving LG&E, I have prepared or supervised the preparation of well over 100 embedded cost of service studies for electric, gas and water utilities. In Kentucky, I supervised and participated in the preparation of gas cost of service studies for Delta (Case No. 99-176 and Case No. 2004-00067) and LG&E (Case No. 2003-00433 and Case No. 2000-080).

Q. Was the same methodology used in the cost of service study submitted in this proceeding that was used in the cost of service study filed by Delta in Case No. 2004-00067?

A. Yes.

Q. Did the Commission accept Delta's cost of service study filed in Case No. 2004-00067?

A. Yes it did, as set forth on page 57 of the Commission's November 10, 2004 Order in Case No. 2004-00067.

Q. Did you develop the model used to perform Delta's cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

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

A. The cost of service study was prepared using the following basic 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; and then (3) costs were allocated to Delta's rate classes. This is a standard approach utilized in the preparation of embedded cost of service studies for gas utilities.

Q. What is the purpose of functionally assigning costs?

A. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a mechanism for separating assignable costs from joint costs, which must be allocated.

Q. What functional groups were used in the natural gas cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Storage, (2) Transmission, (3) Distribution Commodity, (4) Distribution Structures and Equipment, (5) Distribution Mains, (6) Services, (7) Meters, (8) Customer Accounts, and (9) Customer Service Expense.

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

A. Classification provides a method of arranging costs so that the service characteristics which give rise to the costs can serve as a basis for allocation. Costs classified as *commodity related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand related. Distribution Structures and Equipment costs were classified as demand-related. Costs related to Distribution Mains were classified as demand-related and customer-related using the zero intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were all classified as customer-related.

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

A. Yes. Seelye Exhibit 5 shows the results of the first two steps of the cost of service study: functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, Delta's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 5, Delta's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28 of Seelye Exhibit 5. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are shown on pages 29 and 30 of Seelye Exhibit 5. The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors." The results of the class allocation step of the cost of service study are included in Seelye Exhibit 6. The costs shown in the column labeled "Total System" in Seelye Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 5. The column labeled "Ref" in Seelye Exhibit 6 provides a reference to the results included in Seelye Exhibit 5.

Q. Please describe the allocation factors used in the gas cost of service study.

A. The following allocation factors were used in the gas cost of service study:

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on expected winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the expected winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Seelye Exhibit 7.

- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the basis of design-day demands determined at Delta's -3 degree F design-day mean temperature.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at Delta's -3 degree F design day mean temperature. These demands were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment will be discussed later in my testimony.

- **DEM05** is used to allocate the demand-related portion of the cost of distribution mains and represents maximum class demands determined at the design day mean temperature.

- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of December through March.)

- **COM03** is used to allocate Transmission commodity-related costs and represents annual throughput volumes (including both sales and transportation).

- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation) of customers served on the distribution system.

- **CUST01** is used to allocate the customer-related portion of

Delta's distribution mains and represents the year-end number of customers.

- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST03** is used to allocate Meters and is based on the estimated cost of meters and meter installation costs per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and is determined on the basis of the average number of customers.

- **CUST05** is used to allocate customer service expenses using the same allocation factor used to allocate Accounts 901, 902, 903, and 905 in CUST04.

Q. How are mains typically classified between demand and customer costs?

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, a "minimum" standard pipe size is selected and the minimum system is obtained by pricing all of the distribution mains at the unit cost of this minimum size pipe. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the 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, rather than the minimum system methodology, was used to determine the customer component of mains. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size main to determine the customer component. In the zero intercept methodology, a zero-diameter pipe is the absolute minimum system.

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 ($/ft) of mains and the gas flow capability of the pipe, which is proportionate to its diameter. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the pipe,

x is the size of the pipe, and

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

it can be determined that, theoretically, the unit cost of a pipe with zero diameter (or pipe with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of mains that is invariant to the size (and load carrying capability) of the pipe.

Like most gas distribution systems, the number of feet of mains on Delta's system is not uniformly distributed over all sizes of pipe. For example, Delta has over 4.5 million feet of 2-inch plastic mains, but only 74 thousand feet of 3-inch plastic mains. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Using a weighted regression analysis, the cost and diameter of each size pipe is, in effect, weighted by the number of feet of installed pipe. In a weighted 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 (in this case the feet of pipe) for each size of pipe, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Seelye Exhibit 8 is the zero-intercept analysis used in this study. The zero-intercept unit cost of $3.39 per foot pipe is applied to the total feet of mains in the analysis to determine the customer cost component. The listing on page 1 of the analysis indicates that the coefficient of determination R-squared for mains is 0.9194. The coefficient of determination is a relative measure of the goodness of fit, where a coefficient of 0.0 indicates no linear correlation between the independent variable and dependent variable and a coefficient of 1.0 indicates perfect linear correlation.

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

A. Yes, on many occasions. The Commission accepted the methodology in Delta's last rate case (Case No. 2004-00067). LG&E utilized the zero-intercept methodology in the cost of service studies submitted in its last two base rate cases (Case No. 2000-080 and Case No. 90-158) in which the Commission has issued orders and the Commission found them to be reasonable. The Commission also found the embedded cost of service study submitted by The Union Light Heat and Power in its gas base rate case (Case No. 2001-00092), which utilized a zero-intercept methodology, to be reasonable. In my experience, the zero-intercept methodology is the predominant method used in Kentucky and is used widely in other jurisdictions.

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

A. The following table (Table 2) summarizes the rates of return on net cost rate base for each customer class before and after reflecting the rate adjustments proposed by Delta. 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 Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential	3.69%	7.88%
Small Non-Residential	7.03%	9.26%
Large Non-Residential	7.28%	10.10%
Interruptible	19.11%	19.11%
Special Contracts	3.23%	3.23%
Off-System Transportation	8.16%	8.81%
Total System	5.71%	8.82%

Q. Is the current rate of return for the residential class adequate?

A. No. As shown in Table 1, the rate of return for the residential class is below the rates of return for the other customer classes. Delta's overall adjusted rate of return is 5.17%, while the rate of return for the residential class is only 3.69%. In my opinion, Delta should be allowed to charge rates that bring the residential rate of return more in line with the overall rate of return.

Q. Would Delta's proposed rates move the company toward bringing the class rates of return closer together?

A. Yes. As can be seen in Table 1, the residential rates proposed by Delta result in a pro-forma rate of return of 7.88%, which brings the residential class within approximately 1 percentage point of the proposed overall rate of return of 8.82% (compared to 1.5 percentage points, currently).

IV. TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Please explain the calculations and methodology used to determine the temperature normalization adjustment to test period revenue.

A. Delta has a Weather Normalization Adjustment ("WNA") clause that automatically adjusts the commodity charge to reflect normal temperatures. The WNA clause is applicable to residential and small non-residential customers and is currently applied during the months of December through April. Because the WNA automatically normalizes customer billings for these two rate classes during the months of December through April it is not necessary to perform a temperature normalization adjustment for these two classes during these months. However, it is necessary to perform a temperature normalization adjustment for the residential and small non-residential customer classes to reflect the heating months not covered by the WNA. Additionally, it is necessary to perform a temperature normalization adjustment for rate classes not billed under the WNA, namely, large non-residential and interruptible rate classes.

Q. How was the gas temperature normalization adjustment performed for the rate classes not billed under the WNA?

A. A standard temperature normalization adjustment covering the entire heating season was performed for the large non-residential and interruptible rate classes. Heating degree days related to cycle billed customer deliveries were 196 below the 30-year average Weather Bureau heating-degree days of 4,662, where the 30-year average was determined using the period ended November 2006. Thus, Delta's actual revenues were understated due to warmer than normal temperatures experienced during the test period. The degree-day data used for purposes of calculating the temperature normalization adjustment was obtained from the Lexington, Kentucky weather station.

The first step in computing the temperature-related variance in deliveries was to determine the annual non-temperature sensitive and temperature sensitive volumes for each rate class. The determination of the non-temperature sensitive volumes was based on the gas deliveries that occurred in July and August since those months had the lowest volumes and also had no heating degree days. The volumes in those two months were then multiplied by six to calculate an annual non-temperature sensitive load that was deducted from total deliveries to arrive at the annual temperature sensitive volumes.

The next step was to determine the volumetric adjustment required to normalize deliveries to reflect normal temperatures. The annual temperature sensitive volumes were divided by the actual heating degree days (4,662 for billing cycle customers) in the test period and the resulting Mcf per degree day was then multiplied by the degree-day departure from normal (196 HDDs) to arrive at the volumetric adjustment for each rate class. In the final step, the volumetric adjustment for each rate class was applied to the applicable distribution component (rate per Mcf) for each rate schedule not billed under the WNA.

Q. How was the gas temperature normalization adjustment performed for the residential and small non-residential rate classes, which are billed under the WNA?

A. The same methodology was used for the residential and small non-residential rate classes except that the difference in degree days was determined only for the months outside of the period when the WNA is applied. In other words the temperature normalization was only applied to the 7 non-WNA months of May through November. Since the WNA adjusts customer volumes during the months of December through April, it was not necessary to make a temperature normalization adjustment during these months. During the months of May through November, actual heating degree days related to cycle billed customer deliveries were 54 above the 30-year average Weather Bureau heating-degree days of 712 for those months. This difference was then used in the calculation of the temperature normalization adjustment for the residential and small non-residential rate classes.

Q. Please summarize the total impact of the gas temperature normalization adjustment.

A. The temperature normalization adjustment results in a net increase of $106,452 to Delta's gas operating revenue. The calculation of this amount is summarized on Seelye Exhibit 9.

V. REVENUE ADJUSTMENT TO REFLECT YEAR-END CUSTOMERS

Q. Is Delta proposing to make a pro-forma adjustment to reflect the number of customers served at the end of the year?

A. No, and it respectfully asks that a year-end customer adjustment not be made in this proceeding. The purpose of such an adjustment is to normalize annual revenues to reflect a going forward level of customers. The rationale for a year-end adjustment is to compare the number of customers at the end of the test year to the average number of customers during the test year. If the year-end level is higher than the average then it is assumed that the Company is adding customers and that the year-end level of customers and associated revenues is more appropriate than the average test-year level on a going-forward basis for purposes of setting rates. Delta does not believe that the year-end level of customers reflects an appropriate going forward level of customers. In fact, it is likely that the revenues associated with the year-end level will overstate Delta's going forward revenue because the year-end level of customers will almost certainly be higher than the average number of customers during the first full year that the rates go into effect.

In this proceeding, the year-end level of customers is not higher than the average because of customer growth, but, rather, because of the selection of the 12 months ended December as the test year. A significant number of customers disconnect service during the summer months and return to the system during the winter months. Because the test year in this proceeding ends in December – which is a winter month – using the year-end level of customers overstates the customer level that should be used for purposes of normalization. As can be seen from the following table, Delta is not adding customers. In fact, Delta has been consistently losing customers over the past several years:

TABLE 3
Average Customers by Year

Year	Total Average Customers
2002	40,185
2003	39,765
2004	39,358
2005	38,981
2006	38,117

Based on this trend, one could expect that the number of customers served by Delta will continue to decrease, thus suggesting that a downward adjustment should be made to normalize revenues to reflect the number of customers served on a going forward basis. Delta is not proposing to make a downward revenue adjustment to reflect this trend, and asks that the Commission not make a year-end adjustment in this proceeding. The standard year-end adjustment is included in Seelye Exhibit 10 in the event that the Commission rejects the recommendation not to make a year-end adjustment.

VI. DEPRECIATION STUDY AND DEPRECIATION EXPENSE ADJUSTMENT

Q. Did you supervise the preparation of a depreciation study for Delta?

A. Yes.

Q. Was a standard methodology used to determine the depreciation accrual rates?

A. Yes. Where suitable information was available, the Simulated Plant Record (SPR) methodology was used to determine the survivor curve that best fit the plant retirement data for Delta's plant accounts. The SPR methodology is described in *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners and in other publications. Where sufficient data were not available, or the resulting statistics were not satisfactory, we relied heavily on comparisons to the survivor curves and depreciation rates utilized by neighboring gas utilities. The methodology used to develop the depreciation accrual rates is described in more detail in the report included in Seelye Exhibit 11.

Q. Was the same methodology used in this depreciation study as in study filed by Delta in its last rate case (Case No. 2004-00067)?

A. Yes. The Company submitted a depreciation study and made some corrections to the study in rebuttal testimony filed in that proceeding. The Commission accepted the corrected depreciation study filed by the Company. The depreciation study filed in this proceeding follows the methodology used in the corrected study that was approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

Seelye Exhibit 1

Summary of Qualifications

WILLIAM STEVEN SEELYE

Summary of Qualifications

Bachelor of Science degree in Mathematics; completed 54 hours of graduate level course work in Industrial Engineering and Physics. 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

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

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

Prepared and filed Order No. 888 and 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities. Prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; 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.

Various Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department. 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
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

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.

FERC: Testified in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. Testified in Case No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

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: Testified 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: Testified in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies and rate design. Testified in Cause No. 43111 on behalf of Vectren in support of a transmission cost recovery adjustment.

Kansas: Testified 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. Testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates. Testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan and in Case No. 99-176 concerning cost of service, rate design and expense adjustments in connection with Delta's rate case. 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. Testified on behalf of Louisville Gas and Electric Company in Case No. 2003-00433 and on behalf of Kentucky Utilities Company in Case No. 2003-00434 regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design. Testified on behalf of Delta Natural Gas Company in Case No. 2004-00067 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.

Nevada: Testified on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital and rate base adjustments. Testified on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital. Testified on behalf of Sierra Pacific Power Company in Case No. 05-10003 regarding cash working capital for an electric general rate case. Testified on behalf of Sierra Pacific Power Company in Case No. 05-10005 regarding cash working capital for a gas general rate case. Testified on behalf of Nevada Power Company in Case Nos. 06-11022 and 06-11023 regarding cash working capital for a gas general rate case.

Seelye Exhibit 2

Reconstruction of Billing Determinants

Delta Natural Gas Company, Inc.

Calculations to Verify Test Period Billing Determinants
For the 12 months Ended December 31, 2003

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Actual Billed Revenue	Elimination of Gas Cost Adjustment	Billing Correction	Revenue Excluding Gas Cost Adjustment	Elimination of Weather Normalization Adjustment	Net Revenue	Calculated Net Revenue	Correction Factor
REVENUE		(See Gas Cost Exhibit)		(Column (1) + (2))	(See WNA Exhibit)	(Column (3) + (4))	(See Verification of Rates Exhibit)	(Column (6) / Column (5))
Residential	$ 34,527,341.00	$ (22,936,300.71)		$ 11,591,040.29	$ (371,842.00)	$ 11,219,198.29	$ 11,174,973.21	0.99606
Small Non-Residential GS	10,269,885.00	(7,026,753.45)		3,243,131.55	(109,891.00)	3,133,240.55	3,101,068.84	0.98973
Large Non-Residential GS								
Large Non-Residential GS - Commercial	13,254,779.00	(9,926,896.18)		3,327,882.82	-	3,327,882.82	3,328,998.71	1.00034
Large Non-Residential GS - Industrial	1,721,229.00	(1,380,929.29)		340,299.71	-	340,299.71	339,610.95	0.99798
Total Large Non-Residential GS	14,976,008.00	(11,307,825.47)		3,668,182.53	-	3,668,182.53	3,668,609.66	
Interruptible								
Interruptible -Commercial	39,289.00	(33,431.90)		5,857.10	-	5,857.10	5,602.40	0.95651
Interruptible - Industrial	484,019.46	(410,921.61)	(3,992.43)	69,105.42	-	69,105.42	69,674.40	1.00823
Total Interruptible	523,308.46	(444,353.51)	(3,992.43)	74,962.52	-	74,962.52	75,276.80	
Unmetered Gas Lights								
Residential	9,737.45	(7,262.07)		2,475.38	-	2,475.38	2,477.28	1.00077
Commercial	4,291.00	(3,266.82)		1,024.18	-	1,024.18	1,024.65	1.00046
Small Commercial	6,008.05	(4,573.55)		1,434.50	-	1,434.50	1,457.28	1.01588
Unmetered Gas Lights	20,036.50	(15,102.45)		4,934.05		4,934.05	4,959.21	
Total Retail	$ 60,316,578.96	$ (41,730,335.59)	$ (3,992.43)	$ 18,582,250.94	$ (481,733.00)	$ 18,100,517.94	$ 18,024,887.72	0.99582
Special Contracts	608,063.00			608,063.00		608,063.00	$ 608,062.27	1.00000
Small Non-Residential GS	147,218.00			147,218.00		147,218.00	147,698.65	1.00326
Large Non-Residential GS	2,016,375.00			2,016,375.00		2,016,375.00	2,023,250.48	1.00341
Residential	6,377.00			6,377.00		6,377.00	6,495.59	1.01860
Interuptible	1,550,100.00			1,550,100.00		1,550,100.00	1,550,747.52	1.00042
On System Transportation	4,328,133.00			4,328,133.00		4,328,133.00	4,336,254.51	
Off System Transportation	2,484,947.00			2,484,947.00		2,484,947.00	2,484,947.66	1.00000
Total Transportation	$ 6,813,080.00	$ -		$ 6,813,080.00	$ -	$ 6,813,080.00	$ 6,821,202.17	1.00119
Miscellaneous Revenue	$ 261,301.00	$ -		261,301.00		$ 261,301.00	$ 261,301.00	
Total Operating Revenue	$ 67,390,959.96	$ (41,730,335.59)	$ (3,992.43)	$ 25,656,631.94	$ (481,733.00)	$ 25,174,898.94	$ 25,107,390.89	0.99732

MCF	(1)	(6)
Residential	1,778,782	1,778,782
Small Non-Residential GS	544,113	544,113
Large Non-Residential GS - Commercial	781,181	781,181
Large Non-Residential GS - Industrial	107,456	107,456
Interruptible - Commercial	2,564	2,564
Interruptible - Industrial	32,652	32,652
Unmetered Gas Lights - Total	1,250	1,250
Total Retail	3,247,997	3,247,997
On System Transportation Special	5,375,396	5,375,396
Off System Transportation	8,525,855	8,525,855
Total Transportation	13,901,252	13,901,252
Total	17,149,249	17,149,249

Seelye Exhibit 3

Summary of Proposed Increase

Delta Natural Gas Company, Inc.

Summary of Proposed Rate Increase by Rate Class
Based on Adjusted Sales and Transportation for the 12 months Ended December 31, 2006

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Actual Billed Revenue	Elimination of Gas Cost Adjustment	Correction	Net Revenue Before Temperature Adjustment	Temperature Adjustment	GCR at Current Rates	Adjusted Billings at Current Rates	Proposed Increase in Revenue	Percentage Increase
REVENUE		(See Gas Cost Exhibit)		(Column (1) + (2))	(See Temperature Normalization Exhibit)	10.4200	(Column (3) + (4) + (5))		
Residential	$ 34,527,341	$ (22,936,301)		$ 11,591,040	$ (53,005)	$ 19,333,683	$ 30,871,718	$ 3,845,405	12.5%
Small Non-Residential GS	10,269,885	(7,026,753)		3,243,132	(11,271)	5,940,440	9,172,300	471,298	5.1%
Large Non-Residential GS									
Large Non-Residential GS - Commercial	13,254,779	(9,926,896)		3,327,883	89,258	8,384,984	11,802,126	563,300	4.8%
Large Non-Residential GS - Industrial	1,721,229	(1,380,929)		340,300	13,389	1,156,453	1,510,142	57,756	3.8%
Total Large Non-Residential GS	14,976,008	(11,307,825)		3,668,183	102,647	9,541,438	13,312,267	621,056	4.7%
Interruptible									
Interruptible - Commercial	39,289	(33,432)		5,857	314	28,759	34,930	-	
Interruptible - Industrial	484,019	(410,922)	(3,992)	69,105	1,568	350,445	421,119	-	
Total Interruptible	523,308	(444,354)	(3,992)	74,963	1,882	379,205	456,049	-	0.0%
Unmetered Gas Lights									
Residential	9,737	(7,262)		2,475		6,205	8,680	(1)	
Commercial	4,291	(3,267)		1,024		2,813	3,838	97	
Small Commercial	6,008	(4,574)		1,434		4,001	5,436	136	
Unmetered Gas Lights	20,037	(15,102)		4,934		13,020	17,954	232	1.3%
Total Retail	$ 60,316,579	$ (41,730,336)	$ (3,992)	$ 18,582,251	$ 40,253	$ 35,207,784	$ 53,830,288	$ 4,937,991	
Special Contracts	$ 608,063	$ -		$ 608,063	$ -	$ -	$ 608,063	$ -	
Small Non-Residential GS	147,218	-		147,218	5,207	-	152,425	17,885	
Large Non-Residential GS	2,016,375	-		2,016,375	60,993	-	2,077,368	509,063	
Residential	6,377	-		6,377	-	-	6,377	1,826	
Interruptible	1,550,100	-		1,550,100	-	-	1,550,100	-	
On System Transportation	4,328,133	-		4,328,133	66,200	-	4,394,333	528,775	12.0%
Off System Transportation	2,484,947	-		2,484,947	-	-	2,484,947	95,575	3.9%
Total Transportation	$ 6,813,080	$ -		$ 6,813,080	$ 66,200	$ -	$ 6,879,280	$ 624,350	9.1%
Miscellaneous Revenue	$ 261,301	$ -		$ 261,301			$ 261,301	$ 79,309	30.4%
Total Operating Revenue	$ 67,390,960	$ (41,730,336)	$ (3,992)	$ 25,656,632	$ 106,453	$ 35,207,784	$ 60,970,869	$ 5,641,650	9.3%

MCF	(1)	(5)	(6)
Residential	1,778,782	76,658	1,855,440
Small Non-Residential GS	544,113	25,987	570,100
Large Non-Residential GS - Commercial	781,181	23,520	804,701
Large Non-Residential GS - Industrial	107,456	3,528	110,984
Interruptible - Commercial	2,564	196	2,760
Interruptible - Industrial	32,652	980	33,632
Unmetered Gas Lights - Residential	596	-	596
Unmetered Gas Lights - Commercial	270	-	270
Unmetered Gas Lights Small Commercial	384	-	384
Total Retail	3,247,997	130,869	3,378,866
On System Transportation Special	5,375,396	17,444	5,392,840
Off System Transportation	8,525,855		8,525,855
Total Transportation	13,901,252	17,444	13,918,696
Total	17,149,249	148,313	17,297,562

Seelye Exhibit 4

Calculated Billings at Proposed Rates

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Residential

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	385,374	$ 9.80	$ 3,776,665.20	$ 19.74	$ 19.74	$ 7,607,282.76
Commodity Charge	*Mcf*					
All Mcf	1,778,782	$ 4.1592	7,398,308.01	$ 4.1592	$ 0.4159	7,397,952.26
Calculated Billings at Base Rates			$ 11,174,973.21			$ 15,005,235.02
Correction Factor -(Calculated / Actual)		*0.99606*		*0.99606*		
Total After Application of Correction Factor			$ 11,219,198.29			$ 15,064,618.40
Temperature Normalization						
All Mcf	76,658	$ 4.1592	318,837.16	$ 4.1592	$ 0.4159	318,821.83
	Mcf					
Adjusted Billings at Base Rates	1,855,440		$ 11,538,035.45			$ 15,383,440.23
GCR at Current Rates	1,855,440	10.4200	19,333,682.61	10.4200	$ 1.0420	19,333,682.61
Total Adjusted Billings at Base Rates			$ 30,871,718.06			$ 34,717,122.84
Proposed Increase in Revenue						$ 3,845,404.78
						12.46%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Small Non-Residential General Service

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	51,808	$ 20.00	$ 1,036,160.00	$ 25.00	$ 25.00	$ 1,295,200.00
Commodity Charge	*Mcf*					
All Mcf	544,113	$ 3.7950	2,064,908.84	$ 4.1592	$ 0.4159	2,262,965.97
Calculated Billings at Base Rates	544,113		$ 3,101,068.84			$ 3,558,165.97
Correction Factor -(Calculated / Actual)		*0.98973*		*0.9897*		
Total After Application of Correction Factor			$ 3,133,240.55			$ 3,595,079.79
Temperature Normalization						
First 200 Mcf	25,987	$ 3.7950	98,619.85	$ 4.1592	$ 0.4159	108,079.04
	Mcf					
Adjusted Billings at Base Rates	570,100		$ 3,231,860.40			$ 3,703,158.83
GCR at Current Rates	570,100	10.4200	5,940,439.75	10.4200	$ 1.0420	5,940,439.75
Total Adjusted Billings at Base Rates			$ 9,172,300.15			$ 9,643,598.58
Proposed Increase in Revenue						$ 471,298.43
						5.14%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Large Non-Residential General Service - Commercial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	9,664	$ 72.00	$ 695,808.00	$ 100.00	$ 100.00	$ 966,400.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	589,818	$ 3.7950	2,238,359.31	$ 4.1592	$ 0.4159	2,453,053.06
Next 800 Mcf	171,450	$ 2.1461	367,948.85	$ 2.5103	$ 0.2510	430,339.50
Next 4,000 Mcf	19,913	$ 1.3500	26,882.55	$ 1.7142	$ 0.1714	34,130.88
Next 5,000 Mcf	-	$ 0.9500	-	$ 1.3142	$ 0.1314	-
Over 10,000 Mcf	-	$ 0.7500	-	$ 1.1142	$ 0.1114	-
Calculated Billings at Base Rates	781,181		$ 3,328,998.71			$ 3,883,923.44
Correction Factor -(Calculated / Actual)		*1.0003*		*1.0003*		
Total After Application of Correction Factor			$ 3,327,882.82			$ 3,882,621.54
Temperature Normalization						
First 200 Mcf	23,520	$ 3.7950	89,258.40	$ 4.1592	$ 0.4159	97,819.68
	Mcf					
Adjusted Billings at Base Rates	804,701		$ 3,417,141.22			$ 3,980,441.22
GCR at Current Rates	804,701	10.4200	8,384,984.42	10.4200	1.0420	8,384,984.42
			$ 11,802,125.64			$ 12,365,425.64
Proposed Increase in Revenue						$ 563,300.00
						4.77%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Large Non-Residential General Service - Industrial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	616	$ 72.00	$ 44,352.00	$ 100.00	$ 100.00	$ 61,600.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	46,157	$ 3.7950	175,165.82	$ 4.1592	$ 0.4159	191,966.96
Next 800 Mcf	46,903	$ 2.1461	100,658.53	$ 2.5103	$ 0.2510	117,726.53
Next 4,000 Mcf	14,396	$ 1.3500	19,434.60	$ 1.7142	$ 0.1714	24,674.74
Next 5,000 Mcf	-	$ 0.9500	-	$ 1.3142	$ 0.1314	-
Over 10,000 Mcf	-	$ 0.7500	-	$ 1.1142	$ 0.1114	-
Calculated Billings at Base Rates	107,456		$ 339,610.95			$ 395,968.23
Correction Factor -(Calculated / Actual)		*0.99798*		*0.99798*		
Total After Application of Correction Factor			$ 340,299.71			$ 396,771.28
Temperature Normalization						
First 200 Mcf	3528	$ 3.7950	13,388.76	$ 4.1592	$ 0.4159	14,672.95
	Mcf					
Adjusted Billings at Base Rates	110,984		$ 353,688.47			$ 411,444.23
GCR at Current Rates	110,984	10.4200	1,156,453.28	10.4200	1.0420	1,156,453.28
			$ 1,510,141.75			$ 1,567,897.51
Proposed Increase in Revenue						$ 57,755.76
						3.82%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Interruptible Service - Commercial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	6	$ 250.00	$ 1,500.00	$ 250.00	$ 250.00	$ 1,500.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	2,564	$ 1.6000	4,102.40	$ 1.6000	$ 0.1600	4,102.40
Next 4,000 Mcf	-	$ 1.2000	-	$ 1.2000	$ 0.1200	-
Next 5,000 Mcf	-	$ 0.8000	-	$ 0.8000	$ 0.0800	-
Over 10,000 Mcf	-	$ 0.6000	-	$ 0.6000	$ 0.0600	-
Calculated Billings at Base Rates	2,564		$ 5,602.40			$ 5,602.40
Correction Factor -(Calculated / Actual)		*0.95651*		*0.95651*		
Total After Application of Correction Factor			$ 5,857.10			$ 5,857.10
Temperature Normalization						
First 1,000 Mcf	196	$ 1.6000	313.60	$ 1.6000	$ 0.1600	313.60
	Mcf					
Adjusted Billings at Base Rates	2,760		$ 6,170.70			$ 6,170.70
GCR at Current Rates	2,760	10.4200	28,759.20	10.4200	1.0420	28,759.20
			$ 34,929.90			$ 34,929.90
Proposed Increase in Revenue						$ -
						0.00%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Interruptible Service - Industrial

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	84	$ 250.00	$ 21,000.00	$ 250.00	$ 250.00	$ 21,000.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	23,730	$ 1.6000	37,968.00	$ 1.6000	$ 0.1600	37,968.00
Next 4,000 Mcf	8,922	$ 1.2000	10,706.40	$ 1.2000	$ 0.1200	10,706.40
Next 5,000 Mcf	-	$ 0.8000	-	$ 0.8000	$ 0.0800	-
Over 10,000 Mcf	-	$ 0.6000	-	$ 0.6000	$ 0.0600	-
Calculated Billings at Base Rates	32,652		$ 69,674.40			$ 69,674.40
Correction Factor -(Calculated / Actual)		*1.00823*		*1.00823*		
Total After Application of Correction Factor			$ 69,105.42			$ 69,105.42
Temperature Normalization				-		
First 1,000 Mcf	980	$ 1.6000	1,568.00	$ 1.6000	$ 0.1600	1,568.00
	Mcf					
Adjusted Billings at Base Rates	33,632		$ 70,673.42			$ 70,673.42
GCR at Current Rates	33,632	10.4200	350,445.44	10.4200	1.0420	350,445.44
			$ 421,118.86			$ 421,118.86
Proposed Increase in Revenue						$ -
						0.00%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Unmetered Gas Lights - Residential

	Lights	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	397	$ -	$ -	$ -		$ -
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	596	$ 4.1600	2,477.28	$ 4.1592	$ 0.4159	2,476.68
Calculated Billings at Base Rates			$ 2,477.28			$ 2,476.68
Correction Factor -(Calculated / Actual)		*1.00077*		*1.00077*		
Total After Application of Correction Factor			$ 2,475.38			$ 2,474.78
Temperature Normalization						
	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	596		$ 2,475.38			$ 2,474.78
GCR at Current Rates	596	10.4200	6,205.11	10.4200	1.0420	6,205.11
			$ 8,680.49			$ 8,679.89
Proposed Increase in Revenue						$ (0.60)
						-0.01%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Unmetered Gas Lights - Commercial

	Lights	Present Rate		*Calculated Net Revenue@ Present Rates*	*Proposed Rate*	*Proposed Rate Per Ccf*		*Calculated Net Revenue@ Proposed Rates*
Customer Charge	180	$ -	$	-	$ -		$	-
Commodity Charge	*Mcf*	*Present Rate*						
All Mcf	270	$ 3.8000		1,026.00	$ 4.1592	$ 0.4159		1,122.93
Calculated Billings at Base Rates			$	1,026.00			$	1,122.93
Correction Factor -(Calculated / Actual)		*1.00046*			*1.00046*			
Total After Application of Correction Factor			$	1,025.52			$	1,122.41
Temperature Normalization								
	-			-	$ -			-
	Mcf							
Adjusted Billings at Base Rates	270		$	1,025.52			$	1,122.41
GCR at Current Rates	270	10.4200		2,813.40	10.4200	1.0420		2,813.40
			$	3,838.92			$	3,935.81
Proposed Increase in Revenue							$	96.89
								2.52%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Unmetered Gas Lights - Small Commercial

	Lights	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	252	$ -	$ -	$ -		$ -
Commodity Charge	*Mcf*	*Present Rate*				
All Mcf	384	$ 3.8000	1,459.20	$ 4.1592	$ 0.4159	1,597.06
Calculated Billings at Base Rates			$ 1,459.20			$ 1,597.06
Correction Factor -(Calculated / Actual)		*1.01588*		*1.01588*		
Total After Application of Correction Factor			$ 1,436.39			$ 1,572.09
Temperature Normalization						
	-		-	$ -		-
	Mcf					
Adjusted Billings at Base Rates	384		$ 1,436.39			$ 1,572.09
GCR at Current Rates	384	10.4200	4,001.28	10.4200	1.0420	4,001.28
			$ 5,437.67			$ 5,573.37
Proposed Increase in Revenue						$ 135.70
						2.50%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation

Special Contracts (4)

	Customers	*Mcf*		*Net Margin@ Present Rates*		*Net Margin@ Proposed Rates*
	48	2,801,367				
Calcuiated Billings at Base Rates				$ 608,062.27		$ 608,062.27
Correction Factor -(Calculated / Actual)			*1.00000*		*1.00000*	
Total After Application of Correction Factor				$ 608,063.00		$ 608,063.00

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation
Small Non Residential General Service -Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	1,063	$ 20.00	$ 21,260.00	$ 25.00	$ 25.00	$ 26,575.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	33,317	$ 3.7950	126,438.65	$ 4.1592	$ 0.4159	138,566.10
Next 800 Mcf	-	$ 2.1461	-	$ 2.5103	$ 0.2510	-
Next 4,000 Mcf	-	$ 1.3500	-	$ 1.7142	$ 0.1714	-
Next 5,000 Mcf	-	$ 0.9500	-	$ 1.3142	$ 0.1314	-
Over 10,000 Mcf	-	$ 0.7500	-	$ 1.1142	$ 0.1114	-
Calculated Billings at Base Rates	33,317		$ 147,698.65			$ 165,141.10
Correction Factor -(Calculated / Actual)		*1.00326*		*1.00326*		
Total After Application of Correction Factor			$ 147,218.00			$ 164,603.69
Temperature Normalization						
First 200 Mcf	1,372.00	$ 3.7950	5,206.74	$ 4.1592	$ 0.4159	5,706.15
	Mcf					
Adjusted Billings at Base Rates	33,317		$ 152,424.74			$ 170,309.84
Proposed Increase in Revenue						$ 17,885.10
						11.73%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation
Large Non Residential General Service -Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	856	$ 72.00	$ 61,632.00	$ 100.00	$ 100.00	$ 85,600.00
Commodity Charge	*Mcf*	*Present Rate*				
First 200 Mcf	92,819	$ 3.7950	352,249.39	$ 4.1592	$ 0.4159	386,035.63
Next 800 Mcf	212,762	$ 2.1461	456,609.43	$ 2.5103	$ 0.2510	534,033.68
Next 4,000 Mcf	573,158	$ 1.3500	773,763.38	$ 1.7142	$ 0.1714	982,392.91
Next 5,000 Mcf	235,080	$ 0.9500	223,325.92	$ 1.3142	$ 0.1314	308,895.01
Over 10,000 Mcf	207,560	$ 0.7500	155,670.36	$ 1.1142	$ 0.1114	231,222.37
Calculated Billings at Base Rates	1,321,380		$ 2,023,250.48			$ 2,528,179.60
Correction Factor -(Calculated / Actual)		*1.00341*		*1.00341*		
Total After Application of Correction Factor			$ 2,016,375.00			$ 2,519,588.25
Temperature Normalization						
First 200 Mcf	16,072	$ 3.7950	60,993.24	$ 4.1592	$ 0.4159	66,843.45
	Mcf					
Adjusted Billings at Base Rates	1,321,380		$ 2,077,368.24			$ 2,586,431.70
Proposed Increase in Revenue						$ 509,063.46
						24.51%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation

Residential

	Customers	Present Rate		Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf		Calculated Net Revenue@ Proposed Rates
Customer Charge	191	$ 10.00	$	1,910.00	$ 19.74	$ 19.74	$	3,770.34
Commodity Charge	*Mcf*	*Present Rate*						
All Mcf	1,103	$ 4.1592		4,585.59	$ 4.1592	$ 0.4159		4,585.37
Calculated Billings at Base Rates			$	6,495.59			$	8,355.71
Correction Factor -(Calculated / Actual)		*1.01860*			*1.01860*			
Total After Application of Correction Factor			$	6,377.00			$	8,203.16
Temperature Normalization								
All Mcf		$ 4.1592		-	$ 4.1592	$ 0.4159		-
	Mcf							
Adjusted Billings at Base Rates	1,103		$	6,377.00			$	8,203.16
Proposed Increase in Revenue							$	1,826.16
								28.64%

Delta Natural Gas Company, Inc.
Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

On System Transportation
Interruptible Service - Transportation

	Customers	Present Rate	Calculated Net Revenue@ Present Rates	Proposed Rate	Proposed Rate Per Ccf	Calculated Net Revenue@ Proposed Rates
Customer Charge	356	$ 250.00	$ 89,000.00	$ 250.00	$ 250.00	$ 89,000.00
Commodity Charge	*Mcf*	*Present Rate*				
First 1,000 Mcf	299,009	$ 1.6000	478,413.93	$ 1.6000	$ 0.1600	478,413.93
Next 4,000 Mcf	648,134	$ 1.2000	777,760.75	$ 1.2000	$ 0.1200	777,760.75
Next 5,000 Mcf	214,604	$ 0.8000	171,683.24	$ 0.8000	$ 0.0800	171,683.24
Over 10,000 Mcf	56,483	$ 0.6000	33,889.60	$ 0.6000	$ 0.0600	33,889.60
Calculated Billings at Base Rates	1,218,229		$ 1,550,747.52			$ 1,550,747.52
Correction Factor -(Calculated / Actual)		*1.00042*		*1.00042*		
Total After Application of Correction Factor			$ 1,550,100.00			$ 1,550,100.00
Temperature Normalization						
First 1,000 Mcf		$ 1.6000	-	$ 1.6000	$ 0.1600	-
	Mcf					
Adjusted Billings at Base Rates	1,218,229		$ 1,550,100.00			$ 1,550,100.00
Proposed Increase in Revenue						$ -
						0.00%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Off System Transportation

	DDTH	Present Rate per DDTH	Calculated Net Revenue@ Present Rates	Proposed Rate Per DDTH	Calculated Net Revenue@ Proposed Rates
Commodity Charge					
Dekatherms	9,557,491	$ 0.2600	$ 2,484,947.66	$ 0.2700	2,580,522.57
Calculated Billings at Base Rates			$ 2,484,947.66		2,580,522.57
Correction Factor -(Calculated / Actual)		*1.00000*		*1.00000*	
Total After Application of Correction Factor			$ 2,484,947.00		$ 2,580,521.88
Temperature Normalization					
		$ -	-	$ -	-
Adjusted Billings at Base Rates			$ 2,484,947.00		$ 2,580,521.88
Proposed Increase in Revenue					$ 95,574.88
					3.85%

Delta Natural Gas Company, Inc.

Calculated Increase in Revenue under Proposed Revision of Rates
Based on the adjusted sales for the 12 months Ended December 31, 2006

Miscellaneous Charges		Current		Proposed		
	Units	Charge	Revenue	Charge	Revenue	Difference
Collection Fees	9,154	$ 15.00	$ 137,310	$ 15.00	$ 183,080	$ 45,770
Reconnect Revenue	2,373	48.00	113,896.00	48.00	142,380	$ 28,484
Bad Check Revenue	1,010	10.00	10,095.00	10.00	15,150	$ 5,055
Total			$ 261,301		$ 340,610	$ 79,309

Seelye Exhibit 5

Class Cost of Service Study

Functional Assignment
And Classification

Description		Name	Vector		Distribution Mains Demand		Distribution Mains Customer		Services Customer		Meters Customer		Customer Accounts Customer		Customer Service Expense Customer
Labor Expenses (Continued)															
Maintenance Expense -- Transmission and Distribution															
885	Maintenance Supr and Engr	LB885	DMES		-		-		-		-		-		-
886	Maintenance Structures	LB886	F008		-		-		-		-		-		-
887	Maintenance Mains	LB887	F009		37,668		49,004		-		-		-		-
888	Maintenance Comp. Station Equip.	LB888	F007		-		-		-		-		-		-
889	Maintenance Meas and Reg. General	LB889	F008		-		-		-		-		-		-
890	Maintenance Meas and Reg - Industrial	LB890	F011		-		-		-		-		-		-
891	Maintenance Meas and Reg.-City Gate	LB891	F008		-		-		-		-		-		-
892	Maintenance Services	LB892	F010		-		-		-		-		-		-
893	Maintenance Meters and House Reg.	LB893	F011		-		-		-		16,313		-		-
894	Maintenance Other Equipment	LB894	PTDSUB		2,812		3,659		1,344		1,752		-		-
898	Maintenance Transportaion Equip	LB898	PTDSUB		-		-		-		-		-		-
900	Trans & Distribution Expenses	LB900	TDSUB		474,260		616,996		226,583		295,445		-		-
Total Maintenance Labor		LBDM		$	514,740	$	669,659	$	227,927	$	313,510	$	-	$	-
Total Transmission & Distribution Labor		LBTD		$	514,740	$	669,659	$	227,927	$	313,510	$	-	$	-
Customer Accounts Expense															
901	Supervision	LB901	F012		-		-		-		-		-		-
902	Meter Reading	LB902	F012		-		-		-		-		-		-
903	Customer Records and Collections	LB903	F012		-		-		-		-		404,578		-
904	Uncollectible Accounts	LB904	F012		-		-		-		-		-		-
905	Misc. Cust Account Expenses	LB905	F012		-		-		-		-		-		-
Total Customer Accounts Labor		LBCA		$	-	$	-	$	-	$	-	$	404,578	$	-
Customer Service Expenses															
907-910	Customer Service	LB907	F013		-		-		-		-		-		-
Sales Expenses															
911-916	Sales Expenses	LB911	F013		-		-		-		-		-		-

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Labor Expenses (Continued)																	
Administrative & General																	
920	Admin and General Salaries	LB920	LBSUB	$	2,482,184		47,910		23,424		693,391		57,848		-		30,944
921	Office Supplies and Expense	LB921	LBSUB		-		-		-		-		-		-		-
922	Admin. Expenses Transferred	LB922	LBSUB		-		-		-		-		-		-		-
923	Outside Services Employed	LB923	OMSUB		-		-		-		-		-		-		-
924	Property Insurance	LB924	PTT		-		-		-		-		-		-		-
925	Injuries and Damages	LB925	PTT		-		-		-		-		-		-		-
926	Employee Pensions and Benefits	LB926	LBSUB		1,036,705		20,010		9,783		289,600		24,161		-		12,924
927	Franxhise Requirement	LB927	PTT		-		-		-		-		-		-		-
928	Regulatory Commission Fee	LB928	PTT		-		-		-		-		-		-		-
929	Duplicate Charges -Dredit	LB929	PTT		-		-		-		-		-		-		-
930.1	General Advertising Expense	LB930.1	PTT		-		-		-		-		-		-		-
930.2	Misc. General Expense	LB930.2	OMSUB		-		-		-		-		-		-		-
931	Rents	LB931	PTT		-		-		-		-		-		-		-
935	Maintenance of General Plant	LB935	PT389		-		-		-		-		-		-		-
Total Administrative and General Labor		LBAG		$	3,518,889	$	67,920	$	33,207	$	982,991	$	82,008	$	-	$	43,867
Total Labor Expense		LBTOT		$	6,765,762	$	130,590	$	63,847	$	1,889,995	$	157,677	$	-	$	84,344

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)									
Administrative & General									
920	Admin and General Salaries	LB920	LBSUB	393,510	511,944	174,247	239,674	309,294	-
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	-	-	-	-	-	-
923	Outside Services Employed	LB923	OMSUB	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-
925	Injuries and Damages	LB925	PTT	-	-	-	-	-	-
926	Employee Pensions and Benefits	LB926	LBSUB	164,353	213,818	72,776	100,102	129,179	-
927	Franxhise Requirement	LB927	PTT	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-
929	Duplicate Charges -Dredit	LB929	PTT	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	OMSUB	-	-	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	-	-	-	-	-	-
Total Administrative and General Labor		LBAG		$ 557,863	$ 725,761	$ 247,022	$ 339,775	$ 438,473	$ -
Total Labor Expense		LBTOT		$ 1,072,603	$ 1,395,420	$ 474,949	$ 653,285	$ 843,051	$ -

DELTA NATU [illegible]AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses											
Production Expenses											
Operation & Maintenance											
753	Wells and Gathering	OM 753	F006		8,855	-	-	-	8,855	-	-
754	Compressor Station	OM754	F006		121,888	-	-	-	121,888	-	-
764	Maintenance of Wells and Gathering	OM764	F006		316	-	-	-	316	-	-
765	Maintenance of Compressor Station	OM765	F006		33,501	-	-	-	33,501	-	-
Total Production Operation & Maintenance Expenses					164,560	-	-	-	164,560	-	-
807-813	Procurement Expenses	OM807	DMCM	$	-	-	-	-	-	-	-
Storage Expenses											
Operation											
814	Operations Supervision and Engineer	OM814	OSE		-	-	-	-	-	-	-
815	Maps and Records	OM815	F003		-	-	-	-	-	-	-
816	Well Expenses	OM816	F003		61,646	61,646	-	-	-	-	-
817	Lines Expenses	OM817	F003		-	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004		46,077	-	46,077	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004		-	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003		-	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004		103,330	-	103,330	-	-	-	-
823	Gas losses	OM823	F004		-	-	-	-	-	-	-
824	Other Expenses	OM824	F004		1,808	-	1,808	-	-	-	-
825	Storage Well Royalities	OM825	F003		56,371	56,371	-	-	-	-	-
826	Rents	OM826	F003		-	-	-	-	-	-	-
Total Operation Expenses		OMOE		$	269,232	$ 118,017	$ 151,215	$ -	$ -	$ -	$ -
Storage Expense											
Maintenance											
830	Maintenance Super and Eng.	OM830	MSE	$	-	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003		2,649	2,649	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003		44,339	44,339	-	-	-	-	-
833	Maintenance of Lines	OM833	F003		-	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004		35,829	-	35,829	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003		2,218	2,218	-	-	-	-	-
836	Main of Purification Equip	OM836	F004		-	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003		2,303	2,303	-	-	-	-	-
Total Maintenance Expense		OMME		$	87,338	$ 51,509	$ 35,829	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		$	356,570	169,526	187,044	-	-	-	-

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses									
Production Expenses									
Operation & Maintenance									
753	Wells and Gathering	OM 753	F006	-	-	-	-	-	-
754	Compressor Station	OM754	F006	-	-	-	-	-	-
764	Maintenance of Wells and Gathering	OM764	F006	-	-	-	-	-	-
765	Maintenance of Compressor Station	OM765	F006	-	-	-	-	-	-
Total Production Operation & Maintenance Expenses				-	-	-	-	-	-
807-813	Procurement Expenses	OM807	DMCM	-	-	-	-	-	-
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-
816	Well Expenses	OM816	F003	-	-	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-
821	Purification of Natural Gas	OM821	F004	-	-	-	-	-	-
823	Gas losses	OM823	F004	-	-	-	-	-	-
824	Other Expenses	OM824	F004	-	-	-	-	-	-
825	Storage Well Royalities	OM825	F003	-	-	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	-	-	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	-	-	-	-	-	-
Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		-	-	-	-	-	-

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)										
Transmission										
850-867	Transmission Expenses	OM850	F005	$ 66,285	-	-	66,285	-	-	-
Distribution Expenses										
Operation										
870	Operation Supr and Engr	OM870	DOES	$ -	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	58,165	-	-	-	-	58,165	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	349,553	-	-	-	-	-	8,506
881	Rents	OM881	PTDSUB	17,394	-	-	-	-	-	423
Total Operations Distribution Expense		OMDO		$ 425,112	-	-	-	-	58,165	8,930
Total Transmission and Distribution Oper Exp		OMTDO		$ 622,140	$ -	$ -	$ 66,285	$ 130,743	$ 58,165	$ 8,930

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Transmission									
850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-
Distribution Expenses									
Operation									
870	Operation Supr and Engr	OM870	DOES	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	100,258	130,432	47,900	62,457	-	-
881	Rents	OM881	PTDSUB	4,989	6,490	2,384	3,108	-	-
Total Operations Distribution Expense		OMDO		105,247	136,923	50,283	65,565	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 105,247	$ 136,923	$ 50,283	$ 65,565	$ -	$ -

DELTA NATU ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Total Company		Storage Demand		Storage Commodity		Transmission Demand		Transmission Commodity		Distribution Commodity		Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)																	
Maintenance Expense -- Transmission and Distribution																	
885	Maintenance Supr and Engr	OM885	DMES	$	-		-		-		-		-		-		-
886	Maintenance Structures	OM886	F008		-		-		-		-		-		-		-
887	Maintenance Mains	OM887	F009		150,379		-		-		-		-		-		-
888	Maintenance Comp. Station Equip.	OM888	F007		-		-		-		-		-		-		-
889	Maintenance Meas and Reg. General	OM889	F008		7,505		-		-		-		-		-		7,505
890	Maintenance Meas and Reg - Industrial	OM890	F011		-		-		-		-		-		-		-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-		-		-		-		-		-		-
892	Maintenance Services	OM892	F010		-		-		-		-		-		-		-
893	Maintenance Meters and House Reg.	OM893	F011		59,307		-		-		-		-		-		-
894	Maintenance Other Equipment	OM894	PTDSUB		112,086		-		-		-		-		-		2,728
898	Maintenance Transportaion Equip	OM898	PTDSUB		45,916		-		-		-		-		-		1,117
900	Trans & Distribution Expenses	OM900	TDSUB		3,344,534		-		-		1,184,720		-		-		52,558
Total Maintenance Expenses		OMME		$	3,719,727	$	-	$	-	$	1,184,720	$	-	$	-	$	63,908
Total Transmission & Distribution Expenses		OMDE		$	4,375,684	$	-	$	-	$	1,251,005	$	164,560	$	58,165	$	72,838
Customer Accounts Expense																	
901	Supervision	OM901	F012	$	-		-		-		-		-		-		-
902	Meter Reading	OM902	F012		-		-		-		-		-		-		-
903	Customer Records and Collections	OM903	F012	$	628,360		-		-		-		-		-		-
904	Uncollectible Accounts	OM904	F012		484,710		-		-		-		-		-		-
905	Misc. Cust Account Expenses	OM905	F012		-		-		-		-		-		-		-
Total Customer Accounts Expense		OMCA		$	1,113,070	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service Expenses																	
907-910	Customer Service	OM907	F013	$	-		-		-		-		-		-		-
Sales Expenses																	
911-916	Sales Expenses	OM911	F013	$	2,264		-		-		-		-		-		-

DELTA NATU' 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)									
Maintenance Expense -- Transmission and Distribution									
885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009	65,355	85,024	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-	-	-
892	Maintenance Services	OM892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	59,307	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	32,148	41,824	15,359	20,027	-	-
898	Maintenance Transportaion Equip	OM898	PTDSUB	13,170	17,133	6,292	8,204	-	-
900	Trans & Distribution Expenses	OM900	TDSUB	619,473	805,914	295,961	385,908	-	-
Total Maintenance Expenses		OMME		$ 730,146	$ 949,895	$ 317,612	$ 473,446	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 835,393	$ 1,086,818	$ 367,895	$ 539,011	$ -	$ -
Customer Accounts Expense									
901	Supervision	OM901	F012	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	-	-	-	-	628,360	-
904	Uncollectible Accounts	OM904	F012	-	-	-	-	484,710	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ 1,113,070	$ -
Customer Service Expenses									
907-910	Customer Service	OM907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	OM911	F013	-	-	-	-	-	2,264

DELTA NATU ˈAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Operation & Maintenance Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	OM920	LBSUB	$ 2,576,284	49,727	24,312	719,677	60,041	-	32,117
921	Office Supplies and Expense	OM921	LBSUB	579,830	11,192	5,472	161,974	13,513	-	7,228
922	Admin. Expenses Transferred	OM922	LBSUB	(3,036,569)	(58,611)	(28,655)	(848,256)	(70,768)	-	(37,855)
923	Outside Services Employed	OM923	OMSUB	657,984	19,075	21,047	140,766	18,517	6,545	8,196
924	Property Insurance	OM924	PTT	786,124	77,118	-	255,578	-	-	11,021
925	Injuries and Damages	OM925	PTT	-	-	-	-	-	-	-
926	Employee Pensions and Benefits	OM926	LBSUB	3,181,757	61,413	30,026	888,814	74,151	-	39,665
927	Franxhise Requirement	OM927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	163,359	16,025	-	53,110	-	-	2,290
929	Duplicate Charges -Dredit	OM929	PTT	-	-	-	-	-	-	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	OMSUB	562,597	16,310	17,996	120,359	15,832	5,596	7,008
931	Rents	OM931	PTT	-	-	-	-	-	-	-
932	Maintenance of General Plant	OM932	PT389	183,395	14,231	-	59,922	-	-	2,658
Total Administrative and General Expense		OMAGT		$ 5,654,761	$ 206,481	$ 70,196	$ 1,551,944	$ 111,286	$ 12,141	$ 72,329
Total Operation & Maintenance Expense		OMT		$ 11,502,349	$ 376,007	$ 257,240	$ 2,802,949	$ 275,846	$ 70,306	$ 145,166

DELTA NATU' 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector		Distribution Mains Demand		Distribution Mains Customer		Services Customer		Meters Customer		Customer Accounts Customer		Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)															
Administrative & General															
920	Admin and General Salaries	OM920	LBSUB		408,428		531,352		180,852		248,760		321,019		-
921	Office Supplies and Expense	OM921	LBSUB		91,923		119,588		40,703		55,987		72,250		-
922	Admin. Expenses Transferred	OM922	LBSUB		(481,399)		(626,284)		(213,164)		(293,204)		(378,373)		-
923	Outside Services Employed	OM923	OMSUB		94,000		122,291		41,396		60,651		125,245		255
924	Property Insurance	OM924	PTT		130,128		169,292		62,063		80,924		-		-
925	Injuries and Damages	OM925	PTT		-		-		-		-		-		-
926	Employee Pensions and Benefits	OM926	LBSUB		504,416		656,229		223,356		307,223		396,464		-
927	Franxhise Requirement	OM927	PTT		-		-		-		-		-		-
928	Regulatory Commission Fee	OM928	PTT		27,041		35,179		12,897		16,816		-		-
929	Duplicate Charges -Dredit	OM929	PTT		-		-		-		-		-		-
930.1	General Advertising Expense	OM930.1	PTT		-		-		-		-		-		-
930.2	Misc. General Expense	OM930.2	OMSUB		80,373		104,563		35,395		51,858		107,089		218
931	Rents	OM931	PTT		-		-		-		-		-		-
932	Maintenance of General Plant	OM932	PT389		31,332		40,762		14,969		19,519		-		-
Total Administrative and General Expense		OMAGT		$	886,243	$	1,152,972	$	398,469	$	548,534	$	643,694	$	473
Total Operation & Maintenance Expense		OMT		$	1,721,636	$	2,239,790	$	766,364	$	1,087,545	$	1,756,764	$	2,737

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Depreciation Expenses										
Underground Storage										
350-357	Underground Storage Plant	DP350	F003	$ 232,682	232,682	-	-	-	-	-
Transmission										
365-371	Transmission Plant	DP365	F005	$ 1,122,524	-	-	1,122,524	-	-	-
Distribution										
374	Land & Land Rights	DP374	F008	$ -	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	3,300	-	-	-	-	-	3,300
376	Mains	DP376	F009	1,516,595	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	40,376	-	-	-	-	-	40,376
379	Meas & Reg Station Eq.-City Gate	DP379	F008	13,917	-	-	-	-	-	13,917
380	Services	DP380	F010	308,831	-	-	-	-	-	-
381	Meters	DP381	F011	196,929	-	-	-	-	-	-
382	Meter Installations	DP382	F011	129,421	-	-	-	-	-	-
383	House Regulators	DP383	F011	115,137	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	35,864	-	-	-	-	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-	-
	Other		PTSUB	-	-	-	-	-	-	-
Total Distribution				$ 2,360,370	$ -	$ -	$ -	$ -	$ -	$ 57,593
117	Gas Stored Underground	DP117	F003	$ -	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB	531,163	41,218	-	173,551	-	-	7,699
Common Utility Plant		DPCP	PTSUB	-	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB	(12,000)	(931)	-	(3,921)	-	-	(174)
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 4,234,739	$ 272,969	$ -	$ 1,292,154	$ -	$ -	$ 65,118

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description		Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Depreciation Expenses									
Underground Storage									
350-357	Underground Storage Plant	DP350	F003	-	-	-	-	-	-
Transmission									
365-371	Transmission Plant	DP365	F005	-	-	-	-	-	-
Distribution									
374	Land & Land Rights	DP374	F008	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	-	-	-	-	-	-
376	Mains	DP376	F009	659,112	857,483	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-	-	-
380	Services	DP380	F010	-	-	308,831	-	-	-
381	Meters	DP381	F011	-	-	-	196,929	-	-
382	Meter Installations	DP382	F011	-	-	-	129,421	-	-
383	House Regulators	DP383	F011	-	-	-	115,137	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	35,864	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-
	Other		PTSUB	-	-	-	-	-	-
Total Distribution				$ 659,112	$ 857,483	$ 308,831	$ 477,351	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB	90,747	118,059	43,356	56,532	-	-
Common Utility Plant		DPCP	PTSUB	-	-	-	-	-	-
Amortization of Gas Plant		AMORT	PTSUB	(2,050)	(2,667)	(979)	(1,277)	-	-
Accretion Expense		ACCRTN	PTSUB	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ 747,809	$ 972,875	$ 351,207	$ 532,606	$ -	$ -

DELTA NATU' 'AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector		Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Taxes Other Than Income Taxes										
Liscense & Privilege Fee	OTRE	PTT	$	5,432	533	-	1,766	-	-	76
Property Taxes	OTPP	PTT		1,221,140	119,792	-	397,007	-	-	17,120
Payroll Taxes	OTUN	LBTOT		540,909	10,440	5,104	151,101	12,606	-	6,743
Total Taxes Other Than Income Taxes	OTT		$	1,767,481	$ 130,765	$ 5,104	$ 549,874	$ 12,606	$ -	$ 23,940
Interest on Long Term Debt	INT	PTT	$	4,967,706	487,325	-	1,615,059	-	-	69,647

DELTA NATU ꞁAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Taxes Other Than Income Taxes								
Liscense & Privilege Fee	OTRE	PTT	899	1,170	429	559	-	-
Property Taxes	OTPP	PTT	202,136	262,972	96,406	125,705	-	-
Payroll Taxes	OTUN	LBTOT	85,752	111,561	37,971	52,229	67,400	-
Total Taxes Other Than Income Taxes	OTT		$ 288,788	$ 375,703	$ 134,806	$ 178,494	$ 67,400	$ -
Interest on Long Term Debt	INT	PTT	822,308	1,069,795	392,190	511,381	-	-

DELTA NATU ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Functional Assignment Vectors									
Gas Supply Demand	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Distribution Mains	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Accounts	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F013		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB		$ 112,861,466	$ -	$ -	$ 51,227,484	$ -	$ -	$ -

DELTA NATU ↑AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Functional Assignment Vectors								
Gas Supply Demand	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.434600	0.565400	0.000000	0.000000	0.000000	0.000000
Services	F010		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Transmission & Distribution Mains	TDMSUB		$ 26,786,129	$ 34,847,853	$ -	$ -	$ -	$ -

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Total Company	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity	Distribution Commodity	Distribution Structures & Equipment Demand
Internally Generated Functional Vectors									
Sub-Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	0.024335
Storage-Transmission-Distribution Subtotal		PTSUB	1.000000	0.077600	-	0.326738	-	-	0.014495
Total Storage Plant		PTST	1.000000	1.000000	-	-	-	-	-
Transmission Plant		PT365	1.000000	-	-	1.000000	-	-	-
General Plant		PT389	1.000000	0.077600	-	0.326738	-	-	0.014495
Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	0.024335
Sub-Total CWIP		CWIP	1.000000	0.016915	-	0.800457	-	-	0.003160
Total Depreciation Reserve		DEPR	1.000000	0.083443	-	0.336804	-	-	0.014108
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1.000000	0.077600	-	0.326738	-	-	0.014495
Transmission and Distribution Payroll		LBTD	1.000000	-	-	0.329941	0.027526	-	0.014724
Transmission and Distribution Mains		TDMSUB	1.000000	-	-	0.453897	-	-	-
Storage Operation Expenses Subtotal	OSE		82,393	61,280	21,113	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		10,917	1,390	9,527	-	-	-	-
Mains & Services	CADAL		74,431,389	-	-	-	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1.00000						
Distribution Operation Expenses Subtotal	DOES		-	-	-	-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		112,790	-	-	-	-	-	239
Subtotal Labor Expenses	LBSUB		$ 3,246,873	$ 62,670	$ 30,640	$ 907,004	$ 75,669	$ -	$ 40,476
Subtotal O&M Expenses	OMSUB		$ 5,847,588	$ 169,526	$ 187,044	$ 1,251,005	$ 164,560	$ 58,165	$ 72,838

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Functional Assignment and Classification

Description	Name	Vector	Distribution Mains Demand	Distribution Mains Customer	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Internally Generated Functional Vectors								
Sub-Total Distribution Plant		PTDSUB	0.286818	0.373140	0.137031	0.178676	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0.170847	0.222266	0.081624	0.106431	-	-
Total Storage Plant		PTST	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-
General Plant		PT389	0.170847	0.222266	0.081624	0.106431	-	-
Total Distribution Plant		PTDSUB	0.286818	0.373140	0.137031	0.178676	-	-
Sub-Total CWIP		CWIP	0.060182	0.078295	0.017792	0.023199	-	-
Total Depreciation Reserve		DEPR	0.166283	0.216329	0.079444	0.103588	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0.170847	0.222266	0.081624	0.106431	-	-
Transmission and Distribution Payroll		LBTD	0.187247	0.243602	0.082913	0.114046	-	-
Transmission and Distribution Mains		TDMSUB	0.237336	0.308767	-	-	-	-
Storage Operation Expenses Subtotal	OSE		-	-	-	-	-	-
Storage Maintenance Expenses Subtotal	MSE		-	-	-	-	-	-
Mains & Services	CADAL		26,786,129	34,847,853	12,797,407	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM							
Distribution Operation Expenses Subtotal	DOES		-	-	-	-	-	-
Distribution Maintenance Expenses Subtotal	DMES		40,480	52,663	1,344	18,065	-	-
Subtotal Labor Expenses	LBSUB		$ 514,740	$ 669,659	$ 227,927	$ 313,510	$ 404,578	$ -
Subtotal O&M Expenses	OMSUB		$ 835,393	$ 1,086,818	$ 367,895	$ 539,011	$ 1,113,070	$ 2,264

Seelye Exhibit 6

Class Cost of Service Study

Allocation of Costs by Rate Class

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Plant in Service										
Gas Supply Costs										
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	PTIS	PTISSD	DEM02	$ 17,875,861	$ 8,293,256	$ 2,639,573	$ 6,943,033	$ -	$ -	$ -
Commodity	PTIS	PTISSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage				$ 17,875,861	$ 8,293,256	$ 2,639,573	$ 6,943,033	$ -	$ -	$ -
Transmission										
Demand	PTIS	PTISTD	TDEM	$ 57,549,027	$ 16,048,581	$ 5,092,582	$ 12,544,907	$ 2,581,547	$ 5,290,335	$ 15,991,076
Commodity	PTIS	PTISTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission				$ 57,549,027	$ 16,048,581	$ 5,092,582	$ 12,544,907	$ 2,581,547	$ 5,290,335	$ 15,991,076
Distribution Expenses										
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	PTIS	PTISDSD	DEM04	$ 2,553,073	$ 1,117,345	$ 354,559	$ 873,410	$ 179,734	$ 28,025	$ -

DELTA NATUR[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Plant in Service (Continued)																	
Distribution Mains																	
Demand	PTIS	PTISDMD	DEM05	$	30,091,574	$	13,169,488	$	4,178,980	$	10,294,368	$	2,118,421	$	330,319	$	-
Customer	PTIS	PTISDMC	CUST01		39,148,127	$	33,505,627	$	4,694,354	$	907,953	$	39,163	$	1,031	$	-
Total Distribution Mains					69,239,701	$	46,675,115	$	8,873,333	$	11,202,321	$	2,157,583	$	331,349	$	-
Services																	
Customer	PTIS	PTISSC	CUST02	$	14,376,625	$	10,402,095	$	2,949,667	$	979,288	$	42,239	$	3,335	$	-
Meters																	
Customer	PTIS	PTISMC	CUST03	$	18,745,871	$	11,403,369	$	1,852,410	$	4,322,532	$	1,035,848	$	131,713	$	-
Customer Accounts																	
Customer	PTIS	PTISCAC	CUST04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service																	
Customer	PTIS	PTISCSC	CUST05	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Total		PLT		$	180,340,159	$	93,939,761	$	21,762,124	$	36,865,489	$	5,996,952	$	5,784,757	$	15,991,076

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base										
Gas Supply Costs										
Demand	NCRB	RBGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	NCRB	RBGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	NCRB	RBSD	DEM02	$ 21,666,046	$ 10,051,659	$ 3,199,236	$ 8,415,150	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	32,330	$ 14,289	$ 4,722	$ 13,319	$ -	$ -	$ -
Total Storage				$ 21,698,376	$ 10,065,949	$ 3,203,959	$ 8,428,469	$ -	$ -	$ -
Transmission										
Demand	NCRB	RBTD	TDEM	$ 34,615,060	$ 9,653,032	$ 3,063,128	$ 7,545,613	$ 1,552,770	$ 3,182,074	$ 9,618,444
Commodity	NCRB	RBTC	COM03	34,669	$ 3,599	$ 1,168	$ 4,468	$ 2,534	$ 5,663	$ 17,236
Total Transmission				$ 34,649,729	$ 9,656,631	$ 3,064,296	$ 7,550,082	$ 1,555,304	$ 3,187,737	$ 9,635,680
Distribution Expenses										
Commodity	NCRB	RBDEC	COM04	$ 8,836	$ 2,606	$ 846	$ 3,235	$ 1,835	$ 314	$ -
Distribution Structures & Equipment										
Demand	NCRB	RBDSD	DEM04	$ 1,515,862	$ 663,412	$ 210,516	$ 518,578	$ 106,715	$ 16,640	$ -

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Rate Base (Continued)											
Distribution Mains											
Demand	NCRB	RBDMD	DEM05	$	17,901,507 $	7,834,541 $	2,486,079 $	6,124,129 $	1,260,251 $	196,507 $	-
Customer	NCRB	RBDMC	CUST01		23,289,259 $	19,932,530 $	2,792,676 $	540,142 $	23,298 $	613 $	-
Total Distribution Mains					41,190,766 $	27,767,071 $	5,278,755 $	6,664,271 $	1,283,548 $	197,120 $	-
Services											
Customer	NCRB	RBSC	CUST02	$	8,520,666 $	6,165,062 $	1,748,194 $	580,399 $	25,034 $	1,976 $	-
Meters											
Customer	NCRB	RBMC	CUST03	$	11,132,896 $	6,772,292 $	1,100,119 $	2,567,088 $	615,175 $	78,222 $	-
Customer Accounts											
Customer	NCRB	RBCAC	CUST04	$	220,794 $	174,835 $	24,064 $	20,504 $	652 $	87 $	652
Customer Service											
Customer	NCRB	RBCSC	CUST05	$	344 $	294 $	41 $	9 $	0 $	0 $	-
Total		RBT		$	118,938,270 $	61,268,154 $	14,630,788 $	26,332,635 $	3,588,264 $	3,482,097 $	9,636,332

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Operation and Maintenance Expenses										
Gas Supply Costs										
Demand	OMT	OMGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OMT	OMGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		OMGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	OMT	OMSD	DEM02	$ 376,007	$ 174,443	$ 55,522	$ 146,042	$ -	$ -	$ -
Commodity	OMT	OMSC	COM02	257,240	$ 113,694	$ 37,573	$ 105,973	$ -	$ -	$ -
Total Storage		OMST		$ 633,246	$ 288,137	$ 93,095	$ 252,015	$ -	$ -	$ -
Transmission										
Demand	OMT	OMTD	TDEM	$ 2,802,949	$ 781,653	$ 248,036	$ 611,005	$ 125,735	$ 257,668	$ 778,852
Commodity	OMT	OMTC	COM03	275,846	$ 28,639	$ 9,294	$ 35,553	$ 20,162	$ 45,060	$ 137,139
Total Transmission		OMTRT		$ 3,078,795	$ 810,292	$ 257,330	$ 646,557	$ 145,897	$ 302,728	$ 915,991
Distribution Expenses										
Commodity	OMT	OMDEC	COM04	$ 70,306	$ 20,737	$ 6,730	$ 25,742	$ 14,598	$ 2,499	$ -
Distribution Structures & Equipment										
Demand	OMT	OMDSD	DEM04	$ 145,166	$ 63,532	$ 20,160	$ 49,662	$ 10,220	$ 1,594	$ -

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Operation and Maintenance Expenses (Continued)											
Distribution Mains											
Demand	OMT	OMDMD	DEM05	$	1,721,636 $	753,469 $	239,093 $	588,974 $	121,202 $	18,899 $	-
Customer	OMT	OMDMC	CUST01		2,239,790 $	1,916,965 $	268,579 $	51,947 $	2,241 $	59 $	-
Total Distribution Mains					3,961,426 $	2,670,433 $	507,672 $	640,921 $	123,442 $	18,958 $	-
Services											
Customer	OMT	OMSC	CUST02	$	766,364 $	554,497 $	157,236 $	52,202 $	2,252 $	178 $	-
Meters											
Customer	OMT	OMMC	CUST03	$	1,087,545 $	661,568 $	107,468 $	250,772 $	60,095 $	7,641 $	-
Customer Accounts											
Customer	OMT	OMCAC	CUST04	$	1,756,764 $	1,391,087 $	191,467 $	163,138 $	5,190 $	692 $	5,190
Customer Service											
Customer	OMT	OMCSC	CUST05	$	2,737 $	2,343 $	322 $	69 $	2 $	0 $	-
Total		OMTT		$	11,502,349 $	6,462,625 $	1,341,480 $	2,081,078 $	361,696 $	334,289 $	921,181

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Payroll Expenses										
Gas Supply Costs										
Demand	LBTOT	LBGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	LBTOT	LBGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		LBGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	LBTOT	LBSD	DEM02	$ 130,590	$ 60,586	$ 19,283	$ 50,722	$ -	$ -	$ -
Commodity	LBTOT	LBSC	COM02	63,847	$ 28,219	$ 9,326	$ 26,302	$ -	$ -	$ -
Total Storage		LBST		$ 194,437	$ 88,804	$ 28,609	$ 77,024	$ -	$ -	$ -
Transmission										
Demand	LBTOT	LBTD	TDEM	$ 1,889,995	$ 527,059	$ 167,248	$ 411,993	$ 84,782	$ 173,742	$ 525,171
Commodity	LBTOT	LBTC	COM03	157,677	$ 16,370	$ 5,313	$ 20,322	$ 11,525	$ 25,757	$ 78,390
Total Transmission		LBTRT		$ 2,047,672	$ 543,430	$ 172,561	$ 432,316	$ 96,307	$ 199,499	$ 603,561
Distribution Expenses										
Commodity	LBTOT	LBDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	LBTOT	LBDSD	DEM04	$ 84,344	$ 36,913	$ 11,713	$ 28,854	$ 5,938	$ 926	$ -

DELTA NATURAL GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Payroll Expenses										
Distribution Mains										
Demand	LBTOT	LBDMD	DEM05	$ 1,072,603	$ 469,421	$ 148,958	$ 366,939	$ 75,510	$ 11,774	$ -
Customer	LBTOT	LBDMC	CUST01	1,395,420	$ 1,194,295	$ 167,328	$ 32,364	$ 1,396	$ 37	$ -
Total Distribution Mains				2,468,023	$ 1,663,717	$ 316,287	$ 399,302	$ 76,906	$ 11,811	$ -
Services										
Customer	LBTOT	LBSC	CUST02	$ 474,949	$ 343,646	$ 97,446	$ 32,352	$ 1,395	$ 110	$ -
Meters										
Customer	LBTOT	LBMC	CUST03	$ 653,285	$ 397,402	$ 64,556	$ 150,638	$ 36,099	$ 4,590	$ -
Customer Accounts										
Customer	LBTOT	LBCAC	CUST04	$ 843,051	$ 667,566	$ 91,883	$ 78,288	$ 2,491	$ 332	$ 2,491
Customer Service										
Customer	LBTOT	LBCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBTT		$ 6,765,762	$ 3,741,478	$ 783,054	$ 1,198,775	$ 219,135	$ 217,268	$ 606,051

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Depreciation Expenses																	
Gas Supply Costs																	
Demand	DEPREX	DEGSD	DEM01	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Commodity	DEPREX	DEGSC	COM01		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Procurement Expenses		DEGST		$	-	$	-	$	-	$	-	$	-	$	-	$	-
Storage																	
Demand	DEPREX	DESD	DEM02	$	272,969	$	126,640	$	40,307	$	106,022	$	-	$	-	$	-
Commodity	DEPREX	DESC	COM02		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Storage		DEST		$	272,969	$	126,640	$	40,307	$	106,022	$	-	$	-	$	-
Transmission																	
Demand	DEPREX	DETD	TDEM	$	1,292,154	$	360,340	$	114,344	$	281,672	$	57,964	$	118,784	$	359,049
Commodity	DEPREX	DETC	COM03		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Transmission		DETT		$	1,292,154	$	360,340	$	114,344	$	281,672	$	57,964	$	118,784	$	359,049
Distribution Expenses																	
Commodity	DEPREX	DEDEC	COM04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Structures & Equipment																	
Demand	DEPREX	DEDSD	DEM04	$	65,118	$	28,499	$	9,043	$	22,277	$	4,584	$	715	$	-

DELTA NATU GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Depreciation Expenses (Continued)										
Distribution Mains										
Demand	DEPREX	DEDMD	DEM05	$ 747,809	$ 327,277	$ 103,852	$ 255,827	$ 52,645	$ 8,209	$ -
Customer	DEPREX	DEDMC	CUST01	972,875	$ 832,652	$ 116,660	$ 22,564	$ 973	$ 26	$ -
Total Distribution Mains				1,720,684	$ 1,159,929	$ 220,512	$ 278,390	$ 53,618	$ 8,234	$ -
Services										
Customer	DEPREX	DESC	CUST02	$ 351,207	$ 254,113	$ 72,058	$ 23,923	$ 1,032	$ 81	$ -
Meters										
Customer	DEPREX	DEMC	CUST03	$ 532,606	$ 323,991	$ 52,630	$ 122,811	$ 29,430	$ 3,742	$ -
Customer Accounts										
Customer	DEPREX	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	DEPREX	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 4,234,739	$ 2,253,513	$ 508,895	$ 835,096	$ 146,629	$ 131,557	$ 359,049

DELTA NATU.   GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential		Small Non-Res		Large Non-Res		Interruptible		Special		Off Sys Trans
Other Taxes																	
Gas Supply Costs																	
Demand	OTT	OTTGSD	DEM01	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Commodity	OTT	OTTGSC	COM01		-	$	-	$	-	$	-	$	-	$	-	$	-
Total Procurement Expenses		OTTGST		$	-	$	-	$	-	$	-	$	-	$	-	$	-
Storage																	
Demand	OTT	OTTSD	DEM02	$	130,765	$	60,667	$	19,309	$	50,790	$	-	$	-	$	-
Commodity	OTT	OTTSC	COM02		5,104	$	2,256	$	746	$	2,103	$	-	$	-	$	-
Total Storage		OTTST		$	135,870	$	62,923	$	20,055	$	52,892	$	-	$	-	$	-
Transmission																	
Demand	OTT	OTTTD	TDEM	$	549,874	$	153,342	$	48,659	$	119,865	$	24,666	$	50,549	$	152,793
Commodity	OTT	OTTTC	COM03		12,606	$	1,309	$	425	$	1,625	$	921	$	2,059	$	6,267
Total Transmission		OTTTT		$	562,480	$	154,651	$	49,084	$	121,490	$	25,588	$	52,608	$	159,060
Distribution Expenses																	
Commodity	OTT	OTTDEC	COM04	$	-	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Structures & Equipment																	
Demand	OTT	OTTDSD	DEM04	$	23,940	$	10,477	$	3,325	$	8,190	$	1,685	$	263	$	-

DELTA NATUR. ,AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Other Taxes (Continued)										
Distribution Mains										
Demand	OTT	OTTDMD	DEM05	$ 288,788	$ 126,387	$ 40,106	$ 98,795	$ 20,330	$ 3,170	$ -
Customer	OTT	OTTDMC	CUST01	375,703	$ 321,552	$ 45,052	$ 8,714	$ 376	$ 10	$ -
Total Distribution Mains				664,491	$ 447,940	$ 85,157	$ 107,508	$ 20,706	$ 3,180	$ -
Services										
Customer	OTT	OTTSC	CUST02	$ 134,806	$ 97,538	$ 27,658	$ 9,183	$ 396	$ 31	$ -
Meters										
Customer	OTT	OTTMC	CUST03	$ 178,494	$ 108,580	$ 17,638	$ 41,158	$ 9,863	$ 1,254	$ -
Customer Accounts										
Customer	OTT	OTTCAC	CUST04	$ 67,400	$ 53,371	$ 7,346	$ 6,259	$ 199	$ 27	$ 199
Customer Service										
Customer	OTT	OTTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTTT		$ 1,767,481	$ 935,479	$ 210,262	$ 346,680	$ 58,438	$ 57,362	$ 159,259

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense										
Gas Supply Costs										
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	INT	INTSD	DEM02	$ 487,325	$ 226,088	$ 71,959	$ 189,278	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage		INTST		$ 487,325	$ 226,088	$ 71,959	$ 189,278	$ -	$ -	$ -
Transmission										
Demand	INT	INTTD	TDEM	$ 1,615,059	$ 450,388	$ 142,919	$ 352,061	$ 72,449	$ 148,468	$ 448,775
Commodity	INT	INTTC	COM03	-	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission		INTTT		$ 1,615,059	$ 450,388	$ 142,919	$ 352,061	$ 72,449	$ 148,468	$ 448,775
Distribution Expenses										
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	INT	INTDSD	DEM04	$ 69,647	$ 30,481	$ 9,672	$ 23,826	$ 4,903	$ 765	$ -

DELTA NATU.   GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Interest Expense (Continued)										
Distribution Mains										
Demand	INT	INTDMD	DEM05	$ 822,308	$ 359,881	$ 114,198	$ 281,313	$ 57,890	$ 9,027	$ -
Customer	INT	INTDMC	CUST01	1,069,795	$ 915,604	$ 128,282	$ 24,812	$ 1,070	$ 28	$ -
Total Distribution Mains				1,892,104	$ 1,275,484	$ 242,480	$ 306,124	$ 58,960	$ 9,055	$ -
Services										
Customer	INT	INTSC	CUST02	$ 392,190	$ 283,766	$ 80,466	$ 26,715	$ 1,152	$ 91	$ -
Meters										
Customer	INT	INTMC	CUST03	$ 511,381	$ 311,080	$ 50,533	$ 117,917	$ 28,258	$ 3,593	$ -
Customer Accounts										
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 4,967,706	$ 2,577,287	$ 598,029	$ 1,015,922	$ 165,722	$ 161,972	$ 448,775

DELTA NATU[illegible] GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Allocation Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period										
Operating Revenues										
Sales and Transportation	REVUC	R01		25,395,331	11,599,893	3,391,784	5,685,582	1,625,063	608,063	2,484,947
Collection Fees	COLFEE	COLL		$ 137,310	$ 124,139	$ 12,285	$ 886	$ -	$ -	$ -
Reconnect Revenue	RCTREV	RCNCT		113,896	$ 97,954	$ 15,030	$ 864	$ 48	$ -	$ -
Bad Check Revenue	BDCH	BDCK		10,095	$ 9,035	$ 970	$ 90	$ -	$ -	$ -
Total Operating Revenues -- Per Books	TOR			$ 25,656,632	$ 11,831,021	$ 3,420,069	$ 5,687,422	$ 1,625,110	$ 608,063	$ 2,484,947
Pro-Forma Adjustments to Revenues										
Temperature normalization	REVADJ1			$ 106,453	$ (53,005)	$ (6,064)	$ 163,640	$ 1,882	$ -	$ -
Total Revenue Adjustments				$ 106,453	$ (53,005)	$ (6,064)	$ 163,640	$ 1,882	$ -	$ -
Total Adjusted Revenue				$ 25,763,085	$ 11,778,016	$ 3,414,004	$ 5,851,062	$ 1,626,992	$ 608,063	$ 2,484,947
Expenses										
Operation and Maintenance Expenses				$ 11,502,349	$ 6,462,625	$ 1,341,480	$ 2,081,078	$ 361,696	$ 334,289	$ 921,181
Depreciation and Amortization Expenses				$ 4,234,739	2,253,513	508,895	835,096	146,629	131,557	359,049
Other Taxes				$ 1,767,481	935,479	210,262	346,680	58,438	57,362	159,259
Total Operating Expenses	TOE			$ 17,504,569	$ 9,651,617	$ 2,060,637	$ 3,262,854	$ 566,762	$ 523,209	$ 1,439,489

DELTA NATUI ,AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted Test Period (Cont.)										
Pro-Forma Adjustments to Expenses										
Labor Adjustment	EXADJ1	LBTT		$ 52,914	$ 29,262	$ 6,124	$ 9,375	$ 1,714	$ 1,699	$ 4,740
Eliminate Advedrtising Expenses	EXADJ2	REVUC		(2,264)	$ (1,034)	$ (302)	$ (507)	$ (145)	$ (54)	$ (222)
Lobbying Expense	EXADJ3	REVUC		(26,488)	$ (12,099)	$ (3,538)	$ (5,930)	$ (1,695)	$ (634)	$ (2,592)
Community Relations	EXADJ4	REVUC		(22,664)	$ (10,352)	$ (3,027)	$ (5,074)	$ (1,450)	$ (543)	$ (2,218)
Marketing	EXADJ5	OMTT		(3,973)	$ (2,232)	$ (463)	$ (719)	$ (125)	$ (115)	$ (318)
Rate Case Expenses	EXADJ6	OMTT		33,700	$ 18,934	$ 3,930	$ 6,097	$ 1,060	$ 979	$ 2,699
Depreciation Expenses	EXADJ7	DET		292,968	$ 155,903	$ 35,206	$ 57,774	$ 10,144	$ 9,101	$ 24,840
Payroll Tax	EXADJ8	LBTT		3,910	$ 2,162	$ 453	$ 693	$ 127	$ 126	$ 350
Total Expense Adjustments	ADJTOT			$ 328,103	$ 180,543	$ 38,383	$ 61,709	$ 9,629	$ 10,559	$ 27,279
Net Income Before Income Taxes				$ 7,930,413	$ 1,945,856	$ 1,314,984	$ 2,526,499	$ 1,050,601	$ 74,295	$ 1,018,178
Income Taxes		TXINC		$ 1,138,000	$ (315,241)	$ 286,093	$ 608,851	$ 364,834	$ (38,332)	$ 231,797
Net Operating Income (Adjusted)	TOM			$ 6,792,413	$ 2,261,097	$ 1,028,892	$ 1,917,649	$ 685,767	$ 112,627	$ 786,382
Net Cost Rate Base				$ 118,938,270	$ 61,268,154	$ 14,630,788	$ 26,332,635	$ 3,588,264	$ 3,482,097	$ 9,636,332
Rate of Return -- Actual				5.71%	3.69%	7.03%	7.28%	19.11%	3.23%	8.16%

DELTA NATU. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Net Operating Income -- Adjusted For Increase										
Test Year Operating Income				$ 6,792,413	$ 2,261,097	$ 1,028,892	$ 1,917,649	$ 685,767	$ 112,627	$ 786,382
Proposed Increase				$ 5,563,328	$ 3,847,603	489,441	$ 1,130,709	$ -	$ -	$ 95,575
Increase To Misc Revenue			RCNCT	$ 79,309	$ 70,401	$ 8,340	$ 556	$ 12	$ -	$ -
Total Increase		CLSINC		$ 5,642,637	$ 3,918,004	$ 497,781	$ 1,131,265	$ 12	$ -	$ 95,575
Incremental Income Taxes (@39.4445)			CLSINC	1,941,555	$ 1,348,132	$ 171,280	$ 389,253	$ 4	$ -	$ 32,886
Net Operating Income Adjusted for Increase				10,493,495	4,830,969	1,355,393	2,659,661	685,775	112,627	849,071
Net Cost Rate Base				$ 118,938,270	$ 61,268,154	$ 14,630,788	$ 26,332,635	$ 3,588,264	$ 3,482,097	$ 9,636,332
Rate of Return -- Proposed				8.82%	7.88%	9.26%	10.10%	19.11%	3.23%	8.81%

DELTA NATUR. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors			$	3,079,555						
				3079555 $	-					
Commodity										
Procurement Expenses		COM01		17,149,249	1,780,480	577,814	2,210,287	1,253,445	2,801,367	8,525,855
					0.103823	0.033693	0.128885			
Storage (Dec thru March)		COM02		2,671,021	1,180,526	390,137	1,100,357	-	-	-
Transmission		COM03		17,149,249	1,780,480	577,814	2,210,287	1,253,445	2,801,367	8,525,855
Distribution		COM04		6,036,593	1,780,480	577,814	2,210,287	1,253,445	214,567	-
				-	-	-	-	-	-	-
Demand										
Procurement Expenses		DEM01		84,012	23,443	7,439	18,325	3,771	7,675	23,359
Storage		DEM02		1.00000	0.463936	0.147661	0.388403	-	-	-
					0.463936	0.147661	0.388403			
Transmission		DEM03		84,012	23,443	7,439	18,325	3,771	7,675	23,359
Distribution Structures		DEM04		53,566	23,443	7,439	18,325	3,771	588	-
Distribution Mains		DEM05		53,566	23,443	7,439	18,325	3,771	588	-
Customer										
Distribution Mains (Year-end Customers)		CUST01		37,986	32,511	4,555	881	38	1	-
Services		CUST02		13,391,413	9,689,253	2,747,530	912,179	39,345	3,106	-
Meters		CUST03		5,849,497	3,558,329	578,030	1,348,811	323,228	41,100	-
Customer Count (Average)				37,568	32,164	4,427	943	30	4	-
Customer Accounts		CUST04		40,619	32,164	4,427	3,772	120	16	120
Customer Service		CUST05		37,568	32,164	4,427	943	30	4	-
Forfeited Discounts		REVFD		2,641,717	2,168,773	432,108	9,080	2,703	18,740	9,961

DELTA NATU. GAS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Allocation Factors Continued										
Taxable Income Actual										
Net Income Before Income Tax	NIBIT			$ 7,930,413	$ 1,945,856	$ 1,314,984	$ 2,526,499	$ 1,050,601	$ 74,295	$ 1,018,178
Interest Expense	INT	PLT		$ 4,967,706	$ 2,587,694	$ 599,466	$ 1,015,508	$ 165,194	$ 159,349	$ 440,495
Interest Adjustment		PLT		$ 224,173	$ 116,772	$ 27,052	$ 45,826	$ 7,455	$ 7,191	$ 19,878
Taxable Income	TXINC			$ 2,738,534	$ (758,611)	$ 688,467	$ 1,465,165	$ 877,952	$ (92,245)	$ 557,805
Meter Allocation										
Number of Customers				37,988	32,511	4,555	881	38	3	-
Average Cost Per Service					109.45	126.9	1531	8506	13700	
Meter Cost				5,849,497	3,558,329	578,030	1,348,811	323,228	41,100	-
Service Line Allocation										
Number of Customers				37,988	32,511	4,555	881	38	3	-
Average Cost Per Service					298.03	603.19	1035.39	1035.39	1035.39	0
Service Cost				13,391,413	9,689,253	2,747,530	912,179	39,345	3,106	-
Collection Fees	COLL			1.00000	0.90408	0.08947	0.00645			
Reconnect Revenue	RCNCT			1.00000	0.86003	0.13196	0.00759	0.00042		
Bad Check Fees	BDCK			1.00000	0.89500	0.09608	0.00892			
Customer Deposits	CSTDEP			1.00000	0.89690	0.08960	0.00980	0.00370		
Transmission Allocator										
Transmission Demand Allocator				84,012	23,443	7,439	18,325	3,771	7,675	23,359
Transmission Plant				$ 57,549,027						
Specific Assignment				$ 36,192.40					$ 36,192.40	
Residual Transmission Plant		DEM03		57,512,834	$ 16,048,581	$ 5,092,582	$ 12,544,907	$ 2,581,547	$ 5,254,142	$ 15,991,076
Total Allocation of Transmission Plant				$ 57,549,027	$ 16,048,580.89	$ 5,092,581.72	$ 12,544,906.58	$ 2,581,546.67	$ 5,290,334.72	$ 15,991,076.27
Transmission Allocator	TDEM			1.000000	0.27886798	0.088491187	0.217986424	0.044858216	0.09192744	0.277868752

DELTA NATU[illegible] ;AS COMPANY

Cost of Service Study
12 Months Ended December 31, 2006

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential	Small Non-Res	Large Non-Res	Interruptible	Special	Off Sys Trans
Customer Related Unit Cost										
Rate Base				$ 43,163,959	$ 33,045,014	$ 5,665,093	$ 3,708,141	$ 664,160	$ 80,899	$ 652
Rate of Return				8.82%	8.82%	8.82%	8.82%	8.82%	8.82%	8.82%
Return				$ 3,808,201	$ 2,915,443	$ 499,811	$ 327,156	$ 58,596	$ 7,137	$ 58
Income Taxes				$ 413,143	$ (170,043)	$ 110,791	$ 85,763	$ 67,610	$ (892)	$ 16
Operation and Maintenance Expenses				5,853,199	4,526,459	725,072	518,128	69,779	8,570	5,190
Depreciation Expenses				1,856,688	1,410,757	241,348	169,298	31,436	3,849	-
Other Taxes				756,403	581,041	97,694	65,313	10,834	1,322	199
Expense Adjustment (Classified Pro-Rata on the basis of Operating Expenses)				158,805	121,947	19,825	14,243	1,907	278	103
Total Customer-Related Revenue Requirement				$ 12,846,440	$ 9,385,605	$ 1,694,541	$ 1,179,902	$ 240,162	$ 20,265	$ 5,565
Less: Misc Service Revenues				(49,687)	(61,617)	(6,930)	(163)	(9)	-	-
Net Revenue Requirement				$ 12,796,754	$ 9,323,988	$ 1,687,612	$ 1,179,739	$ 240,153	$ 20,265	$ 5,565
Customer-Months				37,568	32,164	4,427	943	30	4	-
Customer-Related Unit Cost ($/Cust/Mo)				28.386	24.157	31.767	104.254	667.092	422.193	

Seelye Exhibit 7

Class Cost of Service Study

Storage Allocation Factor

DELTA NATUF GAS COMPANY

Summary of Allocation of U...erground Storage Investment

Calculation of Maximum Class Demands
On February 10th Design Day Assuming 68 Degree Days
For Determination of Demand Allocation Factors

	Total	Residential	Small Non Residential GS	Large Non Residential GS
Non-Temp Sensitive Load (per Day)	4,463	799	299	3,365
Temp Sensitive Load (per Degree Day)	658	333	105	220
Calculated Daily Requirements at -3 Degrees	49,207	23,443	7,439	18,325
Percentage of Total		47.64%	15.12%	37.24%

Allocation of Underground Storage

		Storage Withdrawals	Residential	Small Non Residential GS	Large Non Residential GS
Total Allocated Withdrawals Thru February 9th					
December		459,865	204,059	65,268	190,538
January		497,654	224,372	71,635	201,647
Feb. 1-9		154,733	69,269	22,134	63,330
	Total	1,112,252	497,700	159,037	455,515
Balance of Working Gas Allocated on the Basis of -3 Degree Feb. 10 Design Day		1,469,337	699,992	222,164	547,181
Total Working Gas		2,581,589	1,197,692	381,201	1,002,696
Total Allocation Factor For Underground Storage		1.000000	0.463936	0.147661	0.388403

DELTA NATU GAS COMPANY
Allocation of Under nd Storage Investment

(December)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	799	299	3,365	4,463
Temperature Sensitive Load (per Degree Day)	333	105	220	658

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	24	8,791	2,819	8,645	20,255	13,649	5,924	1,900	5,825
2	24	8,791	2,819	8,645	20,255	12,537	5,441	1,745	5,351
3	24	8,791	2,819	8,645	20,255	12,556	5,450	1,748	5,359
4	25	9,124	2,924	8,865	20,913	13,466	5,875	1,883	5,708
5	26	9,457	3,029	9,085	21,571	13,859	6,076	1,946	5,837
6	26	9,457	3,029	9,085	21,571	13,994	6,135	1,965	5,894
7	26	9,457	3,029	9,085	21,571	14,387	6,307	2,020	6,059
8	26	9,457	3,029	9,085	21,571	14,388	6,308	2,020	6,060
9	26	9,457	3,029	9,085	21,571	14,390	6,309	2,021	6,061
10	27	9,790	3,134	9,305	22,229	14,391	6,338	2,029	6,024
11	27	9,790	3,134	9,305	22,229	13,950	6,144	1,967	5,839
12	28	10,123	3,239	9,525	22,887	14,342	6,344	2,030	5,969
13	28	10,123	3,239	9,525	22,887	14,343	6,344	2,030	5,969
14	29	10,456	3,344	9,745	23,545	14,735	6,543	2,093	6,098
15	29	10,456	3,344	9,745	23,545	14,735	6,543	2,093	6,098
16	29	10,456	3,344	9,745	23,545	14,753	6,551	2,095	6,106
17	29	10,456	3,344	9,745	23,545	14,753	6,551	2,095	6,106
18	30	10,789	3,449	9,965	24,203	15,144	6,751	2,158	6,235
19	30	10,789	3,449	9,965	24,203	15,144	6,751	2,158	6,235
20	31	11,122	3,554	10,185	24,861	15,535	6,950	2,221	6,364
21	31	11,122	3,554	10,185	24,861	15,483	6,927	2,213	6,343
22	31	11,122	3,554	10,185	24,861	15,483	6,927	2,213	6,343
23	31	11,122	3,554	10,185	24,861	15,874	7,102	2,269	6,503
24	31	11,122	3,554	10,185	24,861	15,874	7,102	2,269	6,503
25	32	11,455	3,659	10,405	25,519	15,874	7,126	2,276	6,472
26	32	11,455	3,659	10,405	25,519	16,007	7,185	2,295	6,527
27	32	11,455	3,659	10,405	25,519	16,007	7,185	2,295	6,527
28	32	11,455	3,659	10,405	25,519	16,007	7,185	2,295	6,527
29	32	11,455	3,659	10,405	25,519	16,069	7,213	2,304	6,552
30	33	11,788	3,764	10,625	26,177	16,069	7,236	2,311	6,522
31	33	11,788	3,764	10,625	26,177	16,069	7,236	2,311	6,522
Total	894	322,471	103,139	300,995	726,605	459,867	204,059	65,268	190,538

DELTA NATU' GAS COMPANY
Allocation of Underg .ıd Storage Investment

(January)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	799	299	3,365	4,463
Temperature Sensitive Load (per Degree Day)	333	105	220	658

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	32	11,455	3,659	10,405	25,519	15,613	7,008	2,239	6,366
2	32	11,455	3,659	10,405	25,519	15,586	6,996	2,235	6,355
3	32	11,455	3,659	10,405	25,519	15,602	7,004	2,237	6,362
4	32	11,455	3,659	10,405	25,519	15,596	7,001	2,236	6,359
5	33	11,788	3,764	10,625	26,177	15,602	7,026	2,243	6,333
6	33	11,788	3,764	10,625	26,177	15,728	7,083	2,262	6,384
7	33	11,788	3,764	10,625	26,177	15,727	7,082	2,261	6,384
8	33	11,788	3,764	10,625	26,177	15,734	7,085	2,262	6,386
9	33	11,788	3,764	10,625	26,177	15,731	7,084	2,262	6,385
10	33	11,788	3,764	10,625	26,177	15,722	7,080	2,261	6,382
11	33	11,788	3,764	10,625	26,177	15,745	7,090	2,264	6,391
12	33	11,788	3,764	10,625	26,177	15,720	7,079	2,260	6,381
13	33	11,788	3,764	10,625	26,177	15,712	7,076	2,259	6,377
14	33	11,788	3,764	10,625	26,177	15,681	7,062	2,255	6,365
15	33	11,788	3,764	10,625	26,177	15,720	7,079	2,260	6,381
16	33	11,788	3,764	10,625	26,177	16,115	7,257	2,317	6,541
17	33	11,788	3,764	10,625	26,177	16,107	7,253	2,316	6,538
18	33	11,788	3,764	10,625	26,177	16,109	7,254	2,316	6,539
19	33	11,788	3,764	10,625	26,177	16,133	7,265	2,320	6,548
20	33	11,788	3,764	10,625	26,177	16,112	7,256	2,317	6,540
21	34	12,121	3,869	10,845	26,835	15,992	7,224	2,306	6,463
22	34	12,121	3,869	10,845	26,835	15,999	7,227	2,307	6,466
23	34	12,121	3,869	10,845	26,835	16,000	7,227	2,307	6,466
24	34	12,121	3,869	10,845	26,835	16,390	7,403	2,363	6,624
25	34	12,121	3,869	10,845	26,835	16,390	7,403	2,363	6,624
26	34	12,121	3,869	10,845	26,835	16,523	7,463	2,382	6,677
27	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
28	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
29	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
30	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
31	35	12,454	3,974	11,065	27,493	16,912	7,661	2,445	6,806
Total	1,035	369,424	117,944	332,015	819,383	497,654	224,372	71,635	201,647

DELTA NATU'   GAS COMPANY
Allocation of Undergi ɔund Storage Investment

(February)

	Residential	Small Non Res GS	Large Non Res GS	Total
Non-Temperature Sensitive Load (per Day)	799	299	3,365	4,463
Temperature Sensitive Load (per Degree Day)	333	105	220	658

		Requirements					Storage Allocation		
Date	Heating Degree Days	Residential	Small Non Res GS	Large Non Res GS	Total	Storage Withdrawals (Injections)	Residential	Small Non Res GS	Large Non Res GS
1	33	11,788	3,764	10,625	26,177	16,348	7,362	2,351	6,636
2	33	11,788	3,764	10,625	26,177	16,321	7,350	2,347	6,625
3	32	11,455	3,659	10,405	25,519	15,952	7,160	2,287	6,504
4	32	11,455	3,659	10,405	25,519	15,560	6,984	2,231	6,344
5	31	11,122	3,554	10,185	24,861	15,180	6,791	2,170	6,219
6	31	11,122	3,554	10,185	24,861	15,306	6,847	2,188	6,270
7	31	11,122	3,554	10,185	24,861	15,305	6,847	2,188	6,270
8	30	10,789	3,449	9,965	24,203	14,926	6,653	2,127	6,145
9	30	10,789	3,449	9,965	24,203	14,923	6,652	2,127	6,144
10	29	10,456	3,344	9,745	23,545	14,914	6,623	2,118	6,173
Total	312	111,886	35,750	102,290	249,926	154,734	69,269	22,134	63,330

Seelye Exhibit 8

Class Cost of Service Study

Zero Intercept Analysis

Delta Natural Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2006

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per Foot)	0.6639341	0.4074573
Zero Intercept ($ per Foot)	3.3945372	1.1990359
R-Square	0.9193681	

Plant Classification

Total Number of Units		7,705,996
Zero Intercept		3.3945372
Zero Intercept Cost	$	26,158,290
Total Cost of Sample	$	39,749,126
Percentage of Total		0.658084664
Percentage Classified as Customer-Related		65.81%
Percentage Classified as Demand-Related		34.19%

Delta Natural ; Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 2006

Description	Pipe Size	Net Cost of Plant	Quantity (Feet)	Unit Cost ($ per Foot)
Distribution Main Pipe, Under 2" Plastic	1.500	$ 2,931,080	508,866	5.76002
Distribution Main Pipe, 2" Plastic	2.000	$ 20,799,781	4,504,311	4.61775
Distribution Main Pipe, 3" Plastic	3.000	$ 101,306	89,043	1.13772
Distribution Main Pipe, 4" Plastic	4.000	$ 10,735,972	1,353,891	7.92972
Distribution Main Pipe, 6" Plastic	6.000	$ 558,228	58,933	9.47225
Distribution Main Pipe, Under 2" Steel	1.500	$ 188,710	85,824	2.19880
Distribution Main Pipe, 2" Steel	2.000	$ 462,919	379,832	1.21875
Distribution Main Pipe, 3" Steel	3.000	$ 73,752	61,367	1.20182
Distribution Main Pipe, 4" Steel	4.000	$ 2,211,801	291,928	7.57653
Distribution Main Pipe, 6" Steel	6.000	$ 1,281,750	277,138	4.62495
Distribution Main Pipe, 8" Steel	8.000	$ 403,827	94,863	4.25695
Total		$ 39,749,126.00	7,705,996	

Seelye Exhibit 9

Temperature Normalization Adjustment

Delta Natural Gas Company, Inc.

Natural Gas Temperature Normalization Adjustment
For the 12 months Ended December 31, 2003

Consumption Not Billed under the Weather Normalization Clause

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days	4,662	4,667
Actual Heating Degree Days	4,466	4,172
Normal over (under) Actual	196	495

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days (7 Non-WNA Months)	712	1,011
Actual Heating Degree Days (7 Non-WNA Months)	766	1,103
Normal over (under) Actual	(54)	(92)

	(1) Total Mcf	(2) Non-Temp Mcf	(3) Non-Temp Mcf Full Year (Column (1) x 6)	(4) Temperature Sensitive Mcf (Column (1) - (3))	(5) Actual Degree Days	(6) Mcf per Degree Days (Column (4) x (5))	(7) Normal Degree Days	(8) Departure From Normal (Column (7) - (5))	(9) Normal Temperature Adjustment (Column (6) x (8))	(10) Net Revenue Per Mcf Sold	(11) Net Revenue Adjustment (Column (9) x (10))
Residential *	350,746	48,520	169,820	180,926	766	236	712	(54)	(12,744)	$ 4.1592	$ (53,004.84)
Small Non-Residential General Service *	104,366	17,766	62,181	42,185	766	55	712	(54)	(2,970)	$ 3.7950	$ (11,271.15)
Large Non-Residential GS - Commercial	781,181	40,889	245,334	535,847	4,466	120	4,662	196	23,520	$ 3.7950	$ 89,258.40
Large Non-Residential GS - Industrial	107,456	4,224	25,344	82,112	4,466	18	4,662	196	3,528	$ 3.7950	$ 13,388.76
Interruptible Service - Commercial	2,564	-	-	2,564	4,466	1	4,662	196	196	$ 1.6000	$ 313.60
Interruptible Service - Industrial	32,652	1,540	9,240	23,412	4,466	5	4,662	196	980	$ 1.6000	$ 1,568.00
Small Non Residential General Service -Transportation	33,317	344	2,063	31,254	4,466	7	4,662	196	1,372	$ 3.7950	$ 5,206.74
Large Non Residential General Service -Transportation	1,321,380	159,543	957,258	364,122	4,466	82	4,662	196	16,072	$ 3.7950	$ 60,993.24
Residential - Transportation	1,103	10	63	1,040	4,466	0	4,662	196	-	$ 4.1592	$ -
	2,734,764	272,836	1,471,303	1,263,461					29,954		$ 106,452.75

* For the seven months May to November only

Seelye Exhibit 10

Year End Customer Adjustment

Not Proposed

Delta Natural Gas Company, Inc.

Adjustment of Gas Re· ·es to reflect Year-end Customers
Over Average Numb· ·stomers in Test Period
12 Months Ended D· ·er 31, 2006

	Average Number of Customers	Customers Served at 12/31/06	Year-End Over (Under) Average (Col. 2 - 1)	Customer Charge	Additional Customer Charge Revenue (Col. 3 x 4)	Weather Normalized Mcf	Average Mcf per Customer (COL. 6 / 1)	Year -End Mcf Adjustment (COL. 7 x 3)	Net Revenue per Mcf Commodity	Additional Revenue Commodity (COL. 8 x 9)	Year-End Revenue Adjustment (COL. 5 + 10)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Residential	32,130	32,498	368	$ 9.80	$ 3,606.40	1,857,139	57.8	21,270	$ 4.1592	$ 88,466.18	$ 92,072.58
Small Non-Residential GS	4,406	4,534	128	$ 20.00	$ 2,560.00	605,173	137.4	17,581	$ 3.7950	$ 66,719.90	$ 69,279.90
Large Non-Residential GS - Retail	928	939	11	$ 72.00	$ 792.00	2,253,407	2,428.2	26,711		$ 59,909.07	$ 60,701.07
First 200 Mcf						772,185		9,150	$ 3.7950	$ 34,724.25	
Next 800 Mcf						431,115		5,111	$ 2.1461	$ 10,968.72	
Next 4,000 Mcf						607,467		7,202	$ 1.3500	$ 9,722.70	
Next 5,000 Mcf						235,080		2,787	$ 0.9500	$ 2,647.65	
Over 10,000 Mcf						207,560		2,461	$ 0.7500	$ 1,845.75	
Interruptible	37	38	1	$ 250.00	$ 250.00	1,254,621	33,908.7	33,909		$ 40,984.20	$ 41,234.20
						326,478		8,824	$ 1.6000	$ 14,118.40	
						657,056		17,758	$ 1.2000	$ 21,309.60	
						214,604		5,800	$ 0.8000	$ 4,640.00	
						56,483		1,527	$ 0.6000	$ 916.20	
On System Transportation Special	4	4	-		$ -	2,801,367	700,341.8	-	$ -	$ -	$ -
	37,505	38,013	508		$ 7,208.40	8,771,707		99,471		$ 256,079.35	$ 263,287.75

Expenses at an Operating Ratio of -	0.3539	93,179
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES		$ 170,108

CALCULATION OF GAS OPERATING RATIO

TOTAL GAS OPERATING EXPENSES	59,234,904
LESS GAS SUPPLY EXPENSES	41,730,337
LESS WAGES AND SALARIES	6,207,165
LESS PENSIONS AND BENEFITS	2,145,052
LESS REGULATORY COMMISSION EXPENSE	163,359
NET EXPENSES	8,988,991

TOTAL GAS OPERATIONS REVENUES (AS BILLED)	67,129,659
LESS GSC REVENUE	41,730,337
NET REVENUE	25,399,322
OPERATING RATIO	0.3539

Seelye Exhibit 11

Depreciation Study

Delta Natural Gas Company, Inc.
Depreciation Study
December 31, 2006

Overview

The purpose of performing a depreciation study is to insure that the depreciation expenses recorded by the utility and included in the cost of service represents a reasonably accurate and systematic measurement of the annual accrual levels necessary to distribute plant costs, less salvage and removal, over the estimated useful life of the assets.

In performing this study, data was compiled showing plant additions, retirements and transfers going back as far as the 1940s. For certain plant accounts, such as distribution mains (Account 376), meters (Account 381), and house regulators (Account 383), data was available going back well into the 1940s. Many other accounts were not utilized until the 1950s, 1960s or later.

Where sufficient data was available, the average service lives ("ASLs") were determined by identifying the survivor curve and associated ASL that best fit the pattern of retirements from the historical data provided by Delta Natural Gas Company, Inc. ("Delta"). In general, the survivor curves and ASLs were identified that produced the lowest sum of square deviations between the actual balances and simulated balances.[1] The simulated balances were determined by applying various survivor curves to the plant additions and transfers for each plant account for which data was available and then computing the resultant plant balances. The sum of square deviations were calculated based on the difference between the computed plant balances and actual plant balances. In selecting a survivor curve and ASL, several goodness-of-fit statistics were examined: (1) sum of squared deviations ("SSD"), (2) conformance index ("CI"), (3) index of variation ("IV"), and (4) retirement experience index ("REI").[2]

Where sufficient data was not available, the ASLs and depreciation accrual rates of neighboring utilities and judgment were used as a guide in developing the proposed depreciation rates.

The survivor curves utilized in this study correspond to the "Iowa" curves that were developed under the direction of Robley Winfrey at Iowa State University, as described in various bulletins and publications.[3] These curves are still the most widely used within the industry.

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[1] A detailed description of the simulated plant record ("SPR") method is included in *Public Utility Depreciation Practices*, August 1996, published by the National Association of Regulatory Commissioners (NARUC").

[2] Ibid., at pp. 92-97.

[3] See Winfrey, Robley, *Depreciation of Group Properties*, Bulletin 155 (Iowa State University, Engineering Research Institute, reprinted 1969); Winfrey, Robley, *Statistical Analyses of Industrial Property Retirements*, Bulletin 125 (Iowa State University, Engineering Research Institute, revised 1967);

The depreciation accrual rates were calculated using the average service life depreciation procedure, the straight-line method, and the remaining life basis. Using this approach, the remaining life annual accrual for each category of plant was determined by dividing the original cost less book reserve by the average remaining life determined based on the selected survivor curve. The average remaining life is a weighted average derived from the estimated future survivor curve based on the age of the actual plant additions. The annual depreciation amount is determined by dividing the net plant balance to be recovered by the estimated remaining life. The depreciation accrual rate is then calculated by dividing the annual depreciation amount by the plant balance for the account.

A table showing the current and proposed depreciation accrual rates is included in Appendix A. The Summary of Results included in Appendix B shows the plant balances, the survivor curve, ASL, estimated salvage percentage, net salvage amount, depreciation reserve per books, balance to be recovered, estimated remaining life, annual depreciation amount and proposed accrual rate for those plant accounts for which sufficient data were available to estimate ASLs and survivor curves. For those accounts for which sufficient data was not available, only the proposed accrual rates are shown. Historical data and the average remaining life calculations based on the selected survivor curves are included in Appendix C. The results of the study are described below.

<u>Distribution Plant</u>

Account 375 – Distribution Structures and Improvements

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.75%. The survivor curve that best fit the data was the L3 curve with an ASL of 34 years. Using these parameters, the average remaining life is calculated to be 16.4 years. There has been no salvage experienced for this account and none is anticipated. Based on a plant balance of $49,873, the recommended accrual rate is 2.67%, which is slightly lower than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 376 – Distribution Mains

Distribution Mains (Account 378) is the account with the largest amount of assets. Delta's records indicated plant additions dating back to 1940. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R3 curve with an ASL of 37 years provided solid results for all four metrics. Using an R3 curve with an ASL of 37 years, the average remaining life is calculated to be 27.0 years. There has been no salvage experienced for this account and none is anticipated. Based on a plant balance of $39,749,124, the calculated accrual rate is 2.67%, which is slightly higher than

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Winfrey, Robley, *Condition – Percent Tables for Depreciation of Unit and Group Properties*, Bulletin 156 (Iowa State University, Engineering Research Institute, reprinted 1970); Marston, Anson, Winfrey, Robley, and Hepstead, Jean C., *Engineering Valuation and Depreciation* (Iowa State University Press, 1963).

the current rate of 2.50%. Although a higher rate could be supported from the data, it is recommended that Delta continue to use the current rate of 2.50%. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 378 – Measuring and Regulator Station Equipment - Distribution

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 3.03%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R1 curve with an ASL of 36 years provided solid results for all four metrics. Using an R1 curve with an ASL of 36 years, the average remaining life is calculated to be 26.6 years. The salvage rate is expected to be –10 % for this account due to removal cost. Based on a plant balance of $1,179,793, the recommended accrual rate is 3.27%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 379 – Measuring and Regulator Station Equipment – City Gate

Delta's records indicated plant additions dating back to 1950. The current depreciation accrual rate for this account is 2.96%. An R2 curve was chosen for this plant account because it had good statistical results and is a common curve used for this account in the industry. Using an R2 curve with an ASL of 37 years, the average remaining life is calculated to be 23.0 years. The salvage rate is expected to be –10 % for this account due to removal cost. Based on a plant balance of $351,979, the recommended accrual rate is 3.19%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 380 – Services – Distribution

Because distribution services were recorded as distribution mains (Account 376) for a number of years, there was not sufficient data to develop survivor curves based on Delta's plant additions and retirements for distribution services. Delta is currently using a depreciation accrual rate of 2.50% for Account 380. Because this is the same accrual rate as for distribution mains (Account 376), no change in the accrual rate is recommended. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 381 – Meters

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 2.25%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the S1 curve with an ASL of 40 years provided excellent results for all four metrics. Using an S1 curve with an ASL of 40 years, the average remaining life is calculated to be 28.9 years. No salvage is anticipated in the future for this account. Based on a plant balance of $5,867,192, the recommended accrual rate is 2.28%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 382 – Meters & Regulator Installations

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 4.17%. An S1 curve was chosen for this plant account because it had excellent statistical results and is the same curve used for Account 381 Meters. Using an S1 curve with an ASL of 54 years, the average remaining life is calculated to be 26.2 years. The salvage rate is expected to be –45% for this account due to removal cost. Based on a plant balance of $3,708,896, the recommended accrual rate is 4.50%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 383 – House Regulators

Delta's records indicated plant additions dating back to 1940. The current depreciation accrual rate for this account is 3.88%. The S6 curve with an ASL of 28 years was chosen because it produced excellent statistical results and maximized all four of the statistics examined (SSD, CI, IV and REI). Using an S6 curve with an ASL of 28 years, the average remaining life is calculated to be 15.0 years. Salvage is anticipated to be 5%. Based on a plant balance of $1,917,622, the recommended accrual rate is 4.13%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 385 – Industrial Measuring and Regulator Station Equipment - Distribution

Delta's records indicated plant additions dating back to 1956. The current depreciation accrual rate for this account is 2.38%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R1 curve with an ASL of 43 years provided very strong results for all four metrics. Using an R1 curve with an ASL of 43 years, the average remaining life is calculated to be 33.5 years. Salvage is anticipated to be -10% due to removal cost. Based on a plant balance of $1,228,372, the recommended accrual rate is 2.40%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

<u>Gathering and Transmission Plant</u>

Account 305 – Structures and Improvements – Manufactured Gas Plant

There is currently no plant balance for this account. The depreciation rate for this account was 2.20%. If additional investment were made in this account, we would recommend using Delta's existing rate of 4.00%.

Account 325 – Gathering Land & Rights

Delta's records indicated plant additions dating back to 1959. The plant balance is $75,987. The current depreciation accrual rate for this account is 3.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment, we are not proposing to modify the existing accrual rate of 3.00%.

Account 327 – Compressor Station Structures

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for this account. Delta is currently using a depreciation accrual rate of 3.00% for Account 327. We are recommending that Delta maintain its current accrual rate of 3.00%. The plant balance is $42,950.

Account 331 – Producing Gas Wells – Well Equipment

Delta's records indicated plant additions dating back to 1969. The plant balance is $7,795. However, the plant in this account is fully depreciated. If additional investment were made in this account, we would recommend using Delta's existing rate of 4.00%.

Account 332 – Gathering Lines

The retirement data for this account produce curves with poor statistical results. Delta is currently using a depreciation accrual rate of 2.25% for Account 332, which has a balance of $1,914,741. We are recommending that Delta maintain its current accrual rate of 2.25%.

Account 333 – Gathering Compressor Stations

Delta's records indicated plant additions dating back only to 1986. The plant balance is $818,994. The current depreciation accrual rate for this account is 4.50%. The curve fitting statistics were poor for all survivor curve types. We are recommending that Delta maintain its current accrual rate of 4.00%.

Account 334 – Gathering Lines

The retirement data for this account produce curves with poor statistical results. Delta is currently using a depreciation accrual rate of 4.00% for Account 334, which has a balance of $107,270. We are recommending that Delta maintain its current accrual rate of 2.72%.

Account 366 – Structures and Improvements - Transmission

Delta's records indicated plant additions dating back to 1951. The plant balance is $173,215. The current depreciation accrual rate for this account is 2.00%. There has been no salvage experienced for this account and none is anticipated. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Account 367 – Mains - Transmission

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 2.22%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the R3 curve with an ASL of 43 years provided excellent results for all four metrics. Using an R3 curve with an ASL of 43 years, the average remaining life is calculated to be 30.2 years. No salvage is anticipated for this account. Based on a plant balance of $28,005,604, the recommended accrual rate is 2.24%, which is slightly higher than the current rate. The recommended accrual rate is reasonable compared with other gas distribution utilities in the region.

Account 368 – Compressor Station Equipment - Transmission

Delta's records indicated plant additions dating back to 1961. The plant balance is $1,413,310. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Account 369 – Measuring and Regulator Station Equipment - Transmission

Delta's records indicated plant additions dating back to 1951. The current depreciation accrual rate for this account is 3.16%. While no single curve maximized all four of the statistics examined (SSD, CI, IV and REI), the S3 curve with an ASL of 39 years provided excellent results for all four metrics. Using an S3 curve with an ASL of 39 years, the average remaining life is calculated to be 27.0 years. Salvage is expected to be –10% due to removal cost. Based on a plant balance of $2,273,559, the recommended accrual rate is 3.14%, which is slightly higher than the current rate.

Account 371 – Other Equipment - Transmission

Delta's records indicated plant additions dating back to 1959. The plant balance is $550,019. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing that Delta maintain its accrual rate of 2.00%.

Storage Plant

Account 351 -- Storage Structures and Improvements

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.22% for Account 351. An accrual rate of 2.48% is recommended based on an expected remaining life of 32 years. The plant balance is $233,229. The recommended accrual rate is consistent with other utilities in the region.

Account 352 -- Storage Wells

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.34% for Account 352. An accrual rate of 2.19% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $252,152. The recommended accrual rate is consistent with other utilities in the region.

Account 352.1 -- Storage Rights

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.98% for Account 352.1. An accrual rate of 1.85% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $509,180. The recommended accrual rate is consistent with other utilities in the region.

Account 352.2 -- Storage Resevoirs

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.91% for Account 352.2. An accrual rate of 1.78% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $1,069,953. The recommended accrual rate is consistent with other utilities in the region.

Account 352.3 -- Storage Nonrec Natural Gas

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.90% for Account 352.2. An accrual rate of 1.75% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $165,205. The recommended accrual rate is consistent with other utilities in the region.

Account 353 -- Storage Lines

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.17% for Account 352.2. An accrual rate of 2.44% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $3,339,099. The recommended accrual rate is consistent with other utilities in the region.

Account 354 -- Storage Compressor Lines

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.61% for Account 354. An accrual rate of 1.90% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $1,468,661. The recommended accrual rate is consistent with other utilities in the region.

Account 355 -- Storage Measuring and Regulator Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.25% for Account 355. An accrual rate of 2.41% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $280,342. The recommended accrual rate is consistent with other utilities in the region.

Account 356 – Purification Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 2.16% for Account 356. An accrual rate of 2.02% is recommended based on an expected remaining life of approximately 32 years. The plant balance is $233,131. The recommended accrual rate is consistent with other utilities in the region.

Account 357 – Storage Other Equipment

There was not sufficient historical data to develop survivor curves based on Delta's plant additions and retirements for its storage investment. Delta is currently using a depreciation accrual rate of 1.15% for Account 357. An accrual rate of 0.53% is recommended based on an expected remaining life of approximately 26 years. The plant balance is $6,524. The recommended accrual rate is consistent with other utilities in the region.

General Plant

Account 390 – Structures and Improvements

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. It is recommended that Delta maintain the use of 2.00% for this account, which is in line with other utilities in the region and is slightly lower than the accrual rate resulting from the best fitting R3 curve with an average life of 32 years.

Account 391 – Office Furniture

The retirement data did not produce a curve with sufficient statistical results. Delta is currently using a depreciation accrual rate of 2.32% for Account 391. It is recommended that Delta reduce the accrual rate to 1.00%, which will be more in line with other utilities in the region.

Account 392 – Autos and Trucks

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. It is recommended that Delta reduce the accrual rate from 7.77% to 8.14% for this account based on an expected remaining life of 2.5 years. This accrual rate is in line with other utilities in the region.

Account 393 – Stores Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were marginal for all survivor curve types. It is recommended that Delta reduce the accrual rate to 2.00%, which is in line with other utilities in the region.

Account 394 – Tools and Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were poor for all survivor curve types. It is recommended that Delta reduce the accrual rate to 4.00%, which is in line with other utilities in the region.

Account 395 – Laboratory Equipment

Delta's records indicated plant additions dating back to 1957. The current depreciation accrual rate for this account is 7.36%. After reviewing the account we recommend that the depreciation rate be lowered to 5.00%, which is in line with other utilities in the region.

Account 396 – Power Operated Equipment

Delta's records indicated plant additions dating back to 1964. The current depreciation accrual rate for this account is 2.00%. The curve fitting statistics were poor for all survivor curve types. Based on judgment and a comparison of depreciation accrual rates of other utilities in the region, we are proposing to maintain accrual rate of 2.00%.

Account 397 – Communication Equipment

The retirement data did not produce a curve with sufficient statistical results. Delta is currently using a depreciation accrual rate of 6.56% for Account 397. It is recommended that Delta reduce the accrual rate to 5.00%, which will be more in line with other utilities in the region.

Account 398 – Miscellaneous Equipment

There was not a sufficient amount of retirements to develop survivor curves based on Delta's plant data. The curve fitting statistics were poor for all survivor curve types. Delta is currently using a depreciation accrual rate of 5.0% for Account 398, which has a balance of $93,747. It is recommended that Delta reduce the accrual rate to 2.0%, which will be more in line with other utilities in the region.

Account 399.1 – Other Tangible Property – Mapping Software

The current depreciation accrual rate for this account is 10.0%. It is recommended that Delta reduce the accrual rate to 4.0%, which will be more in line with other utilities in the region.

Account 399.2 – Other Tangible Property – Computer Software

The current depreciation accrual rate for this account is 20.0%. Based on judgment concerning the expected rate of obsolescence for this type of property, it is recommended that Delta reduce the accrual rate to 10.0%, which will be more in line with other utilities in the region.

Account 399.3 – Other Tangible Property – Computer Equipment

The current depreciation accrual rate for this account is 20.0%. Based on judgment concerning the expected rate of obsolescence for this type of property, it is recommended that Delta reduce the accrual rate to 10.0%, which will be more in line with other utilities in the region.

Appendix A

Delta Natu s Company
Depreci..on Study

Proposed Depreciation Rates

Account		Current Accrual Rate	Proposed Accrual Rate
305	Structures & Improvements - Manufactured Gas Plant	2.20%	2.20%
325	Gathering Land & Rights	3.00%	3.00%
327	Comp Stattion Structures	3.00%	3.00%
331	Producing Gas Wells -- Well Equipment	4.00%	4.00%
332	Gathering Lines	2.25%	2.25%
333	Gathering Compressor Stations	4.00%	4.00%
334	Gathering Measuring and Regulator Station Equipment	2.72%	2.72%
351	Storage Structures and Improvements	2.22%	2.48%
352	Storage Wells	2.34%	2.19%
3521	Storage Rights	1.98%	1.85%
3522	Storage Resevoirs	1.91%	1.78%
3523	Storage Nonrec Natural Gas	1.90%	1.75%
353	Storage Lines	2.17%	2.44%
354	Storage Compressor Stations	1.61%	1.90%
355	Storage Measuring and Regulator Equipment	2.25%	2.41%
356	Purification Equipment	2.16%	2.02%
357	Storage Other Equipment	1.15%	0.53%
3652	Rights of Way	0.00%	0.00%
3653	Land Rights	2.50%	2.50%
366	Structures & Improvements - Transmission	2.00%	2.00%
367	Mains -- Transmission	2.22%	2.24%
368	Compressor Station Equipment -- Transmission	2.00%	2.00%
369	Measuring and Regulator Station Equipment -- Transmission	3.16%	3.14%
371	Other Equipment -- Transmission	2.00%	2.00%
375	Structures and Improvements -- Distribution	2.75%	2.67%
376	Mains -- Distribution	2.50%	2.50%
378	Measuring and Regulator Station Equipment -- Distribution	3.03%	3.27%
379	Measuring and Regulator Station Equipment -- City Gate	2.96%	3.19%
380	Services -- Distribution	2.50%	2.50%
381	Meters	2.25%	2.28%
382	Meter & Regulator Installations	4.17%	4.50%
383	Houes Regulators	3.88%	4.13%
385	Industrial Measuring and Regulator Station Equipment -- Distribution	2.38%	2.40%
390	Structures and Improvements -- General Plant	2.00%	2.00%
391	Office Furniture and Equipment -- General Plant	2.23%	1.00%
392	Transportation Equipment	7.77%	8.14%
393	Stores Equipment	5.00%	2.00%
394	Tools & Equipment	5.00%	4.00%
39401	Comp Nat Gas Stat		
395	Laboratory Equipment	7.36%	5.00%
396	Power Operated Equipment	2.00%	2.00%
397	Communication Equipment	6.56%	5.00%
398	Miscellaneous Equipment	5.00%	2.00%
399.1	Other Tangible Property -- Mapping Costs	10.00%	4.00%
399.2	Other Tangible Property -- Computer Software	20.00%	10.00%
399031	Computerized Office Equipment	20.00%	10.00%
399.3	Computer Hardware	20.00%	10.00%

Appendix B

Delta Natu s Company
Deprecia..on Study

Proposed Depreciation Rates

Account		Plant Balance	Dispersion	ASL	Estimated Salvage %	Net Salvage Amount	Depreciation Book Reserve	Balance To Be Recovered	Estimated Life Remaining	Annual Depreciation Amount	Total Accrual Rate
305	Structures & Improvements - Manufactured Gas Plant					$ -					2.20%
325	Gathering Land & Rights	$ 75,987	O4	41	0%	$ -	$ 52,270	$ 23,717			3.00%
327	Comp Stattion Structures	$ 42,950			0%	$ -	$ 24,418	$ 18,532			3.00%
331	Producing Gas Wells -- Well Equipment	7,795	S6	25	0%	$ -	$ 7,795	$ -			4.00%
332	Gathering Lines	1,914,741	R3	35	0%	$ -	$ 1,233,752	$ 680,989	17.0	$ 40,058	2.25%
333	Gathering Compressor Stations	828,752	R1	47	0%	$ -	$ 660,875	$ 167,877			4.00%
334	Gathering Measuring and Regulator Station Equipment	136,937	R3	31	0%	$ -	$ 69,617	$ 67,321	18.0	$ 3,740	2.72%
351	Storage Structures and Improvements	294,116				$ -	$ 60,887	$ 233,229	32.0	$ 7,288	2.48%
352	Storage Wells	360,583				$ -	$ 108,431	$ 252,152	32.0	$ 7,880	2.19%
3521	Storage Rights	860,396				$ -	$ 351,216	$ 509,180	32.0	$ 15,912	1.85%
3522	Storage Resevoirs	1,881,731				$ -	$ 811,788	$ 1,069,943	32.0	$ 33,436	1.78%
3523	Storage Nonrec Natural Gas	294,307				$ -	$ 129,102	$ 165,205	32.0	$ 5,163	1.75%
353	Storage Lines	5,091,297				$ -	$ 1,752,198	$ 3,339,099	32.0	$ 104,347	2.44%
354	Storage Compressor Stations	2,419,643				$ -	$ 950,982	$ 1,468,661	32.0	$ 45,896	1.90%
355	Storage Measuring and Regulator Equipment	363,662				$ -	$ 83,320	$ 280,342	32.0	$ 8,761	2.41%
356	Purification Equipment	360,432				$ -	$ 127,301	$ 233,131	32.0	$ 7,285	2.02%
357	Storage Other Equipment	47,209				$ -	$ 40,686	$ 6,524	26.0	$ 251	0.53%
3652	Rights of Way	163,626	S3	27	0%	$ -	$ 163,626	$ (0)	26.0	$ (0)	
3653	Land Rights										2.50%
366	Structures & Improvements - Transmission	182,239	R5	49	0%	$ -	$ 74,233	$ 108,006	33.7	$ 3,207	2.00%
367	Mains -- Transmission	41,447,021	R3	43	0%	$ -	$ 13,441,417	$ 28,005,604	30.2	$ 927,645	2.24%
368	Compressor Station Equipment -- Transmission	2,479,974	S4	36	0%	$ -	$ 1,059,244	$ 1,420,730	6.5	$ 218,574	2.00%
369	Measuring and Regulator Station Equipment -- Transmission	2,678,817	S3	39	-10%	$ (267,881.70)	$ 673,139	$ 2,273,559	27.0	$ 84,175	3.14%
371	Other Equipment -- Transmission	579,896	R1	27	0%	$ -	$ 453,352	$ 126,544	17.6	$ 7,190	2.00%
375	Structures and Improvements -- Distribution	113,715	L3	34	0%	$ -	$ 63,842	$ 49,873	16.4	$ 3,041	2.67%
376	Mains -- Distribution	61,423,134	R3	37	0%	$ -	$ 21,674,010	$ 39,749,124	27.0	$ 1,472,190	2.50%
378	Measuring and Regulator Station Equipment -- Distribution	1,356,370	R1	36	-10%	$ (135,636.98)	$ 312,214	$ 1,179,793	26.6	$ 44,320	3.27%
379	Measuring and Regulator Station Equipment -- City Gate	480,352	R2	37	-10%	$ (48,035.15)	$ 176,408	$ 351,979	23.0	$ 15,290	3.19%
380	Services -- Distribution	12,658,475					$ 2,272,997	$ 10,385,478			2.50%
381	Meters	8,917,576	S1	40	0%	$ -	$ 3,050,384	$ 5,867,192	28.9	$ 203,017	2.28%
382	Meter & Regulator Installations	3,145,615	S1	40	-45%	$ (1,415,526.56)	$ 852,245	$ 3,708,896	26.2	$ 141,561	4.50%
383	Houes Regulators	3,093,300	S6	28	5%	$ 154,664.98	$ 1,175,677	$ 1,762,957	15.0	$ 117,530	4.13%
385	Industrial Measuring and Regulator Station Equipment -- Distribution	1,530,217	R1	43	-10%	$ (153,021.70)	$ 454,866	$ 1,228,372	33.5	$ 36,712	2.40%
390	Structures and Improvements -- General Plant	5,452,189	R3	32	40%	$ 2,180,875.50	$ 1,541,971	$ 1,729,343	20.0	$ 86,684	2.00%
391	Office Furniture and Equipment -- General Plant	135,672	L0	17	5%	$ 6,783.59	$ 94,318	$ 34,571			1.00%
392	Transportation Equipment	3,868,757	L3	6	30%	$ 1,160,627.00	$ 1,920,928	$ 787,202	2.5	$ 314,881	8.14%
393	Stores Equipment	36,011	R5	27	0%	$ -	$ 26,487	$ 9,524			2.00%
394	Tools & Equipment	629,382	L5	19	5%	$ 31,469.10	$ 205,031	$ 392,882			4.00%
39401	Comp Nat Gas Stat	283,352					$ 258,732	$ 24,621			
395	Laboratory Equipment	215,820	L4	14	0%	$ -	$ 131,452	$ 84,368			5.00%
396	Power Operated Equipment	2,779,542	S1	16	40%	$ 1,111,816.92	$ 1,603,045	$ 64,681			2.00%
397	Communication Equipment	443,788	S2	14	5%	$ 22,189.38	$ 230,944	$ 190,654			5.00%
398	Miscellaneous Equipment	54,238	S0	21	5%	$ 2,711.90	$ 46,607	$ 4,919			2.00%
399.1	Other Tangible Property -- Mapping Costs	638,509	S6	23	0%	$ -	$ 591,515	$ 46,994			4.00%
399.2	Other Tangible Property -- Computer Software	2,525,991	S6	20	0%	$ -	$ 1,728,173	$ 797,818			10.00%
399031	Computerized Office Equipment	255,272					$ 154,077	$ 101,195			10.00%
399.3	Computer Hardware	937,029					$ 622,816	$ 314,213			10.00%

Appendix C

Delta Natur[illegible] s Company
Depreciation Study
As of December 31, 2006
366 -- Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	49	R5	-	-	0.50	-	-
1941	-	0	49	R5	-	-	0.49	-	-
1942	-	0	49	R5	-	-	0.70	-	-
1943	-	0	49	R5	-	-	0.92	-	-
1944	-	0	49	R5	-	-	1.15	-	-
1945	-	0	49	R5	-	-	1.40	-	-
1946	-	0	49	R5	-	-	1.64	-	-
1947	-	0	49	R5	-	-	1.86	-	-
1948	-	0	49	R5	-	-	2.06	-	-
1949	-	0	49	R5	-	-	2.25	-	-
1950	-	0	49	R5	-	-	2.45	-	-
1951	200	0	49	R5	4	-	2.68	-	11
1952	-	0	49	R5	-	-	2.93	-	-
1953	-	0	49	R5	-	-	3.21	-	-
1954	-	0	49	R5	-	-	3.52	-	-
1955	-	0	49	R5	-	-	3.87	-	-
1956	2,153	0	49	R5	44	-	4.24	-	186
1957	-	0	49	R5	-	-	4.65	-	-
1958	92	0	49	R5	2	-	5.10	-	10
1959	2,000	0	49	R5	41	-	5.58	-	228
1960	339	0	49	R5	7	-	6.10	-	42
1961	250	0	49	R5	5	-	6.66	-	34
1962	604	0	49	R5	12	-	7.26	-	89
1963	-	0	49	R5	-	-	7.89	-	-
1964	707	0	49	R5	14	-	8.56	-	123
1965	395	0	49	R5	8	-	9.26	-	75
1966	1,926	0	49	R5	39	-	10.00	-	393
1967	472	0	49	R5	10	-	10.76	-	104
1968	-	0	49	R5	-	-	11.56	-	-
1969	-	0	49	R5	-	-	12.38	-	-
1970	-	0	49	R5	-	-	13.22	-	-
1971	-	0	49	R5	-	-	14.09	-	-
1972	-	0	49	R5	-	-	14.97	-	-
1973	446	0	49	R5	9	-	15.87	-	144
1974	844	0	49	R5	17	-	16.79	-	289
1975	4,930	0	49	R5	101	-	17.72	-	1,782
1976	-	0	49	R5	-	-	18.66	-	-
1977	(805)	0	49	R5	(16)	-	19.61	-	(322)
1978	-	0	49	R5	-	-	20.58	-	-

Delta Natı ;as Company
Depreciation Study
As of December 31, 2006
366 -- Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	-	0	49	R5	-	-	21.55	-	-
1980	-	0	49	R5	-	-	22.53	-	-
1981	-	0	49	R5	-	-	23.52	-	-
1982	-	0	49	R5	-	-	24.51	-	-
1983	-	0	49	R5	-	-	25.51	-	-
1984	20,275	0	49	R5	414	-	26.50	-	10,966
1985	3,682	0	49	R5	75	-	27.50	-	2,066
1986	22,873	0	49	R5	467	-	28.50	-	13,304
1987	6,415	0	49	R5	131	-	29.50	-	3,862
1988	44,102	0	49	R5	900	-	30.50	-	27,451
1989	6,213	0	49	R5	127	-	31.50	-	3,994
1990	3,904	0	49	R5	80	-	32.50	-	2,589
1991	-	0	49	R5	-	-	33.50	-	-
1992	1,378	0	49	R5	28	-	34.50	-	970
1993	11,471	0	49	R5	234	-	35.50	-	8,310
1994	1,938	0	49	R5	40	-	36.50	-	1,444
1995	-	0	49	R5	-	-	37.50	-	-
1996	-	0	49	R5	-	-	38.50	-	-
1997	6,959	0	49	R5	142	-	39.50	-	5,610
1998	-	0	49	R5	-	-	40.50	-	-
1999	-	0	49	R5	-	-	41.50	-	-
2000	14,791	0	49	R5	302	-	42.50	-	12,829
2001	11,358	0	49	R5	232	-	43.50	-	10,083
2002	-	0	49	R5	-	-	44.50	-	-
2003	-	0	49	R5	-	-	45.50	-	-
2004	4,838	0	49	R5	99	-	46.50	-	4,591
2005	-	0	49	R5	-	-	47.50	-	-
2006	29,306	0	49	R5	598	-	48.50	-	29,007
	204,056	-			4,164	-	33.68		140,265
				Average Remaining Life					33.7

Survivor Curve	R5
ASL	49

Delta Natur[illegible]s Company
Depreciation Study
As of December 31, 2006
367 -- Transmission Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	43	R3	-	-	1.52	-	-
1941	-	0	43	R3	-	-	1.76	-	-
1942	-	0	43	R3	-	-	2.00	-	-
1943	-	0	43	R3	-	-	2.25	-	-
1944	-	0	43	R3	-	-	2.51	-	-
1945	-	0	43	R3	-	-	2.76	-	-
1946	-	0	43	R3	-	-	3.02	-	-
1947	-	0	43	R3	-	-	3.27	-	-
1948	-	0	43	R3	-	-	3.53	-	-
1949	-	0	43	R3	-	-	3.79	-	-
1950	-	0	43	R3	-	-	4.05	-	-
1951	61,761	0	43	R3	1,436	-	4.31	-	6,189
1952	-	0	43	R3	-	-	4.58	-	-
1953	-	0	43	R3	-	-	4.85	-	-
1954	8,944	0	43	R3	208	-	5.14	-	1,069
1955	95,433	0	43	R3	2,219	-	5.44	-	12,072
1956	153,043	0	43	R3	3,559	-	5.75	-	20,471
1957	2,766	0	43	R3	64	-	6.08	-	391
1958	40,731	0	43	R3	947	-	6.42	-	6,086
1959	209,986	0	43	R3	4,883	-	6.79	-	33,150
1960	443,547	0	43	R3	10,315	-	7.17	-	73,977
1961	-	0	43	R3	-	-	7.58	-	-
1962	11,049	0	43	R3	257	-	8.00	-	2,056
1963	5,069	0	43	R3	118	-	8.45	-	996
1964	43,691	0	43	R3	1,016	-	8.92	-	9,061
1965	401,158	0	43	R3	9,329	-	9.41	-	87,780
1966	185,675	0	43	R3	4,318	-	9.92	-	42,847
1967	42,318	0	43	R3	984	-	10.46	-	10,293
1968	570,758	0	43	R3	13,273	-	11.02	-	146,213
1969	10,242	0	43	R3	238	-	11.59	-	2,761
1970	30,291	0	43	R3	704	-	12.19	-	8,589
1971	390,160	0	43	R3	9,073	-	12.81	-	116,231
1972	220,046	0	43	R3	5,117	-	13.45	-	68,812
1973	20,159	0	43	R3	469	-	14.10	-	6,611
1974	155,219	0	43	R3	3,610	-	14.77	-	53,331
1975	1,038,377	0	43	R3	24,148	-	15.46	-	373,403
1976	667,139	0	43	R3	15,515	-	16.17	-	250,837
1977	32,582	0	43	R3	758	-	16.89	-	12,796
1978	351,269	0	43	R3	8,169	-	17.62	-	143,953

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367 -- Transmission Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	157,163	0	43	R3	3,655	-	18.37	-	67,142
1980	637,037	0	43	R3	14,815	-	19.13	-	283,440
1981	94,865	0	43	R3	2,206	-	19.91	-	43,919
1982	67,797	0	43	R3	1,577	-	20.70	-	32,629
1983	100,369	0	43	R3	2,334	-	21.50	-	50,173
1984	124,371	0	43	R3	2,892	-	22.31	-	64,521
1985	920,732	0	43	R3	21,412	-	23.13	-	495,299
1986	656,696	0	43	R3	15,272	-	23.97	-	366,022
1987	419,996	0	43	R3	9,767	-	24.81	-	242,361
1988	407,419	0	43	R3	9,475	-	25.67	-	243,228
1989	1,403,591	171586	43	R3	32,642	3,990	26.54	-	866,271
1990	409,629	0	43	R3	9,526	-	27.42	-	261,181
1991	475,208	114998	43	R3	11,051	2,674	28.30	-	312,808
1992	770,645	0	43	R3	17,922	-	29.20	-	523,365
1993	1,311,531	0	43	R3	30,501	-	30.11	-	918,342
1994	1,842,857	172928	43	R3	42,857	4,022	31.02	-	1,329,598
1995	2,576,777	0	43	R3	59,925	-	31.95	-	1,914,438
1996	2,206,080	0	43	R3	51,304	-	32.88	-	1,686,787
1997	983,281	0	43	R3	22,867	-	33.82	-	773,279
1998	1,073,527	0	43	R3	24,966	-	34.76	-	867,842
1999	664,955	4126412	43	R3	15,464	95,963	35.71	20.70	2,538,224
2000	1,951,563	0	43	R3	45,385	-	36.67	-	1,664,257
2001	710,776	0	43	R3	16,530	-	37.63	-	622,044
2002	3,267,444	0	43	R3	75,987	-	38.60	-	2,933,040
2003	4,131,461	0	43	R3	96,080	-	39.57	-	3,801,986
2004	1,777,954	0	43	R3	41,348	-	40.55	-	1,676,506
2005	767,710	0	43	R3	17,854	-	41.53	-	741,388
2006	3,695,479	0	43	R3	85,941	-	42.51	-	3,653,196
	38,798,326	4,585,924			902,287	106,649	33.76		30,463,261
					Average Remaining Life				30.2

Survivor Curve	R3
ASL	43

Delta Natur. .s Company
Depreciation Study
As of December 31, 2006
368 -- Compressor Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	36	S4	-	-	-	-	-
1941	-	0	36	S4	-	-	-	-	-
1942	-	0	36	S4	-	-	-	-	-
1943	-	0	36	S4	-	-	0.50	-	-
1944	-	0	36	S4	-	-	0.50	-	-
1945	-	0	36	S4	-	-	1.03	-	-
1946	-	0	36	S4	-	-	0.99	-	-
1947	-	0	36	S4	-	-	0.93	-	-
1948	-	0	36	S4	-	-	0.95	-	-
1949	-	0	36	S4	-	-	1.01	-	-
1950	-	0	36	S4	-	-	1.10	-	-
1951	-	0	36	S4	-	-	1.19	-	-
1952	-	0	36	S4	-	-	1.29	-	-
1953	-	0	36	S4	-	-	1.40	-	-
1954	-	0	36	S4	-	-	1.52	-	-
1955	-	0	36	S4	-	-	1.64	-	-
1956	-	0	36	S4	-	-	1.77	-	-
1957	-	0	36	S4	-	-	1.91	-	-
1958	-	0	36	S4	-	-	2.05	-	-
1959	-	0	36	S4	-	-	2.21	-	-
1960	-	0	36	S4	-	-	2.37	-	-
1961	794	0	36	S4	22	-	2.55	-	56
1962	11,090	0	36	S4	308	-	2.73	-	842
1963	89,639	0	36	S4	2,490	-	2.93	-	7,307
1964	2,757	0	36	S4	77	-	3.15	-	241
1965	76,220	0	36	S4	2,117	-	3.38	-	7,163
1966	1,010	0	36	S4	28	-	3.63	-	102
1967	1,745	0	36	S4	48	-	3.90	-	189
1968	-	0	36	S4	-	-	4.20	-	-
1969	3,869	0	36	S4	107	-	4.52	-	485
1970	480	0	36	S4	13	-	4.86	-	65
1971	23,086	0	36	S4	641	-	5.24	-	3,357
1972	309	0	36	S4	9	-	5.64	-	48
1973	-	0	36	S4	-	-	6.08	-	-
1974	958	0	36	S4	27	-	6.56	-	175
1975	57,007	0	36	S4	1,584	-	7.08	-	11,216
1976	43,971	0	36	S4	1,221	-	7.65	-	9,338

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368 -- Compressor Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1977	-	0	36	S4	-	-	8.25	-	-
1978	600	0	36	S4	17	-	8.90	-	148
1979	14,111	0	36	S4	392	-	9.60	-	3,763
1980	12,740	0	36	S4	354	-	10.34	-	3,661
1981	1,020	0	36	S4	28	-	11.13	-	315
1982	640	0	36	S4	18	-	11.96	-	213
1983	-	0	36	S4	-	-	12.82	-	-
1984	483,934	0	36	S4	13,443	-	13.72	-	184,394
1985	77,490	0	36	S4	2,153	-	14.64	-	31,515
1986	397,226	0	36	S4	11,034	-	15.59	-	171,998
1987	42,436	0	36	S4	1,179	-	16.55	-	19,511
1988	-	0	36	S4	-	-	17.53	-	-
1989	11,796	0	36	S4	328	-	18.52	-	6,067
1990	-	0	36	S4	-	-	19.51	-	-
1991	190,334	0	36	S4	5,287	-	20.50	-	108,403
1992	12,181	0	36	S4	338	-	21.50	-	7,275
1993	(2)	0	36	S4	(0)	-	22.50	-	(1)
1994	8,004	0	36	S4	222	-	23.50	-	5,225
1995	-	0	36	S4	-	-	24.50	-	-
1996	-	0	36	S4	-	-	25.50	-	-
1997	-	0	36	S4	-	-	26.50	-	-
1998	8,440	0	36	S4	234	-	27.50	-	6,447
1999	-	519600	36	S4	-	14,433	28.50	-	-
2000	26,345	0	36	S4	732	-	29.50	-	21,588
2001	-	0	36	S4	-	-	30.50	-	-
2002	6,075	0	36	S4	169	-	31.50	-	5,316
2003	443,449	0	36	S4	12,318	-	32.50		
2004	17,735	0	36	S4	493	-	33.50		
2005	-	0	36	S4	-	-	34.50		
2006	827,361	0	36	S4	22,982	-	35.50		
	2,894,850	519,600			80,412	14,433	7.67		616,424
					Average Remaining Life				6.5

Survivor Curve S4
ASL 36

Delta Natura[illegible]s Company
Depreciation Study
As of December 31, 2006
369 -- Measuring Regulating Station Equipment

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	39	S3	-	-	1.49	-	-
1941	-	0	39	S3	-	-	1.63	-	-
1942	-	0	39	S3	-	-	1.77	-	-
1943	-	0	39	S3	-	-	1.91	-	-
1944	-	0	39	S3	-	-	2.06	-	-
1945	-	0	39	S3	-	-	2.22	-	-
1946	-	0	39	S3	-	-	2.38	-	-
1947	-	0	39	S3	-	-	2.54	-	-
1948	-	0	39	S3	-	-	2.71	-	-
1949	-	0	39	S3	-	-	2.89	-	-
1950	-	0	39	S3	-	-	3.07	-	-
1951	604	0	39	S3	15	-	3.26	-	50
1952	-	0	39	S3	-	-	3.45	-	-
1953	-	0	39	S3	-	-	3.65	-	-
1954	-	0	39	S3	-	-	3.86	-	-
1955	2,821	0	39	S3	72	-	4.08	-	295
1956	3,317	0	39	S3	85	-	4.30	-	366
1957	1,730	0	39	S3	44	-	4.53	-	201
1958	4,222	0	39	S3	108	-	4.78	-	517
1959	11,640	0	39	S3	298	-	5.03	-	1,502
1960	36,436	0	39	S3	934	-	5.30	-	4,948
1961	2,350	0	39	S3	60	-	5.57	-	336
1962	143	0	39	S3	4	-	5.86	-	21
1963	1,590	0	39	S3	41	-	6.16	-	251
1964	2,469	0	39	S3	63	-	6.48	-	410
1965	11,196	0	39	S3	287	-	6.81	-	1,955
1966	12,600	0	39	S3	323	-	7.16	-	2,313
1967	6,054	0	39	S3	155	-	7.52	-	1,168
1968	5,943	0	39	S3	152	-	7.91	-	1,205
1969	18,946	0	39	S3	486	-	8.31	-	4,036
1970	4,457	0	39	S3	114	-	8.73	-	998
1971	22,690	0	39	S3	582	-	9.17	-	5,337
1972	1,848	0	39	S3	47	-	9.64	-	457
1973	11,003	0	39	S3	282	-	10.13	-	2,858
1974	21,450	0	39	S3	550	-	10.65	-	5,856
1975	68,977	0	39	S3	1,769	-	11.19	-	19,788
1976	25,972	0	39	S3	666	-	11.76	-	7,829
1977	5,860	0	39	S3	150	-	12.35	-	1,856

Delta Natur   ıs Company
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	2,125	0	39	S3	54	-	12.98	-	707
1979	11,949	0	39	S3	306	-	13.63	-	4,177
1980	4,539	0	39	S3	116	-	14.32	-	1,666
1981	2,096	0	39	S3	54	-	15.03	-	808
1982	2,119	0	39	S3	54	-	15.77	-	857
1983	11,231	0	39	S3	288	-	16.55	-	4,765
1984	93,670	0	39	S3	2,402	-	17.35	-	41,663
1985	40,669	0	39	S3	1,043	-	18.17	-	18,952
1986	4,156	0	39	S3	107	-	19.03	-	2,028
1987	1,551	0	39	S3	40	-	19.90	-	792
1988	14,728	0	39	S3	378	-	20.80	-	7,856
1989	65,410	23055	39	S3	1,677	591	21.72	-	36,432
1990	40,717	0	39	S3	1,044	-	22.66	-	23,656
1991	39,795	0	39	S3	1,020	-	23.61	-	24,091
1992	43,190	0	39	S3	1,107	-	24.57	-	27,213
1993	44,138	0	39	S3	1,132	-	25.55	-	28,913
1994	37,008	0	39	S3	949	-	26.53	-	25,174
1995	11,055	0	39	S3	283	-	27.52	-	7,800
1996	19,636	0	39	S3	503	-	28.51	-	14,354
1997	138,952	0	39	S3	3,563	-	29.50	-	105,122
1998	198,341	0	39	S3	5,086	-	30.50	-	155,124
1999	363,028	163168	39	S3	9,308	4,184	31.50	-	293,224
2000	185,729	0	39	S3	4,762	-	32.50	-	154,776
2001	84,508	0	39	S3	2,167	-	33.50	-	72,590
2002	184,938	0	39	S3	4,742	-	34.50	-	163,599
2003	78,872	0	39	S3	2,022	-	35.50	-	71,794
2004	146,005	0	39	S3	3,744	-	36.50	-	136,646
2005	249,689	0	39	S3	6,402	-	37.50	-	240,086
2006	219,987	0	39	S3	5,641	-	38.50	-	217,166
	2,624,149	186,223			67,286	4,775	28.93		1,946,582
				Average Remaining Life					27

Survivor Curve	S3
ASL	39

Delta Natura[illegible]as Company
Depreciation Study
As of December 31, 2006
375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	34	L3	-	-	2.89	-	-
1941	-	0	34	L3	-	-	3.09	-	-
1942	-	0	34	L3	-	-	3.30	-	-
1943	-	0	34	L3	-	-	3.51	-	-
1944	-	0	34	L3	-	-	3.72	-	-
1945	-	0	34	L3	-	-	3.93	-	-
1946	-	0	34	L3	-	-	4.15	-	-
1947	-	0	34	L3	-	-	4.37	-	-
1948	-	0	34	L3	-	-	4.59	-	-
1949	-	0	34	L3	-	-	4.82	-	-
1950	-	0	34	L3	-	-	5.05	-	-
1951	400	0	34	L3	12	-	5.29	-	62
1952	-	0	34	L3	-	-	5.53	-	-
1953	-	0	34	L3	-	-	5.77	-	-
1954	-	0	34	L3	-	-	6.02	-	-
1955	1,480	0	34	L3	44	-	6.27	-	273
1956	3,602	0	34	L3	106	-	6.52	-	691
1957	814	0	34	L3	24	-	6.77	-	162
1958	199	0	34	L3	6	-	7.03	-	41
1959	500	0	34	L3	15	-	7.29	-	107
1960	488	0	34	L3	14	-	7.55	-	108
1961	1,719	0	34	L3	51	-	7.81	-	395
1962	-	0	34	L3	-	-	8.07	-	-
1963	-	0	34	L3	-	-	8.32	-	-
1964	264	0	34	L3	8	-	8.56	-	66
1965	-	0	34	L3	-	-	8.80	-	-
1966	4,386	0	34	L3	129	-	9.02	-	1,164
1967	2,857	0	34	L3	84	-	9.23	-	776
1968	798	0	34	L3	23	-	9.43	-	221
1969	64	0	34	L3	2	-	9.62	-	18
1970	19,796	0	34	L3	582	-	9.80	-	5,704
1971	1,439	0	34	L3	42	-	9.97	-	422

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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1972	366	0	34	L3	11	-	10.13	-	109
1973	-	0	34	L3	-	-	10.30	-	-
1974	298	0	34	L3	9	-	10.47	-	92
1975	414	0	34	L3	12	-	10.66	-	130
1976	4,664	0	34	L3	137	-	10.87	-	1,491
1977	16,625	0	34	L3	489	-	11.11	-	5,431
1978	-	0	34	L3	-	-	11.38	-	-
1979	2,354	0	34	L3	69	-	11.69	-	809
1980	572	0	34	L3	17	-	12.04	-	203
1981	1,270	0	34	L3	37	-	12.44	-	465
1982	-	0	34	L3	-	-	12.89	-	-
1983	734	0	34	L3	22	-	13.40	-	289
1984	-	0	34	L3	-	-	13.96	-	-
1985	9,863	0	34	L3	290	-	14.57	-	4,226
1986	6,484	0	34	L3	191	-	15.23	-	2,905
1987	-	0	34	L3	-	-	15.94	-	-
1988	5,063	0	34	L3	149	-	16.69	-	2,486
1989	2,806	0	34	L3	83	-	17.48	-	1,443
1990	779	0	34	L3	23	-	18.30	-	419
1991	-	0	34	L3	-	-	19.15	-	-
1992	7,442	0	34	L3	219	-	20.02	-	4,381
1993	3,144	0	34	L3	92	-	20.90	-	1,933
1994	-	0	34	L3	-	-	21.81	-	-
1995	12,893	0	34	L3	379	-	22.73	-	8,618
1996	3,942	0	34	L3	116	-	23.66	-	2,743
1997	4,101	0	34	L3	121	-	24.61	-	2,968
1998	2,265	0	34	L3	67	-	25.57	-	1,703
1999	3,538	0	34	L3	104	-	26.54	-	2,761
2000	-	0	34	L3	-	-	27.52	-	-
2001	5,172	0	34	L3	152	-	28.51	-	4,336
2002	2,756	0	34	L3	81	-	29.50	-	2,391
2003	2,624	0	34	L3	77	-	30.50	-	2,354
2004	2,883	0	34	L3	85	-	31.50	-	2,671

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375 -- Distribution Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2005	1,850	0	34	L3	54	-	32.50	-	1,768
2006	-	0	34	L3	-	-	33.50	-	-
	143,708	-			4,227	-	16.40		69,337
					Average Remaining Life				16.40

Survivor Curve	L3
ASL	34

Delta Natur. .s Company
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376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	58,962	0	34	R4	1,734	-	-	-	-
1941	-	0	34	R4	-	-	-	-	-
1942	-	0	34	R4	-	-	-	-	-
1943	-	0	34	R4	-	-	-	-	-
1944	-	0	34	R4	-	-	-	-	-
1945	-	0	34	R4	-	-	-	-	-
1946	-	0	34	R4	-	-	-	-	-
1947	75,766	0	34	R4	2,228	-	-	-	-
1948	67,865	0	34	R4	1,996	-	-	-	-
1949	62,008	0	34	R4	1,824	-	-	-	-
1950	29,854	0	34	R4	878	-	-	-	-
1951	36,626	0	34	R4	1,077	-	-	-	-
1952	18,609	0	34	R4	547	-	-	-	-
1953	12,981	0	34	R4	382	-	-	-	-
1954	47,353	0	34	R4	1,393	-	0.50	-	696
1955	148,499	0	34	R4	4,368	-	0.50	-	2,184
1956	143,937	0	34	R4	4,233	-	1.88	-	7,948
1957	39,727	0	34	R4	1,168	-	(0.96)	-	(1,120)
1958	34,326	0	34	R4	1,010	-	0.43	-	431
1959	106,509	0	34	R4	3,133	-	0.82	-	2,573
1960	69,660	0	34	R4	2,049	-	1.11	-	2,267
1961	110,606	0	34	R4	3,253	-	1.37	-	4,452
1962	71,538	0	34	R4	2,104	-	1.63	-	3,424
1963	86,884	0	34	R4	2,555	-	1.89	-	4,826
1964	89,514	0	34	R4	2,633	-	2.15	-	5,668
1965	123,728	0	34	R4	3,639	-	2.42	-	8,814
1966	135,264	0	34	R4	3,978	-	2.70	-	10,732
1967	317,430	0	34	R4	9,336	-	2.98	-	27,852
1968	182,038	0	34	R4	5,354	-	3.28	-	17,580
1969	582,335	0	34	R4	17,128	-	3.60	-	61,731
1970	1,455,571	0	34	R4	42,811	-	3.95	-	169,166
1971	1,074,050	0	34	R4	31,590	-	4.33	-	136,844
1972	324,850	0	34	R4	9,554	-	4.75	-	45,400
1973	448,840	0	34	R4	13,201	-	5.22	-	68,859
1974	294,232	0	34	R4	8,654	-	5.73	-	49,572
1975	409,344	0	34	R4	12,040	-	6.29	-	75,709
1976	201,118	0	34	R4	5,915	-	6.89	-	40,772
1977	215,318	0	34	R4	6,333	-	7.53	-	47,709
1978	316,671	0	34	R4	9,314	-	8.20	-	76,392

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As of December 31, 2006
376 -- Distribution Mains

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	723,822	0	34	R4	21,289	-	8.89	-	189,289
1980	646,465	0	34	R4	19,014	-	9.60	-	182,551
1981	1,960,024	0	34	R4	57,648	-	10.33	-	595,613
1982	1,666,448	0	34	R4	49,013	-	11.08	-	543,304
1983	1,579,871	0	34	R4	46,467	-	11.86	-	551,100
1984	1,436,971	0	34	R4	42,264	-	12.66	-	534,953
1985	1,581,605	0	34	R4	46,518	-	13.48	-	626,898
1986	1,840,623	0	34	R4	54,136	-	14.32	-	775,034
1987	1,938,634	0	34	R4	57,019	-	15.18	-	865,327
1988	2,392,247	0	34	R4	70,360	-	16.05	-	1,129,602
1989	2,519,548	0	34	R4	74,104	-	16.95	-	1,256,077
1990	2,464,496	0	34	R4	72,485	-	17.86	-	1,294,684
1991	3,124,355	0	34	R4	91,893	-	18.79	-	1,726,368
1992	2,153,634	0	34	R4	63,342	-	19.72	-	1,249,407
1993	2,518,971	0	34	R4	74,087	-	20.67	-	1,531,663
1994	2,398,105	0	34	R4	70,533	-	21.63	-	1,525,780
1995	3,191,099	0	34	R4	93,856	-	22.60	-	2,121,050
1996	2,627,094	0	34	R4	77,267	-	23.57	-	1,821,397
1997	2,772,515	1000	34	R4	81,545	29	24.55	4.33	2,002,204
1998	4,460,035	0	34	R4	131,178	-	25.54	-	3,349,739
1999	3,295,415	0	34	R4	96,924	-	26.52	-	2,570,782
2000	3,191,898	0	34	R4	93,879	-	27.51	-	2,583,041
2001	1,634,379	6556	34	R4	48,070	193	28.51	26.52	1,375,474
2002	1,118,713	0	34	R4	32,903	-	29.50	-	970,732
2003	1,493,803	0	34	R4	43,935	-	30.50	-	1,339,980
2004	1,866,444	0	34	R4	54,895	-	31.50	-	1,728,999
2005	1,634,459	0	34	R4	48,072	-	32.49	-	1,562,079
2006	1,344,632	0	34	R4	39,548	-	33.49	-	1,324,581
	66,968,318	7,556			1,969,656	222	19.39		38,198,190
					Average Remaining Life				19.4

Survivor Curve	R4
ASL	34

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378 -- Measuring Regulating Equipment - General

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	110	0	36	R1	3	-	1.98	-	6
1941	-	0	36	R1	-	-	2.29	-	-
1942	-	0	36	R1	-	-	2.59	-	-
1943	-	0	36	R1	-	-	2.88	-	-
1944	-	0	36	R1	-	-	3.18	-	-
1945	-	0	36	R1	-	-	3.47	-	-
1946	-	0	36	R1	-	-	3.77	-	-
1947	-	0	36	R1	-	-	4.08	-	-
1948	260	0	36	R1	7	-	4.39	-	32
1949	97	0	36	R1	3	-	4.70	-	13
1950	202	0	36	R1	6	-	5.02	-	28
1951	535	0	36	R1	15	-	5.35	-	80
1952	904	0	36	R1	25	-	5.69	-	143
1953	789	0	36	R1	22	-	6.03	-	132
1954	38	0	36	R1	1	-	6.37	-	7
1955	5,199	0	36	R1	144	-	6.73	-	972
1956	3,855	0	36	R1	107	-	7.09	-	759
1957	1,094	0	36	R1	30	-	7.46	-	227
1958	-	0	36	R1	-	-	7.84	-	-
1959	12,372	0	36	R1	344	-	8.22	-	2,825
1960	-	0	36	R1	-	-	8.61	-	-
1961	-	0	36	R1	-	-	9.01	-	-
1962	321	0	36	R1	9	-	9.42	-	84
1963	-	0	36	R1	-	-	9.83	-	-
1964	608	0	36	R1	17	-	10.26	-	173
1965	881	0	36	R1	24	-	10.69	-	262
1966	5,272	0	36	R1	146	-	11.13	-	1,630
1967	-	0	36	R1	-	-	11.58	-	-
1968	317	0	36	R1	9	-	12.04	-	106
1969	281	0	36	R1	8	-	12.51	-	98
1970	23,330	0	36	R1	648	-	12.98	-	8,413
1971	24,948	0	36	R1	693	-	13.47	-	9,333
1972	13,981	0	36	R1	388	-	13.96	-	5,423
1973	3,975	0	36	R1	110	-	14.47	-	1,598
1974	5,207	0	36	R1	145	-	14.98	-	2,167
1975	6,244	0	36	R1	173	-	15.51	-	2,690
1976	3,610	0	36	R1	100	-	16.04	-	1,609
1977	8,552	0	36	R1	238	-	16.58	-	3,940
1978	7,190	0	36	R1	200	-	17.14	-	3,423

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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	9,000	0	36	R1	250	-	17.70	-	4,425
1980	41,132	0	36	R1	1,143	-	18.27	-	20,879
1981	51,901	0	36	R1	1,442	-	18.86	-	27,184
1982	13,595	0	36	R1	378	-	19.45	-	7,344
1983	20,919	0	36	R1	581	-	20.05	-	11,649
1984	16,759	0	36	R1	466	-	20.66	-	9,616
1985	12,417	0	36	R1	345	-	21.27	-	7,338
1986	37,728	0	36	R1	1,048	-	21.90	-	22,951
1987	54,661	0	36	R1	1,518	-	22.53	-	34,214
1988	57,764	0	36	R1	1,605	-	23.17	-	37,185
1989	87,102	0	36	R1	2,420	-	23.82	-	57,638
1990	51,068	0	36	R1	1,419	-	24.48	-	34,722
1991	44,062	0	36	R1	1,224	-	25.14	-	30,767
1992	52,625	0	36	R1	1,462	-	25.80	-	37,720
1993	49,956	0	36	R1	1,388	-	26.47	-	36,738
1994	44,296	0	36	R1	1,230	-	27.15	-	33,408
1995	101,062	0	36	R1	2,807	-	27.83	-	78,130
1996	58,206	0	36	R1	1,617	-	28.52	-	46,105
1997	116,218	0	36	R1	3,228	-	29.20	-	94,280
1998	62,585	0	36	R1	1,738	-	29.90	-	51,976
1999	133,573	0	36	R1	3,710	-	30.60	-	113,519
2000	8,746	0	36	R1	243	-	31.30	-	7,604
2001	27,018	0	36	R1	751	-	32.01	-	24,020
2002	14,796	0	36	R1	411	-	32.72	-	13,447
2003	132,610	0	36	R1	3,684	-	33.44	-	123,170
2004	59,940	0	36	R1	1,665	-	34.16	-	56,880
2005	117,525	0	36	R1	3,265	-	34.89	-	113,911
2006	21,873	0	36	R1	608	-	35.63	-	21,648
	1,629,309	-			45,259	-	26.62		1,204,637
				Average Remaining Life					26.6

Survivor Curve	R1
ASL	36

Delta Natura s Company
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	37	R2	-	-	0.67	-	-
1941	-	0	37	R2	-	-	0.90	-	-
1942	-	0	37	R2	-	-	1.15	-	-
1943	-	0	37	R2	-	-	1.40	-	-
1944	-	0	37	R2	-	-	1.67	-	-
1945	-	0	37	R2	-	-	1.94	-	-
1946	-	0	37	R2	-	-	2.22	-	-
1947	-	0	37	R2	-	-	2.51	-	-
1948	-	0	37	R2	-	-	2.79	-	-
1949	-	0	37	R2	-	-	3.08	-	-
1950	626	0	37	R2	17	-	3.37	-	57
1951	498	0	37	R2	13	-	3.66	-	49
1952	-	0	37	R2	-	-	3.95	-	-
1953	-	0	37	R2	-	-	4.24	-	-
1954	424	0	37	R2	11	-	4.53	-	52
1955	4,368	0	37	R2	118	-	4.83	-	570
1956	6,252	0	37	R2	169	-	5.13	-	867
1957	2,928	0	37	R2	79	-	5.44	-	430
1958	415	0	37	R2	11	-	5.75	-	65
1959	1,136	0	37	R2	31	-	6.08	-	187
1960	5,188	0	37	R2	140	-	6.41	-	899
1961	729	0	37	R2	20	-	6.75	-	133
1962	103	0	37	R2	3	-	7.11	-	20
1963	-	0	37	R2	-	-	7.48	-	-
1964	118	0	37	R2	3	-	7.86	-	25
1965	185	0	37	R2	5	-	8.26	-	41
1966	10,334	0	37	R2	279	-	8.67	-	2,422
1967	1,607	0	37	R2	43	-	9.10	-	395
1968	13	0	37	R2	0	-	9.54	-	3
1969	1,756	0	37	R2	47	-	10.00	-	475
1970	6,102	0	37	R2	165	-	10.48	-	1,728

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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1971	-	0	37	R2	-	-	10.97	-	-
1972	-	0	37	R2	-	-	11.48	-	-
1973	-	0	37	R2	-	-	12.00	-	-
1974	1,289	0	37	R2	35	-	12.54	-	437
1975	-	0	37	R2	-	-	13.10	-	-
1976	1,180	0	37	R2	32	-	13.67	-	436
1977	9,218	0	37	R2	249	-	14.25	-	3,551
1978	1,634	0	37	R2	44	-	14.86	-	656
1979	32,008	0	37	R2	865	-	15.47	-	13,385
1980	43,580	0	37	R2	1,178	-	16.10	-	18,966
1981	10,544	0	37	R2	285	-	16.75	-	4,773
1982	-	0	37	R2	-	-	17.41	-	-
1983	14,039	0	37	R2	379	-	18.08	-	6,859
1984	13,765	0	37	R2	372	-	18.76	-	6,980
1985	69,107	0	37	R2	1,868	-	19.46	-	36,349
1986	29,155	0	37	R2	788	-	20.17	-	15,894
1987	41,206	0	37	R2	1,114	-	20.89	-	23,269
1988	-	0	37	R2	-	-	21.63	-	-
1989	-	0	37	R2	-	-	22.37	-	-
1990	-	0	37	R2	-	-	23.13	-	-
1991	33,855	0	37	R2	915	-	23.90	-	21,867
1992	8,924	0	37	R2	241	-	24.68	-	5,952
1993	19,002	0	37	R2	514	-	25.47	-	13,079
1994	37,494	0	37	R2	1,013	-	26.27	-	26,616
1995	13,865	0	37	R2	375	-	27.07	-	10,146
1996	-	0	37	R2	-	-	27.89	-	-
1997	2,853	0	37	R2	77	-	28.72	-	2,215
1998	-	0	37	R2	-	-	29.56	-	-
1999	14,844	0	37	R2	401	-	30.40	-	12,197
2000	-	0	37	R2	-	-	31.26	-	-
2001	-	0	37	R2	-	-	32.12	-	-
2002	13,763	0	37	R2	372	-	32.99	-	12,272

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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
2003	-	0	37	R2	-	-	33.87	-	-
2004	79,594	0	37	R2	2,151	-	34.75	-	74,764
2005	19,922	0	37	R2	538	-	35.65	-	19,194
2006	17,058	0	37	R2	461	-	36.55	-	16,849
	570,681	-			15,424	-	23.02		355,125
				Average Remaining Life					23.0

Survivor Curve	R2
ASL	37

Delta Natur s Company
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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	1,300	0	40	S1	33	-	3.73	-	121
1941	-	0	40	S1	-	-	4.03	-	-
1942	-	0	40	S1	-	-	4.32	-	-
1943	-	0	40	S1	-	-	4.62	-	-
1944	-	0	40	S1	-	-	4.92	-	-
1945	-	0	40	S1	-	-	5.23	-	-
1946	-	0	40	S1	-	-	5.53	-	-
1947	1,361	0	40	S1	34	-	5.85	-	199
1948	7,200	0	40	S1	180	-	6.16	-	1,109
1949	12,983	0	40	S1	325	-	6.48	-	2,104
1950	11,515	0	40	S1	288	-	6.80	-	1,959
1951	8,282	0	40	S1	207	-	7.13	-	1,477
1952	25,195	0	40	S1	630	-	7.46	-	4,701
1953	4,329	0	40	S1	108	-	7.80	-	844
1954	6,163	0	40	S1	154	-	8.14	-	1,254
1955	14,171	0	40	S1	354	-	8.48	-	3,005
1956	29,813	0	40	S1	745	-	8.83	-	6,583
1957	15,293	0	40	S1	382	-	9.19	-	3,512
1958	17,188	0	40	S1	430	-	9.55	-	4,102
1959	19,856	0	40	S1	496	-	9.91	-	4,920
1960	21,145	0	40	S1	529	-	10.28	-	5,436
1961	24,843	0	40	S1	621	-	10.66	-	6,620
1962	14,485	0	40	S1	362	-	11.04	-	3,998
1963	31,894	0	40	S1	797	-	11.43	-	9,114
1964	18,103	0	40	S1	453	-	11.83	-	5,352
1965	23,944	0	40	S1	599	-	12.23	-	7,320
1966	20,427	0	40	S1	511	-	12.64	-	6,454
1967	36,960	0	40	S1	924	-	13.05	-	12,063
1968	44,180	0	40	S1	1,105	-	13.48	-	14,888
1969	61,872	0	40	S1	1,547	-	13.91	-	21,519
1970	219,572	0	40	S1	5,489	-	14.35	-	78,786
1971	210,607	0	40	S1	5,265	-	14.80	-	77,937
1972	91,736	0	40	S1	2,293	-	15.26	-	34,999
1973	91,823	0	40	S1	2,296	-	15.73	-	36,107
1974	58,878	0	40	S1	1,472	-	16.21	-	23,856
1975	78,982	0	40	S1	1,975	-	16.70	-	32,966
1976	48,111	0	40	S1	1,203	-	17.19	-	20,681
1977	66,317	0	40	S1	1,658	-	17.70	-	29,352

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Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	67,406	0	40	S1	1,685	-	18.23	-	30,713
1979	53,560	0	40	S1	1,339	-	18.76	-	25,119
1980	69,898	0	40	S1	1,747	-	19.31	-	33,736
1981	92,069	0	40	S1	2,302	-	19.87	-	45,725
1982	195,244	0	40	S1	4,881	-	20.44	-	99,763
1983	125,587	0	40	S1	3,140	-	21.03	-	66,015
1984	147,259	0	40	S1	3,681	-	21.63	-	79,623
1985	82,296	0	40	S1	2,057	-	22.25	-	45,768
1986	81,339	0	40	S1	2,033	-	22.88	-	46,524
1987	125,529	0	40	S1	3,138	-	23.53	-	73,839
1988	216,913	0	40	S1	5,423	-	24.20	-	131,210
1989	86,154	0	40	S1	2,154	-	24.88	-	53,589
1990	195,258	0	40	S1	4,881	-	25.58	-	124,885
1991	142,091	0	40	S1	3,552	-	26.31	-	93,444
1992	105,207	6585	40	S1	2,630	165	27.05	-	71,137
1993	281,873	0	40	S1	7,047	-	27.81	-	195,953
1994	239,405	0	40	S1	5,985	-	28.59	-	171,106
1995	297,778	0	40	S1	7,444	-	29.39	-	218,794
1996	1,004,419	0	40	S1	25,110	-	30.21	-	758,659
1997	94,368	0	40	S1	2,359	-	31.06	-	73,268
1998	828,908	0	40	S1	20,723	-	31.92	-	661,489
1999	221,392	0	40	S1	5,535	-	32.81	-	181,576
2000	203,319	0	40	S1	5,083	-	33.71	-	171,356
2001	408,435	0	40	S1	10,211	-	34.64	-	353,673
2002	577,827	0	40	S1	14,446	-	35.58	-	513,985
2003	1,828,445	0	40	S1	45,711	-	36.54	-	1,670,332
2004	92,829	0	40	S1	2,321	-	37.52	-	87,065
2005	215,473	0	40	S1	5,387	-	38.50	-	207,414
2006	225,642	0	40	S1	5,641	-	39.50	-	222,823
	9,644,451	6,585			241,111	165	28.92		6,971,922
					Average Remaining Life				28.9

Survivor Curve	S1
ASL	40

Delta Natu[illegible] [illegible]s Company
Depreciation Study
As of December 31, 2006
382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	386	0	40	S1	10	-	3.73	-	36
1941	-	0	40	S1	-	-	4.03	-	-
1942	-	0	40	S1	-	-	4.32	-	-
1943	-	0	40	S1	-	-	4.62	-	-
1944	-	0	40	S1	-	-	4.92	-	-
1945	-	0	40	S1	-	-	5.23	-	-
1946	-	0	40	S1	-	-	5.53	-	-
1947	291	0	40	S1	7	-	5.85	-	43
1948	543	0	40	S1	14	-	6.16	-	84
1949	1,057	0	40	S1	26	-	6.48	-	171
1950	1,120	0	40	S1	28	-	6.80	-	191
1951	1,784	0	40	S1	45	-	7.13	-	318
1952	293	0	40	S1	7	-	7.46	-	55
1953	394	0	40	S1	10	-	7.80	-	77
1954	1,666	0	40	S1	42	-	8.14	-	339
1955	2,929	0	40	S1	73	-	8.48	-	621
1956	8,754	0	40	S1	219	-	8.83	-	1,933
1957	8,202	0	40	S1	205	-	9.19	-	1,884
1958	6,222	0	40	S1	156	-	9.55	-	1,485
1959	4,846	0	40	S1	121	-	9.91	-	1,201
1960	3,986	0	40	S1	100	-	10.28	-	1,025
1961	3,306	0	40	S1	83	-	10.66	-	881
1962	9,394	0	40	S1	235	-	11.04	-	2,593
1963	1,800	0	40	S1	45	-	11.43	-	514
1964	1,800	0	40	S1	45	-	11.83	-	532
1965	2,280	0	40	S1	57	-	12.23	-	697
1966	2,088	0	40	S1	52	-	12.64	-	660
1967	4,152	0	40	S1	104	-	13.05	-	1,355
1968	5,823	0	40	S1	146	-	13.48	-	1,962
1969	8,651	0	40	S1	216	-	13.91	-	3,009
1970	8,413	0	40	S1	210	-	14.35	-	3,019
1971	6,017	0	40	S1	150	-	14.80	-	2,227
1972	6,795	0	40	S1	170	-	15.26	-	2,592
1973	8,877	0	40	S1	222	-	15.73	-	3,491
1974	5,641	0	40	S1	141	-	16.21	-	2,286
1975	4,065	0	40	S1	102	-	16.70	-	1,697
1976	2,843	0	40	S1	71	-	17.19	-	1,222
1977	2,209	0	40	S1	55	-	17.70	-	978

Delta Naturɛ ꜱ Company
Depreciation Study
As of December 31, 2006
382 -- Meter Regulator Installation

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1978	1,604	0	40	S1	40	-	18.23	-	731
1979	4,463	0	40	S1	112	-	18.76	-	2,093
1980	5,200	0	40	S1	130	-	19.31	-	2,510
1981	12,046	0	40	S1	301	-	19.87	-	5,983
1982	66,540	0	40	S1	1,664	-	20.44	-	34,000
1983	99,610	0	40	S1	2,490	-	21.03	-	52,360
1984	94,296	0	40	S1	2,357	-	21.63	-	50,986
1985	67,324	0	40	S1	1,683	-	22.25	-	37,442
1986	69,688	0	40	S1	1,742	-	22.88	-	39,860
1987	60,219	0	40	S1	1,505	-	23.53	-	35,422
1988	71,400	0	40	S1	1,785	-	24.20	-	43,190
1989	89,262	296457	40	S1	2,232	7,411	24.88	-	55,522
1990	147,697	0	40	S1	3,692	-	25.58	-	94,465
1991	118,996	0	40	S1	2,975	-	26.31	-	78,256
1992	170,332	0	40	S1	4,258	-	27.05	-	115,172
1993	142,352	0	40	S1	3,559	-	27.81	-	98,961
1994	160,617	0	40	S1	4,015	-	28.59	-	114,795
1995	148,177	0	40	S1	3,704	-	29.39	-	108,874
1996	150,837	0	40	S1	3,771	-	30.21	-	113,930
1997	149,850	0	40	S1	3,746	-	31.06	-	116,345
1998	172,095	0	40	S1	4,302	-	31.92	-	137,336
1999	155,766	0	40	S1	3,894	-	32.81	-	127,753
2000	122,090	0	40	S1	3,052	-	33.71	-	102,897
2001	98,891	0	40	S1	2,472	-	34.64	-	85,632
2002	93,543	0	40	S1	2,339	-	35.58	-	83,208
2003	102,667	0	40	S1	2,567	-	36.54	-	93,789
2004	112,534	0	40	S1	2,813	-	37.52	-	105,547
2005	110,798	0	40	S1	2,770	-	38.50	-	106,655
2006	82,818	0	40	S1	2,070	-	39.50	-	81,783
	3,008,339	296,457			75,208	7,411	28.78		2,164,668
				Average Remaining Life					26.2

Survivor Curve	S1
ASL	40

Delta Natur   ıs Company
Depreciatıon Study
As of December 31, 2006
383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	563	0	28	S6	20	-	-	-	-
1941	-	0	28	S6	-	-	-	-	-
1942	-	0	28	S6	-	-	-	-	-
1943	-	0	28	S6	-	-	-	-	-
1944	-	0	28	S6	-	-	-	-	-
1945	-	0	28	S6	-	-	-	-	-
1946	-	0	28	S6	-	-	-	-	-
1947	6,423	0	28	S6	229	-	-	-	-
1948	560	0	28	S6	20	-	-	-	-
1949	508	0	28	S6	18	-	-	-	-
1950	1,192	0	28	S6	43	-	-	-	-
1951	3,347	0	28	S6	120	-	-	-	-
1952	1,274	0	28	S6	46	-	-	-	-
1953	1,063	0	28	S6	38	-	-	-	-
1954	1,689	0	28	S6	60	-	-	-	-
1955	4,186	0	28	S6	150	-	-	-	-
1956	8,755	0	28	S6	313	-	-	-	-
1957	6,486	0	28	S6	232	-	-	-	-
1958	4,537	0	28	S6	162	-	-	-	-
1959	4,836	0	28	S6	173	-	-	-	-
1960	5,466	0	28	S6	195	-	-	-	-
1961	10,139	0	28	S6	362	-	-	-	-
1962	4,564	0	28	S6	163	-	-	-	-
1963	8,161	0	28	S6	291	-	-	-	-
1964	5,251	0	28	S6	188	-	-	-	-
1965	9,372	0	28	S6	335	-	-	-	-
1966	5,883	0	28	S6	210	-	-	-	-
1967	8,100	0	28	S6	289	-	0.50	-	145
1968	10,199	0	28	S6	364	-	0.50	-	182
1969	15,644	0	28	S6	559	-	0.54	-	303
1970	15,245	0	28	S6	544	-	0.57	-	313
1971	44,148	0	28	S6	1,577	-	0.61	-	968
1972	18,706	0	28	S6	668	-	0.67	-	445
1973	18,408	0	28	S6	657	-	0.73	-	482
1974	29,340	0	28	S6	1,048	-	0.82	-	860
1975	12,375	0	28	S6	442	-	0.94	-	414
1976	18,467	0	28	S6	660	-	1.09	-	717
1977	29,083	0	28	S6	1,039	-	1.29	-	1,337
1978	20,730	0	28	S6	740	-	1.55	-	1,151

Delta Natu as Company
Depreciation Study
As of December 31, 2006
383 -- House Regulators

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1979	17,688	0	28	S6	632	-	1.91	-	1,207
1980	44,258	0	28	S6	1,581	-	2.38	-	3,764
1981	46,611	0	28	S6	1,665	-	2.99	-	4,969
1982	62,018	0	28	S6	2,215	-	3.73	-	8,255
1983	79,203	0	28	S6	2,829	-	4.59	-	12,975
1984	68,536	0	28	S6	2,448	-	5.53	-	13,527
1985	82,809	0	28	S6	2,957	-	6.51	-	19,241
1986	45,980	0	28	S6	1,642	-	7.50	-	12,318
1987	107,385	3463	28	S6	3,835	124	8.50	-	32,599
1988	84,581	0	28	S6	3,021	-	9.50	-	28,697
1989	114,666	0	28	S6	4,095	-	10.50	-	43,000
1990	112,102	0	28	S6	4,004	-	11.50	-	46,042
1991	63,398	0	28	S6	2,264	-	12.50	-	28,303
1992	95,099	0	28	S6	3,396	-	13.50	-	45,851
1993	152,812	0	28	S6	5,458	-	14.50	-	79,135
1994	115,494	0	28	S6	4,125	-	15.50	-	63,934
1995	126,610	0	28	S6	4,522	-	16.50	-	74,609
1996	114,577	0	28	S6	4,092	-	17.50	-	71,611
1997	85,933	0	28	S6	3,069	-	18.50	-	56,777
1998	340,732	295	28	S6	12,169	11	19.50	9.50	237,396
1999	161,756	0	28	S6	5,777	-	20.50	-	118,429
2000	136,617	0	28	S6	4,879	-	21.50	-	104,902
2001	84,144	0	28	S6	3,005	-	22.50	-	67,616
2002	114,466	0	28	S6	4,088	-	23.50	-	96,070
2003	108,820	0	28	S6	3,886	-	24.50	-	95,218
2004	115,491	0	28	S6	4,125	-	25.50	-	105,179
2005	142,384	0	28	S6	5,085	-	26.50	-	134,756
2006	181,209	0	28	S6	6,472	-	27.50	-	177,973
	3,340,079	3,758			119,289	134	15.02		1,791,668
					Average Remaining Life				15.0

Survivor Curve	S6
ASL	28

Delta Natu as Company
Depreciation Study
As of December 31, 2006
385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accruai of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	43	R1	-	-	6.32	-	-
1941	-	0	43	R1	-	-	6.65	-	-
1942	-	0	43	R1	-	-	6.99	-	-
1943	-	0	43	R1	-	-	7.33	-	-
1944	-	0	43	R1	-	-	7.68	-	-
1945	-	0	43	R1	-	-	8.04	-	-
1946	-	0	43	R1	-	-	8.40	-	-
1947	-	0	43	R1	-	-	8.77	-	-
1948	-	0	43	R1	-	-	9.14	-	-
1949	-	0	43	R1	-	-	9.52	-	-
1950	-	0	43	R1	-	-	9.91	-	-
1951	-	0	43	R1	-	-	10.30	-	-
1952	-	0	43	R1	-	-	10.70	-	-
1953	-	0	43	R1	-	-	11.11	-	-
1954	-	0	43	R1	-	-	11.52	-	-
1955	-	0	43	R1	-	-	11.94	-	-
1956	702	0	43	R1	16	-	12.36	-	202
1957	1,860	0	43	R1	43	-	12.80	-	554
1958	1,172	0	43	R1	27	-	13.24	-	361
1959	366	0	43	R1	9	-	13.69	-	116
1960	1,596	0	43	R1	37	-	14.14	-	525
1961	941	0	43	R1	22	-	14.60	-	320
1962	168	0	43	R1	4	-	15.07	-	59
1963	1,767	0	43	R1	41	-	15.55	-	639
1964	308	0	43	R1	7	-	16.04	-	115
1965	1,098	0	43	R1	26	-	16.53	-	422
1966	1,847	0	43	R1	43	-	17.03	-	732
1967	2,885	0	43	R1	67	-	17.54	-	1,177
1968	2,179	0	43	R1	51	-	18.06	-	915
1969	1,759	0	43	R1	41	-	18.59	-	760
1970	3,485	0	43	R1	81	-	19.12	-	1,550
1971	3,084	0	43	R1	72	-	19.66	-	1,410
1972	2,554	0	43	R1	59	-	20.21	-	1,201
1973	3,174	0	43	R1	74	-	20.77	-	1,533
1974	2,543	0	43	R1	59	-	21.34	-	1,262
1975	1,682	0	43	R1	39	-	21.91	-	857
1976	6,518	0	43	R1	152	-	22.50	-	3,410
1977	-	0	43	R1	-	-	23.09	-	-
1978	4,035	0	43	R1	94	-	23.69	-	2,223
1979	3,969	0	43	R1	92	-	24.29	-	2,242

Delta Natur s Company
Depreciation Study
As of December 31, 2006
385 -- Industrial Meter Sets

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1980	4,307	0	43	R1	100	-	24.90	-	2,494
1981	33,109	0	43	R1	770	-	25.52	-	19,652
1982	19,688	0	43	R1	458	-	26.15	-	11,973
1983	17,371	0	43	R1	404	-	26.78	-	10,819
1984	26,528	0	43	R1	617	-	27.42	-	16,917
1985	39,740	0	43	R1	924	-	28.07	-	25,938
1986	70,515	0	43	R1	1,640	-	28.72	-	47,092
1987	58,538	0	43	R1	1,361	-	29.37	-	39,987
1988	109,462	0	43	R1	2,546	-	30.03	-	76,456
1989	141,310	0	43	R1	3,286	-	30.70	-	100,888
1990	98,320	0	43	R1	2,287	-	31.37	-	71,728
1991	71,191	0	43	R1	1,656	-	32.04	-	53,053
1992	42,672	0	43	R1	992	-	32.72	-	32,473
1993	79,131	0	43	R1	1,840	-	33.40	-	61,471
1994	89,330	0	43	R1	2,077	-	34.09	-	70,817
1995	89,881	0	43	R1	2,090	-	34.78	-	72,693
1996	72,772	0	43	R1	1,692	-	35.47	-	60,027
1997	57,974	0	43	R1	1,348	-	36.17	-	48,759
1998	91,757	0	43	R1	2,134	-	36.87	-	78,666
1999	60,714	0	43	R1	1,412	-	37.57	-	53,046
2000	54,409	0	43	R1	1,265	-	38.28	-	48,434
2001	70,925	0	43	R1	1,649	-	38.99	-	64,312
2002	13,368	0	43	R1	311	-	39.71	-	12,345
2003	54,587	0	43	R1	1,269	-	40.43	-	51,326
2004	53,260	0	43	R1	1,239	-	41.16	-	50,980
2005	31,213	0	43	R1	726	-	41.89	-	30,409
2006	51,486	0	43	R1	1,197	-	42.63	-	51,043
	1,653,250	-			38,448	-	33.46		1,286,383
					Average Remaining Life				33.5

Survivor Curve	R1
ASL	43

Delta Natur ıs Company
Depreciatıon Study
As of December 31, 2006
390 -- General Plant Structures and Improvements

Year	Additions	Transfers	ASL	Survivor Curve	Annual Accrual of Additions	Annual Accrual of Transfers	Remaining Life of Additions	Remaining Life of Transfers	Avg Future Accruals
1940	-	0	32	R3	-	-	-	-	-
1941	-	0	32	R3	-	-	-	-	-
1942	-	0	32	R3	-	-	-	-	-
1943	-	0	32	R3	-	-	-	-	-
1944	-	0	32	R3	-	-	-	-	-
1945	-	0	32	R3	-	-	-	-	-
1946	-	0	32	R3	-	-	-	-	-
1947	-	0	32	R3	-	-	-	-	-
1948	-	0	32	R3	-	-	-	-	-
1949	-	0	32	R3	-	-	-	-	-
1950	-	0	32	R3	-	-	-	-	-
1951	-	0	32	R3	-	-	-	-	-
1952	-	0	32	R3	-	-	0.50	-	-
1953	-	0	32	R3	-	-	0.50	-	-
1954	-	0	32	R3	-	-	0.57	-	-
1955	-	0	32	R3	-	-	0.73	-	-
1956	-	0	32	R3	-	-	0.93	-	-
1957	-	0	32	R3	-	-	1.15	-	-
1958	20,586	0	32	R3	643	-	1.39	-	893
1959	27,726	0	32	R3	866	-	1.63	-	1,415
1960	250	0	32	R3	8	-	1.88	-	15
1961	832	0	32	R3	26	-	2.14	-	56
1962	1,197	0	32	R3	37	-	2.39	-	89
1963	23,367	0	32	R3	730	-	2.65	-	1,932
1964	357	0	32	R3	11	-	2.90	-	32
1965	10,712	0	32	R3	335	-	3.16	-	1,059
1966	24,179	0	32	R3	756	-	3.43	-	2,592
1967	149	0	32	R3	5	-	3.71	-	17
1968	3,179	0	32	R3	99	-	4.00	-	398
1969	94	0	32	R3	3	-	4.31	-	13
1970	37,380	0	32	R3	1,168	-	4.64	-	5,425
1971	29,546	0	32	R3	923	-	5.00	-	4,617
1972	11,406	0	32	R3	356	-	5.38	-	1,919
1973	84,336	0	32	R3	2,636	-	5.79	-	15,267
1974	480	0	32	R3	15	-	6.23	-	93
1975	700	0	32	R3	22	-	6.70	-	147
1976	2,119	0	32	R3	66	-	7.20	-	477
1977	1,374	0	32	R3	43	-	7.73	-	332

Delta Naturı s Company
Depreciation Study
As of December 31, 2006
390 -- General Plant Structures and Improvements

1978	568,930	0	32	R3	17,779	-	8.29	-	147,311
1979	23,860	0	32	R3	746	-	8.87	-	6,615
1980	58,518	0	32	R3	1,829	-	9.48	-	17,342
1981	253,709	0	32	R3	7,928	-	10.12	-	80,246
1982	171,370	0	32	R3	5,355	-	10.78	-	57,747
1983	79,384	0	32	R3	2,481	-	11.47	-	28,449
1984	176,763	0	32	R3	5,524	-	12.17	-	67,246
1985	138,267	0	32	R3	4,321	-	12.90	-	55,739
1986	79,344	0	32	R3	2,480	-	13.65	-	33,833
1987	21,786	0	32	R3	681	-	14.41	-	9,810
1988	9,828	0	32	R3	307	-	15.19	-	4,665
1989	158,943	0	32	R3	4,967	-	15.99	-	79,410
1990	247,667	0	32	R3	7,740	-	16.80	-	130,037
1991	910	0	32	R3	28	-	17.63	-	501
1992	26,100	0	32	R3	816	-	18.48	-	15,069
1993	115,754	0	32	R3	3,617	-	19.34	-	69,942
1994	525,596	0	32	R3	16,425	-	20.21	-	331,927
1995	62,193	0	32	R3	1,944	-	21.10	-	41,000
1996	150,022	0	32	R3	4,688	-	21.99	-	103,116
1997	11,853	0	32	R3	370	-	22.91	-	8,485
1998	33,458	0	32	R3	1,046	-	23.83	-	24,914
1999	310,970	0	32	R3	9,718	-	24.76	-	240,627
2000	21,039	0	32	R3	657	-	25.70	-	16,899
2001	41,155	0	32	R3	1,286	-	26.65	-	34,280
2002	1,331,240	0	32	R3	41,601	-	27.61	-	1,148,740
2003	489,667	0	32	R3	15,302	-	28.58	-	437,311
2004	346,841	0	32	R3	10,839	-	29.55	-	320,286
2005	20,333	0	32	R3	635	-	30.53	-	19,397
2006	55,450	0	32	R3	1,733	-	31.51	-	54,598
	5,810,919	-			181,591	-	19.95		3,622,329
				Average Remaining Life					20

Survivor Curve R3
ASL 32

AG Exhibit 2

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	)	**CASE NO. 2016-00370**
CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY	)	
	)	

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: November 23, 2016

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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 Class	Rate of Return on Rate Base BIP Version	Rate of Return on Rate Base LOLP Version	Revenue 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).

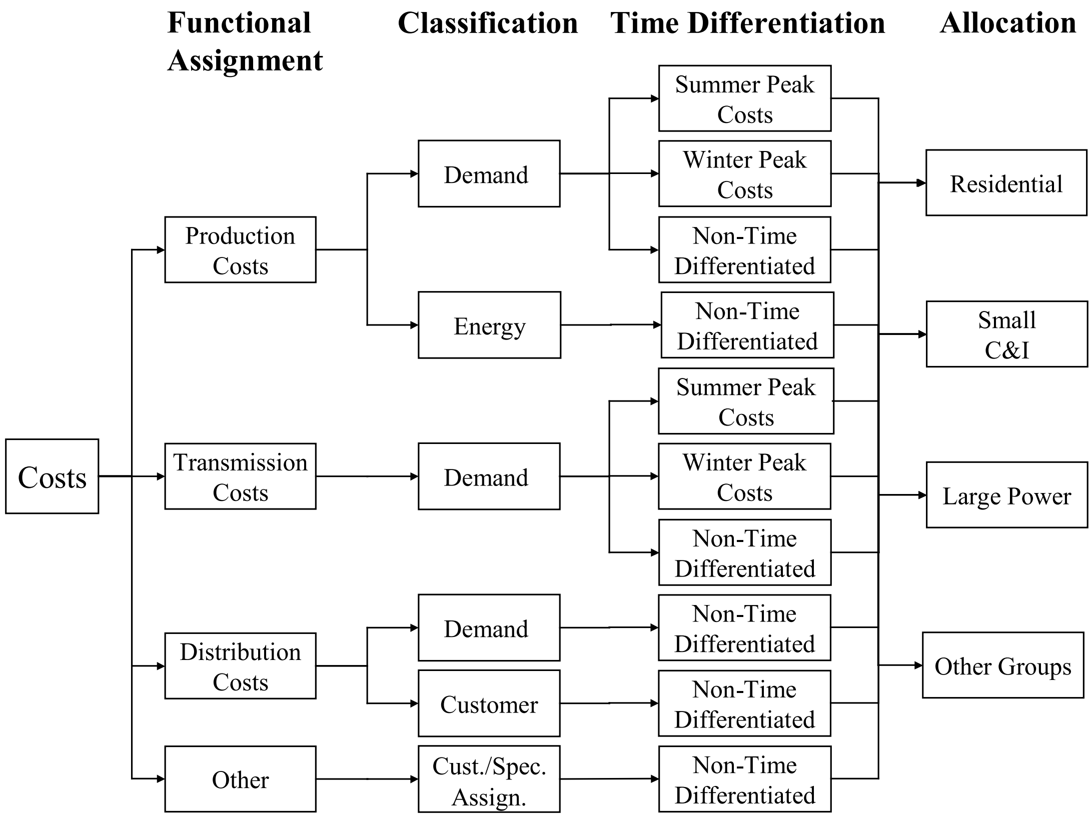

Figure 1

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

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[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.

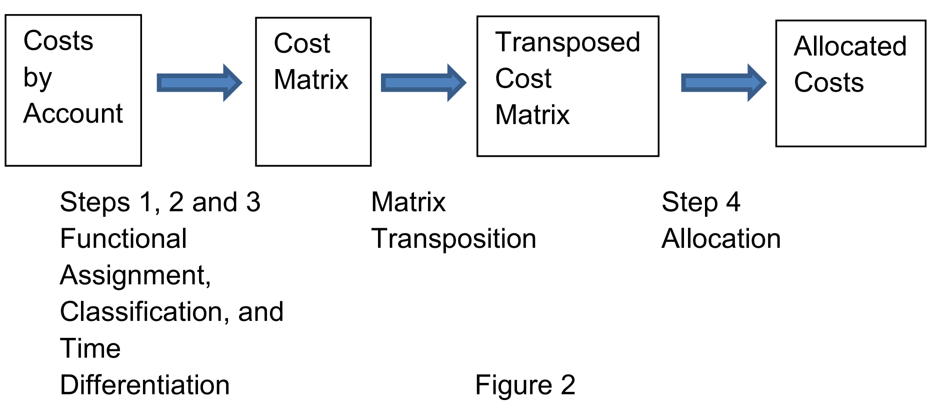

Figure 2

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.

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.

(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			Production Energy		
				Base	Inter.	Peak	Base	Inter.	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

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

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 Demand	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines 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 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	$ -	$ -

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Cost of Service Study
Functional Assignment and Classification
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BIP METHODOLOGY

		Functional	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**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

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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

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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
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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	$ -	$ -

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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			$ -	$ -	$ -	$ -	$ -	$ -

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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			$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Cost of Service Study
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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			$ -	$ -	$ -

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Cost of Service Study
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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
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	$ -	$ -	$ -	$ -	$ -	$ -

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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	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

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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

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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		$ -	$ -	$ -

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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	-	-

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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

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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

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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	-

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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	$ -	$ -

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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
<u>Operation and Maintenance Expenses (Continued)</u>								
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

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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
<u>Operation and Maintenance Expenses (Continued)</u>									
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

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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	$ -

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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	$ -	$ -	$ -

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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		$	-	$	-	$	-	$	-	$	-	$	-

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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		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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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		$ -	$ -	$ -

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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	$ -	$	-	$	-	$	-	$	-	$	-

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			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

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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

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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		$ -	$ -	$ -

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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	-	-

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BIP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	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

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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

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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	-

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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	$ -	$ -

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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

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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

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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	$ -

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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
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
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Functional Assignment and Classification
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BIP METHODOLOGY

			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**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

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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
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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
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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
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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
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

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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
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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
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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									
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
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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
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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
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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
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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								
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			$ -	$ -	$ -	$ -	$ -	$ -

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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			$ -	$ -	$ -	$ -	$ -	$ -	$ -

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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			$ -	$ -	$ -

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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	$ -	$ -	$ -	$ -	$ -	$ -

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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

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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

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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		$ -	$ -	$ -

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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	-	-

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			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Demand**	**Specific**	**General**	**Specific**	**Demand**	**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

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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

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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	-

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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	$ -	$ -

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			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Demand**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
<u>Operation and Maintenance Expenses (Continued)</u>								
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

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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

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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	$ -

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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	$ -	$ -	$ -

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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		$ -	$ -	$ -	$ -	$ -	$ -

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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									
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		$ -	$ -	$ -	$ -	$ -	$ -	$ -

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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		$ -	$ -	$ -

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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	$ -	$ -	$ -	$ -	$ -	$ -

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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

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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

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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		$ -	$ -	$ -

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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
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LOLP METHODOLOGY

Description	Name	Functional Vector	Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
			Demand	Specific	General	Specific	Demand	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

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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

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Functional Assignment and Classification
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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
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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
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LOLP 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

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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

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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	$ -

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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				-						

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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								

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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

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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					

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Description	Name	Functional Vector	Total System	Production Demand			Production Energy		
				Base	Inter.	Peak	Base	Inter.	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	-	-	-

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LOLP METHODOLOGY

			Transmission Demand	Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**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
			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**
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

		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	$ 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

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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
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

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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 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

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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
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

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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**
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

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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
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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
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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
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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
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

		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**
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
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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
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
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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**
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
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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

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
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

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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

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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 -- 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

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 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
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**
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

		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**
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	Name 1	Allocation Vector 2	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

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
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

		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**
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

		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	$ 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	$ 863,151,993	$ 295,478,323	$ 114,689,539	$ 564,507	$ 2,154	$ 216,393
				8.7%						
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

		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 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

		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	$ 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

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	$ 3,274,141	$ 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	Name	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
		1	2							
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
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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

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

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
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	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
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

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

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
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
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Class Allocation
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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

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 -- 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

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 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

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
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

		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				$ 116,412,961	$ 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

		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**
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

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	$ 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

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
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	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)
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

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Service RTS	Service FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
		1	2	11	12	13	14	15	16	17
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

		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**
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

AG Exhibit 3

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	**CASE NO. 2008-00409**
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: October 31, 2008

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of East Kentucky Power Cooperative, Inc. ("EKPC").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to present the financial summary and supporting exhibits detailing how EKPC derived the amount of the requested revenue increase, (ii) describe EKPC's proposed pro-forma revenue, expense, and rate base adjustments, (iii) describe the calculation of EKPC's adjusted net margin and revenue deficiency for the fully forecasted test period ended May 31, 2010, (iv) describe the calculation of the 13-month average of EKPC's rate base and capitalization for the fully forecasted test period; (v) to sponsor the fully allocated class cost of service studies based on EKPC's cost of providing service for the 12 months ended May 31, 2010; and (vi) to support EKPC's proposed wholesale rates to its members.

Q. Please summarize your testimony.

A. EKPC is proposing a rate increase which is designed to produce additional revenues of approximately $67.9 million. EKPC's proposed rate increase is supported by a fully forecasted test period corresponding to the 12 months ended May 31, 2010. The level of the increase is supported by an analysis of EKPC's revenue deficiency based on the pro-forma financial results for the forecasted test period. EKPC's revenue requirement was determined based on net margin requirements necessary to produce a 1.45 Times Interest Earned Ratio ("TIER"). The $67.9 million proposed increase, which was approved by EKPC's Board of Directors, is less than the $70.0 million revenue deficiency determined using a 1.45 TIER.

EKPC's proposed rates will allow it to begin gradually rebuilding its equity, which is currently at a dangerously low level. EKPC's equity as a percentage of total capitalization is expected to drop to around 6.8 percent prior to the implementation of the new rates. It is important to realize, however, that even with the new rates, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which will still not be adequate. One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to its balance sheet in support of its effort to install sufficient generation facilities to meet the needs of its members.

A class cost of service study was performed for the purpose of assisting EKPC in designing its proposed rates. In order to transition to cost-based rates, EKPC is proposing a phased-in approach consisting of *Phase I* rates – which would be placed into effect upon approval by the Kentucky Public Service Commission ("Commission"), which presumably will be at the end of the suspension period in this proceeding, and "Phase II" rates – which would go into effect 12 months later. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenue, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10?

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

Filing Requirement	Description	Volume	Tab #
Section 10(8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	Vol. 1	Tab 20
Section 10(8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	Vol. 1	Tab 21
Section 10(9)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	Vol. 2	Tab 23
Section 10(9)(v)	Cost of service study based on methodology generally accepted in the industry and based on current and reliable data from a single time period.	Vol. 5	Tab 44

Filing Requirement	Description	Volume	Tab #
Section 10(10)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Vol. 5	Tab 46
Section 10(10)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of rate base.	Vol. 5	Tab 47
Section 10(10)(h)	Computation of revenue conversion factor for forecasted period	Vol. 5	Tab 53
Section 10(10)(l)	Narrative description and explanation of all proposed tariff changes	Vol. 5	Tab 57
Section 10(10)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes	Vol. 5	Tab 58
Section 10(10)(n)	Typical bill comparison under present and proposed rates for all customer classes	Vol. 5	Tab 59

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Revenue Requirements, (IV) Cost of Service Study, and (V) Rate Design.

II. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

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 May 1979 until July 1996, I was employed by Louisville

Gas and Electric Company. From May 1979 until December 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. 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 Louisville Gas and Electric Company in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for well over 130 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Seelye Exhibit 1.

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

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions regarding revenue requirements, cost of service and rate design. A listing of my testimony in other proceedings is included in Seelye Exhibit 1.

Q. Have you performed cost of service studies and developed rates for electric cooperatives?

A. Yes. I have performed cost of service studies and developed rates for a number of generation and transmission cooperatives ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power Association, Big Rivers Electric Corp, Southern Illinois Power Cooperative, Corn Belt Power Cooperative, and EKPC. I have also supervised the preparation of cost of service studies and the development of rates for over 130 electric distribution cooperatives.

III. REVENUE REQUIREMENTS

Q. Please describe how EKPC's proposed revenue increase was determined?

A. EKPC is proposing a general adjustment in rates supported by a fully forecasted test period. The proposed revenue increase is supported by an analysis of the revenue deficiency based on financial results for the forecasted test period. The revenue deficiency was determined as the difference between (i) EKPC's adjusted net margins for the forecasted test period without reflecting a general adjustment in rates, and (ii) EKPC's net margin requirement necessary to provide a 1.45 TIER. Based on the forecasted test year, the revenue deficiency is $70,041,960. EKPC's proposed wholesale rates to its members are projected to produce increased revenues of $67,858,922 based on estimated billing determinants for the forecasted test year.

Q. Why is the proposed revenue increase of $67,858,922 less than EKPC's revenue deficiency of $70,041,960?

A. The rates that EKPC is proposing in this proceeding were approved by EKPC's Board of Directors on September 9, 2008. However, the rates were developed using preliminary revenue requirement and billing determinant estimates which indicated that the revenue requirement was approximately $67.7 million based on a forecasted test period for the 12 months ended April 30, 2010, rather than the 12 months ended May 31, 2010, used in the rate case filing. Because EKPC was unable to file the rate case application until the end of October 2008, the forecasted test year utilized in the rate case filing had to be delayed by one month in order to meet the requirement set forth in KRS 278.192 that the forecasted test period must correspond to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. When EKPC finalized the revenue requirement using costs for the fully forecasted test period that had to be utilized in this proceeding, the revenue requirement turned out to be \$70.0 million rather than \$67.7 million. Likewise, when the rates that were approved by the Board of Directors were applied to test-year billing determinants, the revenue increase turned out to be \$67.9 million rather than the \$67.7 million amount indicated in the Board resolution provided as an exhibit to Mr. Marshall's testimony. Because the proposed revenue increase is less than the revenue deficiency determined based on operating results for the fully forecasted test period, EKPC made the decision not to revisit the issue with its Board of Directors for the purpose of obtaining approval to propose a larger increase with the Commission. Particularly, EKPC decided to maintain its proposed rates in this proceeding at the level approved by its Board of Directors even though a higher revenue increase could be supported.

Q. Why did EKPC choose to support the proposed rate increase with a fully forecasted test period?

A. As the Commission is well aware, EKPC has been in financial distress since 2005. Its interest and debt coverage ratios are forecasted to be inadequate to meet the requirements set forth in the mortgage and credit facility agreements with its lenders. Without a rate increase, EKPC's financial condition will deteriorate even further once Spurlock 4 is placed into commercial operation. Considering its dangerously low level of equity capital, without increasing its rates it would be difficult for EKPC to withstand the stress of an unanticipated expense, such as expenditures that might result from an unanticipated equipment failure at one of its generating stations. Spurlock 4, a 278 MW coal-fired generating unit which will cost approximately $528 million, is scheduled to be placed into commercial operation on April 1, 2009. None of the cost of Spurlock 4 is currently in rate base. EKPC has not included the Construction Work In Progress ("CWIP") for Spurlock 4 in rate base. Because it has been accruing an Allowance for Funds Used During Construction ("AFUDC") on its construction expenditures, EKPC is currently not recovering interest expenses associated with Spurlock 4 through rates. Once Spurlock 4 is placed into commercial operation, EKPC will experience a significant increase in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses. Although Spurlock 4 will result in fuel and purchased power cost savings, those savings will be automatically passed along to its members through the application of the monthly fuel adjustment clause. Therefore, the fuel cost savings will not off-set the impact on EKPC's net income from placing Spurlock 4 in service.

With that background, it is easier to understand why EKPC is supporting its rate increase with forecasted test period costs. If EKPC were to use a historical test year, the very earliest that any of the costs of Spurlock 4 would be reflected in historical test period costs would be in April 2009. EKPC simply could not wait until after April 2009 to file a rate case application, which would not provide additional revenues to cover the increased costs of Spurlock 4 until approximately nine months later. Even though EKPC has never filed a fully forecasted rate case, it was critical that the company move forward with a forecasted rate case considering the serious consequences of not being able to adjust its rates until after April 1, 2009. In its Order in Case No. 2006-00472 dated December 5, 2007, the Commission directed EKPC to file its next base rate case when conditions warrant. Given EKPC's precarious financial circumstances, conditions warrant filing a rate case utilizing a forecasted test year that provides increased revenues to cover the additional costs associated with Spurlock 4.

Q. What are the forecasted test period and the base period for the rate case application?

A. The *forecasted test period* for the filing is the 12 months ended May 31, 2010. Consistent with KRS 278.192, the forecasted test period used to determine revenue requirements in this proceeding corresponds to the first 12 consecutive calendar months the proposed increase would be in effect after the maximum suspension period for the proposed rates. According to KRS 278.190, the maximum suspension period is six months for a general adjustment in rates supported by a fully forecasted test period. Because the effective date of the EKPC's proposed rates is December 1, 2008, the first 12 consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning June 1, 2009, and ending on May 31, 2010.

The *base period* for the filing is the 12 months ended January 31, 2009. The base period consists of seven months of actual historical data and five months of estimated data. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, and consisting of not less than six months of actual historical data and not more than six months of estimated data. Because EKPC's proposed base period, which begins February 1, 2008, includes more than six months of actual historical data, includes less than six months of estimated data, and begins less than nine months prior to the October 31, 2008 filing date in this proceeding, its proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Why didn't EKPC file its rate case using a fully forecasted test period beginning April 1, 2009, rather than June 1, 2009?

A. Because EKPC is a member-owned G&T cooperative, preparing a rate case involves considerably more steps than for either an investor owned utility or a distribution cooperative. EKPC had to build in enough time to prepare its financial budget incorporating accurate and up-to-date construction cost estimates for Spurlock 4 and other projects, present the proposed financial budget and wholesale rates to its member systems, obtain EKPC Board approvals for its financial budget and proposed rates, develop pass-through rates for its member systems in accordance with the provisions of KRS 278.455, and then provide enough time for the boards of its member systems to approve their individual pass-through rates and publish their individual statutory notices in newspapers across the state. As it turned out, there was simply not enough time between preparing the financial budget incorporating updated construction cost estimates and publishing the member systems' statutory notices that would have allowed EKPC to file a rate case application with rates to be effective six months prior to the suspension period for a forecasted test year.

Q. Given that EKPC's proposed rates would not go into effect until June 1, 2009, won't there be two months when its rates will be unable to provide recovery of the increased costs associated with Spurlock 4?

A. Yes. The fact that EKPC will not be able to offset its increased non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses associated with Spurlock 4 with additional revenues will cause its net margin for April and May, 2009, to deteriorate sharply. The inability to recover Spurlock 4 carrying charges for those two months would have a significant adverse effect on EKPC's fiscal 2009 financial results. Without some sort of rate recovery mechanism to deal with this short-fall, EKPC will never be able to recover these fixed charges, which represents a serious problem for a utility whose interest and debt coverage ratios are dangerously low and whose equity percentage is projected to be only 6.8 percent during April and May, 2009.

Q. How is EKPC proposing to address these uncollected costs associated with Spurlock 4?

A. As described in greater detail in the *Motion for the Creation of a Regulatory Asset Relating to Spurlock Unit 4 Expenses* that is being filed in this proceeding, EKPC is proposing to establish a regulatory asset that would allow it to record the additional revenue that it would have collected in April and May, 2009, if EKPC's new rates would have gone into effect on April 1, 2009, rather than on June 1, 2009. In other words, EKPC would record the additional revenues that would have been billed through the application of the new rates during April and May 2009 in a deferred debit (Account No. 182.4). The amount ultimately recorded as a regulatory asset in Account No. 182.4 would correspond to the billing difference in April and May 2009, (based on forecasted billing determinants) between the rates ultimately approved by the Commission (without the amortization of the regulatory asset) and EKPC's current rates. Therefore, the ultimate amount recorded as a regulatory asset would be based on the rates that the Commission ultimately authorizes in the rate case order, without considering the amortization of the regulatory asset. The regulatory asset – whatever the amount turns out to be – would be amortized over three years and reflected in the final rates approved by the Commission.

As an alternative to setting up a regulatory asset to provide recovery of the unbilled Spurlock 4 carrying charges, the Commission could waive its six-month *maximum* suspension period applicable to rate applications using a forecasted test period and allow EKPC to place its proposed rates into effect on April 1, 2009, subject to refund. Because this alternative could possibly require that EKPC's member systems make refunds to their retail members, allowing EKPC to establish a regulatory asset would represent a simpler approach.

Q. Have you prepared an exhibit that shows how EKPC's revenue deficiency is calculated?

A. Yes. Seelye Exhibit 2 shows the calculation of EKPC's revenue deficiency.

Q. Please walk us through Seelye Exhibit 2.

A. The purpose of Seelye Exhibit 2 is to calculate the difference between EKPC's adjusted net margin (deficit) for the forecasted test year and the margin necessary for EKPC to achieve a 1.45 TIER. The exhibit starts out with Operating Revenue and Patronage Capital from EKPC's budget for the 12 months ended May 31, 2010 (line 1). This amount is obtained from the 2009 and 2010 budgets that were approved by EKPC's Board of Directors. EKPC's Board is comprised of a board member from each of its 16 member systems. The monthly and 12-month total budget amounts for the forecasted test year are shown in Exhibit 1 to Mr. Eames's testimony. A number of pro-forma adjustments are applied to Operating Revenue. The pro-forma revenue adjustments are shown on lines 4 through 7 of the exhibit. EKPC's Adjusted Revenue, as adjusted to reflect the four pro-forma revenue adjustments, is shown on line 9.

The Total Cost of Service from EKPC's budget is shown on line 12. In the context of EKPC's budget and financial reports, Total Cost of Service includes operation expenses, maintenance expenses, depreciation and amortization expenses, taxes, interest expenses on long-term debt, other interest expenses, and other deductions. Total Cost of Service is then adjusted to reflect pro-forma adjustments shown on lines 15 through 31 of the exhibit. Adjusted Cost of Service, which reflects the pro-forma expense adjustments, is shown on line 34. Adjusted Operating Margins (line 36) is calculated by subtracting Adjusted Cost of Service (line 34) from Adjusted Revenue (line 9). Interest income (line 39), other non-operating income (line 40), and other capital credits/patronage dividends (line 41) are added to Adjusted Operating Margins (line 36) to determine EKPC's Adjusted Net Margin (Deficit). For the forecasted test-period, EKPC is projected to a have an Adjusted Net Deficit of -$25,603,606 (line 46).

The Revenue Deficiency is calculated on page 2 of Seelye Exhibit 2. To achieve a 1.45 TIER, EKPC needs a net margin requirement of $44,438,354. EKPC's $70,041,960 revenue deficiency corresponds to the difference between this net margin requirement of

$44,438,354 and EKPC's adjusted net deficit of -$25,603,606 (calculated as $44,438,354 - (-$25,603,606) = $70,041,960).

Q. Why was a 1.45 TIER used to determine EKPC's revenue requirement?

A. As explained in the prepared direct testimonies of David G. Eames, Jonathon Andrew Don, and Daniel M. Walker, a 1.45 TIER is in line with what other investment-grade G&T cooperatives are earning and is necessary to provide EKPC with an opportunity to maintain its financial integrity, to maintain adequate interest and debt service coverage ratios, and to rebuild its members' equity to a level that will allow EKPC to continue to attract capital on reasonable terms and to serve its members in a safe and reliable manner.

Q. Please explain why it is necessary to make pro-forma adjustments to financial results from EKPC's budget.

A. It was necessary to make a number of pro-forma adjustments to eliminate costs and associated revenues that are recovered through the fuel adjustment clause (FAC) and the environmental surcharge. A number of other adjustments were required to eliminate expenses that are generally not allowed to be recovered through service rates of utilities in Kentucky that are regulated by the Commission. Two other adjustments were required to amortize or re-amortize certain extraordinary expenses. One final adjustment was required to normalize generation overhaul expenses so that forecasted test-year expenses will be representative on a going forward basis. Support for each adjustment is contained in Schedules 1.01 through 1.18 of Seelye Exhibit 2. The pro-forma adjustments are identified as follows:

(a) Eliminate costs recoverable through the FAC and associated revenues (Schedules 1.01, 1.03).

(b) Remove the impact of revenues and expenses included in the environmental surcharge (Schedules 1.02, 1.04, 1.05, 1.06, 1.07, 1.08).

(c) Eliminate expenses normally excluded by the Commission (Schedules 1.09, 1.10, 1.11, 1.12, 1.13, 1.14, 1.15).

(d) Amortize extraordinary expenses (Schedules 1.16 and 1.17).

(e) Normalize overhaul expenses (Schedule 1.18)

Q. Please describe the adjustments necessary to eliminate expenses and associated revenues related to the fuel adjustment clause.

A. EKPC is proposing to eliminate all fuel and purchased power expenses that would be recoverable through the FAC, the fuel cost revenue associated with base fuel cost component of the FAC, and projected FAC billings. In other words, EKPC is proposing to remove all fuel cost and fuel cost revenues that would be considered in the application of the FAC, including fuel costs recovered through the base rate component which is collected through base rates. Specifically, adjustments were made to remove fuel cost revenue recovered through base rates (Schedule 1.01), to remove FAC revenue (Schedule 1.01), to remove fuel expenses recoverable through the FAC (Schedule 1.01), and to remove purchased power expenses recoverable through the FAC (Schedule 1.03).

Q. Please describe the adjustments to eliminate expenses and associated revenues related to the environmental surcharge.

A. EKPC is proposing to eliminate all environmental costs that would be recoverable through the environmental surcharge and associated environmental surcharge revenue. Specifically, adjustments were made to remove environmental surcharge revenue (Seelye Exhibit 2, Page 1 of 2, line 6), to adjust off-system sales environmental surcharge revenue (Schedule 1.02), to remove operation and maintenance expense recoverable through the environmental surcharge (Schedule 1.04), to remove emissions allowance expense recoverable through the environmental surcharge (Schedule 1.05), to remove property taxes and property insurance recoverable through the environmental surcharge (Schedule 1.06), to remove depreciation expense recoverable through the environmental surcharge (Schedule 1.07), and to remove interest expense recoverable through the environmental surcharge (Schedule 1.08). Because EKPC budgets these revenues and expenses individually they were readily identified from the budget for purposes of removing them from the calculation of the revenue deficiency. EKPC is not proposing any roll-in of environmental costs into base rates in this proceeding.

Q. Please explain the adjustment to off-system sales environmental surcharge revenue (Schedule 1.02) in greater detail.

A. In determining the environmental surcharge, a portion of EKPC's environmental compliance costs recovered through the surcharge are allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses related to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement. Therefore, consistent with the Commission's orders in the most recent rate cases filed by Louisville Gas and Electric Company and Kentucky Utilities Company, an adjustment was made to reduce revenues to reflect the environmental surcharge methodology for allocating environmental costs to off-system sales. (Order in Case No. 2003-00433 , pp 24-25 and Appendix F and Order in Case No. 2003-00434, p. 24 and Appendix F.)

Q. Please explain the adjustment to remove promotional advertising shown in Schedule 1.09.

A. Pursuant to 807 KAR 5:016, this adjustment eliminates Touchstone Energy advertising and other promotional items included in EKPC's budget for the forecasted test year. These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please explain the adjustment to remove certain directors' expenses shown in Schedule 1.10.

A. Consistent with the Commission's Order in Case No. 2006-00472, EKPC is removing a portion of directors' expenses from the forecasted test-year revenue requirement. The items not removed include the following: fees for regular board meetings, chair and secretary fees, committee chair fees, audit committee chair fees, two special board meetings for each member, fees for training seminars, and expenses of $25,000 for the test year. A total of $93,300 of directors' expenses has been removed from test-year operating expenses.

Q. Please describe the adjustments to remove donations in Schedule 1.11, affiliate expenses in Schedule 1.12, lobbying expenses in Schedule 1.13, Touchstone Energy dues in Schedule 1.14, and Miscellaneous Expenses in Schedule 1.15.

A. Consistent with Commission practice, all donations, contributions, and sponsorships are removed from test-year expenses in Schedule 1.11. All affiliate expenses related to Alliance for Cooperative Energy Services (ACES) Power Marketing, Envision Energy Services, LLC, and the propane gas program for members are removed from test-year expenses in Schedule 1.12. It should be noted, however, that fees paid to ACES for their power marketing functions on behalf of EKPC have not been removed from revenue requirements in this proceeding. Consistent with the procedure followed in its last rate case application in Case No. 2006-00472, EKPC is removing lobbying expenses (Schedule 1.13), Touchstone Energy dues (Schedule 1.14), and certain employee-related expenses (Schedule 1.15). These expenses are individually projected in developing the budget and are therefore readily identifiable.

Q. Please describe the adjustment to reflect an amortization of rate case expenses in Schedule 1.16.

A. This adjustment is necessary to include amortization of the expense incurred in conjunction with this rate case. It is consistent with similar adjustments in revenue requirements found reasonable in numerous rate case orders issued by the Commission, including the Commission's Order approving the settlement agreement in Union Light, Heat and Power Company's recent rate case, which was supported by a fully forecasted test period. (In its Order in Case No. 2006-00172 dated December 21, 2006, the

Commission affirmed that the accounting and ratemaking treatments to which the parties stipulated in the settlement agreement, including the amortization of rate case expenses over 3 years, "generally reflect the approach the Commission has followed in previous rate cases", pp. 4 and 8.)

Q. Please explain the adjustment to reflect the amortization of the 2004 forced outage balance in Schedule 1.17.

A. In Case No. 2006-00472, the Commission determined that it was appropriate to amortize $20,514,346 of expenses related to a 2004 Spurlock 1 forced outage over a 3-year period. As of the beginning of the forecasted test period on June 1, 2009, EKPC will have amortized $10,257,173, or one half of the original amount, leaving a balance of $10,257,173. EKPC is proposing to amortize the remaining balance of $10,257,173 over three years, resulting in an increase in expenses of $3,419,058.

Q. Please explain the adjustment to normalize generation overhaul expenses in Schedule 1.18.

A. This adjustment is necessary to ensure that forecasted test-year expenses will be representative on a going forward basis. During the forecasted test period, EKPC's overhaul expenses are less than the normal level that would be incurred annually by the company. EKPC projects that it will incur $4.8 million in overhaul expenses during the forecasted test year ($2.1 million for Cooper Unit 1 and $2.7 million for Dale Units 1 and 2) compared to an average annual expense of $7.1 million. For the steam generating units, the boiler and generators are overhauled on a 10-year cycle, and the combustion turbines are overhauled on a six-year cycle. The $7.1 million average overhaul expense was calculated by dividing the estimated cost of a boiler/generator overhaul for each steam generating unit in 2009 dollars by 10 years to determine the average amount for the unit, and by dividing the estimated cost of a generator overhaul for each combustion turbine in 2009 dollars by 6 years to determine the average amount for the unit. Therefore, EKPC is proposing a normalization adjustment of $2.3 million, which represents the difference between $4.8 million amount budgeted for the test year and the $7.1 million average level.

Q. Have you prepared exhibits showing the development of the 13-month average rate base and capitalization for the forecasted test year.

A. Yes. Seelye Exhibit 3 shows the development of the 13-month average rate base for the test year, and Seelye Exhibit 4 shows the development of the 13-month average capitalization for the test year. In Seelye Exhibit 3, rate base is shown both with and without environmental assets for which costs are recovered through the environmental surcharge. These environmental assets have been removed from capitalization in Seelye Exhibit 4. It should be noted that EKPC's revenue requirement was determined using a 1.45 TIER, which is an approach that is often utilized by cooperative utilities, rather than a rate of return on rate base or a rate of return on total capitalization, which is used by investor-owned utilities in Kentucky.

Q. Have you prepared an exhibit that shows key financial performance measurements for EKPC with and without the proposed increase?

A. Yes. Seelye Exhibit 5 shows TIER, debt service coverage ratio (DSC), rate of return on net cost rate base, and rate of return on total capitalization for the forecasted test year with and without the proposed increase. The following table summarizes the financial measurements calculated in Seelye Exhibit 5:

FINANCIAL MEASUREMENT	WITHOUT RATE INCREASE	WITH PROPOSED INCREASE
Times Interest Earned Ratio (TIER)	0.74	1.43
Debt Service Coverage Ratio (DSC)	0.81	1.25
Rate of Return on Net Cost Rate Base (ROR)	3.17%	6.19%
Rate of Return on Total Capitalization (ROI)	3.16%	6.16%

It should be noted that the financial measurements shown in this table are calculated using EKPC's proposed revenue increase of $67,858,922 rather than the $70,041,960 revenue deficiency amount necessary to produce a TIER of 1.45. Because EKPCs Board approved increase is used instead of the revenue deficiency, the TIER shown above is slightly lower than the 1.45 TIER that is appropriate for EKPC. The DSC, ROR and ROI are correspondingly lower than what they would otherwise be if the $70,041,960 revenue deficiency were used to calculate these financial measurements.

Q. Based on your experience in developing rates for other G&T cooperatives, are these financial performance measurements that result from applying the proposed rates reasonable?

A. Yes. They are in line with what the G&T cooperatives I have worked with are using to develop rates. It should be noted, however, that none of the G&T cooperatives for which I have developed base rates are subject to regulation by a public service commission. More important, the proposed TIER will allow EKPC to gradually rebuild its equity over time; however, it is important to realize that even with the new rates which are designed to produce a TIER of 1.43, EKPC's equity as a percentage of total capitalization is projected to only be 9.67 percent in December 2011, which is still inadequate. (See Tab 30, page 10 of the filing requirements set forth in the Application.) One of the main reasons that its equity position will not improve more than this is because EKPC will continue to add assets to the balance sheet in support of its effort to install sufficient generation facilities (e.g., Smith Unit 1) to meet the needs of its members.

IV. CLASS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for EKPC's electric operations based on financial and operating results for the fully forecasted test period?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study. The cost of service study corresponds to the pro-forma financial exhibits included in Seelye Exhibit 2. The objective in performing the electric cost of service study is to determine the rate of return on rate base that EKPC is earning from each rate class, which provides an indication as to whether EKPC's service rates reflect the cost of providing service to each rate class.

Q. Did you develop the model used to perform the cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study submitted in this proceeding.

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

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were utilized. 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; and then (3) costs were allocated to the rate classes.

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

A. Yes.

Q. What functional groups were used in the cost of service study?

A. The following functional groups were identified in the cost of service study: (1) Production, (2) Production Steam – Direct, (3) Transmission, (3) Distribution Substation, and (4) Distribution Meters. Production Steam – Direct corresponds to production costs that are specifically assigned to provide steam service to a industrial customer.

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

A. Classification provides a method of identifying the appropriate cost driver for each functionally assigned cost so that the service characteristics that give rise to the cost can serve as a basis for allocation. Costs classified as *energy related* tend to vary with 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. Production plant and the cost of transmission lines are examples of costs typically classified as demand 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. Distribution meters are the only costs classified as customer-related in the cost of service study.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the electric cost of service study?

A. Yes. Seelye Exhibit 6 shows the results of the first two steps of the cost of service study – functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, EKPC's test-year costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 6, EKPC's accounting costs are functionally assigned and classified using the explicitly determined functional vectors identified in the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28. Internally generated functional vectors are utilized throughout the study to functionally assign costs either on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 27 and 28 of Seelye Exhibit 6. An example of this process is the use of total operation and maintenance 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 and classify these costs on the same basis. (See Seelye Exhibit 6, pages 3 and 4 for the functional assignment of cash working capital on the basis of OMLPP shown on pages 13 and 14.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors".

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 7. The costs shown in the column labeled "Total System" in Seelye

Exhibit 6 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 7. The column labeled "Ref" in Seelye Exhibit 7 provides a reference to the results included in Seelye Exhibit 6.

Q. Please describe the allocation factors used in the electric cost of service study.

A. The following allocation factors were used in the electric cost of service study:

- **PENG** – Production energy-related costs are allocated to the rate classes on the basis of the amount of energy (kWh) delivered to each rate class.
- **6CP** – Production demand-related costs are allocated on the basis of the sum of the class coincident peak demands during the six peak months of June, July, August, December, January, and February.
- **STMD** – The fixed production costs directly assigned in the functional assignment section of the cost of service study are allocated to the industrial customer that receives steam service from EKPC.
- **12CP** – Transmission demand-related costs are allocated on the basis of the sum of the 12 monthly class coincident peak demands during the test year.
- **SUBA** – Distribution substations are allocated to the rate class on the basis of cost weighted number of substations for each rate class by substation capacity category.

- **CUST05** – 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.

Q. How was the cost of providing interruptible service addressed in the cost of service study?

A. Customers taking service under the interruptible service rider are assigned a demand cost credit per kW based on the levelized carrying costs associated with the current cost of a combustion turbine generating unit. The cost credit is calculated in Seelye Exhibit 8. This calculation is based on an installed cost of $550/kW for a combustion turbine and a cost of capital (return) of 7 percent. Subsequent to developing this estimate, it was brought to my attention that this avoided cost credit may be somewhat overstated because the capital cost of financing a new combustion turbine would almost certainly be less than 7 percent. Although the credit shown in Seelye Exhibit 8 may be somewhat overstated, I believe that the avoided cost estimate is within a range that is reasonable, particularly given the volatility in the cost of purchasing new combustion turbines.

Q. Does the cost of service study consider load-following costs that EKPC will likely incur to provide service to non-conforming loads on the system?

A. No. It is my understanding that EKPC is currently having difficulty meeting certain North American Electric Reliability Corporation (NERC) control performance standards as a result of large fluctuations of a non-conforming load in EKPC's control area. EKPC is currently analyzing various options for addressing these load/resource balancing problems. The cost of service study submitted in this proceeding does not consider the load-following costs created by non-conforming loads, which are difficult to quantify. The Midwest Independent System Operator (MISO) and other regional transmission operators are currently developing markets for ancillary services, including markets for the types of regulation services that may possibly be used to follow large non-conforming loads. In the absence of an ancillary service market, EKPC may have to enter into a bilateral agreement to obtain regulation services from an organization that controls large amounts of generation capacity, which could prove to be more costly than services obtained from an ancillary service market. Because it is unclear at this time whether load-following services will be obtained from an ancillary service market, or by entering into a bilateral agreement with a regulation service provider, or in some other manner, EKPC is currently unable to develop a reasonable estimate of the load-following costs associated with serving non-conforming loads.

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

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the Phase 1 rate adjustments proposed by EKPC. 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 pro-forma adjustments discussed earlier in my testimony regarding the determination of EKPC's revenue requirements. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return Phase I Rates**
Rate E	3.20%	6.12%
Rate B	2.53%	6.63%
Rate C	2.33%	6.02%
Rate G	0.50%	4.43%
Large Special Contract	2.86%	5.72%
Special Contract – Pumping Stations	29.52%	29.52%
Steam Service	4.74%	10.66%
Total System	3.17%	6.19%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 7, pages 21-22 and pages 23-24, respectively.

V. RATE DESIGN

Q. Please describe how EKPC proposes to transition to a cost-based rate structure.

A. The unit charge components of EKPC's current rates do not accurately reflect the cost of providing service. From a cost of service perspective, too large of a portion of EKPC's fixed costs are recovered through the energy charge component of its rates. This is particularly true of EKPC's Rate E. The cost of service study indicates that a large portion of its fixed costs that are currently recovered through the energy charge should instead be recovered through the demand charge component of EKPC's rates. Rather than moving to a fully cost-based rate design in a single step, EKPC is proposing to move to a cost-based rate design in two phases. Under its rate design proposal in this proceeding, EKPC's is proposing that its Phase I rates would go into effect upon approval by the Commission, which presumably will be at the end of the 6-month suspension period, and would remain in effect for 12 months, at which time Phase II rates would go into effect and remain in effect as EKPC's on-going rates until superseded by a subsequent rate order. The Phase I rates are designed to serve as a *temporary* or *transitional* rate design until cost-based rates can be implemented in Phase II. A phased-in approach was developed because of concerns expressed by EKPC's member systems about implementing cost-based rates in a short period of time. Although there was a general recognition on the part of the member systems that EKPC's rates should reflect the cost of providing service, a number of member systems expressed a desire to transition to a cost-based rate structure in a more gradual, two-phased manner. This phase-in of cost-based rates would provide the member systems with more time to develop retail rates that reflect wholesale costs and to educate retail customers about how to take advantage of cost-based rate offerings.

Q. Is EKPC's phased-in approach consistent with the ratemaking principle of "gradualism"?

A. Yes.

Q. How were the Phase I rates developed?

A. EKPC's Phase I rates were developed by allocating the proposed revenue increase to each rate component of each rate schedule and special contract on a pro-rata basis, with the exception of the special contract for the pumping stations. In other words, in Phase I

EKPC is proposing to increase each rate component of each rate schedule by the same percentage.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase I rates?

A. Yes. The revenue impact of EKPC's Phase I rates is detailed in Seelye Exhibit 9. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. How were the Phase II rate developed?

A. The Phase II rates were developed based on the results of the cost of service study. Specifically, the individual charges within each rate schedule were based on the unit costs determined from the cost of service study. Consequently, the demand charges, substation charges, and meter-point charges included in the Phase II rates are higher than those included in the Phase I rates. However, the energy charges in the Phase II rates are lower than those included in the Phase I rates.

Q. What is the proposed metering point charge for the Phase II rates?

A. For the Phase II rates, EKPC is proposing to increase the metering point charge from the current level of $125 per month to $230 per month. The $230 charge is supported by the cost of service study.

Q. Please describe the changes to the substation charges in the Phase II rates?

A. EKPC currently has substation categories: (i) 1,000 to 2,999 kVa, (ii) 3,000 to 7,499 kVa, (iii) 7,500 to 14,999 kVa, and (iv) greater than 15,000 kVa. For the Phase II rates, EKPC proposes to incorporate the following six substation categories: (i) 1,000 to 4,999 kVa, (ii) 5,000 to 9,999 kVa, (iii) 10,000 to 14,999 kVa substation, (iv) 15,000 to 29,999 kVa, (v) 30,000 to 50,999, and (iv) greater than 51,000 kVa. These six categories more accurately represent the capacity and cost relationships of the various types of substations that EKPC installs. The proposed unit costs reflect the carrying costs of six categories of substations based on average embedded installed costs.

Q. There are two rate alternatives available to members under EKPC's current Rate E. In the proposed Phase II, rates would this optional rate structure be available.

A. No. In the Phase II rates, the two rate options for Rate E would be eliminated, and the rate schedule would reflect cost-based demand and energy charges.

Q. Would the interruptible credit be modified under the Phase II rates?

A. The interruptible credit is updated for both the Phase I and Phase II rates. For the Phase I rates, the interruptible credit is increased by the same percentage as all other rate components. For the Phase II rates, the interruptible credit is increased to reflect the carrying costs associated with the current cost of installing a combustion turbine, as described earlier in my testimony.

Q. Are the proposed Phase II rates designed to produce the same overall revenue as the Phase I rates?

A. Yes. Although both Phase I and Phase II rates are designed to produce approximately the same overall revenues based on test-year billing determinants, the proposed Phase II rates include unit charges that more accurately track the results of the cost of service study. The two sets of rates result in slightly different overall revenues because of rounding.

Q. Have you prepared an exhibit detailing the revenue impact of the Phase II rates?

A. Yes. The revenue impact of EKPC's Phase II rates is detailed in Seelye Exhibit 10. This schedule shows the impact of the Phase I rates on the components of each rate schedule. The proposed revenue increase for each rate schedule, stated as a dollar amount and as a percentage, is shown on page 1 of this exhibit.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	**CASE NO. 2008-00409**
GENERAL ADJUSTMENT OF ITS	)	
WHOLESALE ELECTRIC RATES	)	

AFFIDAVIT

STATE OF KENTUCKY	)
	)
COUNTY OF CLARK	)

William Steven Seelye, being duly sworn, states that he has read the foregoing prepared testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Subscribed and sworn before me on this 27th day of October, 2008.

Peggy S. Griffin
Notary Public

My Commission expires: December 8, 2009

Seelye Exhibit 1

QUALIFICATIONS OF 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

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

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

Assists utilities with developing strategic marketing plans and implementation of those plans. 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 130 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.

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
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

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.

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.

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.

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 temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

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.

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.

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.

Seelye Exhibit 2

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended May 31, 2010

Line	Description	Reference		Amount
1	**Total Operating Revenue & Patronage Capital Per Budget**	Eames Exhibit 1, Page 1, Line 8	$	886,273,772
2				
3	Adjustments to Revenue:			
4	To Remove Fuel In Base Rates	Schedule 1.01		(350,719,383)
5	To Remove Fuel Adjustment Clause Revenue	Schedule 1.01		(108,692,230)
6	To Remove Environmental Surcharge Revenue	Eames Exhibit 1, Page 1, Line 3		(104,725,169)
7	To Adjust Off-System Sales Environmental Surcharge Revenue	Schedule 1.02		(1,377,517)
8				
9	**Adjusted Revenue**	Lines 1 through 7	$	320,759,474
10				
11				
12	**Total Cost of Service**	Eames Exhibit 1, Page 2, Line 26	$	898,541,897
13				
14	Adjustments to Cost of Service:			
15	To Remove Fuel Expense Recoverable through the FAC	Schedule 1.01	$	(403,441,802)
16	To Remove Purchased Power Expense Recoverable through the FAC	Schedule 1.03		(51,684,614)
17	To Remove O&M Expenses Recoverable through the Environmental Surcharge	Schedule 1.04		(31,800,030)
18	To Remove Emissions Allowance Expense Recoverable through the Environmental Surcharge	Schedule 1.05		(6,615,208)
19	To Remove Property Taxes and Property Insurance Recoverable through the Environmental Surcharge	Schedule 1.06		(2,098,198)
20	To Remove Depreciation Expenses Recoverable through the Environmental Surcharge	Schedule 1.07		(19,564,992)
21	To Remove Interest Expenses Recoverable through the Environmental Surcharge	Schedule 1.08		(37,031,989)
22	To Remove Promotional Advertising Expense pursuant to Commission Rule KAR 5:016	Schedule 1.09		(658,906)
23	To Remove Certain Directors' Expenses	Schedule 1.10		(93,300)
24	To Remove Donations	Schedule 1.11		(95,485)
25	To Remove Affiliate Expenses	Schedule 1.12		(28,712)
26	To Remove Lobbying Expenses	Schedule 1.13		(85,422)
27	To Remove Touchstone Energy Dues	Schedule 1.14		(414,000)
28	To Remove Other Miscellaneous Expenses	Schedule 1.15		(155,940)
29	To Normalize Ratecase Expenses	Schedule 1.16		100,000
30	Amortize 2004 Force Outage Balance	Schedule 1.17		3,419,058
31	To Normalize Generation Overhaul Expenses	Schedule 1.18		2,300,000
32				
33				
34	**Adjusted Cost of Service**	Lines 12 through 31	$	350,592,357
35				
36	**Adjusted Operating Margins**	Line 9 less Line 34	$	(29,832,883)
37				
38	**Non-Operating Items**			
39	Interest Income	Eames Exhibit 1, Page 2, Line 32	$	4,007,189
40	Other Non-Operating Income	Eames Exhibit 1, Page 2, Line 34		(27,912)
41	Other Capital Credits/Patronage Dividends	Eames Exhibit 1, Page 2, Line 35		250,000
42				
43	**Total Non-Operating Items**	Lines 39 through 41	$	4,229,277
44				
45				
46	**Adjusted Net Margin (Deficit)**	Line 36 plus Line 43	$	(25,603,606)

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculation of Revenue Requirement
Based on Forecasted Revenues and Expenses
For the 12 Month Period Ended May 31, 2010

Line	Description	Reference			Amount
1	**Calculation of Revenue Deficiency**				
2					
3	Adjusted Net Margin (Deficit)	Page 1, Line 46		$	(25,603,606)
4					
5	Interest on Long-Term Debt	Eames Exhibit 1, Page 2, Line 19 Less Line 21, Above	$98,751,898.00		
6					
7	Net Margin Requirement at 1.45 TIER (0.45 x Line 5)			$	44,438,354
8					
9	Revenue Deficiency (Line 7 - Line 3)			$	70,041,960

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove FAC Base Rate Revenue

		MWh Sales Subject to FAC	Fuel Cost in Base Rates*	FAC Base Rate Revenue	Member FAC Billings**	Steam FAC Billings	Pumping Station Fuel Cost Billings	Total Fuel Cost Billings
June	2009	1,034,405.00	26.38	27,287,604	4,839,308	94,804	801,201	5,735,313
July	2009	1,170,414.00	26.38	30,875,521	5,695,708	97,842	837,235	6,630,785
August	2009	1,158,883.00	26.38	30,571,334	9,418,926	165,036	691,092	10,275,054
September	2009	1,003,496.00	26.38	26,472,224	7,092,765	142,441	491,972	7,727,178
October	2009	942,223.00	26.38	24,855,843	4,579,464	112,807	431,549	5,123,820
November	2009	1,069,459.00	26.38	28,212,328	4,936,575	100,577	714,603	5,751,755
December	2009	1,301,930.00	26.38	34,344,913	12,775,630	243,670	783,520	13,802,820
January	2010	1,380,682.00	26.38	36,422,391	12,408,150	225,090	916,130	13,549,370
February	2010	1,176,215.00	26.38	31,028,552	12,056,270	235,177	859,292	13,150,739
March	2010	1,147,783.00	26.38	30,278,516	11,385,749	229,815	917,256	12,532,820
April	2010	952,326.00	26.38	25,122,360	6,637,509	152,575	827,377	7,617,461
May	2010	957,081.00	26.38	25,247,797	5,791,586	132,745	870,785	6,795,116
Total		13,294,897.00		350,719,383	97,617,640	1,932,579	9,142,011	108,692,230

* As approved in Case No. 2006-00508, dated July 25, 2007
** Eames Exhibit 1, Page 1, Line 2

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Fuel Costs Recoverable Through the FAC

Total Fuel Costs Excluding Handling -- Eames Exhibit 1, Page 1, Line 3	$412,609,991
Less: Fuel Costs Assigned to Off-System Sales	9,168,189
Fuel Costs Recoverable Through FAC	$403,441,802

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Off-System Sales Environmental Surcharge Revenue

		Off-System Sales Revenue	Monthly Environmental Surcharge Factor	Off-System Sales Environmental Cost
June	2009	1,332,340	13.85%	184,529
July	2009	1,119,946	14.21%	159,144
August	2009	1,159,704	14.22%	164,910
September	2009	1,311,731	13.88%	182,068
October	2009	1,001,815	13.54%	135,646
November	2009	253,615	13.82%	35,050
December	2009	272,436	14.02%	38,196
January	2010	398,354	13.30%	52,981
February	2010	439,280	13.40%	58,864
March	2010	1,096,284	13.54%	148,437
April	2010	866,814	13.46%	116,673
May	2010	734,687	13.75%	101,019
Total		9,987,006		1,377,517

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Purchased Power Expense Recoverable Through the Fuel Adjustment Clause

		Total Purchased Power	Purchased Power Assigned to Forced Outages	Purchased Power Recoverable Through the FAC
June	2009	3,871,392	833,300	3,038,092
July	2009	5,316,797	833,300	4,483,497
August	2009	5,207,600	833,300	4,374,300
September	2009	3,745,707	833,300	2,912,407
October	2009	3,611,051	833,300	2,777,751
November	2009	7,484,043	833,300	6,650,743
December	2009	7,533,457	833,700	6,699,757
January	2010	9,284,117	833,300	8,450,817
February	2010	7,024,925	833,300	6,191,625
March	2010	4,123,190	833,300	3,289,890
April	2010	3,649,035	833,300	2,815,735
May	2010	3,391,056	833,300	2,557,756
Total		$ 64,242,370	$ 10,000,000	$ **51,684,614**

Seelye Exhibit 2
Schedule 1.04

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove O&M Expenses Recoverable Through the Environmental Surcharge

Descr	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	
Ash Storage	$ 553,633	$ 553,633	$ 553,633	$ 553,633	$ 407,573	$ 553,633	$ 553,633	$ 621,047	$ 621,047	$ 621,047	$ 621,047	$ 433,510	$ 6,647,069
Ammonia	325,000	335,000	335,000	304,000	256,000	325,000	333,000	381,654	344,719	381,654	326,426	338,825	$ 3,986,278
Limestone	981,019	1,013,719	1,013,719	829,578	748,707	981,019	1,013,719	1,122,668	1,014,024	1,122,668	1,042,123	822,606	$ 11,705,569
Magnesium	142,000	207,000	208,000	202,000	138,000	202,000	207,000	220,000	199,000	220,000	194,000	220,000	$ 2,359,000
Units 3 and 4 Boiler Controls Maint	110,464	110,435	60,750	60,464	62,346	310,477	63,624	81,110	81,110	121,110	81,110	581,110	$ 1,724,110
Unit 1 Precipitator Maint	500	500	500	500	500	500	500	500	500	500	125,500	500	$ 131,000
Units 3 and 4 BagHouse Maint	59,172	59,172	59,172	59,172	59,172	104,172	71,674	50,951	63,867	63,867	63,867	138,867	$ 853,125
Unit 1 SCR Maint	9,833	9,833	9,833	9,833	9,833	9,833	14,003	4,250	7,375	7,375	27,375	7,375	$ 126,751
Unit 2 SCR Maint	9,833	9,833	9,833	9,833	58,833	9,833	14,003	4,125	7,250	7,250	7,250	7,250	$ 155,126
Unit 1 Scrubber Maint	75,429	75,427	75,451	75,429	75,572	75,430	75,667	29,257	47,091	47,104	47,099	47,091	$ 746,047
Unit 2 Scrubber Maint	85,897	85,896	85,926	85,897	86,083	85,901	123,889	31,695	51,592	51,609	51,617	51,592	$ 877,594
Air Permit Fees	-	-	-	-	-	-	1,410,000	-	-	-	-	-	$ 1,410,000
Stack Monitoring Supplies	19,273	19,273	19,273	19,273	19,273	19,273	28,908	10,036	20,071	20,071	20,071	20,071	$ 234,866
Stack Monitoring Consulting	68,200	68,200	68,200	68,200	68,200	68,200	96,050	38,738	65,472	65,472	65,472	65,472	$ 805,876
Stack Monitoring Maintenance	2,917	2,917	2,917	2,917	2,917	2,917	4,371	1,750	3,499	3,499	3,499	3,499	$ 37,619
Totals by month	$ 2,443,170	$ 2,550,838	$ 2,502,207	$ 2,280,729	$ 1,993,009	$ 2,748,188	$ 4,010,041	$ 2,597,781	$ 2,526,617	$ 2,733,226	$ 2,676,456	$ 2,737,768	**$ 31,800,030**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Emissions Allowance Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	800,853
July	2009	982,179
August	2009	958,652
September	2009	722,765
October	2009	511,628
November	2009	768,152
December	2009	838,169
January	2010	230,884
February	2010	199,796
March	2010	185,781
April	2010	117,482
May	2010	298,867
Total		**$ 6,615,208**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Property Taxes and Insurance Expenses Recoverable Through the Environmental Surcharge

		Amount
June	2009	177,316
July	2009	176,867
August	2009	176,419
September	2009	175,971
October	2009	175,522
November	2009	175,074
December	2009	174,626
January	2010	174,177
February	2010	173,729
March	2010	173,281
April	2010	172,832
May	2010	172,384
Total		**$ 2,098,198**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Depreciation Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	1,630,416
July	2009	1,630,416
August	2009	1,630,416
September	2009	1,630,416
October	2009	1,630,416
November	2009	1,630,416
December	2009	1,630,416
January	2010	1,630,416
February	2010	1,630,416
March	2010	1,630,416
April	2010	1,630,416
May	2010	1,630,416
		$ 19,564,992

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Interest Expense Recoverable Through the Environmental Surcharge

		Amount
June	2009	3,140,884
July	2009	3,129,337
August	2009	3,117,876
September	2009	3,107,416
October	2009	3,097,328
November	2009	3,085,754
December	2009	3,075,310
January	2010	3,072,217
February	2010	3,063,967
March	2010	3,055,908
April	2010	3,047,553
May	2010	3,038,439
		$ 37,031,989

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Promotional Advertising

		Amount
June	2009	24,191
July	2009	19,701
August	2009	62,451
September	2009	65,951
October	2009	62,451
November	2009	59,451
December	2009	36,324
January	2010	149,782
February	2010	67,451
March	2010	72,251
April	2010	19,451
May	2010	19,451
		$ 658,906

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Directors' Expenses

		Amount
June	2009	7,775
July	2009	7,775
August	2009	7,775
September	2009	7,775
October	2009	7,775
November	2009	7,775
December	2009	7,775
January	2010	7,775
February	2010	7,775
March	2010	7,775
April	2010	7,775
May	2010	7,775
		$ 93,300

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Directors' Expenses

1	Test-Year Directors' Fees and Expenses	$	312,000
2			
3	Items not Removed from test year		
4			
5	Fees for Regular Board Meetings	$	163,200
6	Chair and Secretary Fees		9,600
7	Committee Chair Fees		7,200
8	Audit Committee Chair Fees		800
9	Two Special Board Meetings		13,600
10	Fees for Training Seminars for Each Board Member for Three Days		15,300
11	Normal Expenses		25,000
12			
13	Total Ordinary Expenses (lines 5 thru 11)	$	234,700
14			
15	Amounts Removed From Directors' Fees and Expenses (line 1 less 13)	$	77,300
16			
17	Monthly Amounts Removed From Directors' Fees and Expenses (line 15 / 12)	$	6,442
18			
19	Monthly Directors' Severence Fees Budgeted Separately	$	1,333
20			
21	Total Monthly Amount Removed from Test-Year Expenses (line 17 + line 19)	$	7,775

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Donations

		Amount
June	2009	8,317
July	2009	8,327
August	2009	7,667
September	2009	7,667
October	2009	7,867
November	2009	7,667
December	2009	11,587
January	2010	5,418
February	2010	7,937
March	2010	7,667
April	2010	7,667
May	2010	7,697
		$ 95,485

Seelye Exhibit 2
Schedule 1.12

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Affiliate Transactions

		ACES Expenses	Propane Expenses	Envision Expenses	Total
June	2009	458	568	1,124	2,150
July	2009	458	567	1,075	2,100
August	2009	458	570	1,075	2,103
September	2009	458	649	1,112	2,219
October	2009	458	585	1,151	2,194
November	2009	458	567	1,091	2,116
December	2009	690	646	1,250	2,586
January	2010	250	565	2,041	2,856
February	2010	500	611	1,359	2,470
March	2010	1,300	612	1,514	3,426
April	2010	500	611	1,111	2,222
May	2010	500	611	1,159	2,270
		$ 6,488	$ 7,162	$ 15,062	**$ 28,712**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Lobbying Expenses

		Amount
June	2009	$ 29,994
July	2009	4,992
August	2009	5,013
September	2009	4,994
October	2009	5,080
November	2009	4,882
December	2009	5,347
January	2010	4,922
February	2010	4,977
March	2010	5,143
April	2010	4,941
May	2010	5,137
Total		**$ 85,422**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Touchstone Energy Dues

		Amount
January	2010	**$ 414,000**

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Miscellaneous Expenses

	Forecasted Expense June 2009-May 2010
Executive Retirement Plan	$ 45,000
Employee Recognition Dinner	40,000
Employee Food Certificates	26,000
Vending Supplies	25,940
Employee Recreation	19,000
Total	**$ 155,940**

Seelye Exhibit 2
Schedule 1.16

Estimated Rate Case Expenses
Case No. 2008-00409

Rate Case Consultant	$	175,000
TIER and Equity Consultant		25,000
Decoupling Rate Expert		5,000
Rate Design Consultant		5,000
Advertising Member Cooperatives		50,000
Supplies, Expenses, Shipping		40,000
Total	$	300,000
Amortization Period		3 Years
Annual Amortized Amount	$	100,000

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Amortize 2004 Forced Outage Balance

2004 Spurlock 1 Forced Outage Costs-- Allowance for 3-Year Amortization per Order in Case No. 2006-00472, dated December 5, 2007			$ 20,514,346
Monthly Amortization	$ 569,842.94		
Amortization December 2007- May 2009			$ 10,257,173
Unamortized Balance--June 1, 2009			$ 10,257,173
Period for Amortizing Remaining Balance		3 Years	
Annual Amortization			**$ 3,419,058**

Seelye Exhibit 2
Schedule 1.18

East Kentucky Power Cooperative, Inc.
Adjustment to Normalize Generating Unit Turbine/Boiler Overhaul

Unit		Turbine/Boiler Overhaul Costs 2009 Dollars	Scheduled Overhaul Period in Years		Annual Normalization Adjustment
Cooper 1	$	3,100,000	10	$	300,000
Cooper 2		4,400,000	10		400,000
Dale 1		1,500,000	10		200,000
Dale 2		1,500,000	10		200,000
Dale 3		2,500,000	10		300,000
Dale 4		4,000,000	10		400,000
Spurlock 1		8,000,000	10		800,000
Spurlock 2		8,000,000	10		800,000
Spurlock 3		8,000,000	10		800,000
Spurlock 4		8,000,000	10		800,000
Smith CT1		4,000,000	6		700,000
Smith CT2		4,000,000	6		700,000
Smith CT3		4,000,000	6		700,000
Total				$	7,100,000
Less: Overhaul Expenses During Test Year (Cooper 1)					2,100,000
Less: Overhaul Expenses During Test Year (Dale 1&2)					2,700,000
Annual Normalization Adjustment for Turbine/Boiler Overhauls				$	**2,300,000**

Seelye Exhibit 3

EAST KENTUCKY POWER COOPERATIVE, INC.
Forecasted Test Period 13-Month Average Net Cost Rate Base

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Net Cost Rate Base – Including Environmental														
Utility Plant in Service														
Generation	2,551,870,180	2,563,656,180	2,575,442,180	2,587,228,180	2,599,014,180	2,610,800,180	2,622,586,180	2,634,372,180	2,639,663,180	2,644,954,180	2,650,245,180	2,655,536,180	2,660,827,180	2,615,091,949
Transmission	459,617,373	464,793,173	469,968,973	475,144,773	480,320,573	485,496,373	490,672,173	495,847,973	497,393,573	498,939,173	500,484,773	502,030,373	503,575,973	486,483,481
Distribution	166,725,511	168,943,711	171,161,911	173,380,111	175,598,311	177,816,511	180,034,711	182,252,911	182,915,311	183,577,711	184,240,111	184,902,511	185,564,911	178,239,557
General	78,029,799	78,568,799	79,107,799	79,646,799	80,185,799	80,724,799	81,263,799	81,802,799	82,050,799	82,298,799	82,546,799	82,794,799	83,042,799	80,928,030
Total Utility Plant in Service	3,256,242,863	3,275,961,863	3,295,680,863	3,315,399,863	3,335,118,863	3,354,837,863	3,374,556,863	3,394,275,863	3,402,022,863	3,409,769,863	3,417,516,863	3,425,263,863	3,433,010,863	3,360,743,017
Construction Work in Progress (CWIP)														
Generation	189,194,310	191,258,310	193,322,310	195,386,310	197,450,310	199,514,310	201,578,310	203,642,310	226,540,310	249,438,310	272,336,310	295,234,310	318,132,310	225,617,541
Transmission	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134
Distribution	41	41	41	41	41	41	41	41	41	41	41	41	41	41
General	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Total CWIP	190,597,600	192,661,600	194,725,600	196,789,600	198,853,600	200,917,600	202,981,600	205,045,600	227,943,600	250,841,600	273,739,600	296,637,600	319,535,600	227,020,830
Materials & Supplies	48,347,000	50,141,000	51,934,000	53,728,000	55,522,000	57,316,000	59,110,000	60,904,000	61,059,000	61,214,000	61,369,000	61,524,000	61,678,000	57,218,923
Fuel Stock	62,517,000	62,930,000	63,343,000	63,756,000	64,169,000	64,582,000	64,995,000	65,408,000	65,701,000	65,994,000	66,287,000	66,580,000	66,872,000	64,856,462
Cash Working Capital (1/8th of Adj. Annual O&M)	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673	26,985,673
Total	3,584,690,135	3,608,680,135	3,632,669,135	3,656,659,135	3,680,649,135	3,704,639,135	3,728,629,135	3,752,619,135	3,783,712,135	3,814,805,135	3,845,898,135	3,876,991,135	3,908,082,135	3,736,824,904
Less: Accumulated Depreciation														
Generation	585,350,251	589,740,447	594,130,677	598,520,907	603,251,096	608,008,072	612,765,048	617,544,759	622,328,934	627,113,109	631,903,980	636,694,851	641,485,722	612,987,527
Transmission	132,961,962	133,591,648	134,221,334	134,851,020	135,480,706	136,129,210	136,777,714	137,454,202	138,130,693	138,807,184	139,483,675	140,160,166	140,840,135	136,837,665
Distribution	39,576,599	39,913,146	40,249,693	40,586,240	40,922,787	41,259,631	41,596,475	41,944,669	42,292,866	42,641,063	42,989,260	43,337,457	43,692,632	41,615,578
General	49,379,855	49,746,442	50,113,279	50,480,179	50,847,225	51,214,396	51,581,567	52,227,752	52,737,638	53,249,024	53,768,625	54,288,557	54,808,489	51,880,233
Total Accumulated Depreciation	807,268,667	812,991,683	818,714,983	824,438,346	830,501,814	836,611,309	842,720,804	849,171,382	855,490,131	861,810,380	868,145,540	874,481,031	880,826,978	843,321,004
Net Investment Rate Base	2,777,421,468	2,795,688,452	2,813,954,152	2,832,220,789	2,850,147,321	2,868,027,826	2,885,908,331	2,903,447,753	2,928,222,004	2,952,994,755	2,977,752,595	3,002,510,104	3,027,255,157	2,893,503,901

EAST KENTUCKY POWER COOPERATIVE, INC.
Forecasted Test Period 13-Month Average Net Cost Rate Base

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Net Cost Rate Base Items -- Environmental Plant														
Plant in Service	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943	700,309,943
Accumulated Depreciation	53,894,690	55,525,106	57,155,222	58,785,937	60,416,353	62,046,769	63,677,184	65,307,600	66,938,016	68,568,431	70,198,847	71,829,263	73,459,678	63,677,161
Allowance Inventory	8,317,890	7,516,228	6,531,823	5,571,555	4,847,780	4,336,152	3,568,000	2,729,832	3,597,547	3,397,752	3,211,970	3,094,488	2,795,622	4,576,203
Cash Working Capital	2,496,344	2,687,838	2,892,790	3,091,664	3,262,853	3,299,600	3,282,709	3,571,585	3,688,928	3,797,374	3,931,648	3,935,936	3,963,052	3,377,102
Net Cost Rate Base – Excluding Environmental														
Utility Plant in Service														
Generation	1,851,560,237	1,863,346,237	1,875,132,237	1,886,918,237	1,898,704,237	1,910,490,237	1,922,276,237	1,934,062,237	1,939,353,237	1,944,644,237	1,949,935,237	1,955,226,237	1,960,517,237	1,914,782,006
Transmission	459,617,373	464,793,173	469,968,973	475,144,773	480,320,573	485,496,373	490,672,173	495,847,973	497,393,573	498,939,173	500,484,773	502,030,373	503,575,973	486,483,481
Distribution	166,725,511	168,943,711	171,161,911	173,380,111	175,598,311	177,816,511	180,034,711	182,252,911	182,915,311	183,577,711	184,240,111	184,902,511	185,564,911	178,239,557
General	78,029,799	78,568,799	79,107,799	79,646,799	80,185,799	80,724,799	81,263,799	81,802,799	82,050,799	82,298,799	82,546,799	82,794,799	83,042,799	80,928,030
Total Utility Plant in Service	2,555,932,920	2,575,651,920	2,595,370,920	2,615,089,920	2,634,808,920	2,654,527,920	2,674,246,920	2,693,965,920	2,701,712,920	2,709,459,920	2,717,206,920	2,724,953,920	2,732,700,920	2,660,433,074
Construction Work in Progress (CWIP)														
Generation	189,194,310	191,258,310	193,322,310	195,386,310	197,450,310	199,514,310	201,578,310	203,642,310	226,540,310	249,438,310	272,336,310	295,234,310	318,132,310	225,617,541
Transmission	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134	1,403,134
Distribution	41	41	41	41	41	41	41	41	41	41	41	41	41	41
General	114	114	114	114	114	114	114	114	114	114	114	114	114	114
Total CWIP	190,597,600	192,661,600	194,725,600	196,789,600	198,853,600	200,917,600	202,981,600	205,045,600	227,943,600	250,841,600	273,739,600	296,637,600	319,535,600	227,020,830
Materials & Supplies	48,347,000	50,141,000	51,934,000	53,728,000	55,522,000	57,316,000	59,110,000	60,904,000	61,059,000	61,214,000	61,369,000	61,524,000	61,678,000	57,218,923
Fuel Stock	54,199,110	55,413,772	56,811,177	58,184,445	59,321,220	60,245,848	61,427,000	62,678,168	62,103,453	62,596,248	63,075,030	63,485,512	64,076,378	60,278,259
Cash Working Capital (1/8th of Adj. Annual O&M)	24,489,329	24,297,835	24,092,883	23,894,009	23,722,820	23,686,073	23,702,964	23,414,088	23,296,745	23,188,299	23,054,025	23,049,737	23,022,621	23,608,571
Total	2,873,565,958	2,898,166,126	2,922,934,579	2,947,685,973	2,972,228,559	2,996,693,440	3,021,468,483	3,046,007,775	3,076,115,717	3,107,300,066	3,138,444,574	3,169,650,768	3,201,013,518	3,028,559,657
Less: Accumulated Depreciation														
Generation	531,455,561	534,215,341	536,975,455	539,734,970	542,834,743	545,961,303	549,087,864	552,237,159	555,390,918	558,544,678	561,705,133	564,865,588	568,026,044	549,310,366
Transmission	132,961,962	133,591,648	134,221,334	134,851,020	135,480,706	136,129,210	136,777,714	137,454,202	138,130,693	138,807,184	139,483,675	140,160,166	140,840,135	136,837,665
Distribution	39,576,599	39,913,146	40,249,693	40,586,240	40,922,787	41,259,631	41,596,475	41,944,669	42,292,866	42,641,063	42,989,260	43,337,457	43,692,632	41,615,578
General	49,379,855	49,746,442	50,113,279	50,480,179	50,847,225	51,214,396	51,581,567	52,227,752	52,737,638	53,249,024	53,768,625	54,288,557	54,808,489	51,880,233
Total Accumulated Depreciation	753,373,977	757,466,577	761,559,761	765,652,409	770,085,461	774,564,540	779,043,620	783,863,782	788,552,115	793,241,949	797,946,693	802,651,768	807,367,300	779,643,842
Net Investment Rate Base	2,120,191,981	2,140,699,549	2,161,374,818	2,182,033,564	2,202,143,098	2,222,128,900	2,242,424,863	2,262,143,993	2,287,563,602	2,314,058,117	2,340,497,881	2,366,999,000	2,393,646,218	2,248,915,815

Seelye Exhibit 4

EAST KENTUCKY POWER COOPERATIVE, INC.
13-Month Average Capitalization

Item	1 May 2009	2 June 2009	3 July 2009	4 August 2009	5 September 2009	6 October 2009	7 November 2009	8 December 2009	9 January 2010	10 February 2010	11 March 2010	12 April 2010	13 May 2010	13-Month Average
Capitalization														
Members' Equity	186,645,000	189,290,000	192,747,000	203,104,000	208,837,000	205,568,000	202,821,000	214,570,000	227,679,000	237,682,000	247,682,000	247,216,000	246,465,000	216,177,385
Long-Term Debt	2,570,995,000	2,648,125,000	2,666,867,000	2,660,609,000	2,654,351,000	2,678,092,000	2,671,834,000	2,715,576,000	2,708,726,000	2,701,877,000	2,735,027,000	2,778,178,000	2,771,328,000	2,689,352,692
Total	2,757,640,000	2,837,415,000	2,859,614,000	2,863,713,000	2,863,188,000	2,883,660,000	2,874,655,000	2,930,146,000	2,936,405,000	2,939,559,000	2,982,709,000	3,025,394,000	3,017,793,000	2,905,530,077
Capital Structure (Percentage of Total)														
Members' Equity	6.77%	6.67%	6.74%	7.09%	7.29%	7.13%	7.06%	7.32%	7.75%	8.09%	8.30%	8.17%	8.17%	7.44%
Long-Term Debt	93.23%	93.33%	93.26%	92.91%	92.71%	92.87%	92.94%	92.68%	92.25%	91.91%	91.70%	91.83%	91.83%	92.56%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Total Capitalization -- 13-Month Average	$2,905,530,077
Less: Impact on Equity from Rate Increase	(5,219,927)
Less: Environmental Plant	(641,210,985)
	$2,259,099,165

Seelye Exhibit 5

EAST KENTUCKY POWER COOPERATIVE, INC.
Summary of Coverage Ratios and Rates of Return

		Forecast **Net of Adjustments Before Revenue Increase**		*Forecast* **Net of Adjustments After Revenue Increase***
Adjusted Net Margins	$	(25,603,606)	$	42,255,316
Interest		98,751,898		98,751,898
Times Interest Earned (TIER)		**0.74**		**1.43**
Adjusted Net Margins	$	(25,603,606)	$	42,255,316
Interest		98,751,898		98,751,898
Depreciation		53,993,319		53,993,319
Total	$	127,141,611	$	195,000,533
Normalized Principal and Interest (Excluding Environment P&I)	$	156,157,108	$	156,157,108
Debt Service Coverage Ratio (DSC)		**0.81**		**1.25**
Adjusted Net Margins Before Interest		71,322,720.37		139,181,642.37
Net Cost Rate Base		2,248,915,815		2,248,915,815
Rate of Return on Net Cost Rate Base		**3.17%**		**6.19%**
Capitalization		2,259,099,165		2,259,099,165
Rate of Return on Total Capitalization		**3.16%**		**6.16%**

**The Board-approved rate increase is used, which produces a lower TIER than shown in the revenue requirement.*

Seelye Exhibit 6

EAST KENTUCK ... WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	$ -	-	-	-	-
Production Plant	PPROD	F001	1,914,782,006	1,895,587,544	-	19,194,462	-
Transmission Plant	PTRAN	F002	486,483,481	-	-	-	486,483,481
Distribution Plant	PDIST	F003	178,239,557	2,752,427	-	-	618,605
Total Production & Transmission Plant	PT&D		2,579,505,044	1,898,339,971	-	19,194,462	487,102,086
General Plant	PGP	PT&D	$ 80,928,030	59,557,516	-	602,197	15,282,084
Total Plant in Service	TPIS		$ 2,660,433,074	$ 1,957,897,487	$ -	$ 19,796,659	$ 502,384,170
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	$ 225,617,541	223,355,870	-	2,261,671	-
CWIP Transmission	CWIP2	PTRAN	1,403,134	-	-	-	1,403,134
CWIP Distribution Plant	CWIP3	PDIST	41	1	-	-	0
CWIP General Plant	CWIP4	PT&D	114	84	-	1	22
Total Construction Work in Progress	TCWIP		$ 227,020,830	$ 223,355,954	$ -	$ 2,261,672	$ 1,403,156
Total Utility Plant			$ 2,887,453,904	$ 2,181,253,442	$ -	$ 22,058,331	$ 503,787,326

EAST KENTUC. JWER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Plant in Service						
Intangible Plant	INTPLT	PT&D		-		-
Production Plant	PPROD	F001		-		-
Transmission Plant	PTRAN	F002		-		-
Distribution Plant	PDIST	F003		167,119,502		7,749,023
Total Production & Transmission Plant	PT&D			167,119,502		7,749,023
General Plant	PGP	PT&D		5,243,119		243,114
Total Plant in Service	TPIS		$	172,362,621	$	7,992,137
Construction Work in Progress (CWIP)						
CWIP Production	CWIP1	PPROD		-		-
CWIP Transmission	CWIP2	PTRAN		-		-
CWIP Distribution Plant	CWIP3	PDIST		38		2
CWIP General Plant	CWIP4	PT&D		7		0
Total Construction Work in Progress	TCWIP		$	46	$	2
Total Utility Plant			$	172,362,667	$	7,992,139

EAST KENTUCK JER COOPERATIVE, INC.
Cost of Service Study
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12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		$ 2,887,453,904	$ 2,181,253,442	$ -	$ 22,058,331	$ 503,787,326
Less: Acummulated Provision for Depreciation							
Production	ADEPREPA	PPROD	$ 549,310,366	543,803,882	-	5,506,484	-
Transmission	ADEPRTP	PTRAN	136,837,665	-	-	-	136,837,665
Distribution	ADEPRD11	PDIST	41,615,578	642,640	-	-	144,433
General & Common Plant	ADEPRD12	PT&D	51,880,233	38,180,317	-	386,048	9,796,829
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	-	-	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 779,643,842	$ 582,626,838	$ -	$ 5,892,532	$ 146,778,927
Net Utility Plant	NTPLANT		$ 2,107,810,062	$ 1,598,626,603	$ -	$ 16,165,799	$ 357,008,399
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 23,608,571	12,519,953	6,071,375	4,348	4,676,152
Materials and Supplies	M&S	TPIS	57,218,923	42,109,229	-	425,774	10,804,963
Fuel Stock	PREPAY	TPIS	60,278,259	44,360,692	-	448,539	11,382,674
Total Working Capital	TWC		$ 141,105,753	$ 98,989,874	$ 6,071,375	$ 878,662	$ 26,863,789
Net Rate Base	RB		$ 2,248,915,815	$ 1,697,616,477	$ 6,071,375	$ 17,044,460	$ 383,872,188

EAST KENTUC OWER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Rate Base						
Total Utility Plant	TUP		$	172,362,667	$	7,992,139
Less: Acummulated Provision for Depreciation						
Production	ADEPREPA	PPROD		-		-
Transmission	ADEPRTP	PTRAN		-		-
Distribution	ADEPRD11	PDIST		39,019,255		1,809,251
General & Common Plant	ADEPRD12	PT&D		3,361,187		155,852
Intangible, Misc, and Other Plant	ADEPRGP	PT&D		-		-
Retirement Work In Progress	ADEPRRT	PT&D		-		-
Total Accumulated Depreciation	TADEPR		$	42,380,442	$	1,965,103
Net Utility Plant	NTPLANT		$	129,982,225	$	6,027,036
Working Capital						
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP		321,820		14,922
Materials and Supplies	M&S	TPIS		3,707,067		171,890
Fuel Stock	PREPAY	TPIS		3,905,273		181,080
Total Working Capital	TWC		$	7,934,161	$	367,892
Net Rate Base	RB		$	137,916,386	$	6,394,928

EAST KENTUC. ,WER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	$	7,885,308		7,885,308		-		-		-
501 FUEL	OM501	Energy	$	386,058,927		-		386,058,927		-		-
502 STEAM EXPENSES	OM502	PROFIX	$	11,355,691		11,355,691		-		-		-
505 ELECTRIC EXPENSES	OM505	PROFIX	$	5,274,586		5,274,586		-		-		-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$	33,482,685		33,482,685		-		-		-
507 RENTS	OM507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	OM509	Energy	$	6,620,870		-		6,620,870		-		-
Total Steam Power Operation Expenses			$	450,678,067	$	57,998,270	$	392,679,797	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	$	2,604,989		-		2,604,989		-		-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$	3,713,719		3,713,719		-		-		-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$	28,840,241		-		28,840,241		-		-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$	9,015,056		-		9,015,056		-		-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFIX	$	117,139		117,139		-		-		-
Total Steam Power Generation Maintenance Expense			$	44,291,144	$	3,830,858	$	40,460,286	$	-	$	-
Total Steam Power Generation Expense			$	494,969,211	$	61,829,128	$	433,140,083	$	-	$	-

EAST KENTUCK WER COOPERATIVE, INC.
Cost of Service Study
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Description	Name	Functional Vector	Distribution Substations	Distribution Meters
<u>Operation and Maintenance Expenses</u>				
Steam Power Generation Operation Expenses				
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFIX	-	-
501 FUEL	OM501	Energy	-	-
502 STEAM EXPENSES	OM502	PROFIX	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-
507 RENTS	OM507	PROFIX	-	-
509 ALLOWANCES	OM509	Energy	-	-
Total Steam Power Operation Expenses			$ -	$ -
Steam Power Generation Maintenance Expenses				
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	-	-
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	PROFIX	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -
Total Steam Power Generation Expense			$ -	$ -

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	$ 278,826	278,826	-	-	-
547 FUEL	OM547	Energy	$ 40,878,558	-	40,878,558	-	-
548 GENERATION EXPENSE	OM548	PROFIX	$ 3,513,607	3,513,607	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$ 1,055,967	1,055,967	-	-	-
550 RENTS	OM550	PROFIX	$ -	-	-	-	-
Total Other Power Generation Expenses			$ 45,726,958	$ 4,848,400	$ 40,878,558	$ -	$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 170,556	170,556	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$ 186,558	186,558	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$ 3,955,857	3,955,857	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$ 70,216	70,216	-	-	-
Total Other Power Generation Maintenance Expense			$ 4,383,187	$ 4,383,187	$ -	$ -	$ -
Total Other Power Generation Expense			$ 50,110,145	$ 9,231,587	$ 40,878,558	$ -	$ -
Total Station Expense			$ 545,079,356	$ 71,060,715	$ 474,018,641	$ -	$ -

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Operation and Maintenance Expenses (Continued)				
Other Power Generation Operation Expense				
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	-	-
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			$ -	$ -
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			$ -	$ -

EAST KENTUC ... WER COOPERATIVE, INC.
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Supply Expenses							
555 PURCHASED POWER	OM555	OMPP	$ 64,242,370	-	64,242,370	-	-
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	3,993,169	3,993,169	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	8,951,678	8,951,678	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ 77,187,217	$ 12,944,847	$ 64,242,370	$ -	$ -
Total Electric Power Generation Expenses			$ 622,266,573	$ 84,005,562	$ 538,261,011	$ -	$ -
Transmission Expenses							
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 3,904,970	-	-	-	3,904,970
561 LOAD DISPATCHING	OM561	LBTRAN	2,555,050	-	-	-	2,555,050
562 STATION EXPENSES	OM562	PTRAN	2,192,606	-	-	-	2,192,606
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	2,307,161	-	-	-	2,307,161
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	15,632,950	-	-	-	15,632,950
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	945,367	-	-	-	945,367
567 RENTS	OM567	PTRAN	446,300	-	-	-	446,300
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-
569 STRUCTURES	OM569	PTRAN	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	1,920,486	-	-	-	1,920,486
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	2,774,520	-	-	-	2,774,520
572 UNDERGROUND LINES	OM572	PTRAN	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	144,039	-	-	-	144,039
Total Transmission Expenses			$ 32,823,449	$ -	$ -	$ -	$ 32,823,449
Distribution Operation Expense							
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ -	-	-	-	-
581 LOAD DISPATCHING	OM581	PDIST	213,127	3,291	-	-	740
582 STATION EXPENSES	OM582	PDIST	808,499	12,485	-	-	2,806
583 OVERHEAD LINE EXPENSES	OM583	PDIST	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	-	-	-	-	-
586 METER EXPENSES	OM586	PDIST	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 1,021,626	$ 15,776	$ -	$ -	$ 3,546

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Operation and Maintenance Expenses (Continued)						
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		-		-
558 DUPLICATE CHARGES	OM558	Energy		-		-
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	PTRAN		-		-
563 OVERHEAD LINE EXPENSES	OM563	PTRAN		-		-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN		-		-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN		-		-
567 RENTS	OM567	PTRAN		-		-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN		-		-
569 STRUCTURES	OM569	PTRAN		-		-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN		-		-
571 MAINT OF OVERHEAD LINES	OM571	PTRAN		-		-
572 UNDERGROUND LINES	OM572	PTRAN		-		-
573 MISC PLANT	OM573	PTRAN		-		-
Total Transmission Expenses			$	-	$	-
Distribution Operation Expense						
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO		-		-
581 LOAD DISPATCHING	OM581	PDIST		199,830		9,266
582 STATION EXPENSES	OM582	PDIST		758,058		35,150
583 OVERHEAD LINE EXPENSES	OM583	PDIST		-		-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST		-		-
585 STREET LIGHTING EXPENSE	OM585	PDIST		-		-
586 METER EXPENSES	OM586	PDIST		-		-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	PDIST		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST		-		-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST		-		-
589 RENTS	OM589	PDIST		-		-
Total Distribution Operation Expense	OMDO		$	957,889	$	44,416

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Distribution Maintenance Expense												
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$	-		-		-		-		-
591 STRUCTURES	OM591	PDIST	$	-		-		-		-		-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST		987,836		15,254		-		-		3,428
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST		-		-		-		-		-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST		-		-		-		-		-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST		-		-		-		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST		-		-		-		-		-
597 MAINTENANCE OF METERS	OM597	PDIST		-		-		-		-		-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST		-		-		-		-		-
Total Distribution Maintenance Expense	OMDM		$	987,836	$	15,254	$	-	$	-	$	3,428
Total Distribution Operation and Maintenance Expenses				2,009,462		31,031		-		-		6,974
Transmission and Distribution Expenses				34,832,911		31,031		-		-		32,830,423
Production, Transmission and Distribution Expenses	OMSUB		$	657,099,484	$	84,036,593	$	538,261,011	$	-	$	32,830,423
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	TUP	$	-		-		-		-		-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP		1,742,340		1,316,206		-		13,310		303,994
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP		-		-		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP		500		378		-		4		87
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP		-		-		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP		21,750		16,430		-		166		3,795
911 DEMONSTRATION AND SELLING EXP	OM911	TUP		-		-		-		-		-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP		-		-		-		-		-
913 ADVERTISING EXPENSES	OM913	TUP		10,000		7,554		-		76		1,745
915 MDSE-JOBBING-CONTRACT	OM915	TUP		-		-		-		-		-
916 MISC SALES EXPENSE	OM916	TUP		-		-		-		-		-
Total Customer Service Expense	OMCS		$	1,774,590	$	1,340,569	$	-	$	13,557	$	309,621
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			658,874,074		85,377,161		538,261,011		13,557		33,140,044

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Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Operation and Maintenance Expenses (Continued)						
Distribution Maintenance Expense						
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM		-		-
591 STRUCTURES	OM591	PDIST		-		-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST		926,207		42,946
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST		-		-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST		-		-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST		-		-
597 MAINTENANCE OF METERS	OM597	PDIST		-		-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST		-		-
Total Distribution Maintenance Expense	OMDM		$	926,207	$	42,946
Total Distribution Operation and Maintenance Expenses				1,884,095		87,362
Transmission and Distribution Expenses				1,884,095		87,362
Production, Transmission and Distribution Expenses	OMSUB		$	1,884,095	$	87,362
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	TUP		-		-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP		104,007		4,823
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP		-		-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP		30		1
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP		1,298		60
911 DEMONSTRATION AND SELLING EXP	OM911	TUP		-		-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP		-		-
913 ADVERTISING EXPENSES	OM913	TUP		597		28
915 MDSE-JOBBING-CONTRACT	OM915	TUP		-		-
916 MISC SALES EXPENSE	OM916	TUP		-		-
Total Customer Service Expense	OMCS		$	105,932	$	4,912
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			1,990,027		92,274

EAST KENTUCK. ...VER COOPERATIVE, INC.
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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Operation and Maintenance Expenses (Continued)												
Administrative and General Expense												
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$	11,309,693		5,778,671		3,620,520		1,123		1,708,572
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9		5,606,260		2,864,510		1,794,706		557		846,946
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9		-		-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9		2,046,640		1,045,728		655,181		203		309,189
924 PROPERTY INSURANCE	OM924	TUP		-		-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9		905,423		462,625		289,849		90		136,784
926 EMPLOYEE BENEFITS	OM926	LBSUB9		787,580		402,413		252,124		78		118,981
927 FRANCHISE REQUIREMENTS	OM927	TUP		-		-		-		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP		1,238,124		935,309		-		9,458		216,021
929 DUPLICATE CHARGES-CR	OM929	LBSUB9		(478,800)		(244,642)		(153,276)		(48)		(72,333)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9		5,260,409		2,687,798		1,683,991		522		794,698
931 RENTS AND LEASES	OM931	PGP		-		-		-		-		-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP		1,245,791		916,817		-		9,270		235,250
Total Administrative and General Expense	OMAG		$	27,921,120	$	14,849,230	$	8,143,096	$	21,254	$	4,294,106
Total Operation and Maintenance Expenses	TOM		$	686,795,194	$	100,226,391	$	546,404,107	$	34,811	$	37,434,150
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	188,994,469	$	100,226,391	$	48,603,382	$	34,811	$	37,434,150

EAST KENTUC, ,WER COOPERATIVE, INC.
Cost of Service Study
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Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Operation and Maintenance Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9		191,909		8,898
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9		95,130		4,411
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9		-		-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9		34,728		1,610
924 PROPERTY INSURANCE	OM924	TUP		-		-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9		15,364		712
926 EMPLOYEE BENEFITS	OM926	LBSUB9		13,364		620
927 FRANCHISE REQUIREMENTS	OM927	TUP		-		-
928 REGULATORY COMMISSION FEES	OM928	TUP		73,908		3,427
929 DUPLICATE CHARGES-CR	OM929	LBSUB9		(8,125)		(377)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9		89,261		4,139
931 RENTS AND LEASES	OM931	PGP		-		-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP		80,712		3,742
Total Administrative and General Expense	OMAG		$	586,252	$	27,183
Total Operation and Maintenance Expenses	TOM		$	2,576,279	$	119,457
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		$	2,576,279	$	119,457

EAST KENTUCI ... /ER COOPERATIVE, INC.
Cost of Service Study
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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses												
Steam Power Generation Operation Expenses												
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	2,252,669		2,252,669		-		-		-
501 FUEL	LB501	Energy	$	1,477,744		-		1,477,744		-		-
502 STEAM EXPENSES	LB502	PROFIX	$	1,770,487		1,770,487		-		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	1,368,779		1,368,779		-		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	958,705		958,705		-		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	7,828,384	$	6,350,640	$	1,477,744	$	-	$	-
Steam Power Generation Maintenance Expenses												
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	729,965		-		729,965		-		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	306,869		306,869		-		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	2,668,789		-		2,668,789		-		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	645,029		-		645,029		-		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	15,125		15,125		-		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	4,365,777	$	321,994	$	4,043,783	$	-	$	-
Total Steam Power Generation Expense			$	12,194,161	$	6,672,634	$	5,521,527	$	-	$	-

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Labor Expenses				
Steam Power Generation Operation Expenses				
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	-	-
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	-	-
509 ALLOWANCES	LB509	Energy	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -
Steam Power Generation Maintenance Expenses				
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	-	-
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	PROFIX	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -
Total Steam Power Generation Expense			$ -	$ -

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Labor Expenses (Continued)												
Other Power Generation Operation Expense												
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$	79,755		79,755		-		-		-
547 FUEL	LB547	Energy	$	7,355		-		7,355		-		-
548 GENERATION EXPENSE	LB548	PROFIX	$	327,970		327,970		-		-		-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$	34,616		34,616		-		-		-
550 RENTS	LB550	PROFIX	$	-		-		-		-		-
Total Other Power Generation Expenses	LBSUB7		$	449,696	$	442,341	$	7,355	$	-	$	-
Other Power Generation Maintenance Expense												
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$	47,915		47,915		-		-		-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$	1,695		1,695		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$	145,449		145,449		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	5,195		5,195		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB8		$	200,254	$	200,254	$	-	$	-	$	-
Total Other Power Generation Expense			$	649,950	$	642,595	$	7,355	$	-	$	-
Total Production Expense	LPREX		$	12,844,111	$	7,315,229	$	5,528,882	$	-	$	-

EAST KENTUCKY .ER COOPERATIVE, INC.
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Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
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	LBSUB7		$	-	$	-
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	LBSUB8		$	-	$	-
Total Other Power Generation Expense			$	-	$	-
Total Production Expense	LPREX		$	-	$	-

EAST KENTUCKY ER COOPERATIVE, INC.
Cost of Service Study
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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	$ -	-	-	-	-
555 BROKERAGE FEES	LBB555	OMPP	$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP	$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ 969,165	969,165	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	366,045	366,045	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 1,335,210	$ 1,335,210	$ -	$ -	$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 844,080	-	-	-	844,080
561 LOAD DISPATCHING	LB561	PTRAN	511,215	-	-	-	511,215
562 STATION EXPENSES	LB562	PTRAN	225,550	-	-	-	225,550
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	264,500	-	-	-	264,500
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	275,005	-	-	-	275,005
567 RENTS	LB567	PTRAN	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	255,005	-	-	-	255,005
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	193,605	-	-	-	193,605
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 2,568,960	$ -	$ -	$ -	$ 2,568,960
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	21,440	331	-	-	74
582 STATION EXPENSES	LB582	PDIST	136,630	2,110	-	-	474
583 OVERHEAD LINE EXPENSES	LB583	PDIST	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	-	-	-	-	-
586 METER EXPENSES	LB586	PDIST	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 158,070	$ 2,441	$ -	$ -	$ 549

EAST KENTUCKY ER COOPERATIVE, INC.
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Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
Purchased Power						
555 PURCHASED POWER	LB555	OMPP		-		-
555 PURCHASED POWER OPTIONS	LBO555	OMPP		-		-
555 BROKERAGE FEES	LBB555	OMPP		-		-
555 MISO TRANSMISSION EXPENSES	LBM555	OMPP		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX		-		-
557 OTHER EXPENSES	LB557	PROFIX		-		-
558 DUPLICATE CHARGES	LB558	Energy		-		-
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		-		-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN		-		-
567 RENTS	LB567	PTRAN		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN		-		-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN		-		-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN		-		-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN		-		-
Total Transmission Labor Expenses	LBTRAN		$	-	$	-
Distribution Operation Labor Expense						
580 OPERATION SUPERVISION AND ENGI	LB580	F023		-		-
581 LOAD DISPATCHING	LB581	PDIST		20,102		932
582 STATION EXPENSES	LB582	PDIST		128,106		5,940
583 OVERHEAD LINE EXPENSES	LB583	PDIST		-		-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST		-		-
585 STREET LIGHTING EXPENSE	LB585	PDIST		-		-
586 METER EXPENSES	LB586	PDIST		-		-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST		-		-
589 RENTS	LB589	PDIST		-		-
Total Distribution Operation Labor Expense	LBDO		$	148,208	$	6,872

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Distribution Maintenance Labor Expense							
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	140,205	2,165	-	-	487
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 140,205	$ 2,165	$ -	$ -	$ 487
Total Distribution Operation and Maintenance Labor Expenses		PDIST	298,275	4,606	-	-	1,035
Transmission and Distribution Labor Expenses			2,867,235	4,606	-	-	2,569,995
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 17,046,556	$ 8,655,045	$ 5,528,882	$ -	$ 2,569,995
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	TUP	$ -	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	224,432	169,541	-	1,715	39,158
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 224,432	$ 169,541	$ -	$ 1,715	$ 39,158
Sub-Total Labor Exp	LBSUB9		17,270,988	8,824,586	5,528,882	1,715	2,609,153

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
Distribution Maintenance Labor Expense						
590 MAINTENANCE SUPERVISION AND EN	LB590	F024		-		-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST		-		-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST		131,458		6,095
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST		-		-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST		-		-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST		-		-
597 MAINTENANCE OF METERS	LB597	PDIST		-		-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST		-		-
Total Distribution Maintenance Labor Expense	LBDM		$	131,458	$	6,095
Total Distribution Operation and Maintenance Labor Expenses		PDIST		279,666		12,968
Transmission and Distribution Labor Expenses				279,666		12,968
Production, Transmission and Distribution Labor Expenses	LBSUB		$	279,666	$	12,968
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	TUP		-		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP		13,397		621
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP		-		-
915 MDSE-JOBBING-CONTRACT	LB915	TUP		-		-
916 MISC SALES EXPENSE	LB916	TUP		-		-
Total Customer Service Labor Expense	LBCS		$	13,397	$	621
Sub-Total Labor Exp	LBSUB9			293,063		13,589

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$ 3,220,000	1,645,254	1,030,804	320	486,450
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9		-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	-	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	-	-	-	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	322,128	164,591	103,121	32	48,664
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	84,265	62,013	-	627	15,912
Total Administrative and General Expense	LBAG		$ 3,626,393	$ 1,871,859	$ 1,133,925	$ 979	$ 551,027
Total Operation and Maintenance Expenses	TLB		$ 20,897,381	$ 10,696,445	$ 6,662,807	$ 2,693	$ 3,160,179
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 20,897,381	$ 10,696,445	$ 6,662,807	$ 2,693	$ 3,160,179

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Labor Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9		54,639		2,533
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9		-		-
924 PROPERTY INSURANCE	LB924	TUP		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9		-		-
926 EMPLOYEE BENEFITS	LB926	LBSUB9		-		-
928 REGULATORY COMMISSION FEES	LB928	TUP		-		-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9		-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9		5,466		253
931 RENTS AND LEASES	LB931	PGP		-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP		5,459		253
Total Administrative and General Expense	LBAG		$	65,564	$	3,040
Total Operation and Maintenance Expenses	TLB		$	358,627	$	16,629
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	358,627	$	16,629

EAST KENTUCKY ,ER COOPERATIVE, INC.
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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Steam Direct		Transmission Demand
Other Expenses												
Depreciation Expenses												
Production	DEPRDP2	PPROD		56,135,471		55,572,749		-		562,722		-
Transmission	DEPRDP3	PTRAN		-		-		-		-		-
Transmission	DEPRDP4	PTRAN		7,878,173		-		-		-		7,878,173
Distribution	DEPRDP5	PDIST		4,116,033		63,561		-		-		14,285
General & Common Plant	DEPRDP6	PGP		5,428,634		3,995,105		-		40,395		1,025,119
Other Plant	DEPROTH	TPIS		-		-		-		-		-
Total Depreciation Expense	TDEPR		$	73,558,311		59,631,415		-		603,117		8,917,577
Accretion Expense												
Production	ACRTNP	F017	$	-		-		-		-		-
Transmission	ACRTNT	PTRAN	$	-		-		-		-		-
Distribution	ACRTND	PDIST	$	-		-		-		-		-
Total Accretion Expense	TACRTN		$	-	$	-	$	-	$	-	$	-
Property Taxes & Other	PTAX	TUP	$	800		604		-		6		140
Amortization of Investment Tax Credit	OTAX	TUP	$	-		-		-		-		-
Other Expenses	OT	TUP	$	-		-		-		-		-
Interest	INTLTD	TUP	$	135,823,886		102,604,692		-		1,037,609		23,697,816
Other Deductions	DEDUCT	TUP	$	2,363,706		1,785,601		-		18,057		412,407
Total Other Expenses	TOE		$	211,746,703	$	164,022,313	$	-	$	1,658,790	$	33,027,940
Total Cost of Service (O&M + Other Expenses)			$	898,541,897	$	264,248,704	$	546,404,107	$	1,693,600	$	70,462,089

EAST KENTUCK\ ⁄ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector		Distribution Substations		Distribution Meters
Other Expenses						
Depreciation Expenses						
Production	DEPRDP2	PPROD		-		-
Transmission	DEPRDP3	PTRAN		-		-
Transmission	DEPRDP4	PTRAN		-		-
Distribution	DEPRDP5	PDIST		3,859,241		178,946
General & Common Plant	DEPRDP6	PGP		351,707		16,308
Other Plant	DEPROTH	TPIS		-		-
Total Depreciation Expense	TDEPR			4,210,948		195,254
Accretion Expense						
Production	ACRTNP	F017		-		-
Transmission	ACRTNT	PTRAN		-		-
Distribution	ACRTND	PDIST		-		-
Total Accretion Expense	TACRTN		$	-	$	-
Property Taxes & Other	PTAX	TUP		48		2
Amortization of Investment Tax Credit	OTAX	TUP		-		-
Other Expenses	OT	TUP		-		-
Interest	INTLTD	TUP		8,107,824		375,945
Other Deductions	DEDUCT	TUP		141,098		6,542
Total Other Expenses	TOE		$	12,459,918	$	577,743
Total Cost of Service (O&M + Other Expenses)			$	15,036,197	$	697,201

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1,733,178,865	1,715,804,858	0.000000	17,374,007	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.015442	0.000000	0.000000	0.003471
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	0.500000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		158,070.00	2,440.96	-	-	548.60
Distribution Maintenance Labor	F024		140,205.00	2,165.09	-	-	486.60
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000
Purchased Power Expenses	OMPP		1.000000	-	1	-	$ -
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.735932	-	0.007441	0.188835
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.530314	0.257168	0.000184	0.198070
Total Plant in Service		TPIS	1.000000	0.735932	-	0.007441	0.188835
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.511856	0.318835	0.000129	0.151224
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.129580	0.816941	0.000021	0.050298
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.811233	0.188767	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.073754	0.926246	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.983645	0.016355	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.510949	0.320125	0.000099	0.151071
Total General Plant		PGP	1.000000	0.735932	-	0.007441	0.188835
Total Production Plant		PPROD	1.000000	0.989976	-	0.010024	-
Total Intangible Plant		INTPLT	1.000000	-	-	-	-

EAST KENTUCK\ ⁄ER COOPERATIVE, INC.
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
May 31, 2010

Description	Name	Functional Vector	Distribution Substations	Distribution Meters
Functional Vectors				
Production Plant	F001		0.000000	0.000000
Transmission Plant	F002		0.000000	0.000000
Distribution Plant	F003		0.937612	0.043475
Production Plant	F017		0.000000	0.000000
Provar	PROVAR		0.000000	0.500000
PROFIX	PROFIX		0.000000	0.000000
Distribution Operation Labor	F023		148,208.29	6,872.14
Distribution Maintenance Labor	F024		131,457.85	6,095.46
Customer Accounts Expense	F025		0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000
Purchased Power Expenses	OMPP		$ -	$ -
Production Energy	Energy		0.000000	0.00%
Internally Generated Functional Vectors				
Total Prod, Trans, and Dist Plant		PT&D	0.064787	0.003004
Total Transmission Plant		PTRAN	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.013632	0.000632
Total Plant in Service		TPIS	0.064787	0.003004
Total Operation and Maintenance Expenses (Labor)		TLB	0.017161	0.000796
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.003020	0.000140
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-
Total Transmission Labor Expenses		LBTRAN	-	-
Sub-Total Labor Exp		LBSUB7	0.016969	0.000787
Total General Plant		PGP	0.064787	0.003004
Total Production Plant		PPROD	-	-
Total Intangible Plant		INTPLT	-	-

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EAST KENTUCK WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Plant in Service											
Power Production Plant											
Production Demand	TPIS	PLPDMD	6CP	$	1,957,897,487	$	1,657,339,742	$	100,395,334	$	45,383,089
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	19,796,659	$	-	$	-	$	-
Total Power Production Plant		PLPT		$	1,977,694,146	$	1,657,339,742	$	100,395,334	$	45,383,089
Transmission Plant	TPIS	PLTRN	12CP	$	502,384,170	$	411,511,104	$	27,740,381	$	12,524,298
Distribution Substation	TPIS	PLDST	SUBA	$	172,362,621	$	170,619,193	$	-	$	-
Distribution Meters	TPIS	PLDMC	Cust05	$	7,992,137	$	7,966,535	$	-	$	-
Total		PLT		$	2,660,433,074	$	2,247,436,574	$	128,135,715	$	57,907,387

EAST KENTUCK OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Plant in Service											
Power Production Plant											
Production Demand	TPIS	PLPDMD	6CP	$	34,154,141	$	120,625,182	$	-	$	-
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	-	$	-	$	-	$	19,796,659
Total Power Production Plant		PLPT		$	34,154,141	$	120,625,182	$	-	$	19,796,659
Transmission Plant	TPIS	PLTRN	12CP	$	9,377,821	$	33,164,092	$	8,066,474	$	-
Distribution Substation	TPIS	PLDST	SUBA	$	1,743,428	$	-	$	-	$	-
Distribution Meters	TPIS	PLDMC	Cust05	$	25,602	$	-	$	-	$	-
Total		PLT		$	45,300,991	$	153,789,274	$	8,066,474	$	19,796,659

EAST KENTUC\ .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Net Utility Plant							
Power Production Plant							
Production Demand	NTPLANT	NTPDMD	6CP	$ 1,598,626,603	$ 1,353,220,697	$ 81,972,960	$ 37,055,369
Production Energy	NTPLANT	NTPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$ 16,165,799	$ -	$ -	$ -
Total Power Production Plant		NTPT		$ 1,614,792,402	$ 1,353,220,697	$ 81,972,960	$ 37,055,369
Transmission Plant	NTPLANT	NTTRN	12CP	$ 357,008,399	$ 292,431,429	$ 19,713,099	$ 8,900,121
Distribution Substation	NTPLANT	NTDST	SUBA	$ 129,982,225	$ 128,667,470	$ -	$ -
Distribution Meters	NTPLANT	NTDMC	Cust05	$ 6,027,036	$ 6,007,729	$ -	$ -
Total		NTPLT		$ 2,107,810,062	$ 1,780,327,324	$ 101,686,059	$ 45,955,489

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Net Utility Plant											
Power Production Plant											
Production Demand	NTPLANT	NTPDMD	6CP	$	27,886,914	$	98,490,665	$	-	$	-
Production Energy	NTPLANT	NTPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$	-	$	-	$	-	$	16,165,799
Total Power Production Plant		NTPT		$	27,886,914	$	98,490,665	$	-	$	16,165,799
Transmission Plant	NTPLANT	NTTRN	12CP	$	6,664,145	$	23,567,341	$	5,732,265	$	-
Distribution Substation	NTPLANT	NTDST	SUBA	$	1,314,755	$	-	$	-	$	-
Distribution Meters	NTPLANT	NTDMC	Cust05	$	19,307	$	-	$	-	$	-
Total		NTPLT		$	35,885,120	$	122,058,006	$	5,732,265	$	16,165,799

EAST KENTUC JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Net Cost Rate Base											
Power Production Plant											
Production Demand	RB	RBPDMD	6CP	$	1,697,616,477	$	1,437,014,569	$	87,048,875	$	39,349,905
Production Energy	RB	RBPENG	PENG	$	6,071,375	$	4,632,980	$	445,944	$	175,434
Production - Steam Direct	RB	RBPSTM	STMD	$	17,044,460	$	-	$	-	$	-
Total Power Production Plant		RBPT		$	1,720,732,313	$	1,441,647,569	$	87,494,819	$	39,525,338
Transmission Plant	RB	RBTRN	12CP	$	363,872,186	$	314,435,998	$	21,196,450	$	9,569,827
Distribution Substation	RB	RBDST	SUBA	$	137,916,386	$	136,521,378	$	-	$	-
Distribution Meters	RB	RBDMC	Cust05	$	6,394,928	$	6,374,443	$	-	$	-
Total		RBPLT		$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166

EAST KENTUC. ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Net Cost Rate Base											
Power Production Plant											
Production Demand	RB	RBPDMD	6CP	$	29,613,722	$	104,589,386	$	-	$	-
Production Energy	RB	RBPENG	PENG	$	160,098	$	434,722	$	105,352	$	116,846
Production - Steam Direct	RB	RBPSTM	STMD	$	-	$	-	$	-	$	17,044,460
Total Power Production Plant		RBPT		$	29,773,820	$	105,024,108	$	105,352	$	17,161,306
Transmission Plant	RB	RBTRN	12CP	$	7,165,601	$	25,340,712	$	6,163,600	$	-
Distribution Substation	RB	RBDST	SUBA	$	1,395,008	$	-	$	-	$	-
Distribution Meters	RB	RBDMC	Cust05	$	20,486	$	-	$	-	$	-
Total		RBPLT		$	38,354,915	$	130,364,820	$	6,268,952	$	17,161,306

EAST KENTUC, JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Operation and Maintenance Expenses											
Power Production Plant											
Production Demand	TOM	OMPDMD	6CP	$	100,226,391	$	84,840,592	$	5,139,320	$	2,323,198
Production Energy	TOM	OMPENG	PENG	$	546,404,107	$	416,953,137	$	40,133,541	$	15,788,463
Production - Steam Direct	TOM	OMPSTM	STMD	$	34,811	$	-	$	-	$	-
Total Power Production Plant		OMPT		$	646,665,308	$	501,793,729	$	45,272,861	$	18,111,661
Transmission Plant	TOM	OMTRN	12CP	$	37,434,150	$	30,662,925	$	2,067,019	$	933,223
Distribution Substation	TOM	OMDST	SUBA	$	2,576,279	$	2,550,220	$	-	$	-
Distribution Meters	TOM	OMDMC	Cust05	$	119,457	$	119,075	$	-	$	-
Total		OMPLT		$	686,795,194	$	535,125,949	$	47,339,880	$	19,044,884

EAST KENTUC. ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Operation and Maintenance Expenses											
Power Production Plant											
Production Demand	TOM	OMPDMD	6CP	$	1,748,379	$	6,174,903	$	-	$	-
Production Energy	TOM	OMPENG	PENG	$	14,408,275	$	39,123,577	$	9,481,342	$	10,515,771
Production - Steam Direct	TOM	OMPSTM	STMD	$	-	$	-	$	-	$	34,811
Total Power Production Plant		OMPT		$	16,156,654	$	45,298,480	$	9,481,342	$	10,550,582
Transmission Plant	TOM	OMTRN	12CP	$	698,770	$	2,471,156	$	601,057	$	-
Distribution Substation	TOM	OMDST	SUBA	$	26,059	$	-	$	-	$	-
Distribution Meters	TOM	OMDMC	Cust05	$	383	$	-	$	-	$	-
Total		OMPLT		$	16,881,864	$	47,769,636	$	10,082,399	$	10,550,582

EAST KENTUC WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
<u>Labor Expenses</u>											
Power Production Plant											
Production Demand	TLB	LBPDMD	6CP	$	10,696,445	$	9,054,429	$	548,483	$	247,938
Production Energy	TLB	LBPENG	PENG	$	6,662,807	$	5,084,293	$	489,385	$	192,523
Production - Steam Direct	TLB	LBPSTM	STMD	$	2,693	$	-	$	-	$	-
Total Power Production Plant		LBPT		$	17,361,945	$	14,138,721	$	1,037,868	$	440,462
Transmission Plant	TLB	LBTRN	12CP	$	3,160,179	$	2,588,555	$	174,497	$	78,782
Distribution Substation	TLB	LBDST	SUBA	$	358,627	$	355,000	$	-	$	-
Distribution Meters	TLB	LBDMC	Cust05	$	16,629	$	16,576	$	-	$	-
Total		LBPLT		$	20,897,381	$	17,098,852	$	1,212,365	$	519,244

EAST KENTUCK… …ER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Labor Expenses											
Power Production Plant											
Production Demand	TLB	LBPDMD	6CP	$	186,592	$	659,003	$	-	$	-
Production Energy	TLB	LBPENG	PENG	$	175,693	$	477,070	$	115,615	$	128,228
Production - Steam Direct	TLB	LBPSTM	STMD	$	-	$	-	$	-	$	2,693
Total Power Production Plant		LBPT		$	362,285	$	1,136,073	$	115,615	$	130,922
Transmission Plant	TLB	LBTRN	12CP	$	58,990	$	208,614	$	50,741	$	-
Distribution Substation	TLB	LBDST	SUBA	$	3,627	$	-	$	-	$	-
Distribution Meters	TLB	LBDMC	Cust05	$	53	$	-	$	-	$	-
Total		LBPLT		$	424,956	$	1,344,687	$	166,356	$	130,922

EAST KENTUC. .WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Depreciation Expenses											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	6CP	$	59,631,415	$	50,477,369	$	3,057,727	$	1,382,226
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	603,117	$	-	$	-	$	-
Total Power Production Plant		DPPT		$	60,234,532	$	50,477,369	$	3,057,727	$	1,382,226
Transmission Plant	TDEPR	DPTRN	12CP	$	8,917,577	$	7,304,533	$	492,406	$	222,313
Distribution Substation	TDEPR	DPDST	SUBA	$	4,210,948	$	4,168,355	$	-	$	-
Distribution Meters	TDEPR	DPDMC	Cust05	$	195,254	$	194,628	$	-	$	-
Total		DPPLT		$	73,558,311	$	62,144,885	$	3,550,133	$	1,604,539

EAST KENTUC OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Depreciation Expenses											
Power Production Plant											
Production Demand	TDEPR	DPPDMD	6CP	$	1,040,228	$	3,673,865	$	-	$	-
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	-	$	-	$	-	$	603,117
Total Power Production Plant		DPPT		$	1,040,228	$	3,673,865	$	-	$	603,117
Transmission Plant	TDEPR	DPTRN	12CP	$	166,461	$	588,680	$	143,184	$	-
Distribution Substation	TDEPR	DPDST	SUBA	$	42,593	$	-	$	-	$	-
Distribution Meters	TDEPR	DPDMC	Cust05	$	625	$	-	$	-	$	-
Total		DPPLT		$	1,249,908	$	4,262,544	$	143,184	$	603,117

EAST KENTUC.   JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Property and Other Taxes											
Power Production Plant											
Production Demand	PTAX	PRPDMD	6CP	$	604	$	512	$	31	$	14
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	6	$	-	$	-	$	-
Total Power Production Plant		PRPT		$	610	$	512	$	31	$	14
Transmission Plant	PTAX	PRTRN	12CP	$	140	$	114	$	8	$	3
Distribution Substation	PTAX	PRDST	SUBA	$	48	$	47	$	-	$	-
Distribution Meters	PTAX	PRDMC	Cust05	$	2	$	2	$	-	$	-
Total		PRPLT		$	800	$	675	$	39	$	17

EAST KENTUC JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Property and Other Taxes											
Power Production Plant											
Production Demand	PTAX	PRPDMD	6CP	$	11	$	37	$	-	$	-
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	-	$	-	$	-	$	6
Total Power Production Plant		PRPT		$	11	$	37	$	-	$	6
Transmission Plant	PTAX	PRTRN	12CP	$	3	$	9	$	2	$	-
Distribution Substation	PTAX	PRDST	SUBA	$	0	$	-	$	-	$	-
Distribution Meters	PTAX	PRDMC	Cust05	$	0	$	-	$	-	$	-
Total		PRPLT		$	14	$	46	$	2	$	6

EAST KENTUC. ⌐WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	6CP	$	102,604,692	$	86,853,799	$	5,261,273	$	2,378,326
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	1,037,609	$	-	$	-	$	-
Total Power Production Plant		INPT		$	103,642,301	$	86,853,799	$	5,261,273	$	2,378,326
Transmission Plant	INTLTD	INTRN	12CP	$	23,697,816	$	19,411,270	$	1,308,533	$	590,780
Distribution Substation	INTLTD	INDST	SUBA	$	8,107,824	$	8,025,814	$	-	$	-
Distribution Meters	INTLTD	INDMC	Cust05	$	375,945	$	374,741	$	-	$	-
Total		INPLT		$	135,823,886	$	114,665,623	$	6,569,806	$	2,969,106

EAST KENTUC ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	6CP	$	1,789,866	$	6,321,429	$	-	$	-
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	-	$	-	$	-	$	1,037,609
Total Power Production Plant		INPT		$	1,789,866	$	6,321,429	$	-	$	1,037,609
Transmission Plant	INTLTD	INTRN	12CP	$	442,358	$	1,564,374	$	380,501	$	-
Distribution Substation	INTLTD	INDST	SUBA	$	82,010	$	-	$	-	$	-
Distribution Meters	INTLTD	INDMC	Cust05	$	1,204	$	-	$	-	$	-
Total		INPLT		$	2,315,439	$	7,885,802	$	380,501	$	1,037,609

EAST KENTUC WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 873,498,600	$ 698,429,398	$ 57,697,996	$ 23,333,746
Off System Sales Revenue			Energy	$ 9,987,006	$ 7,655,465	$ 736,872	$ 289,884
Wheeling Revenue		LSDPR	RBTRN	$ 2,389,123	$ 1,956,970	$ 131,921	$ 59,560
Other Operating Revenue		OTHREV	RBPLT	$ 399,043	$ 336,951	$ 19,286	$ 8,711
Total Operating Revenues		TOR		$ 886,273,772	$ 708,378,784	$ 58,586,075	$ 23,691,901
Operating Expenses							
Operation and Maintenance Expenses				$ 686,795,194	$ 535,125,949	$ 47,339,880	$ 19,044,884
Depreciation and Amortization Expenses				73,558,311	62,144,885	3,550,133	1,604,539
Property and Other Taxes			NPT	800	675	39	17
Total Operating Expenses		TOE		$ 760,354,305	$ 597,271,510	$ 50,890,052	$ 20,649,441
Utility Operating Margin				$ 125,919,467	$ 111,107,274	$ 7,696,023	$ 3,042,461
Non-Operating Items							
Interest Income			RBPLT	$ 4,007,189	$ 3,383,661	$ 193,670	$ 87,479
Other Non-Operating Income			RBPLT	$ (27,912)	$ (23,569)	$ (1,349)	$ (609)
Other Credits			RBPLT	$ 250,000	$ 211,099	$ 12,083	$ 5,458
Interest on Long Term Debt				$ (135,823,886)	$ (114,665,623)	$ (6,569,806)	$ (2,969,106)
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ (2,363,706)	$ (1,995,908)	$ (114,239)	$ (51,601)
Total Non-Operating Items				$ (133,958,315)	$ (113,090,339)	$ (6,479,642)	$ (2,928,379)
Net Utility Operating Margin		TOM		$ (8,038,848)	$ (1,983,065)	$ 1,216,381	$ 114,082
Net Cost Rate Base				$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166

EAST KENTUCK WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Cost of Service Summary -- Unadjusted											
Operating Revenues											
Sales to Members		REVUC	R01	$	19,703,308	$	49,563,171	$	11,330,994	$	13,439,988
Off System Sales Revenue			Energy	$	264,543	$	718,328	$	128,839	$	193,075
Wheeling Revenue		LSDPR	RBTRN	$	44,597	$	157,714	$	38,361	$	-
Other Operating Revenue		OTHREV	RBPLT	$	6,806	$	23,132	$	1,112	$	3,045
Total Operating Revenues		TOR		$	20,019,253	$	50,462,345	$	11,499,306	$	13,636,108
Operating Expenses											
Operation and Maintenance Expenses				$	16,881,864	$	47,769,636	$	10,082,399	$	10,550,582
Depreciation and Amortization Expenses					1,249,908		4,262,544		143,184		603,117
Property and Other Taxes			NPT		14		46		2		6
Total Operating Expenses		TOE		$	18,131,786	$	52,032,226	$	10,225,585	$	11,153,705
Utility Operating Margin				$	1,887,468	$	(1,569,882)	$	1,273,721	$	2,482,402
Non-Operating Items											
Interest Income			RBPLT	$	68,342	$	232,288	$	11,170	$	30,579
Other Non-Operating Income			RBPLT	$	(476)	$	(1,618)	$	(78)	$	(213)
Other Credits			RBPLT	$	4,264	$	14,492	$	697	$	1,908
Interest on Long Term Debt				$	(2,315,439)	$	(7,885,802)	$	(380,501)	$	(1,037,609)
Other Interest Expense			RBPLT	$	-	$	-	$	-	$	-
Other Deductions			RBPLT	$	(40,313)	$	(137,019)	$	(6,589)	$	(18,037)
Total Non-Operating Items				$	(2,283,622)	$	(7,777,659)	$	(375,301)	$	(1,023,373)
Net Utility Operating Margin		TOM		$	(396,154)	$	(9,347,541)	$	898,420	$	1,459,029
Net Cost Rate Base				$	38,354,915	$	130,364,820	$	6,268,952	$	17,161,306

EAST KENTUCK[illegible]WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue				$	886,273,772	$	708,378,784	$	58,586,075	$	23,691,901
Pro-Forma Adjustments:											
To Remove Base Fuel Revenue				$	350,719,383	$	272,354,902	$	26,215,336	$	10,313,066
To Remove FAC Revenue			FACA		108,692,230		77,066,195		7,417,955		2,918,210
To Remove Environmental Surcharge Revenue		ESR			104,725,170		84,331,966		6,966,754		2,817,437
To Adjust Off-System Sales Environmental Sur. Rev.			RBPLT		1,377,517		1,163,172		66,576		30,072
Total Pro-Forma Operating Revenue				$	320,759,472	$	273,462,548	$	17,919,454	$	7,613,117

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue				$	20,019,253	$	50,462,345	$	11,499,306	$	13,636,108
Pro-Forma Adjustments:											
To Remove Base Fuel Revenue				$	9,411,524	$	25,555,625	$	-	$	6,868,930
To Remove FAC Revenue			FACA		2,663,107		7,231,280		9,451,834		1,943,649
To Remove Environmental Surcharge Revenue		ESR			2,379,079		5,984,513		622,608		1,622,813
To Adjust Off-System Sales Environmental Sur. Rev.			RBPLT		23,493		79,852		3,840		10,512
Total Pro-Forma Operating Revenue				$	5,542,051	$	11,611,075	$	1,421,024	$	3,190,204

EAST KENTUCI ,WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 686,795,194	$ 535,125,949	$ 47,339,880	$ 19,044,884
Depreciation and Amortization Expenses				73,558,311	62,144,885	3,550,133	1,604,539
Property and Other Taxes			NPT	800	675	39	17
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable Through FAC			FACAL	$ (403,441,802)	$ (305,889,756)	$ (29,443,211)	$ (11,582,906)
To Remove Purchased Power Expense Recoverable Through FAC			FACEX	(51,684,614)	$ (39,310,488)	$ (3,783,804)	$ (1,488,542)
To Remove O&M Expenses Recoverable Through Env. Surcharge			6CP	(31,800,030)	$ (26,918,393)	$ (1,630,614)	$ (737,109)
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	(6,615,208)	$ (5,070,838)	$ (488,090)	$ (192,014)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	(2,098,198)	$ (1,776,103)	$ (107,590)	$ (48,635)
To Remove Depreciation Expense Recoverable Through ESR			6CP	(19,564,992)	$ (16,561,561)	$ (1,003,236)	$ (453,507)
To Remove Promotional Advertising Expense			LBPLT	(658,906)	$ (539,136)	$ (38,227)	$ (16,372)
To Remove Certain Director's Expenses			LBPLT	(93,300)	$ (76,341)	$ (5,413)	$ (2,318)
To Remove Donations			LBPLT	(95,485)	$ (78,129)	$ (5,540)	$ (2,373)
To Remove Affiliate Expenses			LBPLT	(28,712)	$ (23,493)	$ (1,666)	$ (713)
To Remove Lobbying Expenses			LBPLT	(85,422)	$ (69,895)	$ (4,956)	$ (2,123)
To Remove Touchstone Energy Dues			LBPLT	(414,000)	$ (338,747)	$ (24,018)	$ (10,287)
To Remove Other Misc. Expenses			LBPLT	(155,940)	$ (127,595)	$ (9,047)	$ (3,875)
To Normalize Rate Case Expenses			RBPLT	100,000	$ 84,440	$ 4,833	$ 2,183
To Amortize 2004 Forced Outage Balance			Energy	3,419,058	$ 2,620,853	$ 252,268	$ 99,242
To Normalize Generation Overhaul Expenses			OMPDMD	$ 2,300,000	$ 1,946,926	$ 117,937	$ 53,313
To Reflect Avoided Costs of Interruptible Service				$ (8,824,500)			
Reallocation of Avoided Cost Savings			6CP	$ 8,824,500	$ 7,469,847	$ 452,495	$ 204,548
Total Expense Adjustments				(510,917,551)	(384,658,408)	(35,717,877)	(14,181,487)
Total Operating Expenses		TOE		$ 249,436,754	$ 212,613,102	$ 15,172,175	$ 6,467,953
Utility Operating Margins -- Pro-Forma				$ 71,322,718	$ 60,849,446	$ 2,747,279	$ 1,145,163
Non-Operating Items							
Sum of Non-Operating Items				$ (133,958,315)	$ (113,090,339)	$ (6,479,642)	$ (2,928,379)
Adjustment To Remove Interest Exp. Recoverable Through ESR			6CP	$ 37,031,989	$ 31,347,191	$ 1,898,894	$ 858,383
Total Non-Operating Items				$ (96,926,326)	$ (81,743,147)	$ (4,580,748)	$ (2,069,996)
Net Utility Operating Margin				$ (25,603,608)	$ (20,893,701)	$ (1,833,469)	$ (924,833)
Net Cost Rate Base				$ 2,248,915,815	$ 1,898,979,388	$ 108,691,268	$ 49,095,166
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				**3.17%**	**3.20%**	**2.53%**	**2.33%**

EAST KENTUC. WER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 16,881,864	$ 47,769,636	$ 10,082,399	$ 10,550,582
Depreciation and Amortization Expenses				1,249,908	4,262,544	143,184	603,117
Property and Other Taxes			NPT	14	46	2	6
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable Through FAC			FACAL	$ (10,570,357)	$ (28,702,269)	$ (9,538,606)	$ (7,714,696)
To Remove Purchased Power Expense Recoverable Through FAC			FACEX	$ (1,358,417)	$ (3,688,584)	$ (1,063,348)	$ (991,431)
To Remove O&M Expenses Recoverable Through Env. Surcharge			6CP	$ (554,729)	$ (1,959,186)	$ -	$ -
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	$ (175,228)	$ (475,807)	$ (85,341)	$ (127,889)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	$ (36,602)	$ (129,269)	$ -	$ -
To Remove Depreciation Expense Recoverable Through ESR			6CP	$ (341,297)	$ (1,205,390)	$ -	$ -
To Remove Promotional Advertising Expense			LBPLT	$ (13,399)	$ (42,399)	$ (5,245)	$ (4,128)
To Remove Certain Director's Expenses			LBPLT	$ (1,897)	$ (6,004)	$ (743)	$ (585)
To Remove Donations			LBPLT	$ (1,942)	$ (6,144)	$ (760)	$ (598)
To Remove Affiliate Expenses			LBPLT	$ (584)	$ (1,848)	$ (229)	$ (180)
To Remove Lobbying Expenses			LBPLT	$ (1,737)	$ (5,497)	$ (680)	$ (535)
To Remove Touchstone Energy Dues			LBPLT	$ (8,419)	$ (26,640)	$ (3,296)	$ (2,594)
To Remove Other Misc. Expenses			LBPLT	$ (3,171)	$ (10,034)	$ (1,241)	$ (977)
To Normalize Rate Case Expenses			RBPLT	$ 1,705	$ 5,797	$ 279	$ 763
To Amortize 2004 Forced Outage Balance			Energy	$ 90,566	$ 245,920	$ 44,108	$ 66,099
To Normalize Generation Overhaul Expenses			OMPDMD	$ 40,122	$ 141,702	$ -	$ -
To Reflect Avoided Costs of Interruptible Service					$ (8,824,500)		
Reallocation of Avoided Cost Savings			6CP	$ 153,937	$ 543,673	$ -	$ -
Total Expense Adjustments				(12,781,449)	(44,146,479)	(10,655,102)	(8,776,750)
Total Operating Expenses	TOE			$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Forma				$ 191,714	$ 3,725,327	$ 1,850,540	$ 813,249
Non-Operating Items							
Sum of Non-Operating Items				$ (2,283,622)	$ (7,777,659)	$ (375,301)	$ (1,023,373)
Adjustment To Remove Interest Exp. Recoverable Through ESR			6CP	$ 645,997	$ 2,281,524	$ -	$ -
Total Non-Operating Items				$ (1,637,625)	$ (5,496,135)	$ (375,301)	$ (1,023,373)
Net Utility Operating Margin				$ (1,445,911)	$ (1,770,808)	$ 1,475,240	$ (210,124)
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				**0.50%**	**2.86%**	**29.52%**	**4.74%**

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)											
Operating Revenues											
Total Operating Revenue				$	320,759,472	$	273,462,548	$	17,919,454	$	7,613,117
Pro-Forma Adjustments: To Reflect Proposed Increase				$	67,858,922	$	55,330,720	$	4,457,951	$	1,811,240
Total Pro-Forma Operating Revenue				$	388,618,394	$	328,793,268	$	22,377,405	$	9,424,357
Operating Expenses											
Total Operating Expenses				$	249,436,754	$	212,613,102	$	15,172,175	$	6,467,953
Utility Operating Margins -- Pro-Formed for Phase I Increase				$	139,181,640	$	116,180,166	$	7,205,230	$	2,956,403
Net Cost Rate Base				$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166
Rate of Return					6.19%		6.12%		6.63%		6.02%
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)											
Operating Revenues											
Total Operating Revenue				$	320,759,472	$	273,462,548	$	17,919,454	$	7,613,117
Pro-Forma Adjustments: To Reflect Proposed Increase				$	67,699,051	$	55,345,926	$	4,635,408	$	2,168,710
Total Pro-Forma Operating Revenue				$	388,458,523	$	328,808,474	$	22,554,862	$	9,781,827
Operating Expenses											
Total Operating Expenses				$	249,436,754	$	212,613,102	$	15,172,175	$	6,467,953
Utility Operating Margins -- Pro-Formed for Phase II Increase				$	139,021,769	$	116,195,372	$	7,382,687	$	3,313,873
Net Cost Rate Base				$	2,248,915,815	$	1,898,979,388	$	108,691,268	$	49,095,166
Rate of Return					6.18%		6.12%		6.79%		6.75%

EAST KENTUC ƆWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)							
Operating Revenues							
Total Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204
Pro-Forma Adjustments:							
To Reflect Proposed Increase				$ 1,506,943	$ 3,736,682	$ -	$ 1,015,386
Total Pro-Forma Operating Revenue				$ 7,048,994	$ 15,347,757	$ 1,421,024	$ 4,205,590
Operating Expenses							
Total Operating Expenses				$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Formed for Phase I Increase				$ 1,698,657	$ 7,462,009	$ 1,850,540	$ 1,828,635
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Rate of Return				**4.43%**	**5.72%**	**29.52%**	**10.66%**
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)							
Operating Revenues							
Total Operating Revenue				$ 5,542,051	$ 11,611,075	$ 1,421,024	$ 3,190,204
Pro-Forma Adjustments:							
To Reflect Proposed Increase				$ 1,858,583	$ 3,017,371	$ -	$ 673,053
Total Pro-Forma Operating Revenue				$ 7,400,634	$ 14,628,446	$ 1,421,024	$ 3,863,257
Operating Expenses							
Total Operating Expenses				$ 5,350,337	$ 7,885,748	$ (429,516)	$ 2,376,955
Utility Operating Margins -- Pro-Formed for Phase II Increase				$ 2,050,297	$ 6,742,698	$ 1,850,540	$ 1,486,302
Net Cost Rate Base				$ 38,354,915	$ 130,364,820	$ 6,268,952	$ 17,161,306
Rate of Return				**5.35%**	**5.17%**	**29.52%**	**8.66%**

EAST KENTUC.   JWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	1.000000	0.766543	0.073783	0.029026
Customer Allocation Factors							
Rev		R01		873,498,603	698,429,400	57,697,996	23,333,746
Energy		Energy		13,468,652,000	10,324,295,000	993,758,000	390,942,617
FAC Revenue Allocator		FACA		109,031,560	$ 77,306,791	$ 7,441,113	$ 2,927,320
Base Fuel Revenue Allocator		BSFL		13,294,897,000	10,324,295,000	993,758,000	390,942,617
Fuel Expense Applicable to FAC Allocator		FACEX		459,411,613	349,421,098	33,633,291	13,231,276
							407,101,213
Customer Allocators							
Customers (Metering Points)		Cust05		3,746	3,734	-	-
Demand Allocators							
Steam - Direct Assignment		STMD		1	-	-	-
Substation Allocator		SUBA		86,668,910	85,792,264	-	-
Production 6 CP Demands		6CP		15,582,000	13,190,000	799,000	361,183
					0.8465	0.0513	0.0232
Production 12 CP Demands		12CP		29,085,000	23,824,000	1,606,000	725,081
					0.8191	0.0552	0.0249

EAST KENTUC   WER COOPERATIVE, INC
Cost of Service Study
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12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	0.026489	0.071926	0.012901	0.019333
Customer Allocation Factors							
Rev		R01		19,703,308	49,563,171	11,330,994	13,439,988
Energy		Energy		356,767,383	968,750,000	173,755,000	260,384,000
FAC Revenue Allocator		FACA		$ 2,671,421	$ 7,253,856	$ 9,481,342	$ 1,949,717
Base Fuel Revenue Allocator		BSFL		356,767,383	968,750,000	-	260,384,000
Fuel Expense Applicable to FAC Allocator		FACEX		12,074,631	32,786,905	9,451,834	8,812,579
				371,513,435	1,008,790,761	18,933,176	-
Customer Allocators							
Customers (Metering Points)		Cust05		12	-	-	-
Demand Allocators							
Steam - Direct Assignment		STMD		-	-	-	1
Substation Allocator		SUBA		876,646	-	-	-
Production 6 CP Demands		6CP		271,817	960,000	-	-
				0.0174	0.0616	-	-
Production 12 CP Demands		12CP		542,919	1,920,000	467,000	-
				0.0187	0.0660	0.0161	-

EAST KENTUC. OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Production Energy Allocation					-						
Production Energy Residual Allocator		PENGA			13,294,897,000		10,324,295,000		993,758,000		390,942,617
Production Energy Costs				$	546,404,107						
Member Specific Assignment				$	9,481,342		-		-		-
Production Energy Residual			PENGA	$	536,922,765	$	416,953,137	$	40,133,541	$	15,788,463
Production Energy Total		PENGT		$	546,404,107	$	416,953,137	$	40,133,541	$	15,788,463
Production Energy Total Allocator		PENG	PENGT		1.000000		0.76309		0.07345		0.02890
FAC Expense Residual Allocator		FACALL			449,959,779		349,421,096		33,633,291		13,231,276
FAC Expense Cost				$	(403,441,802)						
Member Specific Assignment				$	(9,538,606)		-		-		-
FAC Expense Residual			FACALL	$	(393,903,196)	$	(305,889,756)	$	(29,443,211)	$	(11,582,906)
FAC Expense Total		FACT		$	(403,441,802)	$	(305,889,756)	$	(29,443,211)	$	(11,582,906)
FAC Expense Allocator		FACAL	FACT		1.000000		0.75820		0.07298		0.02871

EAST KENTUC. OWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Production Energy Allocation							
Production Energy Residual Allocator		PENGA		356,767,383	968,750,000	-	260,384,000
Production Energy Costs							
Member Specific Assignment				$ -	-	$ 9,481,342	-
Production Energy Residual			PENGA	$ 14,408,275	$ 39,123,577	$ -	$ 10,515,771
Production Energy Total		PENGT		$ 14,408,275	$ 39,123,577	$ 9,481,342	$ 10,515,771
Production Energy Total Allocator		PENG	PENGT	0.02637	0.07160	0.01735	0.01925
FAC Expense Residual Allocator		FACALL		12,074,631	32,786,905	-	8,812,579
FAC Expense Cost							
Member Specific Assignment				$ -	-	(9,538,606)	-
FAC Expense Residual			FACALL	$ (10,570,357)	$ (28,702,269)	$ -	$ (7,714,696)
FAC Expense Total		FACT		$ (10,570,357)	$ (28,702,269)	$ (9,538,606)	$ (7,714,696)
FAC Expense Allocator		FACAL	FACT	0.02620	0.07114	0.02364	0.01912

Seelye Exhibit 8

East Kentucky Power Cooperative, Inc.
Avoided Cost Estimate of Interruptible Power

Estimated Installed Cost of a CT	$ 550	per kW
Estimated Cost of Capital	7.00%	
Depreciation	4.00%	
ASL for CT	25	Years
Annual Capacity Cost	$47.20	per kW
Annual Fixed O&M Expenses	16.5	per kW
Total Annual Cost	$63.70	per kW
Monthly Cost	$5.30	per kW

Seelye Exhibit 9

Forecasted Period Phase 1
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,760,120	55,330,720	7.92%
Rate B	57,697,996	62,155,947	4,457,951	7.73%
Rate C	23,333,746	25,144,986	1,811,240	7.76%
Rate G	19,703,308	21,210,250	1,506,943	7.65%
Large Special Contract	49,563,171	53,299,853	3,736,682	7.54%
Steam Service	13,439,988	14,455,374	1,015,386	7.55%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,357,525	67,858,922	7.77%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current				Proposed	
	Billing Units		Rate	Current $	Billing Units	Rate	Proposed $
RATE E - 16 Customers							
Metering Point Charge							
All Customers	3,734	$	125.00	466,750	3,734	138.00	515,292
Substation charges							
Substation 1,000 - 2,999 kVa	36	$	944	33,984	36	1,041.00	37,476
Substation 3,000 - 7,499 kVa	504		2,373	1,195,992	504	2,617.00	1,318,968
Substation 7,500 - 14,999 kVa	2,544		2,855	7,263,120	2,544	3,149.00	8,011,056
Substation > 15,000 kVa	578		4,605	2,661,690	578	5,079.00	2,935,662
	3,662			11,154,786			12,303,162
Demand Charge							
Option 1 (Owen)	2,343,000	$	6.92	16,213,560	2,343,000	7.63	17,877,090
Option 2	21,481,000	$	5.22	112,130,820	21,481,000	5.76	123,730,560
	23,824,000			128,344,380			141,607,650
Energy Charge	kWh						
On-Peak (Option 1)	564,787,000	$	0.035406	19,996,849	564,787,000	0.039053	22,056,627
Off-Peak (Option 1)	526,652,000	$	0.034904	18,382,261	526,652,000	0.038499	20,275,575
On-Peak (Option 2)	4,782,184,968	$	0.042470	203,099,396	4,782,184,968	0.046844	224,016,673
Off-Peak (Option 2)	4,450,671,032	$	0.034904	155,346,222	4,450,671,032	0.038499	171,346,384
	10,324,295,000			396,824,727			437,695,259
Sub-Total -- Base Rates				536,790,643			592,121,363
FAC	10,324,295,000		0.00749	77,306,791			77,306,791
Environmental Surcharge	$ 614,097,434		13.73%	84,331,966			84,331,966
Total Billings				698,429,400			753,760,120

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current				Proposed	
		Billing Units	Rate	Current $	Billing Units	Rate	Proposed $
RATE B - 9 Customers							
Demand Charge							
Minimum Demand		1,583,516	$ 6.22	9,849,470	1,583,516	6.86	10,862,920
Excess Demand		22,484	$ 8.65	194,487	22,484	9.54	214,497
		1,606,000					
Energy Charge	kWh						
All kWh		993,758,000	$ 0.033455	33,246,174	993,758,000	0.036901	36,670,664
Sub-Total -- Base Rates				43,290,130			47,748,081
FAC		993,758,000	0.00749	7,441,113			7,441,113
Environmental Surcharge	$	50,731,243	13.73%	6,966,754			6,966,754
Total Billings				$ 57,697,996			$ 62,155,947
RATE C - 6 Customers							
Demand Charge							
All Kw		725,081	$ 6.22	4,510,004	725,081	6.86	4,974,056
Energy Charge	kWh						
All kWh		390,942,617	$ 0.033455	13,078,985	390,942,617	0.036901	14,426,174
Sub-Total -- Base Rates				17,588,989			19,400,229
FAC		390,942,617	0.00749	2,927,320			2,927,320
Environmental Surcharge	$	20,516,309	13.73%	2,817,437			2,817,437
Total Billings				$ 23,333,746			$ 25,144,986

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current Billing Units		Current Rate	Current $	Proposed Billing Units	Proposed Rate	Proposed $
RATE G - 2 Customers								
Meter Pt Charge		12		125	1,500	12	138.00	1,656
Substation charges								
Substation 1,000 - 2,999 kVa		-	$	944				
Substation 3,000 - 7,499 kVa		-		2,373				
Substation 7,500 - 14,999 kVa		-		2,855				
Substation > 15,000 kVa		12		4,605	55,260	12	5,079.00	60,948
Demand Charge								
All Kw		542,919	$	6.06	3,290,089	542,919	6.68	3,626,699
Energy Charge	kWh							
All kWh		356,767,383	$	0.031690	11,305,958	356,767,383	0.034954	12,470,447
Sub-Total -- Base Rates					14,652,808			16,159,750
FAC		356,767,383		0.00749	2,671,421			2,671,421
Environmental Surcharge	$	17,324,229		13.73%	2,379,079			2,379,079
Total Billings					19,703,308			21,210,250

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current				Proposed		
	Billing Units		Rate	Current $	Billing Units	Rate	Proposed $
Large Special Contract							
Demand Charge							
Firm Demand	180,000	$	6.06	1,090,800	180,000	6.68	1,202,400
10-Min Inturruptible Demand	1,440,000	$	2.46	3,542,400	1,440,000	2.71	3,902,400
90-Min Inturruptible Demand	300,000	$	3.36	1,008,000	300,000	3.71	1,113,000
	1,920,000						
Energy Charge	kWh						
On-Peak	288,492,371	$	0.033780	9,745,272	288,492,371	0.037259	10,748,937
Off-Peak	680,257,629	$	0.030780	20,938,330	680,257,629	0.033950	23,094,747
	968,750,000						
Sub-Total -- Base Rates				36,324,802			40,061,484
FAC	968,750,000		0.00749	7,253,856			7,253,856
Environmental Surcharge	$ 43,578,659		13.73%	5,984,513			5,984,513
				49,563,171			53,299,853
Total Billings							3,736,682

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description		Current				Proposed			
	Billing Units		Rate	Current $	Billing Units		Rate	Proposed $
Special Contract - Pumping Stations - 2 Customers								
Demand Charge								
All Kw	467,000	$	1.75	817,250	467,000	$	1.75	817,250
Energy Charge	kWh							
Off-Pk Jun-Dec	46,363,340	$	0.004440	205,853	46,363,340	$	0.004440	205,853
Off-Peak Jan-May	45,726,810	$	0.004460	203,942	45,726,810	$	0.004460	203,942
	92,090,150			409,795				409,795
Monthly Revenue								
Off Peak Fuel/Purchased Power Cost Recovery				3,306,725				3,306,725
Sub-Total -- Base Rates				4,533,770				4,533,770
Environmental Surcharge	4,533,770		13.73%	622,608				622,608
On Peak Fuel/Purchased Power Cost Recovery				6,174,617				6,174,617
Total Billings				11,330,994				11,330,994

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase 1
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current				Proposed		
	Billing Units		Rate	Current $	Billing Units	Rate	Proposed $
Steam Service							
Demand Charge							
Per MMBTU	3,790	$	500.49	1,897,068	3,790	552.040	2,092,464
Energy Charge	MMBTU						
Per MMBTU	2,228,233	$	3.577	7,970,390	2,228,233	3.945	8,790,380
Sub-Total -- Base Rates				9,867,458			10,882,844
FAC	260,384,000		0.00749	1,949,717			1,949,717
Environmental Surcharge	$ 11,817,175		13.73%	1,622,813			1,622,813
Total Billings				13,439,988			14,455,374
Total Base Rate Revenue EKPC Members				669,223,217			737,082,138
Total FAC				99,550,218			99,550,218
Total ES				104,725,170			104,725,170
Total EKPC Member Revenue				**873,498,604**			**941,357,525**

Seelye Exhibit 10

Forecasted Period Phase II
Summary
Rate Impact Test Year Ended May 31, 2010

	Current	Proposed	$ Incr	% Incr
Rate E	698,429,400	753,775,327	55,345,926	7.92%
Rate B	57,697,996	62,333,404	4,635,408	8.03%
Rate C	23,333,746	25,502,456	2,168,710	9.29%
Rate G	19,703,308	21,561,891	1,858,583	9.43%
Large Special Contract	49,563,171	52,580,542	3,017,371	6.09%
Steam Service	13,439,988	14,113,041	673,053	5.01%
Pumping Stations	11,330,994	11,330,994	-	0.00%
Total	873,498,604	941,197,656	67,699,051	7.75%

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

	Current				Proposed		
Description	Billing Units	Rate	Current $		Billing Units	Rate	Proposed $
RATE E							
Metering Point Charge				Metering Point Charge			
All Customers	3,734	$ 125.00	466,750	All Customers	3,734	230.00	858,820
Substation charges				Substation charges			
				Substation 1,000-4,999 kVa	48	1,168.00	56,064
				Substation 5,000-9,999 kVa	396	3,087.00	1,222,452
Substation 1,000 - 2,999 kVa	36	$ 944	33,984	Substation 10,000-14,999 kVa	2,513	4,265.00	10,717,945
Substation 3,000 - 7,499 kVa	504	2,373	1,195,992	Substation 15,000-29,999 kVa	645	9,220.00	5,946,900
Substation 7,500 - 14,999 kVa	2,544	2,855	7,263,120	Substation 30,000-50,999 kVa	48	14,488.00	695,424
Substation > 15,000 kVa	578	4,605	2,661,690	Substation > 51,000 kVa	12	16,155.00	193,860
	3,662		11,154,786		3,662		18,832,645
Demand Charge				Demand Charge Rate E			
Option 1 (Owen)	2,343,000	$ 6.92	16,213,560	All kW	23,824,000	10.10	240,622,400
Option 2	21,481,000	$ 5.22	112,130,820				-
	23,824,000		128,344,380				240,622,400
Energy Charge	kWh			Energy Charge			
On-Peak (Option 1)	564,787,000	$ 0.035406	19,996,849	On-Peak kWh	5,346,971,968	0.032382	173,145,646
Off-Peak (Option 1)	526,652,000	$ 0.034904	18,382,261	Off-Peak kWh	4,977,323,032	0.031880	158,677,058
On-Peak (Option 2)	4,782,184,968	$ 0.042470	203,099,396				-
Off-Peak (Option 2)	4,450,671,032	$ 0.034904	155,346,222				-
	10,324,295,000		396,824,727				331,822,705
Sub-Total -- Base Rates			536,790,643	Sub-Total -- Base Rates			592,136,570
FAC	10,324,295,000	0.00749	77,306,791	FAC			77,306,791
Environmental Surcharge	$ 614,097,434	13.73%	84,331,966	Environmental Surcharge			84,331,966
Total Billings			698,429,400	Total Billings			753,775,327

Annual Increase Rate E

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
RATE B								
Demand Charge					**Demand Charge**			
Minimum Demand	1,583,516	$	6.22	9,849,470	Minimum Demand	1,583,516	9.92	15,708,479
Excess Demand	22,484	$	8.65	194,487	Excess Demand	22,484	12.35	277,677
	1,606,000							
Energy Charge	kWh				**Energy Charge**			
All kWh	993,758,000	$	0.033455	33,246,174	All kWh	993,758,000	0.032140	31,939,382
Sub-Total -- Base Rates				43,290,130	Sub-Total -- Base Rates			47,925,538
FAC	993,758,000		0.00749	7,441,113	FAC			7,441,113
Environmental Surcharge	$ 50,731,243		13.73%	6,966,754	Environmental Surcharge			6,966,754
Total Billings				$ 57,697,996	**Total Billings**			$ 62,333,404

RATE C	Billing Units		Rate	Existing $		Billing Units	Rate	Proposed $
Demand Charge					**Demand Charge**			
All kW	725,081	$	6.22	4,510,004	All kW	725,081	9.92	7,192,804
Energy Charge	kWh				**Energy Charge**			
All kWh	390,942,617	$	0.033455	13,078,985	All kWh	390,942,617	0.032140	12,564,896
Sub-Total -- Base Rates				17,588,989	Sub-Total -- Base Rates			19,757,699
FAC	390,942,617		0.00749	2,927,320	FAC			2,927,320
Environmental Surcharge	$ 20,516,309		13.73%	2,817,437	Environmental Surcharge			2,817,437
Total Billings				$ 23,333,746	**Total Billings**			$ 25,502,456

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units		Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
RATE G								
Meter Pt Charge	12		125	1,500	Meter Pt Charge	12	230.00	2,760
Substation Charges					Substation Charges			
Substation 1,000 - 2,999 kVa	-	$	944					
Substation 3,000 - 7,499 kVa	-		2,373					
Substation 7,500 - 14,999 kVa	-		2,855					
Substation > 15,000 kVa	12		4,605	55,260	Substation > 51,000 kVa	12	16,155.00	193,860
Demand Charge					Demand Charge			
All Kw	542,919	$	6.06	3,290,089	All Kw	542,919	8.93	4,848,267
Energy Charge	kWh				Energy Charge			
All kWh	356,767,383	$	0.031690	11,305,958	All kWh	356,767,383	0.032140	11,466,504
Sub-Total -- Base Rates				14,652,808	Sub-Total -- Base Rates			16,511,390
FAC	356,767,383		0.00749	2,671,421	FAC			2,671,421
Environmental Surcharge	$ 17,324,229		13.73%	2,379,079	Environmental Surcharge			2,379,079
Total Billings				19,703,308	**Total Billings**			21,561,891

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current					Proposed		
	Billing Units		Rate	Current $		Billing Units	Rate	Proposed $
Large Special Contract								
Demand Charge					**Demand Charge**			
Firm Demand	180,000	$	6.06	1,090,800	Firm Demand	180,000	8.93	1,607,400
10-Min Inturruptible Demand	1,440,000	$	2.46	3,542,400	10-Min Inturruptible Demand	1,440,000	3.63	5,227,200
90-Min Inturruptible Demand	300,000	$	3.36	1,008,000	90-Min Inturruptible Demand	300,000	4.93	1,479,000
	1,920,000							
Energy Charge	kWh				**Energy Charge**			
On-Peak	288,492,371	$	0.033780	9,745,272	On-Peak	288,492,371	0.032382	9,341,960
Off-Peak	680,257,629	$	0.030780	20,938,330	Off-Peak	680,257,629	0.031880	21,686,613
	968,750,000							
Sub-Total -- Base Rates				36,324,802	Sub-Total -- Base Rates			39,342,173
FAC	968,750,000		0.00749	7,253,856	FAC			7,253,856
Environmental Surcharge	$ 43,578,659		13.73%	5,984,513	Environmental Surcharge			5,984,513
Total Billings				49,563,171	**Total Billings**			52,580,542

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current				Proposed		
	Billing Units	Rate	Current $		Billing Units	Rate	Proposed $
Special Contract - Pumping Stations							
Demand Charge				**Demand Charge**			
All Kw	467,000	$ 1.75	817,250	All Kw	467,000	$ 1.75	817,250
Energy Charge	kWh			**Energy Charge**			
Off-Pk Jun-Dec	46,363,340	$ 0.004440	205,853	Off-Pk Jun-Dec	46,363,340	$ 0.004440	205,853
Off-Peak Jan-May	45,726,810	$ 0.004460	203,942	Off-Peak Jan-May	45,726,810	$ 0.004460	203,942
			409,795				409,795
Monthly Revenue							
Off Peak Fuel/Purchased Power Cost Recovery			3,306,725	Off Peak Fuel/Purchased Power Cost Recovery			3,306,725
Sub-Total -- Base Rates			4,533,770	Sub-Total -- Base Rates			4,533,770
Environmental Surcharge	4,533,770	13.73%	622,608	Environmental Surcharge			622,608
On Peak Fuel/Purchased Power Cost Recovery			6,174,617	On Peak Fuel/Purchased Power Cost Recovery			6,174,617
Total Billings			11,330,994	**Total Billings**			11,330,994

East Kentucky Power Cooperative, Inc.
Forecasted Period Phase II
Billing Analysis - 12-Mo Ended May 31, 2010

Description	Current Billing Units	Current Rate	Current $		Proposed Billing Units	Proposed Rate	Proposed $
Steam Service							
Demand Charge				**Demand Charge**			
Per MMBTU	3,790	$ 500.49	1,897,068	Per MMBTU	3,790	572.830	2,171,267
Energy Charge				**Energy Charge**			
Per MMBTU	2,228,233	$ 3.577	7,970,390	Per MMBTU	2,228,233	3.756	8,369,244
Sub-Total -- Base Rates			9,867,458	Sub-Total -- Base Rates			10,540,511
FAC	260,384,000	0.00749	1,949,717	FAC			1,949,717
Environmental Surcharge	$ 11,817,175	13.73%	1,622,813	Environmental Surcharge			1,622,813
Total Billings			13,439,988	**Total Billings**			14,113,041
Total Base Rate Revenue EKPC Members			669,223,217				736,922,268
Total FAC			99,550,218				99,550,218
Total ES			104,725,170				104,725,170
Total Member Revenue			873,498,604				941,197,656

AG Exhibit 4

Standard Rate **OSL**

OUTDOOR SPORTS LIGHTING SERVICE

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rate schedule is available as an optional pilot program for secondary and primary service used by a customer for lighting specifically designed for outdoor fields which are normally used for organized competitive sports. Service under this rate schedule is limited to a maximum of twenty customers. Company will accept customers on a first-come-first-served basis.

RATE

	Secondary	Primary
Basic Service Charge per month:	$90.00	$240.00
Plus an Energy Charge per kWh of:	$ 0.03288	$ 0.03189
Plus a Maximum Load Charge per kW of:		
Peak Demand Period	$ 16.75	$ 16.88
Base Demand Period	$ 3.03	$ 3.03

Where:
the monthly billing demand for the Peak Demand Period is the greater of:
a) the maximum measured load in the billing period, or
b) a minimum of 50% of the highest billing demand in the preceding eleven (11) monthly billing periods.

the monthly billing demand for the Base Demand Period is the greater of:
a) the maximum measured load in the billing period, or
b) the highest measured load in the preceding eleven (11) monthly billing periods, or
c) if applicable, the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

ADJUSTMENT CLAUSES
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Fuel Adjustment Clause	Sheet No. 85	
Off-System Sales Adjustment Clause	Sheet No. 88	
Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	
Environmental Cost Recovery Surcharge	Sheet No. 87	
Tax Cuts and Jobs Act Surcredit	Sheet No. 89	N
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School Tax	Sheet No. 91	

KENTUCKY
PUBLIC SERVICE COMMISSION
Gwen R. Pinson
Executive Director
Gwen R. Pinson
EFFECTIVE
4/1/2018
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DETERMINATION OF MAXIMUM LOAD

The load will be measured and will be the average kW demand delivered to the customer during the 15-minute period of maximum use during the appropriate rating period each month.

RATING PERIODS

The rating periods applicable to the Maximum Load charges are established in Eastern Standard Time year round by season for weekdays and weekends, throughout Company's service area, and shall be as follows:

Summer peak months of May through September

	Base	Peak
Weekdays	All Hours	1 P.M. – 7 P.M.
Weekends	All Hours	

All other months of October continuously through April

	Base	Peak
Weekdays	All Hours	6 A.M. – 12 Noon
Weekends	All Hours	

DUE DATE OF BILL

Customer's payment will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from the date of the bill.

LATE PAYMENT CHARGE

If full payment is not received by the due date of the bill, a 1% late payment charge will be assessed on the current month's charges.

TERM OF CONTRACT

Service will be furnished under this schedule only under contract for a fixed term of not less than one (1) year, and for yearly periods thereafter until terminated by either party giving written notice to the other party 90 days prior to termination. Company, however, may require a longer fixed term of contract and termination notice because of conditions associated with the customer's requirements for service.

TERMS AND CONDITIONS

Service will be furnished under Company's Terms and Conditions applicable hereto.

KENTUCKY
PUBLIC SERVICE COMMISSION

John Lyons
ACTING EXECUTIVE DIRECTOR

John S. Lyons

EFFECTIVE

7/1/2017

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

AG Exhibit 5

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

<u>ORDER</u>

Kentucky Utilities Company ("KU") is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to consumers in portions of 77 counties in central, northern, southeastern, and western Kentucky.[1] Its most recent general rate increase was granted in Case No. 2014-00371.[2]

<u>BACKGROUND</u>

On October 21, 2016, KU filed a notice of its intent to file an application for approval of an increase in its electric rates based on a forecasted test year ending June 30, 2018. On November 23, 2016, KU filed its application, which included new rates to be effective January 1, 2017, based on a request to increase its electric revenues by $103.1 million, or 6.4 percent per year for the forecasted test period ending June 30, 2018, as compared to the operating revenues for the forecasted test period under existing electric rates.[3] The proposed increase would raise the monthly bill

[1] *See* KU's Application, ¶ 2 for a list of the counties served.

[2] Case No. 2014-00371, *Application of Kentucky Utilities for an Adjustment of Its Electric Rates* (Ky. PSC June 30, 2015).

[3] Application, ¶ 6.

of an average residential customer by $7.16, or 5.9 percent.[4] The average KU residential customer consumes approximately 1,179 kilowatt-hours ("kWh") of electricity monthly.[5] KU's application included requests for Certificates of Public Convenience and Necessity ("CPCNs") to implement an Advanced Meter System ("AMS") and a Distribution Automation system ("DA"). KU stated that the AMS project would involve replacing approximately 530,000 existing electric meters in its service territory with AMS meters, which have two-way communications and remote service switching capabilities.[6] The estimated capital cost of the AMS project is $138.8 million.[7] The estimated incremental operating and maintenance cost during the deployment phase is approximately $13.7 million.[8] The deployment period was expected to begin in late 2017 and to be completed by the end of 2019.[9] KU also requested authority to establish a regulatory asset for the remaining net book value of the electric meters retired as a result of the proposed AMS project.[10] KU estimated that the amount of this regulatory asset would be approximately $26.9 million.[11] In connection with the proposed AMS project, KU also sought deviations from certain regulations dealing with meter inspections and testing.

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[4] *Id.*, ¶ 7.

[5] *Id.*

[6] *Id.*, ¶ 14.

[7] *Id.*

[8] *Id.*

[9] *Id.*

[10] *Id.*, ¶ 33.

[11] *Id.*

According to KU, the proposed DA project involves the extension of intelligent control over electric power grid functions to the distribution system level.[12] The project will enable KU's distribution system to provide real-time information and allow for remote monitoring, remote control, and automation of distribution line equipment.[13] For both KU and Louisville Gas & Electric Company ("LG&E"), KU's sister company,[14] the total capital cost of the proposed DA project is approximately $112 million.[15] The project will be completed in approximately seven years.[16] Of the total capital expenditure, KU estimated $23 million to be incurred before the end of the forecasted test year on June 30, 2018.[17] KU and LG&E (jointly "Companies") estimated the operations and maintenance ("O&M") expense related to the proposed DA project to be $6 million over the seven-year implementation period, $1.16 million of which will be incurred before the end of the forecasted test year.[18] The DA project will affect approximately 20 percent of the Companies' circuits, 40 percent of the Companies' distribution line miles, and 50 percent of the Companies' customers.[19]

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[12] *Id.*, ¶ 23.

[13] *Id.*

[14] LG&E has also filed a base rate application seeking, among other things, an increase in its electric and gas rates. That application is docketed as Case No. 2016-00371, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity* (Application filed Nov. 23, 2016).

[15] Application, ¶ 30.

[16] *Id.*

[17] *Id.*

[18] *Id.*, ¶ 31.

[19] *Id.*, ¶ 23.

KU estimated that it will receive approximately $861,843 of jurisdictional reservation and termination fees in connection with agreements related to the refined coal production facilities at the Companies' Ghent, Mill Creek, and Trimble County Generating Stations.[20] Pursuant to Case No. 2015-00264,[21] KU has been recording these proceeds as a regulatory liability and it now proposes to amortize this regulatory liability over three years.[22]

Lastly, KU also submitted a depreciation study in support of its application and requests that its proposed depreciation rates be approved.

Pursuant to the Commission's December 13, 2016 Order, KU's new rates, which were proposed to become effective on January 1, 2017, were suspended for six months, up to and including June 30, 2017. The December 13, 2016 Order also established a procedural schedule, which provided for a deadline for filing intervention requests; two rounds of discovery upon KU's application; a deadline for the filing of intervenor testimony; one round of discovery upon any intervenor testimony; and an opportunity for KU to file rebuttal testimony.

The following parties were granted intervention in this proceeding: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kroger Company ("Kroger"); Wal-Mart Stores East, LP and Sam's East, Inc. (jointly "Wal-Mart"); Kentucky School Boards Association ("KSBA"); Kentucky Cable Telecommunications

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[20] *Id.*, ¶ 39.

[21] Case No. 2015-00264, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling* (Ky. PSC Nov. 24, 2015).

[22] Application, ¶ 39.

Association ("KCTA"); Alice Howell, Carl Vogel, and Sierra Club (jointly "Sierra Club"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"); Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"); Lexington-Fayette Urban County Government ("LFUCG"); and Kentucky League of Cities ("KLC").

Informal conferences ("IC") were held at the Commission's offices on April 12, 13, and 17, 2017, which resulted in all of the parties to this matter, with the exception of AT&T and KCTA, reaching a settlement agreement in principle on all issues other than those involving the Companies' proposed Rate PSA – Pole and Structure Attachment Charges.[23] On April 19, 2017, KU and LG&E filed a motion requesting leave to submit the written Stipulation and Recommendation ("First Stipulation") intended to address all of the issues, except for the proposed Rate PSA tariff, in the two respective rate cases. An additional IC was held on April 25, 2017, for the limited purpose of discussing and possibly resolving the issues associated with the Companies' proposed Rate PSA tariff. The Companies, KCTA, and AT&T were able to reach an agreement in principle for the resolution of all material issues pertaining to the proposed Rate PSA tariff. On May 1, 2017, KU and LG&E filed a motion requesting leave to submit the written Second Stipulation and Recommendation ("Second Stipulation"), which addresses all of the issues related to the Companies' proposed Rate PSA tariff.

The Commission held information sessions and public meetings for the purpose of taking public comments on April 11, 2017, in Louisville, Kentucky, at Jefferson Community and Technical College; on April 12, 2017, in Madisonville, Kentucky, at

[23] The informal conferences were jointly held to discuss issues in the instant matter and to discuss issues related to the LG&E rate case, Case No. 2016-00371.

Madisonville Community College; and on April 18, 2017, in Lexington, Kentucky, at the Lexington Public Library – Northside Branch.

A formal hearing was held on May 9, 2017, for the purposes of cross-examination of all witnesses and for the consideration of the two stipulations.[24] Pursuant to a May 3, 2017 Order, the Commission required all of the Companies' employee witnesses as well as the Companies' consultant Steven Seelye, KIUC's witness Stephen Baron, and KSBA's witness Ronald Willhite to be present at the hearing.[25] The May 3, 2017 Order provided the parties to this matter an opportunity to cross-examine any of the other witnesses and, accordingly, directed the parties to the two cases to submit written notice on or before May 5, 2017, setting forth the name of each witness that each party intended to cross-examine at the formal hearing.[26] The May 3, 2017 Order noted that in the absence of a notice identifying witnesses whose attendance was not required by the Commission, the parties would be deemed to have waived cross-examination of those witnesses. None of the parties submitted a notice, and the only witnesses presented for cross-examination were those set forth above as named in the May 3, 2017 Order.

KU filed responses to post-hearing data requests on May 26, 2017, and on June 9, 2017. KSBA filed responses to post-hearing data requests on May 26, 2017. All the parties also filed post-hearing statements indicating they would not object to, or withdraw from, the First Stipulation, regardless whether all schools, including non-public

[24] *See* May 3, 2017 Order at 2.

[25] *Id.* at 3.

[26] *Id.*

schools, are included in the optional pilot program for schools as set forth in Article IV, paragraph 4.11 of the First Stipulation. On May 31, 2017, the AG, Sierra Club, CAC, LFUCG, Metropolitan Housing Coalition ("MHC"), Association of Community Ministries ("ACM"), and Louisville/Jefferson County Metro Government ("Louisville Metro"),[27] filed a joint post-hearing brief in the instant matter and in the LG&E rate case proceeding recommending approval of the Residential Basic Service Charge as set forth in the First Stipulation. On May 31, 2017, KU, KIUC, and Kroger filed their respective post-hearing briefs recommending approval of the First and Second Stipulations. On June 1, 2017, KSBA filed a separate post-hearing brief addressing the legality of the optional pilot school rate tariffs. KU and the AG filed their respective briefs on the pilot school tariff issue on June 2, 2017. KSBA and the AG contend that the school-related pilot tariffs do not violate KRS 278.035 because the proposed tariffs set forth a reasonable classification and would not be preferential, given the unique load characteristics and usage patterns of schools as compared to the other customers in their existing rate classes. The AG also pointed out that all public and private schools have similar load and usage characteristics making them a homogenous group, which made it reasonable to include in the pilot school tariff private schools that might wish to participate. The AG opined that "[a]s long as potential school participants to the pilot electric school tariffs are afforded equal opportunity to participate, the pilot electrical tariffs cannot be said to be 'preferential' within the meaning of KRS 278.035."[28] Similarly, KU contends that the pilot school tariffs do not provide a publicly funded entity an entitlement to service under

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[27] MHC, ACM, and Louisville Metro are parties only to the LG&E rate case, Case No. 2016-00371.

[28] AG's Post-Hearing Brief Regarding School Board Pilot Tariff at 7-8.

that rate, and that the pilot tariffs are a reasonable means of gathering data to determine whether such tariffs should be made generally available service offerings. KSBA, KU, and the AG all indicated that they did not object to modifying the First Stipulation to allow schools not covered by KRS 160.325, i.e., non-public schools, to participate in the pilot tariffs.

FIRST STIPULATION

The First Stipulation reflects the agreement of all of the parties to the two cases, with the exception of KCTA and AT&T, addressing all of the issues not related to pole attachments. A summary of the provisions contained in the First Stipulation is as follows:

- KU agrees to withdraw the CPCN request to implement the AMS project and will initiate an AMS collaborative involving the Companies and all interested parties to these proceedings to discuss any concerns about AMS.[29]

- KU will be issued a CPCN to implement the DA project.

- KU revenue will increase by $54.9 million.

- The stipulated level of revenue associated with the electric operations were adjusted by: 1) removal of AMS cost recovery; 2) reduction of Return on Equity ("ROE") to 9.75 percent; 3) revised depreciation rates; 4) revenues from refined coal agreements at Ghent; 5) updated five-year average for uncollectible debt expense; 6) use of an eight-year average of generator outage expenses, based upon four-years' historical expenses and four-years' forecasted expenses; and 7) adjustment to construction work in progress capital slippage.

- The agreed-to revenue allocation is set forth in Exhibit 4 of the First Stipulation.

[29] Because KU has agreed to withdraw its CPCN request to implement the AMS project, the company is also withdrawing its request to establish a regulatory asset for those electric meters that would have been retired as a result of the AMS project and the requests to deviate from certain regulations governing meter inspections and testing. *See* May 9, 2017 Hearing at 2:22:09.

- The Basic Service Charge will increase to $11.50 effective July 1, 2017, and to $12.25 effective July 1, 2018, for KU and LG&E Electric Rates RS, VFD, RTOD-Energy and RTOD-Demand.

- Current CSR customers may choose between Option A and Option B.

  - Option A reflects the Companies' as-filed proposition.

  - Option B reflects the following modifications to the existing CSR tariff:
    - credits for both Companies of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission);

    - KU may request physical curtailment when more than ten of the utility's primary combustion turbines ("CTs") are being dispatched, irrespective of whether the utility is making off-system sales. A CSR customer may avoid a physical curtailment by buying through at the Automatic Buy-Through Price.

- KU and LG&E agree to add a voluntary sports-field-lighting rate schedule, Pilot OSL – Outdoor Sports Lighting Service, on a pilot basis limited to 20 participants per company and will utilize a time-of-day rate structure.

- KU and LG&E agree not to split their residential and general service electric energy charges into Infrastructure and Variable components as proposed.

- KU and LG&E agree to file a study in their next rate cases regarding the impacts of 100 percent base demand ratchets for Rate TODS.

- For customers with their own generation, for 60 minutes following a utility-system fault, KU and LG&E agree to not use any demand data for a Rate TODP customer to set billing demand.

- KU and LG&E agree to add an optional pilot tariff for schools subject to KRS 160.325. The Companies' pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for each company, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served.

- KU and LG&E agree to file an application no later than December 31, 2017, proposing a two-year extension of the School Energy Managers Program (from July 1, 2018, through June 30, 2020) with a proposed total annual level of funding of $725,000.

- KU and LG&E agree to fund a study concerning economical deployment of electric bus infrastructure in the Lexington area, as well as cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

- KU and LG&E agree to establish an LED Lighting Collaborative involving Louisville Metro, LFUCG, and any other interested parties to these proceedings.

- KU agrees to increase its monthly residential Home Energy Assistance ("HEA") charge from $0.25 per month to $0.30 per month, which will remain effective through June 30, 2021.

- KU and LG&E agree to commit to contribute a total of $1.45 million of shareholder funds per year, which will remain in effect through June 30, 2021. These shareholder funds will be applied as follows:

    - From KU, $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs. KU agrees that up to 10 percent of its total contributions to CAC may be used for reasonable administrative expenses.

    - From LG&E, $700,000 to ACM for utility assistance and $180,000 for HEA. LG&E agrees that up to 10 percent of its total contributions to ACM may be used for reasonable administrative expenses.

The First Stipulation results in the monthly bill of an average KU residential customer increasing by $4.20, or 3.49 percent. A summary of the impact of the First Stipulation on KU's revenue requirement is as follows.

- **<u>Electric Operations</u>**. The parties agreed in the First Stipulation to reduce KU's requested revenue increase from $103.1 million to $54.9 million. The adjustments to KU's requested revenue requirement are discussed further below.

    A. <u>Advanced Metering System</u>. As previously discussed, KU requested that the Commission grant a CPCN to install AMS in its service territory. As part of the First Stipulation, the Companies agreed to withdraw their requests for the CPCN and to establish a collaborative to discuss the parties' concerns and seek to address them. In the test year, the cumulative effect of the withdrawal of the CPCN on the revenue requirement of KU is a reduction of $6.3 million.

B. Return on Equity. The agreement to reduce the ROE to 9.75 percent results in a decrease to KU's revenue requirement of $15.3 million.

C. Depreciation. KU proposed to revise its depreciation rates based upon depreciation studies that were performed by John Spanos of the firm Gannett Fleming Valuation and Rate Consultants, LLC. The parties to the First Stipulation agreed to revise KU's proposed depreciation rates resulting in a revenue-requirement reduction of $14.7 million. The revised depreciation rates will also reduce KU's environmental cost recovery revenue requirement by $19.1 million. The impact will be included in the environmental cost recovery filing made for the July 2017 expense month.

D. KU Refined Coal Revenues. The First Stipulation reflects a $9.1 million reduction in KU's revenue requirement related to KU's contract proceeds from the Refined Coal project at the Ghent Generating Station.

E. Uncollectibles Expense. KU proposed to use uncollectible factors based on using a five-year average of write-offs to revenues for the period 2011 through 2015. The First Stipulation uses an updated five-year period, 2012 through 2016, to reduce KU's revenue requirement by $0.5 million.

F. Normalize Generation Outage. KU proposed $90.201 million in generation outage expense for the test year, which exceeded its five-year average of $77.384 million. In the First Stipulation, the parties agreed to use an eight-year average expense, four years of historical expenses, and four years of forecasted expenses. This approach reduces KU's revenue requirement by $1.6 million.

G. Construction Work in Progress Capital Slippage. The First Stipulation reflects a slippage factor to eliminate over estimation in construction budgeting. The slippage factor reduces KU's requested revenue requirement by $0.7 million.

- **Stipulation Summary**. The table below reflects the impact each Stipulation adjustment has on KU.

	KU
Proposed Revenue Requirement	$ 103.1 million
Remove AMS	(6.3) million
9.75% Return on Equity	(15.3) million
Revised Depreciation Rates	(14.7) million
KU Refined Coal Revenues	(9.1) million
Uncollectible Expense	(0.5) million
Generator Outage Expenses	(1.6) million
CWIP Capital Slippage	(0.7) million
Stipulated Revenue Requirements	$ 54.9 million

SECOND STIPULATION

The Second Stipulation reflects the agreement of KU, AT&T, and KCTA as to the terms and conditions of KU's pole and structure attachment charges contained in Tariff PSA. The major substantive areas addressed in the Second Stipulation are as follows:

- Agreement on KU's attachment charges for pole-top wireless facilities;[30]
- Agreement on KU's attachment charges for mid-pole wireless facilities;[31]
- Amendment of the terms and conditions set forth in KU's proposed Tariff PSA rate schedule.[32]

ANALYSIS AND FINDINGS

The Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just, and reasonable."[33] While numerous intervenors with significant experience in rate proceedings and collectively

[30] Second Stipulation, paragraph 1.2.

[31] *Id.* at paragraph 1.3.

[32] *Id.* at paragraph 1.4.

[33] KRS 278.030(1).

representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes fair, just, and reasonable rates. The Commission must review the record, including the two stipulations, and apply its expertise to make an independent decision as to the level of rates, including terms and conditions of service, that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed its traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE.

FIRST STIPULATION

Based upon its review of the First Stipulation, the attachments thereto, and the case record including intervenor testimony, the Commission finds that, with the modifications discussed below, the First Stipulation is reasonable and in the public interest. With those modifications, the Commission finds that the First Stipulation was the product of arm's-length negotiations among knowledgeable, capable parties and should be approved. Such approval is based solely on the reasonableness of the modified First Stipulation and does not constitute a precedent on any individual issue.

Employee Retirement Plans

KU maintains a Defined Dollar Benefit Retirement Plan for those employees hired prior to January 1, 2006 ("Pre 2006 DDB Plan").[34] This plan was closed to new participants and was replaced with a Retirement Income Account ("401(k) Plan") for

[34] See KU's response to Commission Staff's Fourth Request for Information ("Staff's Fourth Request"), Item 6.

those employees hired after January 1, 2006.[35] All employees that were hired prior to January 1, 2006, are eligible to participate in both the Pre 2006 DDB Plan and the 401(k) Plan.[36] KU contributes 100 percent of the Pre 2006 DDB Plan costs.[37] KU also contributes to the 401(k) Plan between 3 percent to 7 percent[38] of eligible employee compensation and $0.70 per dollar match for employee contributions up to 6 percent of the employee's eligible contribution.[39]

The Commission finds that, for ratemaking purposes, it is not reasonable to include both KU's Pre 2006 DDB plan contributions and KU's matching contributions to the 401(k) Plan for the following employee categories: exempt, manager, non-exempt, and officer and director personnel. The Commission chooses not to address similar 401(k) Plan company matching contributions for hourly and bargaining unit employees in this proceeding, as it is not within the Commission's authority to negotiate or modify bargaining agreements. The Commission will not make a distinction between represented and non-represented hourly groups at this time, but will instead provide an opportunity for KU to address these excessive costs for both employee classes prior to its next base rate case, as rate recovery of these contributions will be evaluated for appropriateness as part of its next base rate case. Employees participating in the Pre

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[35] Refer to KU's response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 11. Although throughout this proceeding, KU made references to two separate post-2016 retirement plans, the Retirement Income Account and the 401(k) Savings Plan, they are actually the same plan.

[36] *Id.*

[37] Response to Staff's Fourth Request, Item 6.

[38] The percentage contribution rate depends on the employee's years of service as of January 1 of that year.

[39] Response to Staff's Fourth Request, Item 6.

2006 DDB Plan enjoy generous retirement plan benefits, making the matching 401(k) Plan amounts excessive for ratemaking purposes. Accordingly, the Commission denies for recovery 401(k) Plan matching contributions in the amount of $1,720,383 before gross-up.

Return on Equity

In its application, KU developed its ROE using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), the utility risk premium ("RP"), and the expected earnings approach.[40] Based on the results of the methods employed in its analysis, KU recommended an ROE range for its electric operations of 9.63 percent to 10.83 percent, including flotation cost.[41] KU recommended awarding the midpoint of this range, 10.23 percent, to maintain financial integrity, support additional capital investment and recognize flotation costs.[42] Direct testimony regarding ROE was provided by the AG and KIUC, and was subject to discovery by the Commission Staff and all parties.[43] Per paragraphs 2.2(B) and 3.2(B) of the First Stipulation, KU and the intervenors agreed that a ROE of 9.75 percent is reasonable for KU's electric operations.[44] The following table presents the recommended ROEs from KU and the interveners and the methods used to support each parties' findings:

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[40] Direct Testimony of Adrien M. McKenzie, CFA ("McKenzie Direct Testimony"), at 2.

[41] *Id.*, Exhibit No. 2, page 1 of 1.

[42] *Id.*, at 5–6.

[43] Walmart did not provide an ROE analysis, but pointed out that KU's proposed ROE was higher than natural trends, and that average ROE awards of vertically integrated utilities in 2015 and 2016 was 9.76 percent.

[44] First Stipulation, at 5 and 9.

Party	Recommendation	Methods
KU	10.23%	DCF, CAPM, ECAPM, RP
AG[45]	8.75%	DCF, CAPM
KIUC[46]	9.0%	DCF, CAPM
FIRST STIPULATION	**9.75%**	

In the First Stipulation, all parties agreed that the revenue requirement increases for KU's electric operations will reflect a 9.75 percent ROE as applied to KU's capitalization and capital structure of the proposed electric revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced KU's proposed electric revenue requirement by $15.3 million.[47] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable and higher than required by investors in today's economic climate, and that this provision of the First Stipulation should be modified.

While the Commission does not rely on individual returns awarded in other states in determining the appropriate ROE for Kentucky jurisdictional utilities, the Commission does find it reasonable to expect that other state commissions, each with its own attributes, evaluate expert witness testimony which uses the same or similar cost-of-equity models as those presented by the parties participating in this rate proceeding, and reach conclusions based on the data provided in the records of individual cases. The Regulatory Research Associates ("RRA") reports introduced into the record of this

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[45] Direct Testimony of Dr. J. Randall Woolridge at 67.

[46] Direct Testimony of Richard Baudino at 28.

[47] First Stipulation at 5.

proceeding[48] summarize the conclusions reached by state utility regulatory commissions, including this Commission, with regard to reasonable ROEs and contain explanatory reference points as to individual circumstances, all of which are available to investors. To the extent that investors' expectations are influenced by such publications, and we believe they are, we also find it appropriate to use that information to put their expectations in context. In fact, in KU's rebuttal testimony, KU agreed that allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost-of-equity analysis.[49]

The Commission takes notes of the fact that average annual ROE awards by state public service commissions for the last two years have ranged from 9.23 percent to 10.55 percent.[50] Furthermore, the average authorized ROEs reported by RRA for the fourth quarter of 2016 was 9.6 percent.[51] Authorized ROE data reported to investors by The Value Line Investment Survey for the specific firms in KU's proxy group indicates that state-allowed ROEs for those utilities were in a range of reasonableness of 9.00 to 12.50 percent.[52]

In 2017, the economic environment has shown signs of relative improvement. In response to increased economic growth and low unemployment, the Federal Reserve increased interest rates in March and June 2017, and current outlooks, including comments from government agencies, show that investors anticipate additional interest

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[48] *See* Rebuttal Testimony of Adrien M. McKenzie, CFA, at 11.

[49] *Id.* at 10.

[50] *Id.*, Exhibit 12.

[51] *Id.* at 13.

[52] *Id.*, Exhibit 13.

rate increases.[53] KU's own model produces an ROE, less flotation costs and adjustments, to be in the range of 9.5 percent to 10.7 percent.[54] Even with the current uptick in economic conditions, the economy remains in an era of historically low interest rates and slow economic growth. Therefore, irrespective of the agreement by the parties that a 9.75 percent ROE is appropriate for KU, the Commission finds that a slightly lower ROE is a better reflection of current economic conditions and investor expectations. Based on the entire record developed in this proceeding, we find that KU's required ROE falls within a range of 9.20 percent to 10.20 percent with a midpoint of 9.70 percent. An ROE of 9.70 should be used for the purpose of base rate revenues and certain tariffs, as discussed later in this Order.

This revision to the First Stipulation reduces KU's net operating income before income taxes by $969,324.

Revenue Requirement

As discussed above, the Commission finds the First Stipulation to be reasonable only by eliminating KU's 401(k) Plan contributions for the following employee categories: exempt, manager, non-exempt and officer and director personnel, and by reducing the ROE from 9.75 percent to 9.70 percent. These modifications decrease the stipulated revenue requirement from $54,900,000 to $50,484,652 a decrease of $4,415,348, as calculated in the table below.

[53] *Id.* at 8.

[54] McKenzie Direct Testimony, Exhibit No. 2.

	KU
KU's 401(k) Plan	$ (1,720,383)
ROE from 9.75% to 9.7%	(969,324)
Impact to Net Operating Income Before Taxes	(2,689,707)
Multiplied by: Gross up Factor	1.641572
Revenue Requirement Impact	(4,415,348)
Increase per Stipulation	54,900,000
Net Increase Granted by the Commission	$ 50,484,652

Residential Basic Service Charge

The Commission believes an increase to the Residential Basic Service Charge is warranted, and we find the level of the Year 2 charge to be reasonable. We further find that the two-step increase to $11.50 in Year 1 and to $12.25 in Year 2 is unnecessary. The total increase in the Residential Basic Service Charge of $1.50 is a modest increase from the current level, and the Commission sees no reason to complicate the issue by using a two-step method, which could generate confusion among KU's residential customers. The First Stipulation is therefore modified with respect to the Residential Basic Service Charge, and the Year 2 charge of $12.25 should be approved for service rendered on and after July 1, 2017.

Optional Pilot Rates for Schools Subject to KRS 160.325

At the formal hearing in this matter, the parties were requested to file post-hearing briefs concerning the legality of the proposed school-related pilot rate tariffs, Rates SPS and STOD, with respect to the applicability of KRS 278.035, and to indicate whether they would object to the modification of the First Stipulation to include schools not covered by KRS 160.325. Briefs submitted by KSBA, KU, and the AG acknowledged that the inclusion of non-public schools in the pilot tariffs would avoid a possible violation of KRS 278.035. All parties to this proceeding submitted statements indicating that they had no objection to modification of the First Stipulation to include non-public schools in the pilots.

The Commission finds that the First Stipulation should be modified to include schools not covered by KRS 160.325. The inclusion of non-public schools would rectify any potential conflict with KRS 278.035 and would remove any element of preferential treatment of public schools that could be associated with the pilot tariffs. As previously stated, the pilot rate provisions will be available to new participants until the total projected revenue reduction is $750,000 annually for KU, compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. The Commission notes that the parties to this proceeding agreed that the other ratepayers would assume the revenue shortfall resulting from the lower rates set forth in the pilot school tariffs. Therefore, the Commission will place a limit on the amount of time the pilot tariffs will be in effect and finds that the pilot tariffs should be effective for three years, or until KU files its next rate case, whichever is earlier. In the event that new base rates are not in effect by July 1, 2020, schools participating in the pilot tariffs should be returned to the tariffs under which they were formerly served. In addition, the Commission finds that KU should create a regulatory liability to record the difference between what the schools served under the pilot tariffs would have been billed under the pilot tariffs subsequent to July 1, 2020, and the amounts they are billed under the tariffs to which they are returned. The regulatory liability will be addressed in KU's next base rate proceeding. We further find that, within

30 days of the date of this Order, KSBA should file with the Commission the process by which KSBA will notify and select those schools, both public and non-public, that would be eligible to participate in the pilot tariffs.

With regard to the data gathered from the schools participating in the pilot tariffs, the Commission finds that KU should file reports with the Commission, beginning six months from the date of this Order and every six months thereafter, which set out details concerning monthly load information, individually and in the aggregate, and indicating preliminary findings as conclusions regarding the schools' load characteristics are reached. In the event that a future proposal is made either to extend the pilot school tariffs or to make them permanent, this load information will be used to determine whether the schools' load characteristics justify a special rate classification.

Collaborative Study Regarding Electric Buses

Although this provision will be funded by shareholder contributions and the Commission does not oppose it, this type of provision pertaining to an unrelated business transaction should be negotiated separately between the individual parties and has no bearing on KU's rates as found reasonable herein based on the record of this case. It is therefore superfluous to this regulatory proceeding, contributes nothing to the reasonableness of the First Stipulation, and should be omitted from future ratemaking proceedings.

LED Lighting and Electric Bus Study Collaboratives

Pursuant to the provisions of the First Stipulation, KU commits to engage in good faith with Louisville Metro, LFUCG, and any other interested parties to this proceeding and the LG&E rate proceeding in a collaborative to discuss issues related to LED lighting and electric bus infrastructure and rates. While the provisions limit participation to only those parties to the instant rate proceeding and the LG&E rate proceeding, the Commission finds that the collaboratives should also include the Kentucky Department of Energy Development and Independence, whose mission includes creating efficient, sustainable energy solutions and strategies.

SECOND STIPULATION

As mentioned previously, KU proposed certain changes to its pole attachment tariff in its application. KU currently offers the use of spaces on its poles for cable television attachments under Tariff CTAC, Cable Television Attachment Charges ("Tariff CTAC"). KU proposed to rename Tariff CTAC to Tariff PSA, Pole and Structure Attachment Charges ("Tariff PSA"), and to expand the tariff to include telecommunications wireline and wireless facilities' attachments, which are not currently covered under Tariff CTAC. KU also proposed to modify the rates, terms, and conditions of service for attaching wireline and wireless facilities to its poles.

The Second Stipulation includes the modifications proposed in the application, but also includes additional changes in the rates for pole space use and conditions of service for the placement of an attachment on KU's poles. As originally proposed, the Tariff PSA's rate schedule contained three charges: 1) an annual charge of $7.25 for each wireline pole attachment; 2) an annual charge of $0.81 for each linear foot of duct; and 3) an annual charge of $84.00 for each wireless facility attachment. AT&T and KCTA did not object to the charge for wireline and duct attachments, but did object to the annual charge for wireless facility attachments. KU estimated that wireless facilities occupy an average of 11.5 feet on its poles, and calculated the $84.00 wireless facility attachment charge based on the use of 11.5 feet of pole space at $7.25[55] per foot of pole. AT&T and KCTA did not challenge the $7.25 per foot factor in the calculation, but argued that wireless facility attachments occupy far less pole space. The Second Stipulation provides for a charge of $36.25, based upon a wireless facility attached to the top of a pole using five feet of the pole—one foot for the antenna and four feet of clearance above the power space to maintain a safe working distance between the electric facilities on the pole and the pole top antenna. The Second Stipulation also provides for rates for wireless facilities located mid-pole to be established on a case-by-case basis through special contracts. This provision is based upon the lack of requests for mid-pole wireless facilities, which resulted in a lack of evidence upon which to base a uniform rate for mid-pole wireless facilities.

Another modification is the requirement for a pole-loading study. As originally proposed, Tariff PSA required that a pole-loading study be submitted with each application as a safety and reliability measure. KCTA argued that requiring pole-loading studies for every application provides no appreciable safety or reliability benefit to KU, while unnecessarily increasing construction costs and preventing timely deployment of wireless facilities. The Second Stipulation provides that an attachment applicant may include a pole-load study with the application or, in the alternative, assert that a pole's condition does not warrant the need for a pole-loading study. To confirm the assertion, KU may perform a visual inspection of the pole to which the facility is proposed to be attached. If KU determines that a pole-loading study is needed, the attachment applicant has the option of conducting the pole-loading study itself or requesting that KU

[55] The Commission approved the rate of $7.25 per foot in Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric and Rates* (Ky. PSC June 30, 2015).

perform the study. The attachment applicant is responsible for the costs of any visual inspection or pole-loading study that KU performs. KU contends that the proposed revision to Tariff PSA does not sacrifice safety or system reliability.

The Commission finds that the proposed Tariff PSA with the modifications agreed to in the Second Stipulation is reasonable and that the Second Stipulation should be approved in its entirety.

OTHER ISSUES

Rate Adjustment

In setting the rates shown in Appendix B, the Commission maintained the basic service charges for each class that were included in the First Stipulation, with the exception that the Year 1 Residential Basic Service Charge was not approved as previously discussed, and is therefore not included. The reduction in KU's stipulated revenue increase as found reasonable herein was allocated to the energy charges of those customer classes for which revenue increases were proposed in the First Stipulation. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the First Stipulation.

Electric Vehicle Supply Equipment Calculation

In response to a Post-Hearing Request for Information, KU provided a revised sheet showing the impact on the Electric Vehicle Supply Equipment ("EVSE"), Electric Vehicle Charging Service ("EVC"), and Electric Vehicle Supply Equipment ("EVSE-R") rates of using the 9.75 percent ROE in the capital structure. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the EVSE rates should be further revised to reflect the approved ROE. The Commission also finds that since the

EVSE, EVC, and EVSE-R rates are based, in part, on the General Service ("GS") energy rate, the rates should be updated for the change in the GS energy rate approved with this Order. The EVSE, EVC, and EVSE-R rates set out in Appendix B to this Order reflect both revisions.

Solar Capacity Charge and Solar Energy Credits

In response to a Post-Hearing Request for Information, KU provided a revised sheet showing the impact on the Solar Capacity Charge and Solar Energy Credits of using the 9.75 percent ROE in the capital structure and under each of the corrected cost-of-service studies filed by KU in this proceeding. In light of the 9.70 percent ROE found reasonable herein, the Commission finds that the Solar Capacity Charge and Solar Energy Credits should be further revised to reflect the approved ROE. The Commission also finds that the Solar Energy Credits should be revised for Rate Schedules RS, VFD, RTOD-E, RTOD-D, AES, and GS using the average of the amounts provided in response to the post-hearing information request,[56] but revised for the change in ROE and using the energy rates approved herein for Rate Schedules PS, TODS, and TODP. The rates set out in Appendix B to this Order reflect the revisions.

Demand-Side Management ("DSM")

In response to a Commission Staff Information Request, KU stated that upon the implementation of new base rates, the DSM Revenue from Lost Sales component of its DSM cost-recovery mechanism would change to zero.[57] The Commission finds that

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[56] Response to Commission Staff's First Post-Hearing Request for Information dated May 12, 2017, Item 6, Attachment KU-6-1 and Attachment KU-6-2.

[57] KU's response to Commission Staff's Second Request for Information, Item 10.

KU's compliance tariff that it is directed to file in ordering paragraph 10 should reflect this revision to its DSM cost-recovery mechanism.

Loss of Municipal Load

The Commission takes notice that nine municipal utilities will be terminating their wholesale power contracts with KU effective, at the latest, April 30, 2019.[58] The combined load of those nine departing wholesale customers is approximately 325 megawatts ("MW").[59] At the formal hearing, Victor Staffieri, KU's Chairman, Chief Executive Officer, and President, testified that KU had not secured new customers to purchase the generation that would be available when the nine municipal utilities terminate their contracts with KU, but that the company would take into account any growth in load as potential replacement for the loss of municipal load.[60] Mr. Staffieri also stated that it is not known what impact the loss of municipal load would have on KU's rates when the company files its next rate case.[61] David Sinclair, KU's Vice President, Energy Supply and Analysis, also testified at the formal hearing that, beginning in 2019 and 2020, KU would have a reserve margin of approximately 24 percent, which would be above the upper end of KU's target reserve margin range.[62]

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[58] *See* Case No. 2014-0002, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station* (Ky. PSC Dec. 19, 2014), final Order at 2–3.

[59] The nine municipal wholesale customers are Barbourville, Bardwell, Berea, Corbin, Falmouth, Frankfort, Madisonville, Paris, and Providence.

[60] May 9, 2017 Hearing at 1:37:37.

[61] *Id.* at 1:38:40.

[62] May 10, 2017 Hearing at 9:37:30.

In light of the significant loss of load in connection with the nine municipal customers' leaving KU's system in April 2019, the Commission finds that KU should develop and implement a formal plan to address how KU will mitigate the loss of the approximately 325 MW municipal load, including, but not limited to, how KU will market the excess capacity and energy resulting from the municipals departing the system, the types of measures KU will implement to attract new or expanding load, and whether joining a regional transmission organization would be beneficial in its efforts to market the excess capacity and energy.

Transmission System Improvement Plan

KU is currently implementing a Transmission System Improvement Plan ("Transmission Plan") aimed at reducing outage occurrence and duration and improving overall reliability of service to its customers.[63] KU states that the Transmission Plan contains two primary categories of investment: system integrity and reliability.[64] System integrity involves replacement of aging transmission assets to enhance reliability.[65] The reliability component involves several maintenance programs and capital investment in line sectionalization.[66] KU will spend approximately $149 million between the end of the last base-rate-case test period and the end of the forecasted test period (July 1, 2016 – June 30, 2018) on its Transmission Plan.[67] This spending is part of a total of $511

[63] Direct Testimony of Paul W. Thompson ("Thompson Testimony") at 25.

[64] *Id.* at 26.

[65] *Id.*

[66] *Id.*

[67] *Id.* at 27.

million in transmission capital investments that KU and LG&E project to spend over the five-year period beginning 2017.[68]

In light of the significant investments that KU intends to make pursuant to the Transmission Plan, the Commission will require KU to file annual reports, over the five-year Transmission Plan period, detailing the progress on the spend out for the reporting period, the criteria utilized by KU to prioritize the various transmission projects, the impact on reliability or other benefits to KU's customers resulting from such investments, and outlining the expenditures for the following year.

KU's Tariffs

Commission regulation 807 KAR 5:011, Section 4(1), requires each utility to include an accurate index of the city, town, village, or district in which its rates are applicable. The first page of KU's tariffs references its service as being available "[i]n seventy-seven counties in the Commonwealth of Kentucky as depicted on territorial maps as filed with the Public Service Commission of Kentucky." Because those maps are not readily available to members of the public, KU should revise its tariffs to include a list of the communities in which it serves.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by KU are denied.

2. KU's motions for leave to file the First and Second Stipulations are granted.

3. The First and Second Stipulations, attached hereto as Appendix A, (without exhibits) are approved with the modifications discussed herein.

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[68] *Id.* at 26–27.

4. The rates and charges in Appendix B, attached hereto, are fair, just, and reasonable for KU to charge for service rendered on and after July 1, 2017.

5. KU is granted a CPCN to implement the DA project as described in the application.

6. Within 30 days of the date of this Order, KSBA shall file with the Commission the process by which it will notify and select those schools that are eligible to participate in the pilot tariffs approved herein.

7. KU shall file reports with the Commission as directed herein which set out details concerning the pilot school tariffs study.

8. Within 90 days of the date of this Order, KU shall file a formal plan addressing how KU will mitigate the loss of the approximately 325 MW municipal load as discussed herein.

9. Beginning June 1, 2018, and continuing over the five-year Transmission Plan period, KU shall file an annual Transmission Plan report as discussed herein.

10. Within 20 days of the date of this Order, KU shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised tariffs, including an index of communities served, as set forth in this Order reflecting that they were approved pursuant to this Order.

11. Any document filed pursuant to ordering paragraphs 6, 7, 8, and 9 of this Order shall reference the number of this case and shall be retained in the utility's general correspondence file.

12. The Executive Director is delegated authority to grant reasonable extension of time for the filing of any documents required by ordering paragraphs 6, 7, 8, and 9 of this Order upon KU's showing of good cause for such extension.

By the Commission

ENTERED
JUN 22 2017
KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Talina R. Mathews

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00370 DATED JUN 2 2 2017

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into this 19th day of April 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Association of Community Ministries, Inc. ("ACM"); Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"); United States Department of Defense and All Other Federal Executive Agencies ("DoD"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky League of Cities ("KLC"); The Kroger Company ("Kroger"); Kentucky School Boards Association ("KSBA"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Metropolitan Housing Coalition ("MHC"); Sierra Club, Alice Howell, Carl Vogel and Amy Waters (collectively "Sierra Club"); JBS Swift & Co. ("Swift"); and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart"). (Collectively, the Utilities, ACM, AG, CAC, DoD, KIUC, KLC, Kroger, KSBA, LFUCG, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the AG, BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), CAC, Kentucky Cable Telecommunications Association ("KCTA"), KIUC, KLC, Kroger, KSBA, LFUCG, Sierra Club, and Wal-Mart;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to ACM, AG, AT&T, DoD, KCTA, KIUC, Kroger, KSBA, Louisville Metro, MHC, Sierra Club, Swift and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings, notwithstanding that neither AT&T nor KCTA has agreed with, or entered into, this Stipulation, and therefore neither AT&T nor KCTA is one of the Parties as defined herein;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Stipulation;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. ADVANCED METERING SYSTEMS

1.1. Withdrawing Request for Certificates of Public Convenience and Necessity and Cost Recovery for Advanced Metering Systems. The Utilities agree to withdraw their requests for the Commission to grant certificates of public convenience and necessity ("CPCNs") and to approve cost recovery in these base rate proceedings for the Utilities' proposed full deployment of Advanced Metering Systems ("AMS"). The Parties agree that the Utilities' withdrawal of their requests for CPCNs and cost recovery for AMS in these proceedings does not preclude the Utilities from having full AMS deployment considered in future proceedings.

1.2. AMS Collaborative. The Parties agree that the Utilities and all interested Parties will participate in an AMS Collaborative to discuss the Parties' concerns about AMS and to seek to address them. The AMS Collaborative will begin at a mutually agreeable time after these proceedings conclude and will include only those Parties to these proceedings interested in participating in the collaborative. The Parties agree to engage in the collaborative in good faith not to exceed 15 months from the date the Commission issues orders in these proceedings.

ARTICLE II. ELECTRIC REVENUE REQUIREMENTS

2.1. Utilities' Electric Revenue Requirements. The Parties stipulate that the following increases in annual revenues for LG&E electric operations and for KU operations, for purposes of determining the rates of LG&E and KU in the Rate Proceedings, are fair, just and reasonable for the Parties and for all electric customers of LG&E and KU:

LG&E Electric Operations: $59,400,000.

KU Operations: $54,900,000.

The Parties agree that any increase in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2017.

2.2. Items Reflected in Stipulated Electric Revenue Requirement Increases. The Parties agree that the stipulated electric revenue requirement increases were calculated by beginning with the Utilities' electric revenue requirement increases as presented and supported by the Utilities in their applications in these proceedings and as revised through discovery ($103.1 million for KU; $94.1 million for LG&E electric) and adjusting them by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from the Utilities' electric revenue requirements. This reduces KU's proposed electric revenue requirement increase by $6.3 million, consisting of $3.2 million of operations and maintenance ("O&M") cost and $3.1 million of carrying cost and depreciation expense. Similarly, this reduces LG&E's proposed electric revenue requirement increase by $5.2 million, consisting of $3.0 million of O&M cost and $2.2 million of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for the Utilities' electric operations, and the agreed stipulated revenue requirement increases for the Utilities' electric operations reflect that return on equity as applied to the Utilities' capitalizations and capital structures underlying their originally proposed electric revenue requirement increases as modified through discovery. Use of a 9.75% return on equity reduces the Utilities' proposed electric revenue requirement increases by $15.3 million for KU and $10.1 million for LG&E.

(C) **Revised Depreciation Rates.** The stipulated revenue requirement increases reflect the revised depreciation rates shown in Stipulation Exhibits 1 (KU) and 2 (LG&E electric), which reduce the Utilities' proposed electric revenue requirement increases by $14.7 million for KU and $10.1 million for LG&E. In addition to contributing to reducing the Utilities' proposed electric revenue requirement increases in these proceedings, these revised depreciation rates will reduce environmental cost recovery ("ECR") revenue requirements by $19.1 million for KU and $16.8 million for LG&E relative to the Utilities' proposed depreciation rates as will be included in the ECR mechanism filings beginning with the July 2017 expense month.

(D) **KU Revenues Resulting from the Refined Coal Project at the Ghent Generating Station.** The stipulated revenue requirement increase for KU reflects a $9.1 million revenue-requirement reduction related to KU's contract proceeds resulting from KU's Refined Coal project at the Ghent Generating Station. KU discussed this issue at an Informal Conference held at the Commission on March 14, 2017, in the context of Case No. 2015-00264.

(E) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated electric revenue requirement increases reflect the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average (2011-2015) that was available at the time the Utilities filed their applications in these proceedings. This approach reduces the Utilities' proposed electric revenue requirement increases by $0.5 million for KU and $0.3 million for LG&E.

(F) **Eight-Year Average for Generator Outage Expenses; Related Use of Regulatory Accounting.** The Parties agree to use an eight-year average of generator outage expenses in the Utilities' stipulated electric revenue requirement increases, where the average is of four historical years' expenses (2013-2016) and four years' forecasted expenses (2017-2020). This approach reduces the Utilities' proposed electric revenue requirement increases by $1.6 million for KU and $8.5 million for LG&E. Relatedly, the Parties agree to, and ask the Commission to approve, the Utilities' use of regulatory asset and liability accounting related to generator outage expenses that are greater or less than the eight-year average of the Utilities' generator outage expenses. This regulatory accounting will ensure the Utilities may collect, or will have to return to customers, through future base rates any amounts that are above or below the eight-year average embedded in the stipulated electric revenue requirement increases in these proceedings.

(G) **Adjustment Related to Construction Work in Progress Capital.** The Parties agree to adjust the Utilities' proposed electric revenue requirement increases to reflect differences ("slippage") between past projected and historical capital amounts for construction work in progress ("CWIP"). This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.7 million for KU and $0.4 million for LG&E.

(This space intentionally left blank.)

2.3. Summary Calculation of Electric Revenue Requirement Increases. The table below shows the calculation of the stipulated electric revenue requirement increases:

Item	KU	LG&E
Proposed electric revenue requirement increases	$103.1 million	$94.1 million
Remove AMS	($6.3 million)	($5.2 million)
9.75% return on equity	($15.3 million)	($10.1 million)
Revised depreciation rates	($14.7 million)	($10.1 million)
KU Refined Coal revenues	($9.1 million)	n/a
5-year average uncollectible expense	($0.5 million)	($0.3 million)
8-year average generator outage expense	($1.6 million)	($8.5 million)
CWIP capital slippage	($0.7 million)	($0.4 million)
Stipulated electric revenue requirement increases	$54.9 million	$59.4 million[1]

ARTICLE III. GAS REVENUE REQUIREMENT

3.1. LG&E Gas Revenue Requirement. The Parties stipulate and agree that, effective for service rendered on and after July 1, 2017, an increase in annual revenues for LG&E gas operations of $7,500,000, for purposes of determining the rates of LG&E gas operations in the Rate Proceedings, is fair, just and reasonable for the Parties and for all gas customers of LG&E.

[1] Stipulated LG&E electric revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

3.2. Items Reflected in Stipulated Gas Revenue Requirement Increase. The Parties agree that the stipulated gas revenue requirement was calculated by beginning with LG&E's gas revenue requirement increase as presented and supported by LG&E in its application in Case No. 2016-00371 and as revised through discovery ($13.4 million) and adjusting the proposed gas revenue requirement increase by the following items, which the Parties ask and recommend the Commission accept as reasonable without modification:

(A) **Removal of AMS Cost Recovery.** Because the Utilities are withdrawing their request for CPCNs and cost recovery for their proposed full deployment of AMS, recovery of AMS costs is being removed from LG&E's gas revenue requirement. This reduces LG&E's proposed gas revenue requirement increase by $0.7 million, consisting solely of carrying cost and depreciation expense.

(B) **Return on Equity.** The Parties agree that a return on equity of 9.75% is reasonable for LG&E's gas operations, and the agreed stipulated revenue requirement increase for LG&E's gas operations reflect that return on equity as applied to LG&E's gas capitalization and capital structure underlying its originally proposed gas revenue requirement increase as modified through discovery. Use of a 9.75% return on equity reduces LG&E's proposed gas revenue requirement increase by $2.9 million.

(C) **Depreciation Rates.** The stipulated gas revenue requirement increase reflects the depreciation rates shown in Stipulation Exhibit 3, which reduce LG&E's proposed gas revenue requirement increase by $2.1 million.

(D) **Updated Five-Year Average for Uncollectible Debt Expense.** The stipulated gas revenue requirements increase reflects the use of a five-year average (calendar years 2012-2016) for uncollectible debt expense, which is an update to the five-year average

(2011-2015) that was available at the time LG&E filed its application in Case No. 2016-00371. This approach reduces LG&E's proposed gas revenue requirement increase by $0.1 million.

3.3. Summary Calculation of Gas Revenue Requirement Increase. The table below shows the calculation of the stipulated gas revenue requirement increase:

Item	LG&E Gas
Proposed gas revenue requirement increase	$13.4 million
Remove AMS	($0.7 million)
9.75% return on equity	($2.9 million)
Revised depreciation rates	($2.1 million)
5-year average uncollectible expense	($0.1 million)
Stipulated gas revenue requirement increase	$7.5 million[2]

ARTICLE IV. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

4.1. Revenue Allocation. The Parties hereto agree that the allocations of the increases in annual revenues for KU and LG&E electric operations, and that the allocation of the increase in annual revenue for LG&E gas operations, as set forth on the allocation schedules designated Stipulation Exhibit 4 (KU), Stipulation Exhibit 5 (LG&E electric), and Stipulation Exhibit 6 (LG&E gas) attached hereto, are fair, just, and reasonable for the Parties and for all customers of LG&E and KU.

4.2. Tariff Sheets. The Parties hereto agree that, effective July 1, 2017, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 7

[2] Stipulated gas revenue requirement increase differs from proposed revenue requirement increase less adjustments shown due to rounding.

(KU), Stipulation Exhibit 8 (LG&E electric), and Stipulation Exhibit 9 (LG&E gas) attached hereto, which rates the Parties unanimously stipulate are fair, just, and reasonable, and should be approved by the Commission.

4.3. Basic Service Charges. The Parties agree that the following monthly basic service charge amounts shall be implemented on the schedule shown:

Rates	Effective July 1, 2017	Effective July 1, 2018
LG&E and KU Rates RS, VFD, RTOD-Energy, and RTOD-Demand	$11.50	$12.25
LG&E Rates RGS and VFD	$16.35	$16.35

All other basic service charges shall be the amounts reflected in the proposed tariff sheets attached hereto in Stipulation Exhibits 7 (KU), 8 (LG&E electric), and 9 (LG&E gas).

4.4. Curtailable Service Riders. Concerning the Utilities' Curtailable Service Riders ("CSR"), the Parties agree that CSR customers may choose between Options A and B as follows:

(A) Option A: The Utilities' proposed CSR credits and tariff provisions as filed in these proceedings.

(B) Option B: The Utilities' existing CSR tariff provisions with the modifications below:

(i) CSR credits for both Utilities of $6.00 per kVA-month (primary) and $5.90 per kVA-month (transmission).

(ii) A Utility may request physical curtailment when more than 10 of the Utilities' primary combustion turbines (CTs) (those with a capacity greater than 100 MW) are being dispatched, irrespective of whether the Utilities are making off-system sales. However, to avoid a physical curtailment a CSR customer may buy through a requested curtailment at the Automatic Buy-Through Price. If all available units have been dispatched or are being dispatched, the Utilities may request a physical curtailment of the CSR customer without a buy-through option.

(iii) A Utility may request physical curtailment of a CSR customer no more than 20 times per calendar year totaling no more than 100 hours. Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 hours of economic curtailments.

(iv) After receiving a physical curtailment request from the Utility where a buy-through option is available, a CSR customer will have 10 minutes to inform the Utility whether the customer elects to buy through or physically curtail. If the customer elects to physically curtail, the customer will have 30 minutes to carry out the required physical curtailment (i.e., a total of 40 minutes from the time the Utility requests curtailment to the time the customer must implement the curtailment). If a customer does not respond within 10 minutes of notice of a curtailment request from the Utility, the customer will be assumed to have elected to buy through the requested curtailment, subject to any prior written agreement with the customer.

(v) After receiving a physical curtailment request from the Utility when no buy-through option is available, a CSR customer will have 40 minutes to carry out the required physical curtailment.

(C) The Utilities will initially assign all existing CSR customers to Option B as described above. Following the initial assignment, a CSR customer may elect Option A at any time, which election will take effect beginning with the customer's first full billing cycle following the election. After a CSR makes its first election or any subsequent election, the customer must take service under the chosen option for at least 24 full billing cycles before a new election can become effective.

(D) LG&E will permit any customer interested in participating in CSR to give notice of interest by July 1, 2017; after that date, only those customers already participating in LG&E's CSR may continue their participation at their then-current levels. Customers that have given notice of interest on or before July 1, 2017, may elect to begin participating in CSR no later than January 1, 2019. LG&E's existing capacity cap will continue to apply, and all available CSR capacity will be available for participation on a first come, first served basis to those giving notice of interest by July 1, 2017.

(E) KU's CSR will be closed to new or increased participation as of July 1, 2017.

These proposed tariff changes are shown in Stipulation Exhibits 7 (KU) and 8 (LG&E electric) attached hereto.

4.5. Five-Year Limit to Gas Line Tracker Recovery for Transmission Modernization and Steel Service Line Replacement Programs. The Parties agree that LG&E will recover costs related to its proposed Transmission Modernization and Steel Service Line Replacement Programs through its Gas Line Tracker ("GLT") cost-recovery mechanism for five years ending June 30, 2022. Absent further action by the Commission concerning recovery of these programs' costs by June 30, 2022, any remaining costs for such programs will be recovered through base rates via a base-rate roll-in effective for service rendered on and after July 1, 2022. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto. This provision does not preclude LG&E from seeking Commission approval to recover other appropriate costs through the GLT mechanism.

4.6. Revisions to Proposed Substitute Gas Sales Service (Rate SGSS). The Parties agree that LG&E will revise its proposed Rate SGSS such that monthly billing demand will be based on greatest of (1) Maximum Daily Quantity ("MDQ"), (2) current month's highest daily volume of gas delivered, or (3) 70 percent of the highest daily volume of gas delivered during the previous 11 monthly billing periods. Also, LG&E will revise the provision of Rate SGSS concerning setting the MDQ such that the MDQ for any customer taking service under Rate SGSS when it first becomes effective will be 70% of the highest daily volume projected by LG&E for the customer in the forecasted test year used by LG&E in Case No. 2016-00371. For all other customers that later begin taking service under Rate SGSS, the customer and LG&E may mutually agree to establish the level of the MDQ; provided, however, that in the event that the customer and LG&E cannot agree upon the MDQ, then the level of the MDQ will be equal to 70% of the highest daily volume used by the customer during the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected; in the event that such daily gas usage is not available, then the MDQ will be equal to 70% of the customer's average daily use for the highest month's gas use in the 12 months prior to the date the customer began receiving natural gas from another supplier with which the customer is physically connected. In no case will the MDQ be greater than 5,000 Mcf/day. These proposed tariff changes are shown in Stipulation Exhibit 9 attached hereto.

4.7. Sports Field Lighting Pilot Tariff Provisions. The Parties agree that the Utilities will add to their electric tariffs a voluntary sports field lighting rate schedule, Pilot Rate OSL – Outdoor Sports Lighting Service, on a limited-participation pilot basis (limited to 20 pilot participants per Utility). The pilot rate uses a time-of-day rate structure. The purpose of the pilot is to determine if sports fields have sufficiently different service characteristics to support permanent sports field tariff offerings. The proposed tariff provisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.8. Agreement Not to Split Residential and General Service Electric Energy Charges in Tariffs. The Parties agree that the Utilities will not split their residential and general service electric energy charges into Infrastructure and Variable components as the Utilities had proposed in their applications in these proceedings. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.9. Agreement to File a Study Regarding 100% Base Demand Ratchets for Rate TODS. The Utilities will file in their next base-rate proceedings a study concerning the impacts of 100% base demand ratchets for Rate TODS.

4.10. Rate TODP 60-Minute Exemption from Setting Billing Demand Following Utility System Fault. For customers with their own generation, for 60 minutes immediately following a Utility-system fault, but not a Utility energy spike or a fault on a customer's system, the Utilities will not use any demand data for a Rate TODP customer to set billing demand. This 60-minute exemption from setting billing demand permits customers who have significant onsite generation (i.e., 1 MW or more) that comes offline due to a Utility-system fault to reset and bring back online their own generation before the Utilities will measure demand to be used for billing purposes. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

4.11. Optional Pilot Rates for Schools Subject to KRS 160.325. The Parties agree that the Utilities will add to their electric tariffs optional pilot tariff provisions for schools subject to KRS 160.325. The pilot rates will not be limited in the number of schools that may participate, but will be limited by the projected revenue impact to the Utilities. Each utility's pilot rate provisions will be available to new participants until the total projected revenue impact (reduction) for each Utility is $750,000 annually compared to the projected annual revenues for the participating schools under the rates under which the schools would otherwise be served. KSBA will be responsible for proposing schools for participation in the pilot rates and the order in which such schools are proposed; the Utilities will calculate and provide to KSBA the projected revenue impact of each proposed school's taking service under pilot rates. The proposed tariff revisions are included in the proposed tariff sheets attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

ARTICLE V. TREATMENT OF CERTAIN SPECIFIC ISSUES

5.1. Regulatory Accounting for Over- and Under-Recovery of Regulatory Assets. The Parties agree to, and ask the Commission to approve, the Utilities' continued use of regulatory asset accounting for regulatory assets embedded in the Utilities' proposed revenue requirement except that shorter-lived regulatory assets should be credited for the amounts collected through base rates even if such amortization results in changing such a regulatory asset to a regulatory liability with any remaining balances being addressed in the Utilities' next base rate case. This would include the regulatory assets for rate case expenses, 2011 summer storm expenses, and Green River. This will help ensure the Utilities only recover actual costs incurred and do not ultimately over-recover such regulatory assets as they are amortized and recovered through base rates.

5.2. Commitment to Apply for School Energy Managers Program ("SEMP") Extension. The Utilities commit to file with the Commission an application proposing a two-year extension of SEMP (for July 1, 2018, through June 30, 2020). The total annual level of funding to be proposed is $725,000; prior to filing the application, the Utilities will consult with

KSBA to determine an appropriate allocation of the total annual funds between KU and LG&E. The Utilities commit to file the above-described application with the Commission no later than December 31, 2017.

5.3. Commitment to File Lead-Lag Study in Next Base-Rate Cases. The Utilities commit to file a lead-lag study in their next base-rate cases.

5.4. Collaborative Study Regarding Electric Bus Infrastructure and Rates. The Utilities commit to fund a study concerning economical deployment of electric bus infrastructure in the Louisville and Lexington areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses. The Utilities commit to work collaboratively with Louisville Metro, LFUCG, and any other interested Parties to these proceedings to develop the parameters for the study, including reasonable cost and timing, and to review the study's results with representatives of Louisville Metro and LFUCG. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.5. LED Lighting Collaborative. The Utilities commit to engage in good faith with Louisville Metro, LFUCG, and any other interested Parties to these proceedings in a collaborative to discuss issues related to LED lighting to determine what LED street lighting equipment and rate structures might be offered by the Utilities. The collaborative will include only those Parties to these proceedings interested in participating in the collaborative.

5.6. Home Energy Assistance Charges. The Parties agree that KU will increase its monthly residential charge for the Home Energy Assistance ("HEA") program from the current $0.25 per month to $0.30 per month, which shall remain effective through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period. The Parties further agree that LG&E will continue its monthly residential charge (for gas and electric service) for the Home Energy Assistance ("HEA") program at $0.25 per month, which shall remain effective until the effective date of new base rates for the Utilities following their next general base-rate cases. The change to the KU HEA charge is reflected in the proposed tariff sheets attached hereto as Stipulation Exhibit 7.

5.7. Low-Income Customer Support. The Utilities commit to contribute a total of $1,450,000 of shareholder funds per year, which commitment will remain in effect through June 30, 2021, regardless of whether the Utilities file one or more base-rate cases during that commitment period.

(A) The total annual shareholder contribution from KU shall be as follows: $100,000 for Wintercare and $470,000 for HEA. CAC administers both programs.

(B) The total annual shareholder contribution from LG&E shall be as follows: $700,000 to ACM for utility assistance and $180,000 for HEA.

(C) KU agrees that up to 10% of its total contributions to CAC may be used for reasonable administrative expenses.

(D) LG&E agrees that up to 10% of its total contributions to ACM may be used for reasonable administrative expenses.

(E) None of the Utilities' shareholder contributions will be conditioned upon receiving matching funds from other sources.

(F) The Utilities commit not to seek reductions to their HEA charges that would become effective before June 30, 2021, for LG&E or KU regardless of whether the Utilities file one or more base-rate cases during that commitment period.

5.8. All Other Relief Requested by Utilities to Be Approved as Filed. The Parties agree and recommend to the Commission that, except as modified in this Stipulation and the exhibits attached hereto, the rates, terms, and conditions contained in the Utilities' filings in these Rate Proceedings, as well as the Companies' requests for CPCNs for their proposed Distribution Automation project, should be approved as filed.

ARTICLE VI. MISCELLANEOUS PROVISIONS

6.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

6.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Stipulation.

6.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on or about April 19, 2017, together with a request to the Commission for consideration and approval of this Stipulation for rates to become effective for service rendered on and after July 1, 2017.

6.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

6.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order. With regard to this provision, all of the Parties acknowledge that certain of the Parties, and in particular the Sierra Club, are entities with members who are not under a Party's control but who might purport to act for, or on behalf of, the Party. Therefore, the Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Stipulation in its entirety and without additional conditions.

6.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

6.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

6.8. The Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

6.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

6.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

6.11. The Parties hereto agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

6.12. The Parties hereto agree that neither the Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

6.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

6.14. The Parties hereto agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

6.15. The Parties hereto agree that this Stipulation may be executed in multiple counterparts.

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1: KU Depreciation Rates

Stipulation Exhibit 2: LG&E Electric Depreciation Rates

Stipulation Exhibit 3: LG&E Gas Depreciation Rates

Stipulation Exhibit 4: KU Revenue Allocation Schedule

Stipulation Exhibit 5: LG&E Electric Revenue Allocation Schedule

Stipulation Exhibit 6: LG&E Gas Revenue Allocation Schedule

Stipulation Exhibit 7: KU Tariff Sheets

Stipulation Exhibit 8: LG&E Electric Tariff Sheets

Stipulation Exhibit 9: LG&E Gas Tariff Sheets

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R. Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (KRR w/permission)
Allyson K. Sturgeon

Association of Community Ministries, Inc.

HAVE SEEN AND AGREED:

By: ______________________________
Lisa Kilkelly
Eileen Ordover

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By:______________________________

Kent Chandler
Lawrence W. Cook
Rebecca W. Goodman

Community Action Council for
Lexington-Fayette, Bourbon, Harrison
and Nicholas Counties, Inc.

HAVE SEEN AND AGREED:

By: ______________________
Iris G. Skidmore

United States Department of Defense and All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: Emily W. Medlyn
____

Emily W. Medlyn
G. Houston Parrish

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________
Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

Kentucky League of Cities

HAVE SEEN AND AGREED:

By: ______________________

Laura Ross

The Kroger Company

HAVE SEEN AND AGREED:

By: Robert C. Moore

Robert C. Moore

Kentucky School Boards Association

HAVE SEEN AND AGREED:

By: Matthew R Malone (KRRign w/ permission)
Matthew R. Malone
William H. May, III

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: M. Todd Osterloh

James W. Gardner
M. Todd Osterloh
David J. Barberie
Andrea C. Brown
Janet M. Graham

Subject to ratification by the Urban County Council

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By:
Michael J. O'Connell,
Jefferson County Attorney

-and-

By:
Gregory T. Dutton,
Counsel for Louisville Metro

Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By: Tom FitzGerald (GKRR w/ permission)
Tom FitzGerald

Sierra Club, Alice Howell, Carl Vogel
and Amy Waters

HAVE SEEN AND AGREED:

By:______________________________
Joe F. Childers

____
Casey Roberts

____
Matthew E. Miller

JBS Swift & Co.

HAVE SEEN AND AGREED:

By:________________________________
Dennis G. Howard, II

Wal-Mart Stores East, LP and Sam's East, Inc.

HAVE SEEN AND AGREED:

By: ____________________

Barry N. Naum

Don C.A. Parker

SECOND STIPULATION AND RECOMMENDATION

This Second Stipulation and Recommendation ("Second Stipulation") is entered into this first day of May 2017 by and between Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); BellSouth Telecommunications, LLC d/b/a AT&T Kentucky ("AT&T"), and Kentucky Cable Telecommunications Association ("KCTA"). (Collectively, the Utilities, AT&T and KCTA are the "Parties.")

WITNESSETH:

WHEREAS, on November 23, 2016, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust Electric Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00370 to review KU's base rate application, in which KU requested a revenue increase of $103.1 million;

WHEREAS, on November 23, 2016, LG&E filed with the Commission its Application for Authority to Adjust Electric and Gas Rates and For Certificates of Public Convenience and Necessity, *In the Matter of: An Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity*, and the Commission has established Case No. 2016-00371 to review LG&E's base rate application, in which LG&E requested a revenue increase for its electric operations of $93.6 million and a revenue increase of $13.8 million for its gas operations (Case Nos. 2016-00370 and 2016-00371 are hereafter collectively referenced as the "Rate Proceedings");

WHEREAS, on February 20, 2017, LG&E filed with the Commission in Case No. 2016-00371 a Supplemental Response to Commission Staff's First Request for Information No. 54 in which LG&E corrected its requested revenue increases for its electric operations to be $94.1 million and for its gas operations to be $13.4 million;

WHEREAS, the Commission has granted full intervention in Case No. 2016-00370 to the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"), AT&T, Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. ("CAC"), KCTA, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky League of Cities ("KLC"), The Kroger Company ("Kroger"), Kentucky School Boards Association ("KSBA"), Lexington-Fayette Urban County Government ("LFUCG"), Sierra Club, Alice Howell, and Carl Vogel, and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively "Wal-Mart");

WHEREAS, the Commission has granted full intervention in Case No. 2016-00371 to Association of Community Ministries, Inc., AG, AT&T, United States Department of Defense and All Other Federal Executive Agencies, KCTA, KIUC, Kroger, KSBA, Louisville/Jefferson County Metro Government, Metropolitan Housing Coalition, Sierra Club and Amy Waters, JBS Swift & Co., and Wal-Mart;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of a stipulation and recommendation, attended by representatives of the Parties and the Commission Staff, took place on April 12, 13, and 17, 2017, at the offices of the Commission, which representatives of AT&T and KCTA also attended on April 12 and 13, and which representatives of KCTA also attended on April 17, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, all parties to these proceedings except AT&T and KCTA reached agreement and entered into a stipulation and recommendation ("First Stipulation"), which the Utilities filed with the Commission on April 19, 2017;

WHEREAS, a prehearing informal conference for the purpose of discussing settlement and the text of this Second Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 25, 2017, at the offices of the Commission, during which a number of procedural and substantive issues were discussed;

WHEREAS, it is understood by all Parties hereto that this Second Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Second Stipulation;

WHEREAS, the Parties agree that this Second Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues addressed herein, and that the First and Second Stipulations, considered together, produce a fair, just, and reasonable resolution of all the issues in the Rate Proceedings; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Second Stipulation, and further believe the Commission should approve it;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. RATE PSA MODIFICATIONS

1.1. Attachment Charges for Wireline Facilities. The Parties stipulate that an annual attachment charge of $7.25 for a wireline facility is fair, just, and reasonable. The Commission previously approved this charge in the Utilities' most recent general rate case proceedings, Cases No. 2014-00371 and No. 2014-00372. The Utilities have not proposed to adjust this rate, which assumes that a wireline facility will require one foot of usable pole space. AT&T and KCTA have previously advised the Commission that they have no objections to this rate remaining in effect.

1.2. Attachment Charges for Pole-Top Wireless Facilities. The Parties stipulate that a fair, just, and reasonable rate for wireless facilities attached to the top of the Utilities' structures is $36.25 per year. They agree that for purposes of determining the annual charge, a pole-top wireless facility should be allocated five feet of usable pole space. The Utilities assert that this allocation is based upon the premise that, as the Utilities typically have electric facilities located at or near the top of their distribution poles, a pole top wireless facility, such as an antenna, requires a five foot taller pole to maintain a safe working distance of at least 48 inches between the electric facilities and the pole top antenna. Thus, the Utilities assert that the Wireless Facility owner is responsible for the top 5 feet of the pole: one foot for the antenna and four feet of clearance above the power space. Without adopting the Utilities' assertions set out in the preceding two sentences, AT&T agrees that an allocation of five feet of usable pole space is supported by evidence in the record. As the Commission has previously approved the annual rate of $7.25 for one foot of pole space, the use of five feet will produce an annual charge of $36.25.

1.3. Attachment Charges for Mid-Pole Wireless Facilities. The Parties stipulate and agree that, given the lack of information regarding the size and characteristic of wireless antennas and other devices that may be attached to an electric utility pole in the communications space, a uniform rate for such attachments cannot be easily developed and that the rate for such attachments should be developed on a case-by-case basis through special contracts until a sufficient number of such attachments have been made to the Utilities' structures to develop a tariffed rate. At the time of their next general rate applications, the Utilities will determine if they have sufficient evidence regarding mid-pole devices to determine whether a uniform rate is appropriate and, if so, revise the PSA Rate Schedule accordingly.

1.4. Terms and Conditions of Rate PSA. The Parties stipulate and agree that revisions to the originally proposed version of the PSA Rate Schedule are necessary to afford sufficient flexibility for Attachment Customers to permit them to operate effectively in the unregulated, market-based telecommunications industry. The revised PSA Rate Schedules, which are shown in Exhibits 1 and 2 to this Second Stipulation, with the proposed additions and deletions clearly marked, appropriately balance an Attachment Customer's need for flexibility with the public's interest in reliable and safe electric service. The Parties stipulate that, as revised, the terms and conditions set forth in the proposed PSA Rate Schedule are fair, just, and reasonable, will promote public safety, enhance the reliability of electric service, and ensure fair and uniform treatment of Attachment Customers as well as promote the deployment and adoption of advanced communications services.

ARTICLE II. FIRST STIPULATION

2.1. No objections. AT&T and KCTA have reviewed the First Stipulation filed with the Commission on April 19, 2017 and have no objections to it, except to the extent the First

Stipulation's electric tariff exhibits contained PSA Rate Schedules inconsistent with this Second Stipulation and its exhibits, in which case the latter should control.

2.2. AMS Collaborative. The Parties agree that the Utilities shall notify AT&T and KCTA if and when it engages in any AMS Collaborative pursuant to the First Stipulation § 1.2 and that AT&T and KCTA may, at their option, participate in any or all phases of the AMS Collaborative.

ARTICLE III. MISCELLANEOUS PROVISIONS

3.1. Except as specifically stated otherwise in this Second Stipulation, entering into this Second Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

3.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and request the Commission to approve the Second Stipulation.

3.3. Following the execution of this Second Stipulation, the Parties shall cause it to be filed with the Commission on or about May 1, 2017, together with a request to the Commission for consideration and approval of this Second Stipulation for rates to become effective for service rendered on and after July 1, 2017.

3.4. This Second Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Second Stipulation and the First Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the First and Second Stipulations, taken together, produce a fair, just, and reasonable means of resolving all issues in these proceedings, and will clearly and definitively ask the Commission to accept and approve the First and Second Stipulations as such.

3.5. If the Commission issues an order adopting this Second Stipulation in its entirety and without additional conditions, irrespective of whether the Commission approves the terms of the First Stipulation, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to the portions of such order that concern this Second Stipulation. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation. All Parties agree that no monetary damages will be sought or obtained from a Party if the Party is not in breach, but rather a non-Party purporting to act for the Party has sought rehearing or appeal of a Commission order adopting this Second Stipulation in its entirety and without additional conditions.

3.6. If the Commission does not accept and approve this Second Stipulation in its entirety and without additional conditions, then any adversely affected Party may withdraw from the Second Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all

Parties that have not withdrawn will continue to be bound by the terms of the Second Stipulation as modified by the Commission's order.

3.7. If the Second Stipulation is voided or vacated for any reason after the Commission has approved the Second Stipulation, none of the Parties will be bound by the Second Stipulation.

3.8. The Second Stipulation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

3.9. The Second Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

3.10. The Second Stipulation, including its Exhibits, constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Second Stipulation.

3.11. The Parties hereto agree that, for the purpose of the Second Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

3.12. The Parties hereto agree that neither the Second Stipulation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Second Stipulation. This Second Stipulation shall not have any precedential value in this or any other jurisdiction.

3.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Second

Stipulation and based upon the foregoing are authorized to execute this Second Stipulation on behalf of their respective Parties.

3.14. The Parties hereto agree that this Second Stipulation is a product of negotiation among all Parties hereto, and no provision of this Second Stipulation shall be strictly construed in favor of or against any party.

3.15. The Parties hereto agree that this Second Stipulation may be executed in multiple counterparts.

(This space intentionally left blank.)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R. Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (with permission KRR)
Allyson K. Sturgeon

BellSouth Telecommunications, LLC d/b/a AT&T Kentucky

HAVE SEEN AND AGREED:

By: Cheryl R Winn

Cheryl R. Winn

Kentucky Cable Telecommunications Association

HAVE SEEN AND AGREED:

By: ______________________________

Gardner F. Gillespie
Paul Werner
Megan Grant

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2016-00370 DATED JUN 22 2017

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09070

SCHEDULE RTOD-ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Month	$12.25
Energy Charge per kWh	
Off Peak Hours	$ .05916
On Peak Hours	$ .27646

SCHEDULE RTOD-DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Month	$12.25
Energy charge per kWh	$ 0.04504
Demand Charge per kW	
Off Peak Hours	$ 3.44
On Peak Hours	$ 7.87

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per Month	$12.25
Energy Charge per kWh	$ .09070

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Month – Single Phase	$31.50
Basic Service Charge per Month – Three Phase	$50.40
Energy Charge per kWh	$ .10428

SCHEDULE AES
ALL ELECTRIC SCHOOL

Basic Service Charge per Month – Single Phase	$ 85.00
Basic Service Charge per Month – Three Phase	$140.00
Energy Charge per kWh	$ .08306

SCHEDULE PS
POWER SERVICE

Secondary Service:	
Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$ 20.17
Winter Rate	$ 17.95
Energy Charge per kWh	$ .03547
Primary Service:	
Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Summer Rate	$ 20.35
Winter Rate	$ 18.16
Energy Charge per kWh	$ .03448

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 2.73
Intermediate Demand Period	$ 6.11
Peak Demand Period	$ 7.79
Energy Charge per kWh	$ .03508

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.75
Intermediate Demand Period	$ 5.03
Peak Demand Period	$ 6.43
Energy Charge per kWh	$ .03415

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.99
Intermediate Demand Period	$ 4.94
Peak Demand Period	$ 6.31
Energy Charge per kWh	$ .03338

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:

Basic Service Charge per Month	$ 330.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.45
Intermediate Demand Period	$ 4.48
Peak Demand Period	$ 5.91
Energy Charge per kWh	$ .03415

Transmission:

Basic Service Charge per Month	$1,500.00
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.53
Intermediate Demand Period	$ 2.29
Peak Demand Period	$ 3.25
Energy Charge per kWh	$ .03315

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only	Ornamental
High Pressure Sodium:		
5,800 Lumens - Cobra Head	$ 9.86	$ 13.52
9,500 Lumens - Cobra Head	$ 10.34	$ 14.21
22,000 Lumens - Cobra Head	$ 16.08	$ 20.22
50,000 Lumens - Cobra Head	$ 25.61	$ 28.37
9,500 Lumens - Directional	$ 10.19	
22,000 Lumens - Directional	$ 15.42	
50,000 Lumens - Directional	$ 21.95	
9,500 Lumens - Open Bottom	$ 8.87	
Metal Halide		
32,000 Lumens - Directional	$ 22.80	
Light Emitting Diode (LED)		
8,179 Lumens - Cobra Head	$ 14.92	
14,166 Lumens - Cobra Head	$ 18.09	
23,214 Lumens - Cobra Head	$ 27.63	
5,007 Lumens - Open Bottom	$ 9.94	

Underground:

	Fixture Only	Decorative Smooth	Historic Fluted
High Pressure Sodium:			
5,800 Lumens - Colonial		$ 12.59	
9,500 Lumens - Colonial		$ 12.92	
5,800 Lumens - Acorn		$ 17.18	$ 24.50
9,500 Lumens - Acorn		$ 17.63	$ 25.09
5,800 Lumens - Victorian			$ 34.07
9,500 Lumens - Victorian			$ 34.39
5,800 Lumens - Contemporary	$ 17.12	$ 19.35	
9,500 Lumens - Contemporary	$ 17.00	$ 23.94	

22,000 Lumens - Contemporary	$ 19.84	$ 30.82
50,000 Lumens - Contemporary	$ 24.15	$ 38.09
4,000 Lumens - Dark Sky Lantern		$ 24.87
9,500 Lumens - Dark Sky Lantern		$ 25.99
Metal Halide		
32,000 Lumens - Contemporary	$ 24.68	$ 38.87
Light Emitting Diode (LED)		
8,179 Lumens - Cobra Head		$ 35.44
14,166 Lumens - Cobra Head		$ 38.61
23,214 Lumens - Cobra Head		$ 48.14
5,665 Lumens - Open Bottom		$ 37.51

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture and Pole
High Pressure Sodium:		
4,000 Lumens - Cobra Head	$ 8.84	$ 12.16
50,000 Lumens - Cobra Head	$ 14.06	
5,800 Lumens - Open Bottom	$ 8.54	
Metal Halide		
12,000 Lumens - Directional	$ 16.13	$ 20.89
32,000 Lumens - Directional		$ 27.56
107,800 Lumens - Directional	$ 47.70	$ 52.45
Mercury Vapor:		
7,000 Lumens - Cobra Head	$ 10.83	$ 13.34
10,000 Lumens - Cobra Head	$ 12.84	$ 15.07
20,000 Lumens - Cobra Head	$ 14.53	$ 17.01
7,000 Lumens - Open Bottom	$ 11.87	
Incandescent:		
1,000 Lumens - Tear Drop	$ 3.81	
2,500 Lumens - Tear Drop	$ 5.11	
4,000 Lumens - Tear Drop	$ 7.63	
6,000 Lumens - Tear Drop	$ 10.19	

Underground:

		Decorative Smooth	Historic Fluted
Metal Halide			
12,000 Lumens - Directional		$ 31.20	
32,000 Lumens - Directional		$ 36.99	
107,800 Lumens - Directional		$ 61.66	
12,000 Lumens - Contemporary	$ 17.45	$ 31.42	
107,800 Lumens - Contemporary	$ 51.32	$ 65.28	
High Pressure Sodium:			
4,000 Lumens - Acorn		$ 15.69	$ 23.13
4,000 Lumens - Colonial		$ 11.18	
5,800 Lumens - Coach		$ 34.07	
9,500 Lumens - Coach		$ 34.39	
16,000 Lumens - Granville		$ 62.30	

SCHEDULE TE
TRAFFIC ENERGY SERVICE

Basic Service Charge per Month	$ 4.00
Energy Charge per kWh	$ .09013

SCHEDULE PSA
POLE AND STRUCTURE ATTACHMENT CHARGES

Per Year for Each Attachment to Pole	$ 7.25
Per Year for Each Linear Foot of Duct	$ .81
Per Year for Each Wireless Facility	$36.25

RATE CSR-1
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 3.20	$ 3.31
Non-compliance Charge Per kVA	$16.00	$16.00

RATE CSR-2
CURTAILABLE SERVICE RIDER

	Transmission	Primary
Demand Credit per kVA	$ 5.90	$ 6.00
Non-compliance Charge Per kVA	$ 16.00	$ 16.00

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	$ 1.04
Primary Distribution	$ .86

EVSE
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	$182.27
Dual Charger	$306.01

EVC
ELECTRIC VEHICLE CHARGING SERVICE

Fee per Hour	$ 2.84

EVSE-R
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:	
Single Charger	$131.41
Dual Charger	$204.31

SSP
SOLAR SHARE PROGRAM RIDER

Monthly Charge:	
Solar Capacity Charge	$ 6.24
Solar Energy Credit per kWh of Pro Rata Energy Produced:	
RS	$ .03520
RTOD-Energy	$ .03520
RTOD-Demand	$ .03520
VFD	$ .03520

GS	$ .03524
AES	$ .03526
PS Secondary	$ .03547
PS Primary	$ .03448
TODS	$ .03508
TODP	$ .03415

SPS
SCHOOL POWER SERVICE

Secondary Service:	
Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Summer Rate	$ 17.89
Winter Rate	$ 15.92
Energy Charge per kWh	$ .03572

STOD
SCHOOL TIME-OF-DAY SERVICE

Basic Service Charge per Month	$200.00
Maximum Load Charge per kW:	
Base Demand Period	$ 4.83
Intermediate Demand Period	$ 4.25
Peak Demand Period	$ 5.76
Energy Charge per kWh	$ .03527

OSL
OUTDOOR SPORTS LIGHTING SERVICE

Secondary Service:	
Basic Service Charge per Month	$ 90.00
Demand Charge per kW:	
Peak Demand Period	$ 16.15
Base Demand Period	$ 2.73
Energy Charge per kWh	$ .03571
Primary Service:	
Basic Service Charge per Month	$240.00
Demand Charge per kW:	
Peak Demand Period	$ 16.32
Base Demand Period	$ 2.75
Energy Charge per kWh	$ .03472

UNAUTHORIZED RECONNECT CHARGE

Tampering or Unauthorized Connection or Reconnection Fee:	
Meter Replacement Not Required	$ 70.00
Single Phase Standard Meter Replacement Required	$ 90.00
Single Phase AMR Meter Replacement Required	$ 110.00
Single Phase AMS Meter Replacement Required	$ 174.00
Three Phase Meter Replacement Required	$ 177.00

HEA
HOME ENERGY ASSISTANCE PROGRAM

Per Month	$ .30

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Atlanta, GEORGIA 30308

AG Exhibit 6

RATE SP

SEASONAL SPORTS SERVICE

APPLICABILITY

Applicable to electric service required for sports installations, such as football and baseball fields, swimming pools, tennis courts, and recreational areas, promoted, operated and maintained by non-profit organizations, such as schools, churches, civic clubs, service clubs, community groups, and municipalities, where such service is separately metered and supplied at one point of delivery, except, not applicable to private sports installations which are not open to the general public. This rate is available only to customers to whom service was supplied in accordance with its terms on June 25, 1981.

TYPE OF SERVICE

Alternating current 60 Hz, single or three phase at the Company's standard secondary voltage.

NET MONTHLY BILL

Computed in accordance with the following charges (kilowatt hours are abbreviated as kWh):

1. Base Rate
   (a) Customer Charge $7.50 per month

   (b) Energy Charge $0.100598 per kWh (R)

2. Applicable Riders
   The following riders are applicable pursuant to the specific terms contained within each rider:
   Sheet No. 78, Rider DSMR, Demand Side Management Rider
   Sheet No. 80, Rider FAC, Fuel Adjustment Clause
   Sheet No. 81, Rider MSR-E, Merger Savings Credit Rider – Electric
   Sheet No. 82, Rider PSM, Profit Sharing Mechanism

The minimum charge shall be a sum equal to 1.5% of the Company's installed cost of transformers and metering equipment required to supply and measure service, but not less than the customer charge whether service is on or disconnected.

RECONNECTION CHARGE

A charge of $25.00 is applicable to each season to cover in part the cost of reconnection of service.

LATE PAYMENT CHARGE

Payment of the Net Monthly Bill must be received in the Company's office within twenty-one (21) days from the date the bill is mailed by the Company. When not so paid, the Gross Monthly Bill, which is the Net Monthly Bill plus 5%, is due and payable.

Issued by authority of an Order of the Kentucky Public Service Commission dated July 31, 2017 in Case No. 2017-00005. (T)

Issued: August 18, 2017 (T)
Effective: August 30, 2017 (T)
Issued by James P. Henning, President (T)

KENTUCKY
PUBLIC SERVICE COMMISSION
John Lyons
ACTING EXECUTIVE DIRECTOR
EFFECTIVE
8/30/2017
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TERMS AND CONDITIONS

The term of contract shall be for a minimum period of one (1) year terminable thereafter on thirty (30) days written notice by either the customer or the Company.

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission, as provided by law.

(T)
(T)
(T)
(T)

AG Exhibit 7

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00321

ORDER

Duke Energy Kentucky, Inc. ("Duke Kentucky") is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to approximately 140,600 consumers in Boone, Campbell, Grant, Kenton, and Pendleton counties.[1] Duke Kentucky also is a utility engaged in purchasing, selling, storing, and transporting natural gas to approximately 98,200 customers in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton counties.[2] Its most recent general rate increase for its electric operations was granted in Case No. 2006-00172.[3]

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[1] Application at 2. *See also*, Direct Testimony of James P. Henning ("Henning Testimony") at 4.

[2] *Id.*

[3] Application at 4. Case No. 2006-00172, *Application of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky for an Adjustment of Electric Rates* (Ky. PSC Dec. 21, 2006).

BACKGROUND

On September 1, 2017, Duke Kentucky filed an application requesting authorization to increase its electric base rate revenue to a new total of $357.5 million, which reflects an increase from its current rates of approximately $48.6 million.[4] The monthly residential electric bill increase due to the proposed electric base rates would be 17.1 percent, or approximately $15.17, for a typical residential customer using 1,000 kWh of electricity.[5] Duke Kentucky subsequently revised its proposed revenue increase to $30.12 million.[6] The revised revenue requirement would amount to an 11 percent increase, or approximately $9.73, for a typical residential customer using 1,000 kWh of electricity each month.[7] Duke Kentucky states that the primary reason for the requested increase is that Duke Kentucky's earned rate of return on capitalization obtained from its current electric operations is 2.850 percent, which is inadequate to enable Duke Kentucky to continue providing safe, reasonable, and reliable service to its customers, and is insufficient to afford Duke Kentucky a reasonable opportunity to earn a fair return on its investment property that is used to provide such service while attracting necessary capital at reasonable rates.[8] In addition to the base rate increase, Duke Kentucky also is requesting authority to recover certain regulatory assets, including storm restoration expenses resulting from Hurricane Ike in 2008; research and development investments;

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[4] Application at 5.

[5] *Id.*

[6] Amended Rebuttal Testimony of Sarah E. Lawler at 1.

[7] Duke Kentucky's response to Commission Staff's Post-Hearing Data Request ("Staff's PH-DR"), Item 9.

[8] Application at 6.

incremental operations and maintenance ("O&M") related to the acquisition of the entirety of the East Bend Generating Station ("East Bend"); and O&M expenses related to the creation of a residential Advanced Metering Infrastructure ("AMI") opt-out tariff.[9]

Duke Kentucky also is proposing to implement a distribution reliability and integrity improvement plan that will be comprised of specific new and Commission-approved measures to enhance the safety and reliability of Duke Kentucky's distribution system.[10] Duke Kentucky requests to recover the costs of this plan through a surcharge mechanism called Rider Distribution Capital Investment ("Rider DCI").[11] Duke Kentucky proposes, as part of this application, a Targeted Underground program to improve distribution reliability by relocating at-risk overhead circuits to underground service.[12] Rider DCI would include incremental capital investment, depreciation, taxes, and a reasonable return that is incremental to base rates.[13] Rider DCI would be adjusted and subject to annual true-up following Commission review and approval; the annual application also would include any new reliability or integrity programs for Commission consideration and approval for implementation as part of Duke Kentucky's distribution integrity and reliability plan.[14]

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[9] *Id.*

[10] *Id.* at 13–14.

[11] *Id.*

[12] Application at 14.

[13] *Id.*

[14] *Id.*

Also as part of the instant application, Duke Kentucky is requesting approval of an environmental compliance plan and the establishment of an environmental surcharge mechanism, both pursuant to KRS 278.183.[15]

Duke Kentucky is seeking approval of a new reconciliation mechanism to recover FERC-jurisdictional transmission expenses that Duke Kentucky incurs, incremental (above and below) to what is reflected in base rates ("Rider FTR").[16] According to Duke Kentucky, Rider FTR will operate much like its fuel adjustment clause ("FAC") and Accelerated Service Replacement Program in that such transmission costs will be filed regularly and subject to periodic review by the Commission.[17]

Lastly, Duke Kentucky also is proposing to modify the following existing policies and tariffs and implement the following new programs and measures: a voluntary Enhanced Customer Solutions, including optional billing alternatives and notifications; a revised FAC; a revised Profit Sharing Mechanism Rider ("Rider PSM"); a new LED street lighting tariff; and revisions to its cogeneration tariff.[18] Duke Kentucky submitted a depreciation study in support of its application, and requests that its proposed depreciation rates be approved.

By letter dated September 7, 2017, the Commission notified Duke Kentucky that its application was rejected because it contained filing deficiencies and that the application would not be deemed filed until the deficiencies were cured. Duke Kentucky submitted information on September 15, 2017, addressing the deficiencies. By Order

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[15] Application at 15.

[16] Application at 18–19.

[17] Application at 19.

[18] Application at 20.

dated September 27, 2017, the Commission determined that Duke Kentucky had cured all of the filing deficiencies and that Duke Kentucky's application was deemed filed as of September 15, 2017. The September 27, 2017 Order also found that the earliest date that Duke Kentucky's proposed rates could be effective was October 15, 2017. Pursuant to the September 27, 2017 Order, the Commission suspended Duke Kentucky's proposed rates for six months, up to and including April 14, 2018. Further, the September 27, 2017 Order established a procedural schedule for the processing of this matter, which provided for a deadline for filing intervention requests; two rounds of discovery upon Duke Kentucky's application; a deadline for the filing of intervenor testimony; one round of discovery upon any intervenor testimony; and an opportunity for Duke Kentucky to file rebuttal testimony.

The following parties were granted intervention in this proceeding: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Board Association ("KSBA"); Kroger Company ("Kroger"); and Northern Kentucky University ("NKU").

The Commission held an information session and public meeting for the purpose of taking public comments on February 8, 2018, at Boone County High School in Florence, Kentucky. A formal hearing was held at the Commission's offices on March 6–8, 2018. Duke Kentucky provided responses to post-hearing data requests on March 23, 2018, and April 10, 2018. All of the parties filed simultaneous post-hearing briefs on April 2, 2018. The matter now stands submitted for a decision.

REVENUE AND EXPENSES

Contested Revenue Requirement Issues

Duke Kentucky originally proposed an annual increase in its electric revenues of $48,646,213.[19] Duke Kentucky subsequently revised its requested revenue requirement increase to $30,119,059.[20] The Attorney General is the only intervenor who presented evidence addressing Duke Kentucky's proposed revenue increase, arguing that Duke Kentucky should be required to decrease its electric revenues by $11,901,000.[21] The Commission must consider the evidentiary record on these issues as presented by Duke Kentucky and the Attorney General and render a decision based on a determination of Duke Kentucky's capital, rate base, operating revenues, operating expenses, and revenue allocation.

Test Period

Duke Kentucky proposes the 12-month period ending March 31, 2019, as the forecasted test period for determining the reasonableness of its proposed rates. None of the intervenors contested the use of this period as the test period. The Commission finds it is reasonable to use the 12-month period ending March 31, 2019, as the test period in this case. That 12-month period is the most feasible period to use for setting rates based on the timing of Duke Kentucky's filing and, except for the adjustments approved herein, the revenues and expenses incurred during that period are neither unusual nor

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[19] Application, Schedule C-1.

[20] Amended Rebuttal Testimonies of William Don Wathen, Jr. and Sarah E. Lawler ("Amended Rebuttal Testimonies of Wathen and Lawler") at page 3.

[21] Testimony Errata for Lane Kollen at page 4. In his Post-Hearing Brief, the Attorney General revised his recommended decrease to $14.839 million.

extraordinary. In using this forecasted test period, the Commission has given full consideration to appropriate known and measurable changes.

Jurisdictional Rate Base Ratio

Duke Kentucky proposed a test-year-end Kentucky jurisdictional rate base of $700,204,561.[22] The Kentucky jurisdictional electric rate base is divided by Duke Kentucky's test-year-end total company electric rate base to derive the Kentucky jurisdictional electric rate base ratio ("Jurisdictional Ratio") for Duke Kentucky. This Jurisdictional Ratio is then applied to Duke Kentucky's total company electric capitalization to derive its Kentucky jurisdictional electric capitalization. The Jurisdictional Ratio uses the test-year-end rate base before any ratemaking adjustments applicable to either Kentucky jurisdictional operations or other jurisdictional operations. Duke Kentucky used a Jurisdictional Ratio of 100 percent.[23] The Commission has reviewed and agrees with the calculation of Duke Kentucky's test-year electric rate base for purposes of establishing the Jurisdictional Ratio.

Pro Forma Jurisdictional Rate Base

Duke Kentucky calculated a pro forma jurisdictional rate base of $700,204,561,[24] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base. The Attorney General provided testimony and several adjustments to Duke Kentucky's proposed rate base as discussed below. The Commission finds seven adjustments are warranted to Duke Kentucky's rate base. The

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[22] Application, Schedule B-1.

[23] *Id.*, Schedule B-7.

[24] *Id.*, Schedule B.1. Duke Kentucky is not requesting to include recovery of Construction Work in Progress in base rates.

Commission finds that the excess amortization of the Carbon Management Research Group regulatory asset in the test year and the amortization of excess accumulated deferred income tax ("ADIT") should be added to the rate base. The Commission also finds that the East Bend Operations and Maintenance Expense ("East Bend O&M") regulatory asset, the East Bend Ash Pond Asset Retirement Obligation ("East Bend Ash Pond ARO") regulatory asset, the reduction in cash working capital ("CWC"), and the reduction in depreciation expense as discussed herein due to the Commission's decision to deny use of the Equal Life Group ("ELG") procedure and require use of the Average Life Group ("ALG") procedure for computing depreciation rates, net of the related ADIT as found reasonable herein, should be removed from rate base.

The Commission accepts Duke Kentucky's proposed amortization of the protected excess ADIT. The amortization for the protected excess ADIT is based upon the Average Rate Assumption Method ("ARAM"). For the unprotected excess ADIT, the Attorney General initially proposed a 20-year amortization period.[25] Subsequently, the Attorney General proposed a five-year amortization period for the unprotected excess ADIT but did not amend his testimony to reflect the change in the amortization period.[26] The Commission finds that a reasonable amortization period for the excess ADIT for Duke Kentucky's unprotected assets should be 10 years. A 10-year amortization period for the unprotected excess ADIT will balance the impact to Duke Kentucky's cash flow and provide ratepayers the full benefit of the reduction in the federal corporate income tax in a timely manner. As a result of the foregoing adjustments, the Commission finds the total

[25] *Id.*

[26] March 8, 2018, Video Transcript of Evidence at 3:35:00.

test-year amortization for the total excess ADIT to be $4,471,984, which is an increase of $1,651,639 over the amount proposed by Duke Kentucky. The Commission finds that the amortization of the excess ADIT related to protected and unprotected excess ADIT found reasonable herein should be removed from Duke Kentucky's ADIT, which increases its rate base. Therefore, Duke Kentucky's rate base should be increased by $4,471,984 for this adjustment.

Duke Kentucky deferred $2 million it incurred to fund carbon management research by the Carbon Management Research Group ("CMRG"). In Case No. 2008-00308, Duke Kentucky sought and obtained authorization from the Commission to defer these costs for accounting purposes.[27] The regulatory asset, net of ADIT, is included in the capitalization in this proceeding. In the instant matter, Duke Kentucky sought to recover the amortization of the deferred asset over a five-year period at $400,000 per year. In the Commission's Order in Case No. 2008-00308, it stated that the CMRG regulatory asset will be amortized over a 10-year period or $200,000 per year. Therefore, the Commission finds that the Duke Kentucky's capitalization should be increased by $200,000 to reflect the proper amount of the regulatory asset in the rate base.

The Commission finds that the ADIT arising from its requirement to change Duke Kentucky's procedure for computing depreciation rates from the ELG to the ALG procedure should reduce Duke Kentucky's rate base. As discussed in the testimony of the Attorney General, the ELG procedure front-loads depreciation expense in earlier

[27] Case No. 2008-00308, *Joint Application of Duke Energy Kentucky, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets* (Ky. PSC Oct. 30, 2008).

years and decreases it in the later years of an asset's depreciable life, creating a mismatch of revenues and expenses.[28] The Attorney General states that the ALG procedure is the dominant procedure for other electric utilities, including all other electric utilities in Kentucky.[29] Therefore, the Commission finds that the Attorney General's position on this issue is reasonable and that Duke Kentucky should use the ALG procedure for computing depreciation rates, and that its rate base should be reduced by $2,733,299 to reflect the increase in ADIT.

The East Bend O&M regulatory asset was approved by the Commission in Case No. 2014-00201.[30] In addition, in that proceeding, the Commission authorized Duke Kentucky to defer carrying charges on the O&M expense at its cost of debt. The Attorney General disputed the amount of the regulatory asset and made a recommendation of the amount of amortization assuming that the regulatory asset was included in rate base.[31]

The Commission finds that the East Bend O&M regulatory asset should be removed from rate base and Duke Kentucky's request to amortize the East Bend O&M regulatory asset over a 10-year period is reasonable and should be approved. The Commission also finds that carrying charges should be based on the cost of debt approved herein. This adjustment reduces Duke Kentucky's rate base by $36,540,123.

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[28] Direct Testimony of Lane Kollen ("Kollen Testimony") beginning at 31.

[29] *Id.* at 32

[30] Case No. 2014-00201, *Application of Duke Energy Kentucky, Inc. for (1) a Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs Incurred as part of the Acquisition; and (4) All Other Necessary Waivers, Approvals and Relief* (Ky. PSC Dec. 4, 2014).

[31] Kollen Testimony at 31.

The East Bend Ash Pond ARO was approved by the Commission in Case No. 2015-00187.[32] Duke Kentucky proposed that the East Bend Ash Pond ARO amortization be recovered through the Environmental Surcharge Mechanism ("ESM") in its application. In addition, Duke Kentucky requested a 10-year amortization period. The Attorney General proposed that the East Bend Ash Pond ARO be removed from capitalization, as it was erroneous for Duke Kentucky to include it in both its ESM rider rate base and in base rates. The Commission finds the East Bend Ash Pond ARO should not be included in base rates because that amount is proposed to be recovered through Duke Kentucky's ESM. The Commission also finds that a 10-year amortization period is reasonable and should be approved. The parties have agreed upon this issue. This adjustment reduces Duke Kentucky's rate base by $18,509,346.

The CWC allowance included in rate base shown below is based on the adjusted operation and maintenance expenses discussed in this Order, as approved by the Commission. This adjustment reduces Duke Kentucky's rate base by $2,008,320.

Based on the Commission's finding herein where it denied Duke Kentucky's proposal to use ELG procedure rather than the ALG procedure for computing depreciation rates, the Commission finds that Duke Kentucky's accumulated depreciation in its rate base should be increased by $6,919,475.

We have determined Duke Kentucky's pro forma jurisdictional rate base for rate-making purposes for the test year to be as follows:

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[32] Case No. 2015-00187, *Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations* (Ky. PSC Dec. 15, 2015).

Total Utility Plant in Service	$1,675,994,650
Add:	
Cash Working Capital Allowance	12,207,087
Other Working Capital Allowances	40,420,974
Subtotal	$52,628,061
Deduct:	
Accumulated Depreciation	839,228,648
Accumulated Deferred Income Taxes	237,388,861
Subtotal	$1,076,617,509
Pro Forma Rate Base	$652,005,202

Reproduction Cost Rate Base

KRS 278.290 (1) states, in relevant part, that:

> the commission shall give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for rate-making purposes.

Neither Duke Kentucky nor the Attorney General provided information relative to Duke Kentucky's proposed Kentucky jurisdictional reproduction cost rate base. Therefore, the Commission finds that using Duke Kentucky's historic costs for deriving its rate base is appropriate and consistent with Commission precedents involving Duke Kentucky as well as other Kentucky jurisdictional utilities.

Revenue and Expenses

For the test year, Duke Kentucky reported actual net operating income from its electric operations of \$19,212,679.[33] Duke Kentucky proposed 33 adjustments to revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income of \$20,091,071.[34] Through discovery, this amount was adjusted to \$38,533,427. With this level of net operating income, Duke Kentucky reported an adjusted test-year revenue deficiency of \$30,119,059.[35]

The Attorney General accepted 28 of Duke Kentucky's proposed adjustments to its test-year revenues and expenses; adjustments that are also acceptable to the Commission.[36] A list of the accepted adjustments is contained in the attached Appendix A.

The Attorney General proposed 17 adjustments to Duke Kentucky's operating income. Through discovery, the Attorney General and Duke Kentucky agreed on four of the operating income issues. The four items agreed upon are the inclusion of PJM make-whole and other revenues not included in Duke Kentucky's revenue forecast, the reduction in RTEP charges, the CMRG regulatory amortization expense, and the reduction in income tax expense for the research tax credits. The remaining operating income issues relate to: 1) including off-system sales ("OSS") margins to reset Rider PSM to zero; 2) reduce replacement power expense; 3) reduce vegetation management

[33] Application, Schedule C-2.

[34] *Id.*

[35] Amended Rebuttal Testimonies of Wathen and Lawler at 3.

[36] Appendix A shows the 33 adjustments to revenues and expenses accepted by the Attorney General.

expense to historic levels; 4) reduce planned outage O&M normalization; 5) reduce incentive compensation expense tied to financial performance; 6) reduce retirement plan expense; 7) increase AMI benefit levelization adjustment; 8) reduce amortization of East Bend regulatory asset to reflect lower O&M expense prior to test year; 9) reduce depreciation expense by using the ALG procedure; 10) reduce depreciation expense by removing terminal net salvage for generating units; 11) reduce remaining net salvage value included in depreciation expense; 12) reduce income tax expense to reflect reduction in federal rate; and, 13) reduce income tax expense to reflect amortization of excess ADIT, which the Commission makes the following conclusions listed below. In addition, the Commission has a discussion on the impacts of the Tax Cuts and Jobs Act ("TCJA") which was enacted on December 23, 2017.

These adjustments, and the discussion and findings thereon pertain solely to Duke Kentucky's base-rate revenue requirements. In addition to base rates, Duke Kentucky's application includes a number of proposed riders or surcharges. On the various base-rate adjustments, the Commission makes the following findings:

Rider PSM Margins

Duke Kentucky proposes to continue to include all OSS margins in the Rider PSM and that the margins be shared between customers and shareholders. Currently, ratepayers receive the benefit of the first $1 million and any margins above $1 million are shared 75 percent to ratepayers and 25 percent to shareholders. Duke Kentucky proposes to have all margins shared 90 percent to ratepayers and 10 percent to shareholders. In response to Staff's Post-Hearing Data Request, Item 11, regarding a comparison of the level of sharing under the current methodology and under the proposed change for the last three years, if Duke Kentucky's proposed split had been in effect for the years 2015, 2016, and 2017, customers would have benefited by an additional $2.1 million in 2015, $0.8 million in 2016, and $1.6 million in 2017.

The Attorney General recommends the forecasted OSS margins be removed from Rider PSM and be included as a reduction to base rates. The Attorney General states that the Commission has historically included OSS margins in the base revenue requirement and contemporaneously reset the relevant sharing mechanism to $0. The impact of this adjustment would be to reduce Duke Kentucky's proposed revenue requirement by $3.826 million.

The Commission finds that Duke Kentucky's proposal to not include PSM margins in base rates is reasonable and should be approved because the proposal would provide savings to its customers. The other Duke Kentucky proposals related to Rider PSM are discussed in the Proposed Tariff Changes section of this Order.

Replacement Power Expense

Duke Kentucky proposes to include $5.668 million that cannot be recovered through the FAC as replacement power expense for the incremental fuel and other expenses due to unplanned outages at the East Bend Station.[37] Duke Kentucky also requests authority to defer replacement power expense greater than or less than the expense included in the base rate requirement, subject to future review for ratemaking recovery.

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[37] Duke Kentucky's response to the Attorney General's First Set of Data Requests ("AG's First Request"), Item 11.

The Attorney General argues that Duke Kentucky's forecasted replacement power expense is excessive compared to the actual replacement power expense of the East Bend Station for the last three years.[38] Based on the average actual replacement power expense of $1.610 million for the years 2015–2017, the Attorney General recommends Duke Kentucky's purchased power expense be reduced by $4.058 million. The Attorney General, however, agrees that Duke Kentucky should be authorized to establish a deferral mechanism for those incremental amounts greater than or less than what is in base rates for replacement power expense.[39]

The Commission agrees with the Attorney General's recommendation to reduce replacement power expense by $4.058 million, as Duke Kentucky's proposed adjustment is significantly greater than its actual costs for the prior three years (2015-2017). The changes in Duke Kentucky's generation mix, the abnormal purchased power costs in 2014 due to the polar vortex, and the use of future years in the computation of the replacement power expense make Duke Kentucky's proposed adjustment unreasonable relative to historical normalized costs. The Commission also finds that Duke Kentucky's proposed deferral mechanism is reasonable and should be approved.

Vegetation Management Expense

Duke Kentucky proposed a vegetation management expense of $4.480 million in its application.[40] This number is based in part upon Duke Energy Business Services' ("DEBS") experience in the Midwest market in its three jurisdictions (Kentucky, Indiana,

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[38] Kollen Testimony at 11.

[39] *Id.* at 12.

[40] Duke Kentucky's response to Commission Staff's Second Request for Information ("Staff's Second Request"), Item 18.

and Ohio) for the period that extends into the first quarter of 2019. The proposed amount for the vegetation management expense represents an increase of $2.879 million over the base period amount.

Duke Kentucky states that its vegetation management service is almost exclusively performed by outside contractors.[41] It maintains that the large increase was primarily due to market forces as resources eligible to properly engage in vegetation management activities have become constrictive and extremely competitive for limited qualified resources.[42] Duke Energy Corporation contracts for vegetation management services throughout its service territory.[43] Its sourcing specialists engage in a Request for Proposal ("RFP") process to seek out companies that can provide the best service at the least cost throughout its entire service territory.[44] Duke Energy Corporation issued a RFP for vegetation management services for calendar years 2018 through 2020. Duke Kentucky chose a contractor who could perform the required service, but it resulted in a substantially higher cost than it had historically incurred.

Duke Kentucky maintains that it is not cost-effective for a supplier to split up vegetation management services by a smaller geographic area in its service territory.[45] Duke Kentucky further states that the means to gain the most effective contract pricing is to have sufficient work to keep a contractor's resources working all year, and that

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[41] April N. Edwards Rebuttal Testimony at 5.

[42] *Id*. at 6.

[43] *Id*.

[44] *Id*.

[45] Duke Kentucky's response to Staff's Post-Hearing Data Request, Item 2.b.

subdividing its zone into smaller segments would not provide enough work to allow that to take place.[46]

The Attorney General argued that Duke Kentucky's proposed vegetation management expense is excessive compared to the company's actual expense in the years 2012 through 2016, which ranged from a low of $1.774 million to a high of $2.309 million, with an average of $2.080 million.[47] The Attorney General recommended the Commission use a more realistic forecast based on the actual average expense mentioned above, which results in a reduction in vegetation management expense of $2.400 million.

The Commission has reviewed the confidential cost-benefit study[48] and other information related to vegetation management expense in the record of this case. We understand the market forces that have influenced this area of expense. However, we are concerned about the large increase and will require Duke Kentucky to study this issue further in order to find ways of making its vegetation management more cost-effective.

The Commission finds Duke Kentucky's proposed vegetation management expense should be reduced by $0.444 million, based on deducting the four-year average for fiscal years ending March 31, 2019, through March 31, 2022, of $4,035,571 from Duke Kentucky's proposed test year amount of vegetation management expense of $4,479,887.[49] Further, the Commission finds that, in conjunction with its next Master

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[46] *Id.*

[47] Kollen Testimony at 15.

[48] Duke Kentucky's response to the Attorney General's Post-Hearing Data Request, Item 4.

[49] Duke Kentucky response to Commission Staff's Third Request for Information ("Staff's Third Request"), Item 14.

Agreement for Vegetation Management Service ("MAVMS") contract, DEBS, in conjunction with Duke Kentucky, should bid the next MAVMS contract for the Midwest market that includes Kentucky, Indiana, and Ohio, and for a smaller geographic area limited to Duke Kentucky's service territory. The smaller geographic area should include Duke Kentucky's service territory by itself or by county or such other discrete area(s) within its service territory that it deems to be reasonable. Duke Kentucky shall provide an update of this process in its annual Vegetation Management Plan ("VMP") filings beginning with the 2019 VMP.

Planned Outage Expense

Duke Kentucky's forecasted test year included $8.400 million in East Bend planned outage expense, which was calculated based on the average of the actual expense for years 2013 through 2016 and forecast expense for years 2017 and 2018.[50] Duke Kentucky also requests authority to defer any actual planned outage expense that is more or less than the normalized planned outage expense included in its base rates.

The Attorney General contends that the amount is excessive because Duke Kentucky failed to include the forecast expense for 2019, which would have reduced the average amount of planned outage expenses to $7.200 million.[51] The Attorney General recommends reducing Duke Kentucky's revenue requirement by $1.200 million for the planned outage expense.[52] The Attorney General also recommends denying Duke Kentucky's request for a new accounting deferral mechanism for its planned outage

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[50] Duke Kentucky's response to Staff's Second Request, Item 23.

[51] Kollen Testimony at 16.

[52] *Id.* at 17.

expense, arguing that such a mechanism would remove any incentive for Duke Kentucky to minimize planned outage costs.

The Commission finds that Duke Kentucky's planned outage expense should be reduced by $1.223 million based on Commission precedent of using the average of four historical and four projected years for the calculation.[53] The Commission also finds Duke Kentucky's request for a deferral mechanism is reasonable and should be approved.

Incentive Compensation

Duke Kentucky included $1.634 million of incentive compensation plan expense tied to financial performance in its test year.[54] The Attorney General recommends reducing Duke Kentucky's incentive compensation expense tied to Duke Kentucky's financial performance by $1.634 million.[55]

Duke Kentucky argues that its incentive compensation plans are designed to be market-based and competitive and that disallowing recovery of a portion of its compensation program would place Duke Kentucky at a competitive disadvantage and hinder its ability to attract the talent the company needs to run a safe, efficient, and reliable electric system.[56] Duke Kentucky asserts that the earnings-per-share ("EPS") or total-shareholder-reward metrics, whether tied to long-term or short-term incentive compensation, encourage eligible employees to reduce expenses, operate efficiently,

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[53] Duke Kentucky's response to Staff's Post-Hearing Request, Item 12.

[54] Kollen Testimony at 21.

[55] *Id.*

[56] Thomas Silinski Rebuttal Testimony ("Silinski Rebuttal Testimony") at 2.

and conserve financial resources, all of which inure to the benefit of ratepayers by keeping rates competitive.[57]

The Attorney General asserts that Duke Kentucky included $0.751 million in Short-Term Incentive Plan expense tied to the achievement of earnings per share and $0.883 million in Long-Term Incentive Plan expense paid in the form of performance shares and restricted stock units tied primarily to Duke Kentucky's financial performance. The Attorney General argues that the Commission has historically disallowed all incentive compensation expenses from the revenue requirement that were incurred to incentivize the achievement of shareholder goals as measured by financial performance.

The Commission is in agreement with the Attorney General on this matter. Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in Case Nos. 2010-00036[58] and 2013-00148,[59] the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find that Duke Kentucky's argument to the contrary does nothing to change this holding, as it is unpersuasive. The Commission finds the Attorney General's position is

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[57] *Id.*

[58] Case No. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010).

[59] Case No. 2013-00148, *Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, (Ky. PSC Apr. 22, 2014).

reasonable and that Duke Kentucky's incentive compensation expense should be reduced by $1.634 million.

Retirement Plan Expense

Duke Kentucky included $1.580 million in retirement plan expense related to its employees or its affiliates' employees who were covered by both a defined dollar benefit ("DDB") plan and a defined contribution ("DC") plan.[60]

The Attorney General recommends reducing Duke Kentucky's retirement plan expense by $1.584 million based on recent decisions in which the Commission denied recovery of retirement expenses in which a utility made contributions to both a DDB pension plan and a DC plan for certain employees.[61]

Duke Kentucky contends that the Attorney General has offered no justification as to why the company's test-year retirement plan expense is unreasonable.[62] Duke Kentucky argues that it has significantly reduced retirement-related expenses by transitioning many employees eligible for pension benefits from a DDB plan to a less rich formula and partially utilizing those pension savings to enhance DC 401(k) matching formulas.[63] Duke Kentucky states that it has aggressively managed costs related to its retirement benefits program by closing the DDB pension plans to new hires, and, for existing employees, lock and freezing final average pay benefit formulas for all non-union employees and transitioning those employees from a final average pay formula to a more

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[60] Duke Kentucky's response to Staff's Post-Hearing Request, Item 4.

[61] Kollen Testimony at 19–21.

[62] Silinski Rebuttal Testimony at 9.

[63] *Id.*

"Defined Contribution like" cash balance benefit formula.[64] Lastly, Duke Kentucky asserts that its benefits packages, including retirement programs, as a whole are designed to be market competitive and are benchmarked to ensure that is the case.[65]

The Commission is in partial agreement with Duke Kentucky on this issue and concludes that Duke Kentucky's retirement plan expense should be accepted as proposed. However, the Commission notes that the changes Duke Kentucky has made to the DDB pension plan were not applicable to union employees.[66] We will not make a distinction between union and non-union employees at this time in order to provide Duke Kentucky an opportunity to address these costs prior to its next base rate case, as rate recovery of these duplicative pension contributions for union employees will be evaluated for appropriateness as part of its next base rate case.

AMI Benefit Levelization Adjustment

Duke Kentucky incorporated an AMI benefit levelization adjustment, as required by the stipulation approved by the Commission in Case No. 2016-00152,[67] of $2.321 million.[68] However, Duke Kentucky's calculation of the AMI benefit was based on the net present value annual savings forecast for the five years from 2018 through 2022.

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[64] Duke Energy Kentucky Inc.'s Brief at 57.

[65] *Id*. at 9–10.

[66] Duke Energy Kentucky Inc.'s Brief at 57.

[67] 2016-00152, *Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief* (Ky. PSC May 25, 2017).

[68] Kollen Testimony at 21.

The Attorney General contends that the economic analysis conducted by Duke Kentucky and reflected in the stipulation in Case No. 2016-00152 represents a savings period of 15 years.[69] The Attorney General argues that Duke Kentucky unilaterally shortened the benefits period in providing the AMI benefit adjustment in this case, causing the adjustment to be reduced.[70] The Attorney General maintains that using a 15-year benefits period results in an increase in the AMI levelization adjustment to $3.177 million. This reflects an increase of $0.856 million from the $2.321 million calculated by Duke Kentucky.

Based on the changes made by Duke Kentucky to the AMI levelization calculation to reflect a full 15-year benefits period, Duke Kentucky maintains that the maximum adjustment the Commission should make to Duke Kentucky's request is $0.855 million if the Attorney General's position is accepted.[71]

The Attorney General filed Errata Testimony for Lane Kollen and, based on the changes made during discovery, amended his AMI benefit levelization adjustment to a revenue requirement reduction of $0.858 million.

Given the parties changes in position and the small difference in the amount of the AMI benefit levelization adjustment, the Commission finds that the levelization adjustment should be based on cost savings before gross-up of $0.855 million.

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[69] *Id.* at 22.

[70] *Id.*

[71] Rebuttal Testimony of William Don Wathen, Jr., at 11.

East Bend O&M Expense Regulatory Asset

Duke Kentucky is seeking to recover the East Bend O&M expense regulatory asset in the amount of $4.490 million, based on a levelized recovery of the $36.540 million regulatory asset over 10 years using Duke Kentucky's forecasted cost of debt.[72] This correction reduced the East Bend O&M expense related to the regulatory asset by $0.323 million. Duke Kentucky also provided an adjustment in rebuttal reducing its revenue requirement by $1.555 million to reflect the debt return that is already accruing on the regulatory asset at Duke Kentucky's long-term debt rate.[73]

The Attorney General argues that Duke Kentucky's forecast deferrals from January 2017 through March 2018 are excessive.[74] The Attorney General recommends that the regulatory asset be reduced to reflect the actual deferrals through October 2017, and to revise the forecast so that it is consistent with the actual monthly deferrals for the 12 months ending October 2017.[75] The Attorney General thus recommends that Duke Kentucky's revenue requirement be reduced by $0.406 million.

The Commission finds that Duke Kentucky's adjustment for the East Bend O&M regulatory asset amortization is more accurate as it is based upon corrections made to the Attorney General's calculation. Therefore, the Commission finds that no further adjustment is warranted for this issue.

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[72] Amended Rebuttal Testimony of Wathen and Waller, Errata Sheet at 1.

[73] Amended Rebuttal Testimony of Sarah E. Lawler at 1.

[74] Kollen Testimony at 29.

[75] *Id.* at 30-31.

Depreciation Expense

Duke Kentucky proposes, as part of developing its depreciation rates, the continued use of the ELG procedure. The Attorney General recommends the Commission adopt the ALG procedure in developing Duke Kentucky's depreciation rates. The Attorney General contends that the ALG methodology is the predominant method that is used in the electric industry for developing depreciation rates. The Attorney General contends that, under the ELG methodology, the capital recovery periods are accelerated and shortened and, thus, the depreciation rates are greater than if the ALG procedure was used.[76] The Attorney General argues that the ALG procedure is as accurate as the ELG procedure and the ALG procedure smooths the data so that the depreciation rates for the group of assets tend to remain constant.[77] Use of the ALG procedure will result in a decrease in Duke Kentucky's depreciation expense of $6.920 million.

Duke Kentucky requested an increase in depreciation expense of $6.920 million, based on its request to utilize the ELG procedure for computing depreciation rates. As was discussed in the rate base section of this Order, this Commission has found that the ELG procedure does not accurately match revenues and expenses, is front-loaded, and Duke Kentucky is the only Kentucky based utility that utilizes the ELG procedure for computing depreciation rates.

Regulatory accounting requires the proper matching of revenues and expense in order to produce fair, just and reasonable rates. The Commission finds Duke Kentucky's

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[76] *Id.* at 33.

[77] *Id.* at 35

proposed ELG procedure does not meet that criteria and that Duke Kentucky's depreciation expense should be reduced by $6.920 million.

Terminal Net Salvage – Generation Units

Duke Kentucky included an adjustment of its depreciation expense of $4.506 million to reflect the impact of terminal net salvage value.[78] Duke Kentucky's proposed depreciation rates reflect terminal net salvage, which the company contends is required under the Federal Energy Regulatory Commissions' Uniform System of Accounts.[79] Duke Kentucky further contends that, to avoid intergenerational inequity, these costs should be borne by those ratepayers who receive the benefit from the production assets.[80]

The Attorney General recommends reducing the proposed depreciation rates by removing terminal net salvage from production plant depreciation rates. The Attorney General argues that Duke Kentucky's proposed recovery of future terminal net negative salvage for production plant is unreasonable because those costs are not known with reasonable certainty today.[81] The Attorney General's recommendation is to reduce Duke Kentucky's depreciation expense by $4.506 million.[82]

The Commission finds Dukes Kentucky's recommendation on the treatment of terminal net salvage value in the computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved.

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[78] *Id.* at 42.

[79] John J. Spanos Rebuttal Testimony ("Spanos Rebuttal Testimony") at 4–5.

[80] Spanos Rebuttal Testimony at 4.

[81] Kollen Testimony at 39.

[82] *Id.* at 42.

Interim Net Salvage

Duke Kentucky proposed a $4.617 increase in depreciation expense to reflect the impact of interim net salvage value in its depreciation rates.[83] Duke Kentucky included interim net salvage based on forecasts of the future cost of removal and salvage income.[84]

The Attorney General contends that Duke Kentucky's methodology front-loads forecasted costs based on limited data applied to the interim retirement portion of the production plant accounts and the entirety of the transmission and distribution plant accounts.[85] By presuming to recover costs that have not and may not be incurred, the Attorney General argues that Duke Kentucky's methodology overstates depreciation rates and expense. The Attorney General recommends applying a methodology that calculates the interim net salvage based on the same historical data used by Duke Kentucky, but uses the average annual historic interim net salvage dollars divided by the interim retirement portion of the production plant account and the entirety of the transmission and distribution plant accounts, rather than the annual historic retirements. Under the Attorney General's recommended methodology, Duke Kentucky's depreciation expense would decrease by $4.617 million.

The Commission finds Duke Kentucky's recommendation for the treatment of interim net salvage value in the computing of its depreciation rates to be reasonable to avoid intergenerational inequity and should be approved.

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[83] *Id.* at 45.

[84] *Id.* at 43.

[85] *Id.* at 44.

Federal Income Tax Expense

In its rebuttal testimony, Duke Kentucky proposed a reduction in Federal Income Tax ("FIT") of $10.623 million to reflect the impacts of the TCJA.[86] Duke Kentucky states that the adjustment is due to updating the gross-revenue conversion factor ("GRCF") for the decrease in the federal income tax rate.[87] The Attorney General proposed a $10.255 million reduction to reflect the impact of the TCJA, using the same methodology.[88]

The Commission has carefully reviewed the parties' methodology and computations in determining their respective FIT impacts of the TCJA. The Commission finds the Attorney General's calculations to be more accurate and therefore will reduce Duke Kentucky's revenue requirement by $10.255 million.

Excess Deferred Taxes

Duke Kentucky proposed a reduction in its revenue requirement of $3.782 million to reflect the impact of the TCJA on the amortization of its excess ADIT.[89] The Attorney General proposed a reduction of $6.054 million. Both Duke Kentucky and the Attorney General utilized the ARAM method to compute the amortization of the protected excess ADIT and both parties originally utilized a 20-year amortization for the unprotected excess ADIT. As was discussed in the rate base section of this Order, the Commission has accepted the ARAM calculation of the protected excess ADIT and has found a ten-year amortization period for the unprotected excess ADIT to be reasonable. As a result, the

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[86] Sarah E. Lawler Rebuttal Testimony ("Lawler Rebuttal Testimony") at 3.

[87] *Id.*

[88] Kollen Testimony at 48.

[89] Lawler Rebuttal Testimony at 3.

Commission finds that Duke Kentucky's test-year federal income tax expense should be reduced by $4.472 million to reflect this adjustment.

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, Duke Kentucky's adjusted net operating income is as follows:

Operating Revenues	$308,549,356
Operating Expenses	270,589,404
Adjusted Net Operating Income	$ 37,959,952

Capitalization

Duke Kentucky's proposed capitalization represents the end-of-year balances of the 13-month average for the test period ending March 31, 2019. Because Duke Kentucky's total capitalization is for its electric and gas operations, the amount allocated to its electric operations is determined by taking the total capitalization for both electric and gas and applying the electric rate base ratio.[90] This is consistent with the approach used in previous Duke Kentucky rate cases. Accordingly, the total capitalization allocated to its electric operations is $705,051,140.[91]

The Attorney General recommended several adjustments to Duke Kentucky's capitalization. Each adjustment was made proportionally based upon Duke Kentucky's capital ratio for a final capitalization of $647,314,275.[92] No other intervenor

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[90] *See* Application, Work Papers, WPA1 d for the electric rate base ratio.

[91] Direct Testimony of Sarah E. Lawler ("Lawler Testimony") at 5.

[92] Kollen Testimony, Exhibit 23.

recommended any capitalization adjustment. The Attorney General proposed the following adjustments:

- A reduction of $5.126 million for loans Duke Kentucky made to other Duke Energy affiliates as a member of Duke Energy Money Pool ("Money Pool"). The Money Pool is used to meet short-term cash requirements and the Attorney General states that Duke Kentucky should not be allowed a return on these investments because if the revenue requirements were calculated using rate base this Money Pool investment would be excluded. The Attorney General adjusted the capitalization downward by Duke Kentucky's forecasted test year Money Pool investments, reducing Duke Kentucky's revenue requirement by $0.451 million.[93] In its rebuttal testimony, Duke Kentucky states that the money pool is used to manage short-term cash positions and any reduction to its capitalization should be solely attributed to the short-term debt portion of the capital structure and not applied proportionally based on its capital ratio of short-term debt, long-term debt, and common equity.[94] The Commission agrees that any adjustment should be made solely to short-term debt and will adjust the capitalization downward for a revenue reduction of $0.158 million.[95]

- A reduction of $39.162 million to reflect the removal of the East Bend O&M expense regulatory asset. The Attorney General argues that Duke Kentucky has already included a debt-only rate of return in the levelized amortization expense for the East Bend O&M expense regulatory asset and in the revenue requirement. The adjustment reduces

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[93] *Id.* at 51–52.

[94] Rebuttal Testimony of Stephen G. De May at 17–18.

[95] This adjustment alters the capitalization ratio. Further adjustments are made to this revised capitalization.

Duke Kentucky's revenue requirement by $3.449 million. In its rebuttal testimony, Duke Kentucky agrees to remove this regulatory asset from capitalization and, in response to Duke Kentucky's Post-Hearing Data Request, the projected East Bend O&M Expense regulatory asset was updated to $36.540 million.[96] Removing this updated amount from the Commission adjusted capitalization results in a decrease in the revenue requirement of $3.231 million.

- The removal of the demand-side management ("DSM") regulatory asset for a reduction of $1.477 million from the capitalization and a reduction in the revenue requirement of $0.130 million. The Attorney General states that Duke Kentucky erred by not removing the DSM regulatory asset from its electric capitalization. Duke Kentucky counters that all DSM revenue and expenses have been removed, but the deferred balance should not be removed as it is exclusively related to a cash flow issue and is financed by shareholders and recommended rejecting this adjustment as it is an asset on Duke Kentucky's balance sheet and is not accruing carrying costs.[97] The Commission agrees that the DSM regulatory asset is a cash flow issue and rejects the proposed adjustment.

- The removal of $18.509 million from capitalization for the East Bend coal ash regulatory asset as the Attorney General proposed that these costs be recovered through the proposed Environmental Surcharge Mechanism Rider. The impact of this adjustment is a reduction in Duke Kentucky's revenue requirement of $1.630 million.

[96] Duke Kentucky's Response to Staff's PH–DR, Item 2.

[97] Rebuttal Testimony of Sarah E. Lawler ("Lawler Rebuttal") at 7.

Duke Kentucky agreed with this adjustment.[98] The Commission finds this proposed adjustment to be reasonable and will remove this from the Commission's adjusted capitalization, which results in a decrease of $1.637 million in the revenue requirement.

- An increase to the revenue requirement of $0.018 million to reflect a $0.200 million increase to capitalization to account for the impact of amortizing the Carbon Management Research Group regulatory asset over a ten-year period as compared to Duke Kentucky's proposed five-year period. Duke Kentucky agrees with this recommendation and the Commission finds this adjustment to be reasonable and should be accepted. This adjustment increases the revenue requirement by $0.018 million on the Commission's adjusted capitalization.

- An increase of $2.733 million to reflect the reduction in depreciation expense resulting from use of the ALG depreciation method instead of Duke Kentucky's proposed ELG depreciation method. As stated earlier, the Commission agrees with the application of the ALG methodology in developing Duke Kentucky's depreciation rates and, accordingly, accepts the corresponding adjustment to capitalization. Based on the revised capitalization, the revenue impact is $0.242 million.

- The Attorney General recommends Duke Kentucky's revenue requirement be increased $0.157 million to reflect the $1.780 million increase in capitalization resulting from the reduction in depreciation expense from the proposed removal of terminal net salvage value. As stated earlier, the Commission rejected the Attorney General's recommendation on this issue and, therefore, no corresponding adjustment to capitalization will be made.

[98] Duke Kentucky's Response to the Attorney General's Second Request for Information, Item 4e.

- An increase of $1.824 million to capitalization to reflect the increased capitalization resulting from the reduction in depreciation expense from the proposed removal of the remaining net salvage. The Commission rejected the Attorney General's recommendation on this issue and, therefore, no corresponding adjustment to capitalization will be made.

Appendix B illustrates the impact of each capitalization adjustment. The total Commission approved adjustments lower Duke Kentucky's electric operations capitalization to $647,809,050.

Rate of Return, Capital Structure, and Cost of Debt

Duke Kentucky proposed a test-year-end capital structure consisting of 40.68 percent long-term debt at a cost of 4.24 percent; 10.43 percent short-term debt at a cost of 3.08 percent; and 48.89 percent common equity with a proposed return of 10.30 percent.[99] Although the capitalization is lower, the capital structure proposed by the Attorney General maintains the same capital ratios and short-term and long-term debt costs but adjusts the cost of common equity. Neither NKU, KSBA, nor Kroger addressed the capital structure.

Return on Equity

In its application, Duke Kentucky developed its proposed return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the Empirical CAPM model, and Risk Premium analysis ("RP"). Derived from these cost of capital evaluations, Duke Kentucky proposed an ROE range, adjusted for flotation costs, of 9.0 percent to 10.7 percent, and recommended an ROE be awarded within the

[99] Application, Schedule J-1, page 2.

upper half portion of this range, or between 9.9 and 10.7 percent.[100] Duke Kentucky used the midpoint of this upper portion, or 10.3 percent, in calculating its revenue requirements. Duke Kentucky maintained that an ROE in this range fairly compensates investors, maintains Duke Kentucky's credit strength and attracts the capital needed for utility infrastructure and reliability capital investments.[101] Duke Kentucky further emphasized that an ROE in the upper portion of the recommended range accounts for the high external financing risks facing Duke Kentucky relative to its small size, forecasted increases in interest rates, a highly concentrated generation mix, and a higher degree of regulatory risk.[102] The table below summarizes Duke Kentucky's ROE estimates:[103]

STUDY	ROE
DCF – Value Line Growth	9.4%
DCF – Analyst Growth	9.0%
CAPM	9.5%
Empirical CAPM	10.0%
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

Direct testimony and analysis regarding the ROE were also provided by the Attorney General. The Attorney General employed the DCF and CAPM models for its analysis but based its recommendation on the results of the DCF model.[104] The Attorney General used 19 proxy companies as compared to the 23 Duke Kentucky utilized. The Attorney General stated that due to significant events, including acquisition activity,

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[100] Direct Testimony of Roger A. Morin, PhD ("Morin Testimony") at 4.

[101] *Id*. at 5.

[102] *Id*. at 4.

[103] *Id*. at 62.

[104] Direct Testimony of Richard A. Baudino ("Baudino Testimony") at 3.

natural disasters, and capital investment cancellations, the exclusion of the four proxy companies was warranted.[105] In the DCF model, the Attorney General employed both the average and the median values for the expected growth rates. The model results indicated equity cost rates ranging from 8.07 percent to 9.16 percent for the average growth rates and for the median growth rates, 8.19 percent to 9.21 percent. The Attorney General recommended removing the low end of the average growth range, stating that 8.07 percent appeared to be understated and that the remaining DCF estimates reflect a range of approximately 8.2 percent to 9.2 percent. Thus, the Attorney General recommended a point slightly higher than the midpoint, or 8.8 percent.[106]

The Attorney General disagreed with Duke Kentucky's overall analysis, stating that Duke Kentucky's requested ROE is overstated, inconsistent with the current low–interest-rate environment, and not supported by current market evidence.[107] In particular, the Attorney General disagreed with Duke Kentucky's DCF analysis, arguing that Duke Kentucky's exclusion of forecasted dividend growth in the DCF analysis, due to Duke Kentucky's concern regarding slower dividend growth in the near term was not reflective of long-run expected earnings growth. The Attorney General also questioned Duke Kentucky's use of 1+g to calculate the expected dividend yield as compared to 1+.5g. The Attorney General noted that although the two approaches do not yield significantly different results, the 1+g approach is overstated as it assumes an investor receives the

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[105] *Id.* at 19. The four companies were Avista Corp. (which had announced that it would be acquired by Hydro One); PG&E Corp. (which recently announced that it would be eliminating its common and deferred stock dividends); SCANA (who's stock price has fallen significantly due to the cancellation of the Summer nuclear power plant); and Sempra Energy (which recently announced its acquisition of Oncor).

[106] *Id.* at 31.

[107] *Id.* at 32.

full amount of growth throughout the next year and given the timing of dividend increases and the level of the dividend, the investor may or may not actually receive a full year of increased dividend payments.[108]

The Attorney General's CAPM results range from 7.01 percent to 7.23 percent for the forward-looking CAPM ROE estimates and 6.02 percent to 7.39 percent using historical risk premiums.[109] The Attorney General stated that Duke Kentucky's CAPM analysis employed an inflated projected interest rate, and that current interest rates and bond yields embody all relevant market data and expectations of investors.[110] He further argues that the use of the Empirical CAPM analysis is not a reasonable method to use for Duke Kentucky's ROE estimate, as the use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas are incorrect and investors should not rely on them.[111] The Attorney General rejects the RP analysis calling it imprecise and stating that it should only be used for general guidance.[112]

Finally, the Attorney General disagreed with Duke Kentucky's inclusion of an upward adjustment for flotation costs. The Attorney General notes that flotation costs attempt to collect the costs of issuing common stock and that these costs are already accounted for in current stock prices and that adding an adjustment for flotation costs

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[108] *Id*. at 34.

[109] *Id*. at 30.

[110] *Id*. at 34.

[111] *Id*. at 39.

[112] *Id*. at 40.

amounts to double counting.[113] The Attorney General further notes that if flotation costs are excluded from the Duke Kentucky's DCF analysis, the cost of equity results fall to a range of 8.86 percent to 9.27 percent.[114]

In its rebuttal testimony, Duke Kentucky contends that the Attorney General's proposed ROE would be one of the lowest authorized returns in the industry, that it lies outside the zone of reasonableness, and, if adopted, would cause adverse consequences to Duke Kentucky's creditworthiness, financial integrity, capital-raising ability and ultimately to its customers. Duke Kentucky further disagrees with the Attorney General exclusively relying on the results of the DCF analysis and the procedures and methodologies used in his analysis.

In his post-hearing brief, the Attorney General pointed out that in the recent Kentucky Power Company ("Kentucky Power") rate case,[115] the Commission noted that the increase in interest rates is happening slowly and interest rates are still historically low. He also noted that the Commission stated that models supporting a low-interest-rate environment should be given more weight. The Attorney General contends that Duke Kentucky did not provide any evidence to sway this Commission from that position and that an ROE of 8.8 percent should be adopted.[116] Duke Kentucky's post-hearing brief

[113] *Id*. at 33.

[114] *Id*.

[115] Case No. 2017-00179, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service, (2) An Order Approving its 2017 Environmental Compliance Plan; (3) An Order Approving its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) An Order Granting All Other Required Approvals and Relief* (Ky. PSC Jan. 18, 2018).

[116] Attorney General's Post Hearing Brief at 5–6.

contends that the Attorney General's proposed ROE is unreasonable and lies outside the zone of currently authorized ROEs for electric utilities.[117] For the reasons discussed below, the Commission finds a ROE of 9.725 percent to be reasonable, and for the purpose of base rate revenues and certain tariffs, an ROE of 9.725 percent should be applied.

The Commission agrees that financial markets are still in a low–interest-rate environment. However, economic data indicates a healthy outlook with steady growth, low unemployment, and inflation at the Federal Reserve's ("Fed") target level. Citing a solid economic outlook, the Fed increased the federal funds interest rate to 1.75 percent this past March, the highest level in a decade, and signaled that two to three more rate hikes are possible in 2018. Increased government spending, the possible impact of current tariff policy on net imports, and the Tax Cut and Jobs Act of 2017 should all contribute to a healthier economy. These macroeconomic inputs point to a robust outlook and an economy that has recovered from the Great Recession. However, notwithstanding these improvements, interest rates are still historically low, the impact of interest rate changes is unpredictable, and increases in the federal funds rate are not guaranteed.

The Commission agrees with the Attorney General that flotation costs should be excluded from the analysis as they are already accounted for in the current stock prices. Removal of the flotation costs from Duke Kentucky's ROE model produces the following results:

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[117] Duke Kentucky's Post-Hearing Brief at 73.

STUDY	ROE
DCF – Value Line Growth	9.3%[118]
DCF – Analyst Growth	8.9%[119]
CAPM	9.3%[120]
Empirical CAPM	9.8%[121]
Historical Risk Premium	10.5%[122]
Allowed Risk Premium	10.5%[123]

For 2017, the average authorized ROE in the electric utility industry as reported in the Regulatory Research Associates ("RRA") quarterly review was 9.80 percent, and the average of allowed ROEs for the proxy group of 19 companies is 9.88.[124] Further, the Commission notes its last award of 9.7 percent for an investor-owned electric utility. The Commission believes these ROE reports are benchmarks worthy of consideration in determining a reasonable ROE. The Commission believes that since its last award of 9.7 percent, the economy has shown quantifiable signs of improvement. Further, the Commission recognizes the risk inherent to Duke Kentucky's lack of diversity in its generation fleet. Based on the entire record developed in this proceeding, we find that the approved ROE of 9.725 falls within the range of Duke Kentucky's proposed ROE of 8.86 percent to 10.5 percent, adjusted for flotation costs. While the ROE of 9.725 exceeds the Attorney General's range of 8.2 percent to 9.2 percent, the Commission believes that

[118] Morin Testimony at 30.

[119] *Id*. at 31.

[120] *Id*. at 44.

[121] *Id*. at 47.

[122] *Id*. at 49.

[123] *Id*. at 52. No flotation cost is noted.

[124] *Id*. *See also,* Rebuttal Testimony of Roger A. Morin, PhD at 10.

the Attorney General recommended range is unreasonably low. The Commission agrees with Duke Kentucky that awarding an ROE that is significantly lower than other electric utility authorized ROEs may cause it financial stress and fails to take into account Duke Kentucky's highly concentrated generation portfolio. Additionally, an ROE of 9.725 is within the range of the benchmarks provided by RRA and approved for the proxy group, and recognizes the economic improvements since the last Commission decisions involving rate cases of other investor-owned electric utilities in Kentucky.

Rate-of-Return Summary

Applying the rates of 3.08 percent for short-term debt, 4.24 percent for long-term debt, and 9.725 for common equity to the Commission adjusted capital structure consisting of 9.77 percent, 40.98 percent, and 49.25 percent, respectively, produces an overall cost of capital of 6.83 percent.[125]

Base Rate Revenue Requirement

The Commission has determined that, based upon Duke Kentucky's capitalization of $647,809,050 and an overall cost of capital of 6.83 percent, Duke Kentucky's net operating income that could be justified by the evidence of record is $44,245,358. Based on the adjustments found reasonable herein, Duke Kentucky's pro forma net operating income for the test year is $37,959,952. Therefore, Duke Kentucky would need an increase in annual base rate operating income of $6,285,406. After the provision for uncollectible accounts, the PSC Assessment, and state and federal income taxes, Duke Kentucky would have a base-rate electric revenue deficiency of $8,428,645.

The calculation of this base-rate revenue deficiency is as follows:

[125] *See,* Appendix B.

Net Operating Income Found Reasonable	$ 44,245,358
Pro Forma Net Operating Income	37,959,952
Net Operating Income Deficiency	$ 6,285,406
Gross Revenue Conversion Factor	1.3409866
Base Rate Revenue Deficiency	$ 8,428,645

REVENUE ALLOCATION AND RATE DESIGN

Cost of Service Study ("COSS") and Revenue Allocation

Duke Kentucky prepared three fully embedded COSSs in this proceeding that contain essentially the same data, except that different methodologies were used to develop the allocation factor for the demand component of Production-related costs. The demand allocation methods are as follows: (1) 12-CP method; (2) the Average and Excess method; and (3) the Summer/NonSummer method. Of those three, Duke Kentucky recommends using the 12-CP methodology, stating that it is generally accepted in the utility industry and was approved by the Commission in its most recent electric base rate case.[126] Using the 12-CP method, the allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of what their respective loads were at other times of the day. Duke Kentucky states that due to an anticipated future replacement of its billing system, it is not seeking to implement any significant rate design changes. Duke Kentucky is proposing to increase customer charges and energy charges and, where applicable, demand charges, across the board. Duke Kentucky's proposed rate design is based upon its 12-CP COSS

[126] Case No. 2006-00172, Duke Kentucky (Ky. PSC Dec. 21, 2006).

increases are supported by the COSS.[127] For the residential class, the customer charge is proposed to increase from $4.50 to $11.10, or 147 percent.[128] This amount represents nearly the full customer charge as calculated by the COSS.[129] Duke Kentucky is also proposing to increase its street lighting and traffic lighting rates. The revised proposed increase by rate class is as follows:[130]

Rate RS	14,780,440
Rate DS	7,870,484
Rate GS-FL	51,793
Rate EH	54,744
Rate SP	1,897
Rate DT-Secondary	3,854,808
Rate DT-Primary	2,442,311
Rate DP	105,930
Rate TT	807,689
Lighting	146,956
Total	30,117,052

The Attorney General's witness, Mr. Glenn Watkins, prepared two COSSs but stated that he accepts Duke Kentucky's 12-CP method for evaluating class profitability. While Mr. Watkins stated that he believes that Duke Kentucky's revenue distribution is reasonable for the residential class, he states that Duke Kentucky's proposed revenue allocation produces anomalous results for several nonresidential classes but did not offer any suggested changes. In addition, Mr. Watkins calculated a customer charge between

[127] As originally proposed, the customer charges for rate class DT, both Primary and Secondary, were not supported by the COSS. However, through discovery, Duke Kentucky proposed that the customer charges be revised to reflect the COSS.

[128] As revised in the billing analysis provided in Duke Kentucky's response to Staff's PH-DR, Item 9.

[129] The revised COSS filed by Duke Kentucky in response to Staff's PH-DR, Item 8, supports a residential customer charge of $11.31.

[130] *See* revised billing analysis provided in Duke Kentucky's response to Staff's PH-DR, Item 9, Tab Sch M-2.2.

any suggested changes. In addition, Mr. Watkins calculated a customer charge between $2.69 and $3.49 using "a direct customer cost analysis" and objected to any increase in the residential customer charge. Mr. Watkins asserts that Duke Kentucky's proposed residential rate design violates the principle of gradualism, the theory of efficiency competitive prices and is contrary to effective conservation efforts.

NKU did not object to Duke Kentucky's 12-CP COSS and did not oppose Duke Kentucky's revenue allocation. Kroger's witness, Mr. Justin Bieber, proposed that the Commission allocate 50 percent of the benefits of the tax impact to all rate classes and then use the remaining 50 percent to further reduce interclass subsidies, as he believes the proposed 10 percent subsidy reduction is insufficient. Duke Kentucky believes Mr. Bieber's proposal is not a fair result for its customers, stating the changes due to the tax reduction should follow the customer contribution to costs.

The Commission accepts Duke Kentucky's revised 12-CP COSS to use as a guide in determining revenue allocation and rate design. The Commission also accepts Duke Kentucky's proposed revenue allocation and finds that the proposed revenue allocation, which reduces class subsidies by 10 percent, conforms to the principle of gradualism. As previously stated, the Commission is granting less of an increase than that requested by Duke Kentucky. Therefore, the Commission will allocate the increase granted herein on a proportional basis to each of the rate classes, based generally on Duke Kentucky's proposed revenue allocation.

Rate Design

Duke Kentucky's revised 12-CP COSS supports a residential customer charge in the amount of $11.31, which includes all costs identified as customer-related in its

COSS.[131] This method of calculating the customer charge is generally accepted in the utility industry and is being accepted by the Commission. Although the Commission has been reluctant to approve an increase in the residential customer charge in excess of 50 percent due to the principle of gradualism, we believe that a larger increase is warranted in this proceeding given Duke Kentucky's lowest-in-Kentucky current residential customer charge of $4.50 and the amount of time that has passed since the charge was established. Therefore, the Commission will approve a residential customer charge of $11.00. Given the reduction to the requested increase granted herein, allocating the entirety of the increase authorized for the residential class to the customer charge will not achieve an $11.00 customer charge. Therefore, the Commission will decrease the current residential energy charge in order to establish an $11.00 customer charge and achieve the increase authorized for the residential class. The Commission will also accept Duke Kentucky's proposed customer charges and demand charges for the nonresidential rate classes, as revised. Therefore, in order to achieve the decrease in the requested increase granted herein, the Commission has adjusted the energy charges of all rate classes. The monthly increase for the residential class results in an increase of 3.2 percent, or approximately $2.56, for a typical residential customer using 1,000 kWh of electricity per month.

PROPOSED TARIFF CHANGES

Fixed Bill Program. Duke Kentucky is proposing to offer a Fixed Bill program to its customers. A customer signing up for the Fixed Bill program would pay a flat monthly billing charge for electric service for 12 months. The flat monthly charge would include a

[131] Duke Kentucky's Response to Staff's PH-DR, Item 8, Attachment, Tab Customer Charge.

premium in order to take into account the risk of weather and commodity volatility. Duke Kentucky stated that the premium has not yet been finalized for inclusion in the program but that, if approved, the premium to be charged to customers would be determined and added to the applicable section in the compliance tariff.[132] Duke Kentucky also states that significant changes in the customer's consumption behavior may require the Fixed Bill amount to be recalculated before the 12-month period ends. If a customer's actual usage is more than 30 percent higher than their expected weather-adjusted usage, Duke Kentucky stated that it would send them a warning letter and, if the excessive usage continues, the company would have the right to remove the customer from the program or adjust their fixed bill amount to reflect the increased usage.[133] At the end of 12 months, Duke Kentucky would calculate a new charge to the customer, which will factor in any changes in usage patterns for the customer. The customer would be required to re-enroll in the Fixed Bill payment option every 12 months.

Duke Kentucky's initial proposed tariff did not contain the provisions of the Fixed Bill Program but Duke Kentucky indicated that it would be willing to include the provisions of the Fixed Bill Program in its tariff if the program is approved.[134]

Mr. Watkins, the Attorney General's witness, filed testimony recommending that the Fixed Bill Program be rejected. Mr. Watkins stated that the Fixed Bill program is not in the public interest and provides windfall profits to Duke Kentucky with no realistic benefits to consumers. Mr. Watkins also states that the Fixed Bill program would provide

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[132] Duke Kentucky's Response to Staff's Fourth Request for Information ("Staff's Fourth Request"), Item 17 b.

[133] Duke Kentucky's Response to Staff's Fourth Request, Item 17. a.

[134] Duke Kentucky's Response to Commission Staff's Second Request for Information ("Staff's Second Request"), Item 9 d.

benefits to consumers. Mr. Watkins also states that the Fixed Bill program would provide for a constant "flat" bill to customers regardless of how much energy they consume or when they consume it, and that policies such as this are contrary to the objectives of efficient pricing.

The Commission finds that the Fixed Bill Program is not reasonable and should not be approved. A jurisdictional utility must charge its filed rates for usage and the Commission finds that this program does not adhere to the Commission's filed rate doctrine. Because Duke Kentucky included $122,230 in the forecasted test year as the amount of premium associated with this program, in rejecting the Fixed Bill Program, the Commission has made an adjustment to increase the revenue requirement by $122,230.

Rate RTP-M, Real-Time Pricing. Duke Kentucky is proposing to cancel and withdraw Rate RTP-M, Real-Time Pricing – Market-Based Pricing. Duke Kentucky states that this rate option has not been utilized by any customers since its inception and that it was proposed when Duke Kentucky purchased all of its power from Duke Energy Ohio, which is no longer the case. Duke Kentucky states that it has another RTP tariff available for nonresidential customers. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate TT, Time of Day Rate – Transmission Voltage. Duke Kentucky is proposing to add a summer and winter on-peak energy rate similar to Rate DT. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate DT, Time of Day Rate – Distribution Voltage. Duke Kentucky is proposing to remove language referencing an expired optional pilot rate for low load factor customers from this tariff. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate LED, LED Outdoor Lighting Service. Duke Kentucky is proposing to introduce a LED lighting tariff due to increased customer requests for LED fixtures. The minimum term for the tariff is proposed to be 10 years. The rates proposed by Duke Kentucky included a carrying charge based on a 10.30 percent ROE. As previously stated, the ROE approved in this proceeding is 9.725 percent. Therefore, the Commission has recalculated the proposed LED rates using a ROE of 9.725 percent. With this recalculation of rates, the Commission finds that the proposed LED lighting tariff is reasonable and should be approved.

Rate OL, Outdoor Lighting Service. Duke Kentucky is proposing to cancel and withdraw Rate OL, Outdoor Lighting Service. Per Duke Kentucky's current tariff, this rate schedule terminated December 31, 2016. Duke Kentucky is proposing that all remaining participants be moved to Rate UOLS, Unmetered Outdoor Lighting and, as applicable, Rate OL-E – Outdoor Lighting Equipment Installation. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate NSP, Private Outdoor Lighting Service for Nonstandard Units. Duke Kentucky is proposing to cancel and withdraw Rate NSP, Private Outdoor Lighting for Non-Standard Units. Per Duke Kentucky's current tariff, this rate schedule terminated December 31, 2016. Duke Kentucky is proposing that all remaining participants be moved to Rate UOLS, Unmetered Outdoor Lighting and, as applicable, Rate OL-E, Outdoor Lighting Equipment Installation. There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rider LM, Load Management Rider. Duke Kentucky is proposing to revise Rider LM to reflect the fact that it no longer utilizes the magnetic tape recording devices included in Section II of the Rider. Section II will be eliminated and all participants utilizing interval data recorders and time-of-use meters will be combined under Section I.[135] There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rate MDC, Meter Data Charges. Duke Kentucky is proposing to revise Rate MDC to clarify that it is for nonresidential customers and to rename it Meter Data Charges for Enhanced Usage Data Services. In addition, the name of the software that enables the service is changed from EnFocus to Energy Profiler Online (EPO).[136] There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rider GSS, Generation Support Service. Duke Kentucky is proposing to combine the Monthly Distribution Reservation Charge, Monthly Transmission Reservation Charge, and Monthly Ancillary Services Reservation Charge values into a combined value called Monthly Transmission and Distribution Reservation Charge.[137] Duke Kentucky clarified

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[135] Direct Testimony of Bruce L. Sailers ("Sailers Testimony") at 17.

[136] Sailers Testimony at 20.

[137] Sailers Testimony at 20.

in the discovery and at the hearing in this matter that proposed Rider GSS does not include a Monthly Ancillary Services Reservation Charge.[138] There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rider FAC, Fuel Adjustment Clause. Duke Kentucky is proposing to include additional PJM Interconnection, LLC ("PJM") Billing Line Items for recovery through its FAC. Duke Kentucky's proposal is the same, with respect to the PJM billing line items, as was made by Kentucky Power in its recent base-rate proceeding and approved by the Commission.[139] There were no objections to this tariff change from the intervenors. The Commission will approve Duke Kentucky's proposal with the requirement that Duke Kentucky list each of the PJM billing line items that will flow through the FAC in its compliance tariff.

Rider PSM, Off-System Sales Profit Sharing Mechanism. Duke Kentucky is proposing changes to its Rider PSM to expand the categories of revenues (net of costs) available for inclusion in Rider PSM and to streamline the administration and calculation of Rider PSM. Duke Kentucky is proposing to make adjustments to Rider PSM to reflect PJM billing line items that are related to credits and charges attributable to the off-system sales shared with customers under Rider PSM. Duke Kentucky is proposing to adjust the categories of eligible net proceeds (credits and charges) that can be flowed through the PSM to include all wholesale energy, capacity, and ancillary services markets (net of costs and credits) that are now available or may become available in PJM. This will

[138] Duke Kentucky's response to Staff's Fourth Request, Item 14, and March 7, 2018 hearing at 2:07:45.

[139] Case No. 2017-00179, Kentucky Power (Ky. PSC Jan. 18, 2018).

capacity performance market requirements and for short-term capacity purchases necessary to meet Duke Kentucky's three-year fixed resource requirement plan. Duke Kentucky is also proposing to include costs of any capacity payments made to cogeneration facilities under the terms of its cogeneration tariffs, as well as any net proceeds from the sale of renewable energy certificates derived from any Company-owned renewable generating resources. Since Duke Kentucky is proposing to implement an environmental surcharge mechanism, cost recovery and the sharing of any gains or losses on the sale of emission allowances will begin to be addressed in Rider ESM.[140] None of the intervenors filed testimony objecting to the expansion of items proposed to be included in Rider PSM. However, in its post-hearing brief, the Attorney General stated that the proposed changes to Rider PSM should be denied because Duke Kentucky has not met its burden as to the necessity of the changes. The Attorney General argued that Duke Kentucky is attempting to turn Rider PSM into a way to pass costs on to customers instead of a way to share profits.

Duke Kentucky is also proposing to revise the sharing percentage between customers and shareholders. Currently, the first $1 million in annual margins from off-system sales flow to customers and anything over $1 million is shared 75 percent to customers and 25 percent to Duke Kentucky shareholders. Duke Kentucky is proposing to revise the sharing percentage between customers and shareholders to a 90/10 split and eliminate the $1 million threshold in the formula. Duke Kentucky argues that the proposed split will simplify and streamline the process. Duke Kentucky also provided

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[140] Direct Testimony of William Don Wathen, Jr. ("Wathen Testimony") at 14 and 15.

calculations showing that the change to Rider PSM would benefit customers during the forecasted period in the amount of $322,294.[141]

The Attorney General did not provide testimony opposing Duke Kentucky's proposed 90/10 customer/shareholder split but did recommend that the forecasted off-system sales margins be removed from Rider PSM and be included in base rates, as discussed previously in this Order.

Having reviewed the record in this proceeding, the Commission finds Duke Kentucky's proposed changes to Rider PSM to be reasonable and will approve Duke Kentucky's proposal with the requirement that Duke Kentucky list each of the PJM billing line items that will flow through Rider PSM in its compliance tariff. In addition, the Commission will require Duke Kentucky to notify the Commission within seven days of incurring any capacity performance assessment from PJM.

Reconnection of Service. Duke Kentucky is proposing to revise its reconnection fees as follows:

Charge	Current Charge	Proposed Charge
Remote Reconnection	$0.00	$25.00
Reconnection (Nonremote, Electric Only)	25.00	75.00
Reconnection (Nonremote, Electric & Gas)	38.00	88.00
Reconnection at pole (Electric Only)	65.00	125.00
Reconnection at pole (Electric & Gas)	90.00	150.00
Collection Fee	15.00	50.00

[141] Duke Kentucky's Response to Staff's Second Request, Item 28.

Duke Kentucky filed cost support for its proposed reconnection charges. In response to questioning from the Attorney General regarding the calculation of the remote reconnection charge, Duke Kentucky offered to revise its remote reconnection charge using an alternate labor rate which would result in a remote reconnection charge of $3.45. Duke Kentucky stated that if this revised rate was approved rather than the proposed rate, a corresponding adjustment totaling $170,759 would need to be made to its revenue requirement to account for the loss of the reconnection revenue.[142]

With the exception of the remote reconnection charge, the Commission finds that the proposed charges in the table above are reasonable and should be approved. The Commission also finds that the remote reconnection charge should be $3.45 and has made an adjustment to increase Duke Kentucky's revenue requirement in the amount of $170,759.

Rate CATV, Rate for Pole Attachments of Cable Television Systems. Duke Kentucky is proposing to increase the pole attachment rates and to broaden the rate language to apply the per foot charge to other pole attachments on a contract basis based on the footage required for the attachment. Duke Kentucky is also proposing that this rate schedule be renamed to Rate DPA, Distribution Pole Attachment Rate, thereby limiting the attachments to distribution poles.[143] There were no objections to this tariff change from the intervenors. The Commission will approve Duke Kentucky's proposed changes to this tariff; however, the rates proposed by Duke Kentucky will not be approved as they were calculated using a rate of return based on a 10.30 percent ROE. Therefore,

[142] Sailers Rebuttal Testimony at 15.

[143] Sailers Testimony at 18.

the Commission has recalculated the proposed pole attachment rates using the Commission approved ROE of 9.725 percent and will approve a two-user-pole rate of $5.92 and a three-user-pole rate of $4.95. Because this change to the proposed pole attachment rates will impact revenue, the Commission has made an adjustment to increase Duke Kentucky's revenue requirement in the amount of $15,601.

Cogeneration and Small Power Production Sale and Purchase Tariffs ("Cogen Tariffs"). Duke Kentucky has two Cogen Tariffs, one for cogeneration facilities that are 100 kW or less ("Small Cogen Tariff") and one for cogeneration facilities that are greater than 100 kW ("Large Cogen Tariff"). For the Small Cogen Tariff, Duke Kentucky is proposing to revise the Energy Purchase Rate to reflect avoided energy cost equal to a two-year average PJM Locational Marginal Price ("LMP") at the Duke Energy node. The Energy Purchase for the Large Cogen Tariff is based on the PJM real-time LMP for power at the DEK Aggregate price node for each hour of the billing month.

For both Cogen Tariffs, Duke Kentucky proposes to recover required energy purchases through the FAC as an economy energy purchase. Duke is also proposing to add a Capacity Purchase Rate to both Cogen tariffs that will be based on the Company's avoided capacity cost in Duke Kentucky's last Integrated Resource Plan, which was reviewed in Case No. 2014-00273.[144] Duke Kentucky proposes to adjust the Capacity Purchase Rate after the Commission completes its review of the next IRP, which is due to be filed in June 2018. Due to the fact that Duke Kentucky may need to purchase

[144] Case No. 2014-00273, *2014 Integrated Resource Plan of Duke Energy Kentucky, Inc.* (Ky. PSC Sept. 23, 2015).

capacity to meet its own resource needs in PJM, it is proposing to reconcile and recover costs of any purchases of capacity under these tariffs through Rider PSM.

Duke Kentucky is also proposing to add language to both of its Cogen Tariffs stating that no capacity purchase will be made if the qualifying facility cannot satisfy the Company's capacity need or the Company does not have a capacity need.

The Commission finds that the proposed changes to Duke Kentucky's Cogen Tariffs should be approved except as discussed below.

Capacity Rate. Duke Kentucky's calculation of the capacity rate used an ROE of 10.3 percent. As the ROE approved in this proceeding is 9.725 percent, the Commission has recalculated the capacity rate using an ROE of 9.725 percent and will approve a capacity rate of $3.61 per kW-month.

Language related to Capacity Purchases. 807 KAR 5:054, Section 6 states, in relevant part, as follows:

> (1) Each electric utility shall purchase any energy and capacity which is made available from a qualifying facility except as provided in subsections (2) and (3) of this section.
>
> (2) The qualifying facility's right to sell power to the utility shall be curtailed in periods when purchases from qualifying facilities will result in costs greater than those which the utility would incur if it generated an equivalent amount of energy instead of purchasing that energy.
>
> (3) During any system emergency, an electric utility may discontinue:
>
> (a) Purchases from a qualifying facility if such purchases would contribute to such emergency; and
>
> (b) Sales to a qualifying facility if discontinuance is nondiscriminatory.

The Commission finds that Duke Kentucky's proposed language stating that no capacity purchase will be made if the qualifying facility cannot satisfy Duke Kentucky's capacity need or when Duke Kentucky does not have a capacity need is inconsistent with the requirements of 807 KAR 5:054, Section 6(1). The regulation requires Duke Kentucky to purchase energy and capacity from a qualifying facility except as set forth in subsections 2 and 3, both of which do not apply in the language proposed by Duke Kentucky. Therefore, the proposed language should not be approved.

In addition, Duke Kentucky is reminded that 807 KAR 5:054, Section 5, requires all electric utilities with annual retail sales greater than 500 million kWhs to provide data to the Commission from which avoided costs may be derived not less often than every two years unless otherwise determined by the Commission.

Rider DCI and Targeted Underground Program. Duke Kentucky requests authority to implement Rider DCI to recover the incremental capital costs, above what is to be included in base rates, for specific Commission-approved programs aimed at accelerating, improving, and enhancing the performance of Duke Kentucky's electric delivery system in terms of reliability and integrity.[145] Duke Kentucky states that Rider DCI is modeled after similar Commission-approved programs for its gas operations as well as similar mechanisms implemented in by its affiliates in Ohio and Indiana.[146] Duke Kentucky explains that it will file an annual application to set and true-up its Rider DCI for the duration of a Commission-approved program.[147] The annual applications will

[145] Henning Testimony at 24.

[146] *Id.*

[147] *Id.*

establish new rider rates based on the actual incremental investment in the eligible plant in service as of the end of each calendar year. The revenue requirement for the rider will include a return on incremental rate base, income taxes on the equity component of the return, property taxes, and depreciation expense associated with the incremental investment. The rider will not include recovery of incremental O&M expenses. Duke Kentucky is proposing to allocate the resulting revenue requirement based on the allocation factors used for the underground distribution equipment from its COSS.

Duke Kentucky is seeking authority for a CPCN to implement a Targeted Underground program to be included in Rider DCI.[148] Duke Kentucky maintains that due to the advancements in consumer electronics, customer expectations are evolving and customers are requiring a higher degree of reliability, performance, and response with respect to the provision of electric service.[149] As part of its philosophy to evolve to meet new and growing customer demands, Duke Kentucky is proposing to implement a Targeted Underground program, which will identify specific areas of the company's distribution system that experience higher-than-acceptable frequency of outages and replace overhead wires with underground cables to harden the system, thereby increasing reliability.[150] The Targeted Underground program will focus on undergrounding certain small overhead distribution conductors which have been identified as having the highest likelihood of outages within Duke Kentucky's distribution

[148] *Id.*

[149] Platz Testimony at 20.

[150] Platz Testimony at 25.

system.[151] The types of overhead line segments that have performed worse as compared to the remainder of Duke Kentucky's overhead facilities are remote lines that are located close to trees and certain line segments located along major thoroughfares.[152] Tree-related customer interruptions and public action (i.e., cars crashing into poles) customer interruptions account for 18 percent and 9 percent, respectively, of all customer interruptions for Duke Kentucky.[153] Duke Kentucky states that it will also ultimately take ownership of those underground service lines that are replaced either as part of the Targeted Underground program or existing customer-owned underground service lines that experience a failure and are replaced by Duke Kentucky.[154] Duke Kentucky maintains that hardening these underperforming line segments provides broad benefits for all customers while addressing these poor performing areas.[155] Over the next 10 years, Duke Kentucky expects to spend approximately $67 million as part of its Targeted Underground efforts.[156]

The Attorney General, Kroger, and NKU recommend that Rider DCI be rejected. The Attorney General argues that automatic capital and investment adjustment clauses, such as Rider DCI, are poor policies and do not allow the requisite amount of regulatory review that is provided in a full base-rate proceeding.[157] The Attorney General contends

[151] Platz Testimony at 25–26.

[152] Platz Testimony at 27.

[153] *Id.*

[154] Platz Testimony at 26.

[155] *Id.*

[156] Platz Testimony at 28–29.

[157] Baudino Testimony at 46.

that Duke Kentucky has failed to quantify any customer benefits associated with either Rider DCI or the Targeted Underground Program.[158] The Attorney General also contends that the areas that have been identified by Duke Kentucky as experiencing higher than average outages should be considered a high priority and addressed by the company as part of its normal budgeting and system operations regardless of the existence of Rider DCI.[159] Should the Commission consider approving Rider DCI, the Attorney General recommends that the Commission take the following into consideration: 1) Rider DCI should be limited to a three-year pilot program; 2) Duke Kentucky should only be allowed to include actual investment costs after the year they are closed to plant in service; 3) the inclusion of a yearly 2.5 percent cap on rate increases associated with Rider DCI; 4) the inclusion of a cumulative cap of 5 percent on rate increases from Rider DCI between base rate cases; and 5) offsets that reflect the build-up of accumulated depreciation and ADIT associated with investments included in Rider DCI during the period that the mechanism is in effect.[160]

NKU states that Duke Kentucky has not demonstrated that the costs to be recovered through Rider DCI are volatile, unpredictable, or outside its control.[161] NKU argues that the risk of recovery of these costs is mitigated by Duke Kentucky's use of a forecasted test year and that, to the extent the projects that would be recovered under Rider DCI are prudent projects that are beneficial to consumers, Duke Kentucky should

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[158] Baudino Testimony at 47.

[159] Baudino Testimony at 49.

[160] Baudino Testimony at 52–54.

[161] Direct Testimony of Brian C. Collins at 14.

plan the projects as part of the normal capital budgeting process and include the project costs in future rate cases.[162]

Kroger argues that the proposed DCI rider amounts to single-issue ratemaking and reduces Duke Kentucky's incentive to manage its costs effectively, particularly with respect to the proposed Targeted Underground program.[163]

On rebuttal, Duke Kentucky asserts that recovery of any costs associated with the proposed Targeted Underground program through Rider DCI will be subjected to greater scrutiny because those would be the only costs that would be the subject of review in any Rider DCI proceeding.[164] Duke Kentucky avers that in these separate rider proceedings, the company would have more detailed cost estimates for the near-term work to be performed and would not be able to recover costs until the plant was in service.[165] Thus, according to Duke Kentucky, the Commission would have greater transparency into how Duke Kentucky's program is impacting reliability performance for customers.[166] Further, Duke Kentucky maintains that it would have the burden of proof that any new program would be reasonable and performed at a reasonable cost prior to cost recovery being included in Rider DCI.[167]

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[162] *Id.*

[163] Bieber Testimony at 4, 13–14.

[164] Rebuttal Testimony of Anthony J. Platz ("Platz Rebuttal") at 3.

[165] *Id.*

[166] *Id.*

[167] Platz Rebuttal at 5.

Duke Kentucky also takes issue with the Attorney General's argument that the company has failed to quantify the benefits of the proposed Targeted Underground program, noting that the company provided those quantifications in response to the Attorney General's discovery requests, which were referenced by one of the Attorney General's witnesses in the pre-filed testimony.[168] Duke Kentucky argues that the Targeted Underground program would reduce major event day ("MED") outage events by 16 percent and reduce MED outage duration by 15–20 percent.[169]

Having reviewed the record, the Commission finds that Duke Kentucky has failed to establish a need for either Rider DCI or the Targeted Underground program. Rider DCI and the Targeted Underground program are designed to improve and enhance Duke Kentucky's electric distribution system and to allow Duke Kentucky timely cost recovery of those investments. The record, however, indicates that Duke Kentucky's electric distribution system is performing well based on customer expectations and reliability metrics. As noted in the pre-filed testimony of Mr. James P. Henning and according to a J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study, the overall satisfaction scores of Duke Kentucky Energy Midwest, which includes Duke Kentucky, outperformed both the Midwest Region average scores and the large utility industry average, finishing in the second quartile among large utilities nationally.[170] The J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study calculates overall

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[168] Platz Rebuttal at 5–6.

[169] Platz Rebuttal at 7.

[170] Henning Testimony at 13; *See also*, Henning Testimony, Exhibit JPH–1.

customer satisfaction based on six performance areas.[171] One of those performance areas is power quality and reliability, which was weighted the highest at 28 percent.[172]

In addition, Duke Kentucky conducts internal customer satisfaction studies, which surveys residential customers who have had a recent service interaction with the company.[173] The internal customer satisfaction surveys show that Duke Kentucky customers were highly satisfied overall with the services provided by Duke Kentucky and that the level of customer satisfaction was either steady or improving.[174] In particular, one of the processes measured in the internal customer satisfaction study was outage restoration and experiences.[175] The study indicates that 77 percent of Duke Kentucky residential customers were highly satisfied with their overall outage and restoration experience.[176]

Lastly, Duke Kentucky witness Anthony J. Platz testified that Duke Kentucky's distribution system has performed well and that the company's reliability scores have exceeded industry average reliability scores and are among the best performing throughout Duke Energy's six-state electric service areas.[177]

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[171] Henning Testimony at 12.

[172] Henning Testimony, Exhibit JPH–1 at 2 of 17.

[173] Henning Testimony at 13.

[174] Henning Testimony at 14.

[175] Henning Testimony at 14–15.

[176] Henning Testimony, Exhibit JPH–2 at 2–3 of 24.

[177] Platz Testimony at 13–15. Duke Kentucky's 2016 Customer Average Interruption Duration Index ("CAIDI"), which measures the average interruption duration or average time to restore service per interrupted customer was 130 minutes, excluding major event days. Duke Kentucky's 2016 System Average Interruption Duration Index ("SAIDI"), which measures the average time each customer was interrupted, 99 minutes, excluding major event days. Duke Kentucky's 2016 System Average Interruption Frequency Index ("SAIFI"), which measures the average number of interruptions that a customer would experience, was 0.76 interruptions, excluding major event days.

Duke Kentucky states that Rider DCI is modeled after its existing riders to recover costs associated with the accelerated replacements of gas pipeline mains and service lines. We note, however, that the need to have a surcharge mechanism to timely recover the substantial investments required to replace aging and bare steel gas pipelines with polyethylene pipelines was based on a public safety concern that those gas pipelines be replaced on an accelerated schedule in order to minimize the risk of a catastrophic pipeline failure. In the instant proceeding, Duke Kentucky has identified no critical system-wide need to justify the implementation of a surcharge to recover costs associated with improvements to the company's distribution system. We note that the proposed Targeted Underground program targets only discrete sections of Duke Kentucky's distribution system that have experienced higher outage occurrences as compared to the rest of the company's distribution system.[178] The Targeted Underground program would impact approximately 5,600 customers over the next 10 years, but at a cost of almost $67 million.[179] While Duke Kentucky projects that there will be a reduction in MED outage events by 16 percent and a reduction in MED outage duration by 15–20 percent, the Targeted Underground program would have no impact on the projected frequency of system outages as measured by SAIFI and would have very little impact in the projected duration of a customer's outage as measured by SAIDI.[180] Given the absence of a need

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[178] Duke Kentucky identified approximately 140 miles of overhead distribution lines that will need to be placed underground and approximately 5,600 customers impacted by the Targeted Underground program over the next 10 years. *See*, Duke Kentucky's response to the Attorney General's Second Data Request, Item 41.

[179] Platz Testimony at 28 – 29.

[180] Duke Kentucky's response to the Attorney General's First Data Request, Item 89. Duke Kentucky forecasted that system-wide SAIDI would improve by from 66 minutes to 60 minutes due to the Targeted Underground program.

and the limited impact of the proposed Targeted Underground program and Rider DCI, the Commission finds that any such distribution related improvements should be performed by Duke Kentucky as part of its normal operations and those costs should be recovered in base rates and not through a surcharge mechanism.

Rate UDP-R, Underground Residential Distribution Policy. Duke Kentucky is proposing to add language to this tariff to create the ability for the Company to pay for and own, with revenues to be recovered through Rider DCI, underground installations associated with the Targeted Underground program. Since neither Rider DCI nor the Targeted Underground program are being approved, the Commission denies this tariff change.

Rate UDP-G, General Underground Distribution Policy. Duke Kentucky is proposing to add language to this tariff to create the ability for the Company to pay for and own, with revenues to be recovered through Rider DCI, underground installations associated with the Targeted Underground program. Since neither Rider DCI nor the Targeted Underground program are being approved, the Commission denies this tariff change.

Rate RTP. Duke Kentucky is proposing to combine the energy delivery charge and ancillary services charge. Duke Kentucky is also proposing to correct the reference to the "PJM Real-Time Total Locational Marginal Price" to "PJM Day-Ahead Total Locational Marginal Price." There were no objections to this tariff change from the intervenors. The Commission finds that the proposed tariff change is reasonable and should be approved.

Rider FTR, FERC Transmission Cost Reconciliation Rider. Duke Kentucky is proposing to implement Rider FTR, which is intended to recover or credit specific PJM transmission costs. The specific costs include network integration transmission service, both firm and non-firm point-to-point market administration fees, and potentially other transmission costs that may be billed in the future related to serving retail load that is above or below the level included in the Company's base rates established in this proceeding. Duke Kentucky is also proposing that the rider track incremental changes in costs associated with PJM's Regional Transmission Expansion Plan costs that are incremental to what the Company is proposing to include in its base rates.[181]

On a quarterly basis, Duke Kentucky proposes to adjust Rider FTR based on the most recent actual monthly invoices received from PJM. Duke Kentucky also proposes to submit to an annual review of this rider by the Commission of the invoiced costs and the revenue collected under the rider. The rider will be filed 30 days before it is scheduled to go into effect.[182]

Both the Attorney General and NKU filed testimony recommending that Rider FTR be rejected by the Commission. The Attorney General's witness, Mr. Lane Kollen, states that the rider would increase the retail revenue requirement in real time based on net expense pursuant to FERC tariffs, and would change recovery from a fixed amount based on the test-year expense revised with periodic base rate increases to a series of automatic quarterly Rider FTR rate increases. Mr. Kollen also states that Rider FTR "would change

[181] Wathen Testimony at 18.

[182] Wathen Testimony at 19.

Duke Kentucky's incentives to attempt to influence these expenses or to reduce other expenses to compensate for the increases in these expenses due to the selective single nature of these expenses."[183] NKU witness Mr. Brian Collins argues that Duke Kentucky has not demonstrated that the incremental transmission costs not included in base rates proposed to be recovered through Rider FTR would significantly impact Duke Kentucky's ability to earn its authorized rate of return.

After reviewing the evidence of record in this proceeding, the Commission finds that Duke Kentucky's proposed Rider FTR should not be approved. Although the Commission is aware that it recently approved a similar rider for Kentucky Power in Case No. 2017-00179, the decision in that proceeding was based on evidence which demonstrated that Kentucky Power's transmission costs were significant and volatile; therefore, the approval of such a rider was warranted in that proceeding. Duke Kentucky testified during the hearing in this matter that Duke Kentucky's transmission rates are significantly less than those for Kentucky Power and "the volatility has a much bigger impact" on Kentucky Power than Duke Kentucky.[184] The Commission finds no evidence in this proceeding to suggest that the proposed FTR is warranted for Duke Kentucky at this time.

Budget Payment Plan. Duke Kentucky's current and initially proposed tariff do not comply with 807 KAR 5:006, Section 14(2)(a)(3), which requires that the provisions of the budget payment plan be included in a utility's tariffed rules. Through discovery, Duke

[183] Kollen Testimony at 62.

[184] March 7, 2018 Hearing at 3:50:48.

Kentucky indicated that it would be willing to include the provisions of the budget payment plan in its tariff.[185] Duke Kentucky is directed to do so when filing its compliance tariff.

Pick Your Own Due Date and Usage Alerts and Outage Alerts with AMI. Duke Kentucky is proposing to implement a pick your own due date billing option and a Usage Alerts and Outage Alerts with AMI service; however, Duke Kentucky did not include the provisions of these items in its proposed tariff. Through discovery, Duke Kentucky indicated that it would be willing to include the provisions of these programs/services in its tariff.[186] Duke Kentucky is directed to do so when filing its compliance tariff.

Miscellaneous Tariff Changes. Duke Kentucky is proposing various minor text changes to its tariff. Unless otherwise stated in this Order, the Commission finds that the proposed changes are reasonable and should be approved.

Bill and Bill Format. Duke Kentucky is proposing to update its bill format to reflect the riders proposed in this case and the new company logo. The Commission approves Duke Kentucky's proposal to change its bill format to the extent that the bill reflects the riders and rates approved herein.

Duke Kentucky's tariff contains its bill format, which consists of three pages. However, when Duke Kentucky bills its customers, it does not include page 2, which contains the billing details, unless the customer checks a block that indicates he or she would like to receive page 2. The Commission finds that page 2 provides customers with the ability to check the accuracy of the bill and should be sent to every customer. With this Order, the Commission will require the entire bill be sent to every customer, thereby

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[185] Duke Kentucky's Response to Staff's Second Request, Item 9 c.

[186] Duke Kentucky's Response to Commission Staff's Third Request for Information ("Staff's Third Request"), Item 6 b.

eliminating the requirement that the customer elect to receive the entire bill. This directive applies to all Duke Kentucky customers, including those that are gas customers only.

Tariff Format. Numerous tariff pages Duke Kentucky submitted in this case did not appear to comply with 807 KAR 5:006, Section 3(4), which states "[e]ach tariff sheet shall contain a blank space at its bottom right corner that measures at least three and one-half (3.5) inches from the right of the tariff sheet by two and one-half (2.5) inches from the bottom of the tariff sheet to allow space for the commission to affix the commission's stamp." This ensures that no language is obscured by the Commission's stamp. When filing its compliance tariff reflecting the rates, rules, and terms of service approved in this Order, Duke Kentucky should ensure that all of its tariff pages comply with 807 KAR 5:006, Section 3(4).

Rider DSM, Demand-Side Management. The Commission finds that, upon the implementation of new base rates, the Lost Revenue from Lost Sales Recovery component of Duke Kentucky's DSM cost-recovery rider should be reset to zero. Duke Kentucky's compliance tariff should reflect this revision to Rider DSM.

KSBA Recommendations. The KSBA made certain recommendations that the Commission will address herein.

1. Elimination of Demand Ratchet from Rate DS. KSBA witness Mr. Ron Willhite recommends that the Commission eliminate the demand ratchet from Rate DS for P–12 public and private schools or alternatively minimize the demand ratchet for said schools billed under this rate schedule. KSBA argues that Duke Kentucky is a summer peaking utility and that schools are not typically in session during the summer peak but peak during the month of September. As a result, because of the demand ratchet for

Rate DS, a school's September billing demand becomes the basis for demand billing in many of the non-summer revenue months. Mr. Willhite states that schools billed under Rate DS are subsiding other customers within the class and that the demand ratchet for schools should be eliminated or reduced. As an alternative, Mr. Willhite suggests the establishment of a new P–12 School Tariff. Duke Kentucky opposes the creation of a new P–12 School Tariff, stating that Mr. Willhite provided no information that specifically demonstrates how the energy demand requirements of schools are substantially dissimilar from other Rate DS Rate DS.

The Commission is not convinced that public school usage characteristics support special treatment compared to other customers serviced under Rate DS and will not approve KSBA's recommendation.

2. Rate SP, Seasonal Sports Service. KSBA recommends that the Commission allow some sports fields to move to Rate SP. Currently, Rate SP is a closed tariff and has been closed since June 25, 1981. According to KSBA, subsequent to 1981new sports fields are being served on Rate DS and must pay a demand charge and minimum payments based on off-peak night-time load in the months they are not in full operation. KSBA argues that sports fields clearly are not similar to other commercial and industrial loads served on Rate DS. KSBA states that it is aware of three sports fields that are interested in taking service under the closed tariff. Duke Kentucky is opposed to reopening the tariff, stating that KSBA has not met the burden of proof to establish the reasonableness of re-opening Rate SP.

At the hearing in this matter, Duke Kentucky could not explain why the tariff was closed or whether it had been reopened temporarily over the intervening years. In its post-hearing brief, Duke Kentucky stated that it was closed due to lack of interest and has remained closed since 1981. The Commission finds that the load for sports fields would differ significantly from that of other customers and that Duke Kentucky should be directed to reopen Rate SP permanently. Given that there will be a revenue impact to Duke Kentucky if current customers move to Rate SP, the Commission will allow Duke Kentucky to defer the difference between what it would have billed the sports field customer under its current rate and what it will bill under Rate SP as a regulatory asset and request recovery in its next base-rate proceeding.

3. Funding for SEMP, School Energy Manager Program. KSBA recommends that the Commission require Duke Kentucky to fund the SEMP through shareholder funds. Mr. Willhite states that public schools must pursue energy savings pursuant to KRS 160.325 and that SEMP has significantly improved cost savings for schools in the territories of other jurisdictional utilities. Duke Kentucky opposes Mr. Willhite recommendation, stating that he does not "offer any evidence that shows the Company's choice not to fund SEMP to date has somehow prevented school districts in the Company's service territory from moving forward with meaningful energy efficiency programs."[187]

The Commission agrees with Duke Kentucky on this issue and will not approve KSBA's recommendation to require Duke Kentucky to fund SEMP.

2018 ENVIRONMENTAL COMPLIANCE PLAN AND ENVIRONMENTAL SURCHARGE

[187] Duke Kentucky's Post-Hearing Brief at 119–120.

As part of this proceeding, Duke Kentucky filed an application, pursuant to KRS 278.183, for authority to establish and assess an environmental surcharge rider ("Rider ESM") and for approval of its environmental compliance plan ("2018 Plan").[188] KRS 278.183 provides that a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act ("CAA") as amended and those federal, state, or local environmental requirements that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Pursuant to KRS 278.183(2), a utility seeking to recover its environmental compliance costs through an environmental surcharge must first submit to the Commission a plan that addresses compliance with the applicable environmental requirements. The plan must also include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of the proposed surcharge applied to individual rate classes. Within six months of submission, the Commission must conduct a hearing to:

(a) Consider and approve the compliance plan and rate surcharge if the plan and rate surcharge are found reasonable and cost-effective for compliance with the applicable environmental requirements;

(b) Establish a reasonable return on compliance-related capital expenditures; and

(c) Approve the application of the surcharge.

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[188] Duke Kentucky's Application and witness testimony refers to the environmental compliance plan as the 2017 Plan. In prior compliance plan orders, the Commission has named the plan according to the year in which the order is issued. Accordingly, the Commission will refer to the subject environmental compliance plan as the 2018 Plan.

The 2018 Environmental Compliance Plan

As required by KRS 278.183, Duke Kentucky filed its 2018 Plan, consisting of five projects necessary to comply with the CAA or other environmental regulations applicable to coal combustion wastes and by-products. Duke Kentucky's 2018 Plan reflects environmental compliance costs at its only coal-fired generation facility, East Bend. The projects include:[189]

1. Project EB020290 Lined Retention Basin West;
2. Project EB020745 Lined Retention Basin East;
3. Project EB020298 East Bend SW/PW Reroute;
4. ARO amortization for Pond Closure; and
5. Consumables (Reagents and emission allowances).

The 2018 Plan includes projects that were previously approved Case Nos. 2015-00187[190] and 2016-00398.[191] At the time of the filing of this case, two projects at East Bend were in progress, with planned in-service dates after the test period in this proceeding.[192]

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[189] Application at 16.

[190] Case No. 2015-00187, *Application of Duke Energy Kentucky Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations* (Ky. PSC Dec. 15, 2015). The Commission approved Duke Kentucky's proposed accounting treatment to classify ARO costs for the East Bend Ash Pond, including amortization and depreciation expenses, closure costs, and carrying charges on the unamortized balance as regulatory assets for 2015 and subsequent years ("East Bend Coal Ash ARO regulatory asset").

[191] Case No. 2016-00398, *Electronic Application of Duke Energy Kentucky, Inc. for a Certificate of Public Convenience and Necessity Authorizing the Company to Close the East Bend Generation Station Coal Ash Impoundment and for All Other Required Approvals and Relief* (Ky. PSC June 6, 2017). Duke Kentucky received certificates of public convenience and necessity to close and repurpose its existing East Bend ash impoundment and construct new water redirection and wastewater treatment systems.

[192] Application at 17. Construction has begun for the process water system and pond repurposing projects.

Duke Kentucky states that the pollution control projects included in the 2018 Plan amendment are necessary for Duke Kentucky to comply with the CAA and other federal, state, and local regulations, which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal.

Environmental Requirements

Clean Air Interstate Rule and Cross-State Air Pollution Rule. The Clean Air Interstate Rule ("CAIR") and Cross-State Air Pollution Rule ("CSAPR") are regional rules that set state-level annual standards for the emission of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") from electric generating units.[193] Published in the Federal Register on October 26, 2016, the CSAPR Update reduced the number of ozone season NO_x allowances for East Bend effective January 1, 2017.[194] The East Bend selective catalytic reduction controls and allowances from Duke Kentucky's retired Miami Fort Unit 6 station are expected to comply with the CSAPR Update, but East Bend can also buy allowances on the market if necessary.[195]

CCR Rule. Coal combustion residuals ("CCRs") include fly ash, bottom ash, and flue-gas desulfurization byproducts. The Disposal of Coal Combustion Residuals from Electric Utilities Final Rule ("CCR Rule") was published as a Subtitle D, nonhazardous waste rule on April 17, 2015. The CCR Rule includes dam safety requirements for ash ponds and new requirements for the handling, disposal, and beneficial reuse of CCRs

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[193] Direct Testimony of Tammy Jett ("Jett Testimony") at 5.

[194] *Id.*

[195] *Id.* at 6.

except when reused in encapsulated applications, such as concrete and wallboard.[196] Together with the Steam Electric Effluent Limitation Guidelines Final Rule ("ELG Rule"), the CCR Rule requires dry handling of fly and bottom ash, increased use of landfills, closure of existing wet ash storage ponds, and alternative wastewater treatment systems.[197]

ELG Rule. The ELG Rule was published on November 3, 2015, and sets requirements for wastewater streams, including fly ash and bottom ash wastewaters, at steam electric generating units.[198] Compliance activities include converting ash handling systems from wet to dry handling and clean closure of the existing East Bend Ash Pond. The ELG Rule compliance deadline was originally set for November 1, 2018, through December 31, 2023, but has been stayed as the EPA requests reconsideration. However, East Bend's compliance projects schedules are not impacted, as the ELG Rule was not the only driver.[199]

RIDER ESM

Duke Kentucky is proposing a new tariff to implement Rider ESM. Through discovery, Duke Kentucky was made aware of inconsistencies in the Rider ESM tariff and proposed changes through rebuttal testimony to make the tariff consistent with the proposed mechanism.[200] The Commission finds that the tariff as discussed and modified

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[196] Jett Testimony at 11–12.

[197] *Id.* at 12.

[198] *Id.* at 12–13.

[199] *Id.*

[200] Lawler Rebuttal at 12–13.

in this order should become effective for service rendered on and after the date of this order.

Costs Associated with the 2018 Plan. Duke Kentucky proposes to recover the costs associated with the amortization of the East Bend Coal Ash ARO regulatory asset, including projected costs, on a levelized basis over ten years.[201] The Attorney General recommends that the Commission authorize recovery of current ARO–related costs in the second month after they are incurred and of amortization of only previously incurred costs.[202] The Attorney General explains that KRS 278.183(2) allows recovery of environmental compliance costs "in the second month following the month in which they are incurred" and, furthermore, that recovery of ARO–related costs before they are actually incurred would result in increased current income tax expense and negative deferred income tax expense, which would increase E(m).[203] The Commission concurs with the Attorney General that KRS 278.183 does not allow for recovery of projected or estimated costs. Therefore, the Commission finds that Duke Kentucky should amortize only the actual balance of the East Bend Coal Ash ARO regulatory asset over 10 years and recover additional actual costs associated with the settlement of the East Bend Coal Ash ARO in the second month after they are incurred.

Duke Kentucky has identified the environmental compliance costs for the 2018 Plan projects and these are the costs that Duke Kentucky proposes to recover through

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[201] Lawler Testimony at 11–12.

[202] Kollen Testimony at 60.

[203] *Id.* at 59–60.

its environmental surcharge. Duke Kentucky has removed these costs from the base period and excluded these costs from its forecasted period in this proceeding to ensure that no costs are recovered through its base rates and Rider ESM.[204] The costs identified here by Duke Kentucky, as modified above, are eligible for surcharge recovery if they are shown to be reasonable and cost-effective for complying with the environmental requirements specified in KRS 278.183. The Commission finds that the costs identified for the 2018 Plan projects have been shown to be reasonable and cost-effective for environmental compliance. Thus, they are reasonable and should be approved for recovery through Duke Kentucky's environmental surcharge.

Qualifying Costs. The qualifying costs included in E(m) will reflect only the Commission-approved environmental projects from the 2018 Plan. Should Duke Kentucky desire to include other environmental projects in the future, it will have to apply for an amendment to its approved compliance plan.

Rate of Return. As specified in this order, Duke Kentucky is authorized to use a 9.725 percent return on equity that will be utilized in Rider ESM to determine the Weighted Average Cost of Capital ("WACC").

Capitalization and Gross Revenue Conversion Factor. As specified in this order and proposed by Duke Kentucky, Duke Kentucky should utilize a WACC of 6.830 percent and a gross revenue conversion factor ("GRCF") of 1.337304[205] in determining the rate of return to be used in the monthly environmental surcharge filings. Duke Kentucky

[204] Application at 17 and Lawler Testimony at 9.

[205] Lawler Rebuttal, Attachment SEL-Rebuttal-2(b), page 3 of 11. Duke Kentucky's proposed GRCF has been updated for the 21 percent federal income tax rate.

proposes to update the WACC and GRCF when it files a base rate case. The WACC and GRCF should remain constant until such time as the Commission sets base rates in Duke Kentucky's next base rate case proceeding.

Surcharge Mechanism and Calculation. As proposed by Duke Kentucky, the environmental revenue requirement ("E(m)") is comprised of a return on the environmental compliance rate base, plus specified environmental compliance operating expenses, less proceeds from emission allowance sales, plus or minus prior period adjustments as determined by the Commission during six-month and two-year review cases, plus or minus surcharge over- or under-recovery adjustments.[206] Environmental compliance rate base is defined as electric plant in service for specified environmental compliance projects adjusted for accumulated depreciation, accumulated deferred income taxes, accumulated investment tax credits, construction work in progress, and emission allowance inventory.

To calculate the monthly Rider ESM factor, Duke Kentucky proposes to divide the E(m) by the average revenues excluding Rider ESM revenue of the preceding 12-month period ("R(m)").

Surcharge Allocation. Duke Kentucky proposes to allocate the E(m) to residential[207] and nonresidential[208] rate schedules on the basis of the percentage of total

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[206] Lawler Rebuttal, Attachment SEL-Rebuttal 1(b).

[207] *Id.* Residential includes the following rate schedules: Residential Service.

[208] *Id.* Nonresidential includes the following rate schedules: Service at Secondary Distribution Voltage, Optional Rate for Electric Space Heating, Seasonal Sports Service, Service at Primary Distribution Voltage, Time-of-Day Rate for Service at Distribution Voltage, General Service Rate for Small Fixed Loads, Time-of-Day Rate for Service at Transmission Voltage, Street Lighting Service, Traffic Lighting Service, Unmetered Outdoor Lighting, Street Lighting Service for Nonstandard Units, Street Lighting Service – Customer Owned, Street Lighting Service – Overhead Equipment, and LED Outdoor Lighting Service.

R(m) for the 12-month period ending with the current expense month. Rider ESM will be implemented as a percentage of R(m) for the Residential rate schedule and as a percentage of R(m) excluding fuel revenues for Nonresidential rate schedules.[209]

Duke Kentucky proposes to utilize a jurisdictional allocation ratio of 100 percent to allocate E(m) to native retail customers because Duke Kentucky has no firm wholesale customers and PJM Manual 15 does not allow nonvariable production costs to be included in offer cost components.[210] The Commission finds this argument unpersuasive.[211] The jurisdictional allocation ratio should be calculated as total jurisdictional retail revenues excluding Rider ESM revenues, divided by total company revenues excluding Rider ESM revenues, consistent with all other electric utilities that have an environmental surcharge mechanism pursuant to KRS 278.183.

Monthly Reporting Forms. Duke Kentucky provided proposed monthly reporting forms to be used in the monthly environmental reports.[212] Duke Kentucky provided revised forms to make clerical adjustments and revisions necessary to align the forms with the revised Rider ESM tariff.[213] The Commission finds that Duke Kentucky's proposed monthly environmental surcharge reporting forms, as revised through testimony and this order, should be approved.

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209 Lawler Rebuttal at 12.

210 Lawler Testimony, Attachment SEL-2, page 2 of 10, and Duke Kentucky's response to Commission Staff's Third Request for Information ("Staff's Third Request"), Item 3.

211 *See* Case No. 1994-00332, *The Application of Louisville Gas and Electric Company for Approval of Compliance Plan and to Assess a Surcharge Pursuant to KRS 278.183 to Recover Costs of Compliance with Environmental Requirements for Coal Combustion Wastes and By-Products* (Ky. PSC Apr. 6, 1995), Order Denying Rehearing at 1–2.

212 Lawler Testimony, Attachment SEL-2.

213 Lawler Rebuttal, Attachments SEL-Rebttual-2(a) and SEL-Rebuttal-2(b).

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by Duke Kentucky are denied.

2. The rates and charges, as set forth in Appendix C to this Order, are approved as fair, just, and reasonable rates for Duke Kentucky and these rates and charges are approved for service rendered on and after April 14, 2018.

3. Duke Kentucky's depreciation rates, as modified herein, are approved.

4. Duke Kentucky's proposal for a deferral mechanism for planned outage expense is approved.

5. Duke Kentucky's request to amortize the East Bend O&M regulatory asset over a ten-year period is approved.

6. Duke Kentucky's carrying charges on the East Bend O&M regulatory asset shall be based on its cost of debt.

7. Duke Kentucky request to amortize the East Bend Ash Pond ARO over a ten-year period is approved.

8. Duke Kentucky proposal for a deferral mechanism for replacement power expense is approved.

9. Duke Kentucky, in conjunction with DEBS, shall bid the next MAVMS contract for the Midwest market that includes Kentucky, Indiana, and Ohio and for a smaller geographic area limited to Duke Kentucky's service territory. The smaller geographic area shall include Duke Kentucky's service territory by itself or by county or such other discrete area(s) within its service territory that it deems to be reasonable. Duke Kentucky shall also provide an update of this process in each annual VMP filings beginning with the 2019 VMP.

10. Duke Kentucky's request to implement a Fixed Bill Program is denied.

11. Duke Kentucky's request to cancel and withdraw Rate RTP – M is approved.

12. Duke Kentucky's request to revise Rate TT as discussed herein is approved.

13. Duke Kentucky's request to revise Rate DT as discussed herein is approved.

14. Duke Kentucky's request to revise Rate LED is approved as modified herein.

15. Duke Kentucky's request to cancel and withdraw Rate OL is approved.

16. Duke Kentucky's request to cancel and withdraw Rate NSP is approved.

17. Duke Kentucky's request to revise Rate LM as discussed herein is approved.

18. Duke Kentucky's request to revise Rate MDC as discussed herein is approved.

19. Duke Kentucky's request to revise Rider GSS as discussed herein is approved.

20. Duke Kentucky's request to revise Rider FAC is approved as directed herein.

21. Duke Kentucky's request to revise and modify Rider PSM is approved as directed herein. Duke Kentucky shall notify the Commission within seven days of incurring any capacity performance assessments from PJM.

22. Duke Kentucky's request to modify its reconnection fees is approved as modified herein.

23. Duke Kentucky's request to revise Rate CATV is approved as modified herein.

24. Duke Kentucky's request to revise its Cogen Tariffs is denied in part and granted in part. Duke Kentucky's request to include language in its Cogen Tariffs limiting capacity purchases from qualifying facilities is denied. Duke Kentucky's request to revise its capacity rate is approved as modified herein. All other proposed revisions to the Cogen Tariffs are approved.

25. Duke Kentucky's request to implement Rider DCI is denied.

26. Duke Kentucky's request for a CPCN to implement the Targeted Underground program is denied.

27. Duke Kentucky's request to make revisions to Rate UDP – R and Rate UDP – G related to the Targeted Underground program is denied.

28. Duke Kentucky's request to revise Rate RTP as discussed herein is approved.

29. Duke Kentucky's request to implement Rider FTR is denied.

30. Duke Kentucky's 2018 Environmental Compliance Plan is approved.

31. Duke Kentucky shall file its Budget Payment Plan tariff in compliance with 807 KAR 5:006, Section 14(2)(a)(3).

32. Duke Kentucky shall provide to each of its customers, including gas only customers, the entire content of its bills as provided in its tariff.

33. Duke Kentucky shall ensure that all of its tariff pages comply with 807 KAR 5:006, Section 3(4) when filing its compliance tariff reflecting the rates, rules, and terms of service approved herein.

34. Duke Kentucky shall reopen Rate – SP to allow any sports field to receive service under this rate schedule. Duke Kentucky shall be authorized, for accounting purposes only, to defer the difference between what it would have billed the sports field customer under its current rate and what it will bill under Rate SP as a regulatory asset.

35. Duke Kentucky's Rider ESM tariff, as described in this order, is approved for service rendered on and after the date of this order.

36. The Rider ESM reporting formats described in this order shall be used for the monthly environmental surcharge filings.

37. Within 20 days of the date of this Order, Duke Kentucky shall file with the Commission, using the Commission's electronic Tariff Filing System, new tariff sheets setting forth the rates, charges, and modifications approved or as required herein and reflecting their effective date and that they were authorized by this Order.

38. This case is closed and removed from the Commission's docket.

By the Commission

ENTERED

APR 13 2018

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Gwen R. Pinson
Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00321 DATED APR 13 2018

Adjustments	Amounts
Adjust Revenue from Base Period to Test Period	($5,133,384)
Adjust Fuel & Purchased Power	($1,284,619)
Adjust Other Production Expense	$12,650,083
Adjust Transmission Expense	$919,747
Adjust Regional Market Expense	$79,447
Adjust Distribution Expense	($43,555)
Adjust Customer Account Expense	$671,968
Adjust Customer Service and Information Expense	$183,121
Adjust Sales Expense	($151,501)
Adjust A &G Expense	($1,497,124)
Adjust Other Operating Expense	$2,680,605
Adjust Other Tax Expense	$2,105,609
Amortization of Deferred Asset	$463,931
Rate Case Expense	$120,538
Eliminate ESM Expense from Base Rates	($12,398,573)
Interest Expense Adjustment (Net)	($107,901)
Eliminate Non-Native Revenue and Expense (Net)	($1,823,636)
Amortization of Deferred Depreciation	$490,618
DSM Elimination (Net)	($225,378)
Eliminate Miscellaneous Expense	($539,892)
Eliminate Unbilled Revenue	$3,258,473
Eliminate Merger CTA Expense	($237,780)
Annualize PJM Charges and Credits	$774,947
Annualize East Bend Maintenance	$4,777,143
Amortization of Deferred Expenses	$6,247,623
Adjust Uncollectible Expense	($1,418,703)
Annualize RTEP Expense	$1,979,833
Adjust Revenue to Reconcile Schedule M with Budget	$4,801,375

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00321 DATED APR 1 3 2018

DUKE FILED

	Duke Energy KY Electric Capitalization	Adjustment	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment
Stort Term Debt	$ 73,522,733		10.428%	3.083%	0.321%	0.321%	$ 2,266,706
Long Term Debt	$ 286,807,753		40.679%	4.243%	1.726%	1.726%	$ 12,169,253
Common Equity	$ 344,720,654		48.893%	10.30%	5.036%	8.208%	$ 57,868,571
	$ 705,051,140		100%		7.083%	10.26%	$ 72,304,530

TAX IMPACT

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 73,522,733		$ 73,522,733	10.428%	3.083%	0.321%	0.321%	$ 2,266,706	$ -
Long Term Debt	$ 286,807,753		$ 286,807,753	40.679%	4.243%	1.726%	1.726%	$ 12,169,253	$ -
Common Equity	$ 344,720,654		$ 344,720,654	48.893%	10.300%	5.036%	6.753%	$ 47,613,375	$ (10,255,196)
	$ 705,051,140		$ 705,051,140	100%		7.083%	8.800%	$ 62,049,334	$ (10,255,196)
				100.000%					

ST DEBT IMPACT

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 73,522,733	$ (5,125,578)	$ 68,397,155	9.772%	3.083%	0.301%	0.301%	$ 2,108,684	$ (158,022)
Long Term Debt	$ 286,807,753		$ 286,807,753	40.977%	4.243%	1.739%	1.739%	$ 12,169,253	$ -
Common Equity	$ 344,720,654		$ 344,720,654	49.251%	10.300%	5.073%	6.803%	$ 47,613,375	$ -
	$ 705,051,140	$ (5,125,578)	$ 699,925,562	100%		7.113%	8.843%	$ 61,891,312	$ (158,022)
				100.000%					

EAST BEND O&M REG ASSET

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 68,397,155	$ (3,570,734)	$ 64,826,421	9.772%	3.083%	0.301%	0.301%	$ 1,998,599	$ (110,086)
Long Term Debt	$ 286,807,753	$ (14,973,186)	$ 271,834,567	40.977%	4.243%	1.739%	1.739%	$ 11,533,941	$ (635,312)
Common Equity	$ 344,720,654	$ (17,996,544)	$ 326,724,110	49.251%	10.300%	5.073%	6.803%	$ 45,127,663	$ (2,485,712)
	$ 699,925,562	$ (36,540,465)	$ 663,385,097	100%		7.113%	8.843%	$ 58,660,202	$ (3,231,110)

East End Coal Ash ARO

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 64,826,421	$ (1,808,733)	$ 63,017,687	9.772%	3.083%	0.301%	0.301%	$ 1,942,835	$ (55,763)
Long Term Debt	$ 271,834,567	$ (7,584,575)	$ 264,249,992	40.977%	4.243%	1.739%	1.739%	$ 11,212,127	$ (321,814)
Common Equity	$ 326,724,110	$ (9,116,038)	$ 317,608,072	49.251%	10.300%	5.073%	6.803%	$ 43,868,541	$ (1,259,122)
	$ 663,385,097	$ (18,509,346)	$ 644,875,751	100%		7.113%	8.843%	$ 57,023,504	$ (1,636,699)

Carbon Management Reg Asset

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 63,017,687	$ 19,544	$ 63,037,231	9.772%	3.083%	0.301%	0.301%	$ 1,943,438	$ 603
Long Term Debt	$ 264,249,992	$ 81,954	$ 264,331,946	40.977%	4.243%	1.739%	1.739%	$ 11,215,604	$ 3,477
Common Equity	$ 317,608,072	$ 98,502	$ 317,706,574	49.251%	10.300%	5.073%	6.803%	$ 43,882,147	$ 13,605
	$ 644,875,751	$ 200,000	$ 645,075,751	100%		7.113%	8.843%	$ 57,041,189	$ 17,685

ASL Methodology

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 63,037,231	$ 267,098	$ 63,304,329	9.772%	3.083%	0.301%	0.301%	$ 1,951,672	$ 8,235
Long Term Debt	$ 264,331,946	$ 1,120,024	$ 265,451,970	40.977%	4.243%	1.739%	1.739%	$ 11,263,127	$ 47,523
Common Equity	$ 317,706,574	$ 1,346,177	$ 319,052,751	49.251%	10.300%	5.073%	6.803%	$ 44,068,083	$ 185,936
	$ 645,075,751	$ 2,733,299	$ 647,809,050	100%		7.113%	8.843%	$ 57,282,882	$ 241,693

ROE

	Duke Energy KY Electric Capitalization	Adjustment	Adjusted Capitalization	Capital Ratio	Component Costs	Weigted Avg cost	Grossed Up Cost	Revenue Requirment	Incremmental revenue requirement
Stort Term Debt	$ 63,304,329		$ 63,304,329	9.772%	3.083%	0.301%	0.30%	$ 1,951,672	$ -
Long Term Debt	$ 265,451,970		$ 265,451,970	40.977%	4.243%	1.739%	1.74%	$ 11,263,127	$ -
Common Equity	$ 319,052,751		$ 319,052,751	49.251%	9.725%	4.790%	6.42%	$ 41,607,971	$ (2,460,111)
	$ 647,809,050		$ 647,809,050	100%		6.830%	8.46%	$ 54,822,771	$ (2,460,111)

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APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00321 DATED APR 13 2018

The following rates and charges are prescribed for the customers in the area served by Duke Energy Kentucky, Inc. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under the authority of the Commission prior to the effective date of this Order.

RATE RS
RESIDENTIAL SERVICE

Customer Charge per month	$	11.00
Energy Charge per kWh:		
All kWh per month	$	0.071520

RATE DS
SERVICE AT SECONDARY DISTRIBUTION VOLTAGE

Customer Charge per month:		
Single Phase Service	$	17.14
Three Phase Service	$	34.28
Demand Charge per kW:		
First 15 kW	$	.00
Additional kW	$	8.25
Energy Charge per kWh:		
First 6,000 kWh	$	0.080075
Next 300 kWh/kW	$	0.049155
Additional kWh	$	0.040254

The maximum monthly rate, excluding the customer charge, and all applicable riders, shall now exceed $0.236547 per kWh

For customers receiving service under the provisions of former Rate C, Optional Rate for Churches, as of June 25, 1981, the maximum monthly rate per kWh shall not exceed $0.145219 per kWh

RATE DT
TIME-OF-DAY RATE FOR SERVICE AT DISTRIBUTION VOLTAGE

Customer Charge per month:		
Single Phase	$	63.50
Three Phase	$	127.00
Primary Voltage Service	$	138.00
Demand Charge per kW:		
Summer on-peak	$	13.78
Winter on-peak	$	13.04
Off-peak	$	1.24
Energy Charge per kWh:		
Summer on-peak	$	0.043370
Winter on-peak	$	0.041403
Off-peak	$	0.035516
Primary Service Discount:		
Metering of on-peak billing demand per kW:		
First 1,000 kW	$	(0.70)
Additional kW	$	(0.54)

RATE EH
OPTIONAL RATE FOR ELECTRIC SPACE HEATING

Winter Period		
Customer Charge per month:		
Single Phase Service	$	17.14
Three Phase Service	$	34.28
Primary Voltage Service	$	117.00
Energy Charge per kWh:		
All kWh per month	$	0.062202

RATE SP
SEASONAL SPORTS SERVICE

Customer Charge per month:	$	17.14
Energy Charge per kWh:		
All kWh per month	$	0.096130

RATE GS-FL
OPTIONAL UNMETERED GENERAL SERVICE RATE FOR SMALL FIXED LOADS

Base Rate per kWh:		
Load range of 540 to 720 hours per month	$	0.082708
Loads less than 540 hours per month	$	0.095240
Minimum per Fixed Load Location per month:	$	2.98

RATE DP
SERVICE AT PRIMARY DISTRIBUTION VOLTAGE

Customer Charge per month:		
Primary Voltage Service (12.5 or 34.5 kV)	$	117.00
Demand Charge per kW:		
All kW	$	7.92
Energy Charge per kWh:		
First 300 kWh/kW	$	0.051092
Additional kWh	$	0.043219

The maximum monthly rate, excluding the customer charge, electric fuel component charges, and DSM charge shall not exceed $0.241312 per kWh.

RATE TT
TIME-OF-DAY RATE FOR SERVICE AT TRANSMISSION VOLTAGE

Customer Charge per month:	$	500.00
Demand Charge per kW:		
Summer on-peak	$	8.07
Winter on-peak	$	6.62
Off-peak	$	1.22
Energy Charge per kWh:		
Summer on-peak	$	0.048997
Winter on-peak	$	0.046775
Off-peak	$	0.040124

RIDER GSS
GENERATION SUPPORT SERVICE

Administrative Charge:	$	50.00
Monthly Transmission and Distribution Reservation Charge:		
Rate DS – Secondary Distribution Service	$	0.047126
Rate DT – Distribution Service	$	0.058517
Rate DP – Primary Distribution Service	$	0.059794
Rate TT – Transmission Service	$	0.026391

RATE SL
STREET LIGHTING SERVICE

Base Rate per Unit per Month:

OVERHEAD DISTRIBUTION AREA

Standard Fixture (Cobra Head)

Mercury Vapor:

7,000 Lumen	$	7.27
7,000 Lumen (Open Refractor)	$	6.07
10,000 Lumen	$	8.39
21,000 Lumen	$	11.23

Metal Halide:

14,000 Lumen	$	7.27
20,500 Lumen	$	8.39
36,000 Lumen	$	11.23

Sodium Vapor:

9,500 Lumen	$	8.04
9,500 Lumen (Open Refractor)	$	6.04
16,000 Lumen	$	8.77
22,000 Lumen	$	11.37
27,500 Lumen	$	11.37
50,000 Lumen	$	15.28

Decorative Fixtures

Sodium Vapor:

9,500 Lumen (Rectilinear)	$	10.00
22,000 Lumen (Rectilinear)	$	12.36
50,000 Lumen (Rectilinear)	$	16.35
50,000 Lumen (Setback)	$	24.31

Spans of Secondary Wiring: For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $ 0.53

UNDERGROUND DISTRIBUTION AREA

Standard Fixture (Cobra Head)

Mercury Vapor:

7,000 Lumen	$	7.40
7,000 Lumen (Open Refractor)	$	6.07
10,000 Lumen	$	8.54
21,000 Lumen	$	11.50

Metal Halide:		
14,000 Lumen	$	7.40
20,500 Lumen	$	8.54
36,000 Lumen	$	11.50
Sodium Vapor:		
9,500 Lumen	$	8.04
9,500 Lumen (Open Refractor)	$	6.12
16,000 Lumen	$	8.74
22,000 Lumen	$	11.37
27,500 Lumen	$	11.37
50,000 Lumen	$	15.28
Decorative Fixture:		
Mercury Vapor:		
7,000 Lumen (Town & Country)	$	7.65
7,000 Lumen (Holophane)	$	9.61
7,000 Lumen (Gas Replica)	$	21.96
7,000 Lumen (Granville)	$	7.73
7,000 Lumen (Aspen)	$	13.91
Metal Halide:		
14,000 Lumen (Traditionaire)	$	7.64
14,000 Lumen (Granville Acorn)	$	13.91
14,000/14,500 Lumen (Gas Replica)[214]	$	22.04
Sodium Vapor:		
9,500 Lumen (Town & Country)	$	11.17
9,500 Lumen (Holophane)	$	12.10
9,500 Lumen (Rectilinear)	$	9.02
9,500 Lumen (Gas Replica)	$	22.75
9,500 Lumen (Aspen)	$	14.09
9,500 Lumen (Traditionaire)	$	11.17
9,500 Lumen (Granville Acorn)	$	14.09
22,000 Lumen (Rectilinear)	$	12.42
50,000 Lumen (Rectilinear)	$	16.41
50,000 Lumen (Setback)	$	24.31

[214] Duke Kentucky's billing analysis lists both a 14,000 and 14,500 Lumen Gas Replica light at the same rate.

POLE CHARGES

Pole Description:

Wood:

17 Foot (Wood Laminated) (a)	$	4.50
30 Foot	$	4.44
35 Foot	$	4.50
40 Foot	$	5.39

Aluminum:

12 Foot (Decorative)	$	12.23
28 Foot	$	7.09
28 Foot (Heavy Duty)	$	7.16
30 Foot (Anchor Base)	$	14.16

Fiberglass:

17 Foot	$	4.50
12 Foot (Decorative)	$	13.15
30 Foot (Bronze)	$	8.56
35 Foot (Bronze)	$	8.79

Steel:

27 Foot (11 gauge)	$	11.56
27 Foot (3 gauge)	$	17.43

Spans of Secondary Wiring: For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $ 0.77

RATE TL
TRAFFIC LIGHTING SERVICE

Base Rate per kWh:		
Energy only	$	0.038903
Energy from separately metered source w/maintenance	$	0.021543
Energy w/maintenance	$	0.060446

RATE UOLS
UNMETERED OUTDOOR LIGHTING ELECTRIC SERVICE

Base Rate per kWh:		
All kWh per month	$	0.038305

RATE LED
LED OUTDOOR LIGHTING ELECTRIC SERVICE

Base Rate per kWh:

All kWh per month $ 0.038305

Monthly Maintenance and Fixture Charge Per Unit Per Month

Fixtures:

	Fixture	Maintenance
50W Standard LED-Black	$ 4.96	$ 4.24
70W Standard LED-Black	$ 4.95	$ 4.24
110W Standard LED-Black	$ 5.62	$ 4.24
150W Standard LED-Black	$ 7.44	$ 4.24
220W Standard LED-Black	$ 8.43	$ 5.17
280 W Standard LED-Black	$ 10.38	$ 5.17
50W Deluxe Acorn LED-Black	$ 14.47	$ 4.24
50W Acorn LED-Black	$ 13.04	$ 4.24
50W Mini Bell LED-Black	$ 12.30	$ 4.24
70W Bell LED-Black	$ 15.66	$ 4.24
50W Traditional LED-Black	$ 9.45	$ 4.24
50W Open Traditional LED-Black	$ 9.45	$ 4.24
50W Enterprise LED-Black	$ 12.70	$ 4.24
70W LED Open Deluxe Acorn	$ 14.11	$ 4.24
150W LED Teardrop	$ 18.95	$ 4.24
50W LED Teardrop Pedestrian	$ 15.37	$ 4.24
220W LED Shoebox	$ 13.13	$ 5.17
LED 50W 4521 Lumens Standard LED Black Type III 4000K	$ 4.96	$ 4.24
LED 70W 6261 Lumens Standard LED Black Type III 4000K	$ 4.95	$ 4.24
LED 110W 9336 Lumens Standard LED Black Type III 4000K	$ 5.62	$ 4.24
LED 150W 12642 Lumens Standard LED Black Type III 4000K	$ 7.44	$ 4.24
LED 150W 13156 Lumens Standard LED Type IV Black 4000K	$ 7.44	$ 4.24
LED 220W 18642 Lumens Standard LED Black Type III 4000K	$ 8.43	$ 5.17
LED 280W 24191 Lumens Standard LED Black Type III 4000K	$ 10.38	$ 5.17
LED 50W Deluxe Acorn Black Type III 4000K	$ 14.47	$ 4.24
LED 70W Open Deluxe Acorn Black Type III 4000K	$ 14.11	$ 4.24
LED 50W Acorn Black Type III 4000K	$ 13.04	$ 4.24
LED 50W Mini Bell LED Black Type III		

4000K Midwest	$ 12.30	$ 4.24
LED 70W 5508 Lumens Sanibell Black Type III 4000K	$ 15.66	$ 4.24
LED 50W Traditional Black Type III 4000K	$ 9.45	$ 4.24
LED 50W Open Traditional Black Type III 4000K	$ 9.45	$ 4.24
LED 50W Enterprise Black Type III 4000K	$ 12.70	$ 4.24
LED 150W Large Teardrop Black Type III 4000K	$ 18.95	$ 4.24
LED 50W Teardrop Pedestrian Black Type III 4000K	$ 15.37	$ 4.24
LED 220W Shoebox Black Type IV 4000K	$ 13.13	$ 5.17
150W Sanibel	$ 15.66	$ 4.24
420W LED Shoebox	$ 19.58	$ 5.17
50W Neighborhood	$ 4.04	$ 4.24
50W Neighborhood with Lens	$ 4.21	$ 4.24

Monthly Pole Charges Per Unit Per Month:

12' C-Post Top Anchor Base-Black	$ 9.39
25' C-Davit Bracket-Anchor Base-Black	$ 24.69
25' C-Boston Harbor Bracket-Anchor Base-Black	$ 24.96
12' E-AL – Anchor Base-Black	$ 9.38
35' AL-Side Mounted-Direct Buried Pole	$ 15.89
30' AL-Side Mounted-Anchor Base	$ 12.24
35' AL-Side Mounted-Anchor Base	$ 11.91
40' AL-Side Mounted-Anchor Base	$ 14.73
30' Class 7 Wood Pole	$ 5.82
35' Class 5 Wood Pole	$ 6.33
40' Class 4 Wood Pole	$ 9.53
45' Class 4 Wood Pole	$ 9.88
20' Galleria Anchor Based Pole	$ 8.40
30' Galleria Anchor Based Pole	$ 9.93
35' Galleria Anchor Based Pole	$ 28.56
MW-Light Pole-12' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 5.69
MW-Light Pole-Post Top-12' MH-Style A-Alum-Direct Buried-Top Tenon-Black	$ 4.87
Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 5.85
Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 5.07
Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 6.14

Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 9.41
Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 7.27
Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 10.49
Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 8.60
Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 11.67
Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 9.93
Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 12.61
MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$ 6.93
MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$ 9.39
MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$ 12.56
MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$ 24.69
MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 10.07
MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 24.96
MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$ 9.29
MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$ 9.38
MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Pri	$ 10.06
MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$ 8.40
MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$ 9.93
MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$ 28.56
MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$ 15.89
MW-15320-30FT Mounting Height Aluminum Anchor Base Pole-OLE	$ 12.24
MW-15320-35FT Mounting Height Aluminum Anchor Base Pole-OLE	$ 11.91
MW-15320-40FT Mounting Height Aluminum Anchor Base Pole-OLE	$ 14.73
MW-POLE-30-7	$ 5.82
MW-POLE-35-5	$ 6.33
MW-POLE-40-4	$ 9.53
MW-POLE-45-4	$ 9.88

RATE NSU
STREET LIGHTING SERVICE - NONSTANDARD UNITS

Rate per Unit per Month:

Company Owned

Boulevard Units Served Underground:

2,500 Lumen Incandescent - Series	$	9.42
2,500 Lumen Incandescent - Multiple	$	7.32

Holophane Decorative Served Underground:

10,000 Lumen Mercury Vapor on Fiberglass Pole	$	17.16

The cable span charge of $0.77 per each increment of 25 feet of secondary wiring shall be added to the rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street Lighting Served Overhead:

2,500 Lumen Incandescent	$	7.26
2,500 Lumen Mercury Vapor	$	6.87
21,000 Lumen Mercury Vapor	$	10.89

Customer Owned

Steel Boulevard Units Served Underground:

2,500 Lumen Incandescent - Series	$	5.56
2,500 Lumens Incandescent - Multiple	$	7.07

RATE SC
STREET LIGHTING SERVICE – CUSTOMER OWNED

Base Rate per Unit per Month:

Standard Fixture (Cobra Head):

Mercury Vapor:

7,000 Lumen	$	4.28
10,000 Lumen	$	5.45
21,000 Lumen	$	7.56

Metal Halide:

14,000 Lumen	$	4.28
20,500 Lumen	$	5.45
36,000 Lumen	$	7.56

Sodium Vapor:		
9,500 Lumen	$	5.15
16,000 Lumen	$	5.74
22,000 Lumen	$	6.31
27,500 Lumen	$	6.31
50,000 Lumen	$	8.54
Decorative Fixture:		
Mercury Vapor:		
7,000 Lumen (Holophane)	$	5.44
7,000 Lumen (Town & Country)	$	5.39
7,000 Lumen (Gas Replica)	$	5.44
7,000 Lumen (Aspen)	$	5.44
Metal Halide:		
14,000 Lumen (Traditionaire)	$	5.39
14,000 Lumen (Granville Acorn)	$	5.44
14,000 Lumen (Gas Replica)	$	5.44
Sodium Vapor:		
9,500 Lumen (Town & Country)	$	5.07
9,500 Lumen (Traditionaire)	$	5.07
9,500 Lumen (Granville Acorn)	$	5.29
9,500 Lumen (Rectilinear)	$	5.07
9,500 Lumen (Aspen)	$	5.29
9,500 Lumen (Holophane)	$	5.29
9,500 Lumen (Gas Replica)	$	5.29
22,000 Lumen (Rectilinear)	$	6.68
50,000 Lumen (Rectilinear)	$	8.84
Pole Description:		
Wood:		
30 Foot	$	4.44
35 Foot	$	4.50
40 Foot	$	5.39
Customer Owned and Maintained Units per kWh	$	0.038305

RATE SE
STREET LIGHTING SERVICE – OVERHEAD EQUIVALENT

Base Rate per Unit per Month:		
Decorative Fixtures:		
Mercury Vapor:		
7,000 Lumen (Town & Country)	$	7.45
7,000 Lumen (Holophane)	$	7.48

7,000 Lumen (Gas Replica)	$	7.48
7,000 Lumen (Aspen)	$	7.48

Metal Halide:

14,000 Lumen (Traditionaire)	$	7.45
14,000 Lumen (Granville Acorn)	$	7.48
14,000 Lumen (Gas Replica)	$	7.48

Sodium Vapor:

9,500 Lumen (Town & Country)	$	8.12
9,500 Lumen (Holophane)	$	8.23
9,500 Lumen (Rectilinear)	$	8.12
9,500 Lumen (Gas Replica)	$	8.22
9,500 Lumen (Aspen)	$	8.22
9,500 Lumen (Traditionaire)	$	8.12
9,500 Lumen (Granville Acorn)	$	8.22
22,000 Lumen (Rectilinear)	$	11.67
50,000 Lumen (Rectilinear)	$	15.44
50,000 Lumen (Setback)	$	15.44

RATE DPA
DISTRIBUTION POLE ATTACHMENTS

Annual rental per pole per foot:

Two-User pole	$	5.92
Three-User pole	$	4.95

COGENERATION AND SMALL POWER
PRODUCTION SALE AND PURCHASE TARIFF-100 kW OR LESS

Rates for Purchases from Qualifying Facilities

Energy Purchase Rate per kWh	$	0.027645
Capacity Purchase Rate per kW-month	$	3.61

COGENERATION AND SMALL POWER
PRODUCTION SALE AND PURCHASE TARIFF-GREATER THAN 100 kW

Rates for Purchases from Qualifying Facilities

The Energy Purchase Rate for all kWh delivered shall be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour of the billing month.

Capacity Purchase Rate per kW-month	$	3.61

SCHEDULE RTP
REAL-TIME PRICING PROGRAM

Energy Delivery Charge (Credit) per kW per hour from CBL		
Secondary Service	$	0.009104
Primary Service	$	0.007850
Transmission Service	$	0.003576

NON-RECURRING CHARGES

Remote Reconnection	$	3.45
Reconnection – Non-remote (Electric Only)	$	75.00
Reconnection - Non-remote (Electric and Gas)	$	88.00
Reconnection at pole (Electric Only)	$	125.00
Reconnection at pole (Electric and Gas)	$	150.00
Collection Charge	$	50.00

RIDER LM
LOAD MANAGEMENT RIDER

When a customer elects the off-peak provision, the monthly customer charge of the applicable Rate DS or DP will be increased by an additional monthly charge of $5.00 for each installed time-of-use or interval data recorder meter.

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