**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF:**

| | | |
|---|---|---|
| **APPLICATION OF KENTUCKY** | ) | |
| **UTILITIES COMPANY FOR AN** | ) | **CASE NO. 2008-00251** |
| **ADJUSTMENT OF BASE RATES** | ) | |

# PREPARED DIRECT TESTIMONY AND SCHEDULES

**OF**

**GLENN A. WATKINS**

**ON BEHALF OF THE**

**KENTUCKY OFFICE OF THE ATTORNEY GENERAL**

**OCTOBER 30, 2008**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economic and financial consulting firm with offices in Richmond, Virginia.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am testifying on behalf of the Office of Rate Intervention of the Kentucky Office of Attorney General ("OAG").

**Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.**

A. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Georgia, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, Ohio, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in my Schedule GAW_1 to my testimony.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. Technical Associates has been retained by the OAG to evaluate the reasonableness of Kentucky Utilities Company's ("KU" or "Company") proposed electric weather normalization adjustment, electric and gas class cost of service studies

(CCOSS), proposed distribution of revenues by class, and residential electric and gas rate designs. The purpose of my testimony, therefore, is to comment on KU's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

## ELECTRIC WEATHER NORMALIZATION

**Q. HAVE YOU EXAMINED KU'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?**

A. Yes.

**Q. WHAT IS THE NET EFFECT OF THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT?**

A. KU witness William Seelye sponsors a weather normalization adjustment that will impact customers' ultimate rates in two respects: the first is the overall revenue requirement effect and the second is a rate design effect. In terms of the overall revenue requirement effect, Mr. Seelye adjusts actual test year revenues and variable expenses downward to correct for what he considers to be unusual (or abnormal) weather occurring during the test year. In other words, the Company does not expect to achieve the same level of kWh sales (and revenue) that was experienced during the test year on a going forward basis. Mr. Seelye's weather normalization adjustment results in reduction to actual test year revenues of $8.721 million and a reduction in variable expenses of $4.355 million. This downward adjustment to actual net revenues has an upward impact on the Company's revenue requirement on a going forward basis; i.e., all other things constant, this adjustment increases the revenue requirement. The second aspect of this weather normalization adjustment is the rate design effect. Because the weather adjustment reduces test year kWh sales, there are fewer units (kWh) to collect the overall revenue requirement such that there is an additional upward pressure on customers resulting from the weather normalization adjustment.

**Q. MR. WATKINS, WHAT IS THE BASIS FOR KU'S REQUEST TO ADJUST ITS ACTUAL TEST YEAR SALES VOLUMES AND REVENUES?**

A. As a result of abnormal weather, the Company claims that actual test year sales volumes (kWh) were greater than can be expected on a going forward basis.

**Q. DO YOU AGREE THAT THE COMPANY'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT SHOULD BE USED FOR RATEMAKING PURPOSES?**

A. From a conceptual standpoint, the general consensus of public utility commissions throughout the United States is that it is unreasonable to weather normalize electric utility revenues for ratemaking purposes. In this regard, this Commission would be well advised to continue its current practice of not considering electric weather normalization which is consistent with the vast majority of other states. This would translate to a disallowance of $4.366 million from the company's request in net revenue ($8.721 million in revenue less $4.355 million in variable expense).

**Q. DO CUSTOMERS KWH ENERGY USAGES VARY MATERIALLY WITH CHANGES IN WEATHER CONDITIONS?**

A. Yes for some customers, and no for other customers. As a result of variances in electrical appliance and equipment saturations, some customers' electric usage varies significantly with changes in weather (temperature) while other customers' energy usage vary much less. For example, on an extremely hot summer day, residential customers will generally use considerably more electricity than on a mild, spring like day due to air conditioning load. On the other hand, the total electricity used by an industrial customer may not be materially different on the hot verses mild days due to this customer's non-weather sensitive load over shadowing its space cooling requirements (at least in terms of ambient outdoor temperatures).

**Q. OVER THE COURSE OF AN ENTIRE YEAR, DO PERIODS OF MILD WEATHER OFFSET PERIODS OF EXTREME WEATHER IN TERMS OF ELECTRICITY USAGE?**

A. In general, yes. This is particularly true for electricity sales.

**Q. PLEASE EXPLAIN.**

A. Although the following is common knowledge, it is important to consider how electricity is used and how weather affects this usage. For purposes of my explanation, I will focus on residential customers. As indicated earlier, there is no doubt that weather, primarily temperature, effects energy usage. In the summer there are periods of days that are very hot and electricity sales are elevated. Similarly there are mild days throughout the summer in which electricity sales are depressed due to reduced air conditioner loads. These hot and mild periods occur virtually every year. The question then arises if a particular cooling season (summer) as a whole is abnormally warm with an attendant abnormally high level of energy sales. In addition to cooling load (air conditions), electricity is also used for space heating by many customers in the winter. Similar to severe and mild weather in the summer, electricity sales on a daily basis are affected in the winter due to electric heating requirements. In addition to weather sensitive appliances, residential customers use a significant amount of electricity for other appliances that do not vary with weather; e.g., refrigerators/freezers, televisions, etc. Because of these factors and situations, annual electricity sales tend to be much more stable than say, natural gas sales, which are predominated by space heating load requirements in the winter. For these reasons, it is rare for commissions to consider weather normalization for electric utilities. In this regard, and as a matter of policy, the Commission would be well guided to continue its practice of not considering weather normalization for Kentucky electric utilities.

**Q. WE KNOW THAT RESIDENTIAL KWH SALES VARY DUE TO WEATHER CONDITIONS ON A DAY-TO-DAY BASIS BUT HOW DOES ONE DETERMINE IF WEATHER IS ABNORMAL OVER THE COURSE OF A SEASON?**

A. There is no definitive answer to this question. There is no doubt that a summer day in the high 90's is a hot day and warmer than "average". However, the question that must be answered is whether the summer overall was "abnormal". Similarly, one must determine if a winter season is materially different than normal; i.e., extremely severe or

mild. With regard to seasonal variations from year to year, there is significant debate as to what constitutes departure from what is reasonably normal or expected. The National Oceanic and Atmospheric Administration ("NOAA"), National Climatic Data Center defines normal weather as a thirty-year average for the most recent completed three decades. In other words, the current NOAA definition of normal weather is for the period 1971 through 2000. Because of short-term trends in seasonal weather patters, shorter periods are sometimes used to define normal weather as well as using the most recent thirty years to define normal. I am also aware of instances in which much longer periods are used to define normal weather for a season.

Even with these differences in defining "normal" weather, one cannot say that the weather was particularly extreme simply because there is somewhat of a deviation from a historical average. In other words, assume the average maximum temperature for a given summer day is 85 degrees. If the actual temperature is 87 degrees, I do not believe it can be said that this is "abnormal" or "extreme" for that day. In this regard, the determination of "abnormal" or "extreme" is truly subjective.

**Q. EVEN THOUGH THE DEFINITION OF ABNORMAL WEATHER IS SUBJECTIVE, ARE THERE METHODS THAT CAN BE USED TO FAIRLY AND REASONABLY DEFINE NORMAL AND ABNORMAL WEATHER?**

A. Yes.

**Q. PLEASE EXPLAIN.**

A. Remembering that we should be concerned about the overall variation in weather over an entire season (hearting or cooling), a banding approach is, in my opinion, a fair and reasonable way to determine if a season's weather falls inside or outside of a band of reasonably normal weather. This banding approach is used by Mr. Seelye in this case. To the extent the Commission authorizes a weather normalization adjustment in this case, I could support the concept of banding, as it eliminates quibbling over minor variances from a pre-determined average or "normal" weather pattern.

**Q. PLEASE EXPLAIN THIS BANDING APPROACH IN LAYMAN'S TERMS.**

A. The traditional unit to measure summer temperatures over time is cooling degree days ("CDD") and the traditional unit to measure winter temperatures over time is Heating Degree Days ("HDD").[1] Assume that "normal" or average CDD's over the entire cooling season are 1,000. As discussed earlier, if the actual CDD were say 1010, we likely would not consider this an abnormally warm summer. However, if we subjectively determine a relative percentage of time in which we deem weather as abnormal, we can apply a simple statistical technique to determine the bands of normalcy. If we assume the variations in weather from year to year are random (no trend or pattern) we can subjectively define a percentage of time (years) in which weather is considered normal. For example, suppose we decide (subjectively) that weather occurring 75% of the time within a long term average is normal and the remaining 25% of the time the weather is defined as abnormal (12.5% mild and 12.5% severe), we can quantify the bands of normal weather. Consider the following hypothetical example:

Seasonal Cooling Degree Days

```
            900          1,000          1,100
←----------------|----------------|----------------|----------------→
Abnormal → |          ←Normal→          | ← Abnormal
```

If we know that 75% of the time a season's CDD fall between 900 and 1,100 we would define this range as normal. If a season's actual CDD's are greater than 1,100 we would deem that season as abnormally warm. Similarly, if the actual CDD's in a season are less than 900 we would deem that season abnormally mild. This is the approach proposed by Mr. Seelye. As indicated earlier, I support this approach but it must be emphasized that the range of normalcy is subjective and should be determined by the Commission. It should also be noted that this approach requires the assumption that annual seasonal weather variations are truly random; i.e., no trends or patterns are present.

**Q. IN YOUR HYPOTHETICAL EXAMPLE, YOU USED A NORMALCY BAND OF 75%. WHAT BAND IS USED BY MR. SEELYE?**

A. Approximately sixty-eight percent.

[1] CDD is traditionally defined as 65 degrees minus the average temperature (High and Low) for a day. HDD is traditionally defined as average temperature minus 65 degrees. CDD and HDD cannot be negative.

**Q. HOW DID MR. SEELYE SELECT SIXTY-EIGHT PERCENT AS HIS NORMAL BAND FOR WEATHER?**

A. This 68% is a convenient percentage in statistics in that it represents the percentage of time that one can expect weather to vary within plus or minus one standard deviation. There is nothing especially significant about a standard deviation of 1.0, as the exact same statistical techniques can be used at any level selected for normalcy; e.g., 50%, 75%, etc.

**Q. WHAT WEATHER PATTERNS WERE ACTUALLY EXPERIENCED IN THE KU SERVICE AREA DURING THE TEST YEAR?**

A. Overall, the cooling season (summer period) was exceptionally warm during the test year, whereas the heating season (winter period) was somewhat milder than average. The following is a comparison of monthly CDD and HDD to the most recent 30-year average for CDD and HDD:

| Month | CDD or HDD Actual Test Year | 30-Year Average | Difference |
|---|---|---|---|
| Cooling Season (CDD) | | | |
| June | 284 | 242 | 42 |
| July | 309 | 361 | <52> |
| August | 496 | 332 | 164 |
| September | 238 | 151 | 87 |
| Total | 1,327 | 1,085 | 242 |
| Heating Season (HDD) | | | |
| November | 577 | 555 | 22 |
| December | 765 | 883 | <118> |
| January | 1,012 | 989 | 23 |
| February | 849 | 801 | 48 |
| March | 638 | 609 | 29 |
| Total | 3,841 | 3,837 | 4 |

As can be seen above, August and September 2007 were exceptionally warmer than the 30-year average, while December 2007 was considerably milder than the 30-year average.

**Q. WHY ARE APRIL, MAY AND OCTOBER NOT PROVIDED IN THE TABLE ABOVE?**

A. These months are considered shoulder months. Days in April and May can be cool or fairly warm such that these months are comprised of heating degree days and cooling degree days. As such, heating and air conditioning loads are usually not predictable in April and May. The same is true for October. Generally, the early part of October is warm and air conditioning load is still present. By the middle to end of October, the weather cools to the point that there is some heating load. As such, October is not very consistent as far as what can be considered "normal" weather.

**Q. MR. WATKINS, IT IS GENERALLY FAIRLY COOL IN APRIL AND FAIRLY WARM BY THE END OF MAY IN KENTUCKY. WOULD IT BE APPROPRIATE TO CONSIDER EACH APRIL AS PART OF THE HEATING SEASON AND LATE MAY AS PART OF THE COOLING SEASON?**

A. In my opinion no. Both of these months experience considerable variation between periods cold enough for space heating, mild enough for open windows, and warm enough for air conditioning load.

**Q. FOR PURPOSES OF WEATHER NORMALIZATIONS, HOW DO YOU DEFINE KU'S COOLING AND HEATING SEASONS?**

A. I define KU's cooling season as the months of June through September and the heating season as the months of November through March.

**Q. IF THE COMMISSION ACCEPTS A BANDING APPROACH AS PROPOSED BY MR. SEELYE AND SUPPORTED BY YOU, HOW SHOULD THIS APPROACH BE APPLIED TO THE HEATING AND COOLING SEASONS?**

A. The banding should be applied separately to the entire heating season and again separately for the entire cooling season. This is a major difference in the manner in which Mr. Seelye applied his weather banding, in that Mr. Seelye applies a weather normalcy band to each individual month. Mr. Seelye's monthly banding results in a bias to the annual normalized sales volumes.

**Q. PLEASE EXPLAIN.**

A. As discussed earlier, a given heating or cooling season is comprised of days in which it is milder than expected and more severe than expected. The overall objective is to consider the overall effects of weather during a heating or cooling season and Mr. Seelye's monthly banding does not meet this objective. To illustrate, consider the actual experience of July and August during the test year. July's actual CDDs were 309 which compare to a 30-year average July CDD of 361. This is a difference of -52 CDD which indicates that July was somewhat milder than the long-term average. Because this deviation from average (-52) does not fall outside of Mr. Seelye's monthly band, it is not adjusted and this mild weather for July is not considered any further in his analysis.

However, August was adjusted by Mr. Seelye because this individual month's weather fell outside of his monthly band. The actual CDDs for August in the test year were 496. This compares with a long-term average of 332 for August and is a difference of 164 CDDs. This exceptionally hot weather during August 2007 falls outside of Mr. Seelye's normalcy band and August's kWh sales were adjusted downward. However, no adjustment or consideration was given to the somewhat milder weather experienced during July 2007.

**Q. HOW HAVE YOU ESTIMATED THE EFFECTS OF WEATHER ON CUSTOMER'S ELECTRICITY USAGE?**

A. As discussed earlier, variations in electricity sales during the summer are affected by variations in air conditioning load, while winter kWh sales variations are affected by changes in space heating load. The two uses cannot be measured together and must be examined separately. Therefore, I have conducted separate analyses for the cooling (summer) and heating (winter) seasons.

I conducted linear regression analyses by season for each rate class in order to develop a weather sensitive usage coefficient for each class. In other words, the weather sensitive coefficient measures the incremental level at which a classes kWh usage varies with an incremental change in weather (CDD in summer, HDD in winter). Specifically, I developed a separate regression model for each class and each season (cooling and heating). These regression models were developed based on daily kWh usage and daily

degree days. In other words, the cooling season is comprised of four months (June through September). My model was developed using each daily observation during this season (142 days). Because usage patterns can and do vary significantly between weekdays and weekends/holidays, I have also reflected this reality in my analysis of daily observations. With regard to the Residential class, I have expressed daily kWh usage on a per customer basis in order to prevent any skewness in my regression models. The Commercial and Industrial classes were analyzed on a total class basis.

**Q. WHAT ARE YOUR CONCLUSIONS REGARDING WEATHER NORMALIZATION FOR KU'S ELECTRIC OPERATIONS DURING THE TEST YEAR?**

A. Based on my analyses, I conclude that the overall cooling season (summer) during the test year was exceptionally warm which translated into exceptionally high summer energy sales for KU. This weather (and attendant kWh sales) falls beyond what can reasonably be expected on a going-forward basis and warrants a downward adjustment. Although the test year's heating season was somewhat milder than normal, these sales do not warrant adjustment.

**Q. IS THERE ANY BIAS IN YOUR CONCLUSION THAT SUMMER KWH SALES SHOULD BE ADJUSTED DOWNWARD DUE TO EXCEPTIONALLY SEVERE WEATHER, BUT WINTER KWH SALES DO NOT WARRANT AN OPPOSITE UPWARD ADJUSTMENT DUE TO A SOMEWHAT MILDER WINTER?**

A. As long as a banding approach is used, the answer is no. This is because the summer normalization is made only to the outer limit of the "normalcy" band and not all the way to an average historical experience. Thus, while it is true that the milder winter sales somewhat offset the extreme weather-related summer sales, each season reflects a reasonable level of what can be expected on a going-forward basis.

**Q. WHAT ARE THE RESULTS OF YOUR WEATHER NORMALIZATION ANALYSIS FOR KU'S ELECTRIC OPERATIONS?**

A. My Schedule GAW_2 presents the results of my weather normalization analysis for KU's electric operations. Page 1 of this Schedule provides a summary of each class' kWh and revenue adjustment as well as the adjustment required to variable expenses. Pages 2 through 12 present the detailed kWh adjustment for each class. My weather normalization analysis results in a reduction to actual test year revenues of $2.603 million and a reduction to actual test year expenses of $1.320 million.

**Q. YOU HAVE ALREADY DISCUSSED YOUR DISAGREEMENT WITH MR. SEELYE REGARDING MONTHLY VERSUS SEASONAL ANALYSIS AND ADJUSTMENTS. DO YOU HAVE ANY OTHER DISAGREEMENTS WITH MR. SEELYE'S PROPOSED WEATHER NORMALIZATION ANALYSES?**

A. Yes.

**Q. PLEASE EXPLAIN THESE OTHER DISAGREEMENTS.**

A. I disagree with Mr. Seelye's decision to use the step-wise multiple regression technique as well as his inclusion of numerous weather-related variables. At the outset I want it to be clear that I understand and appreciate Mr. Seelye's desire to conduct his statistical analysis on an objective basis. However, Mr. Seelye's procedures are not warranted and often produce conflicting model results.

We have already established that weather generally affects electricity sales. On an hourly or daily basis, these weather factors can include ambient temperature, wind velocity, relative humidity, the degree of cloud cover, whether snow cover is present to insulate structures, whether a thunderstorm appears on a hot afternoon and dramatically and suddenly reduces load (and sales), wind direction, and perhaps a few more factors.

Mr. Seelye has attempted to consider many of these short-term factors in his modeling analysis by using a technique known as step-wise regression. This statistical technique selects a combination of possible variables to be considered and selects an equation that maximizes certain statistic parameters. This step-wise technique is simply a mathematical algorithm calculated by a computer. In other words, the variables offered to a computer in the step-wise technique are simply sets of numbers. Obviously, the computer has no ability to determine if the potential variables are consistent with the task

at hand or even if they make sense from a conceptual perspective. There is no doubt that variables selected using the step-wise technique are objective. However, this technique is no substitute for informed human judgment. In their much respected text book, Applied Regression Analysis, Norman Draper and Harry Smith render the following opinion regarding the step-wise procedure used for econometric regression analyses:

> ***Opinion.*** We believe this to be one of the best of the variable selection procedures and recommend its use. It makes economical use of computer facilities, and it avoids working with more *X*'s than are necessary while improving the equation at every stage. However, stepwise regression can easily be abused by the "amateur" statistician. As with all the procedures discussed, sensible judgment is still required in the initial selection of variables and in the critical examination of the model through examination of residuals. It is easy to rely too heavily on the automatic selection performed in the computer. [Third Edition, page 338]

As a result of Mr. Seelye's attempt to be unnecessarily surgically precise, he arrives at nonsensical conclusions and models. As an illustration, remember that Mr. Seelye developed a separate regression equation, by class, for each month. Consider and compare Mr. Seelye's step-wise derived Residential models for July and August.

| Variable | July 1/ | August 1/ |
|---|---|---|
| Intercept | -2,394,075 | 8,474,433 |
| Maximum Temperature | 129,398 | -- |
| CDD70 | 212,068 | 391,299 |
| Weekend | 453,879 | 1,055,056 |

1/ Per Seelye Exhibit 11.

Mr. Seelye's step-wise procedures result in a finding that in July, kWh sales are a function (related to) of maximum temperature, cooling degree days (CDD70), and weekday versus weekends. However, in August, the computer determined that Residential kWh sales are not a function of this same set of explanatory variables, but rather, only cooling degree days (CDD70) and weekdays versus weekends. Related to the inconsistency of these adjoining summer months is the level in which kWh usage varies with changes in overall average daily temperatures (CDD70). Notice that the July model has a CDD70 coefficient of 212,068, while the August coefficient of 391,299.

What this means is that, all other things constant, kWh sales will vary by 212,068 kWh for each variation in CDD70 during July, but will vary by 391,299 in August.

There are many more inconsistencies and seemingly non-sensical results for other months as well as across classes, that I will not dwell on. In my opinion, and that of the industry, HDD and CDD are the accepted and most appropriate explanatory variables.

## ELECTRIC CLASS COST OF SERVICE

**Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").**

A. First, I note that there are two general types of cost of service studies used for public utility ratemaking: marginal cost studies; and embedded, fully allocated cost studies. KU has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its class cost of service study ("CCOSS"). As such, I will limit my explanation to embedded class cost of service studies.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of an electric utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributable to a particular customer (or group of customers), these costs are often directly assigned in a CCOSS. However, the vast majority of KU's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes. It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs in which cost causation can be attributed, cost of service experts often

disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

**Q. PLEASE EXPLAIN HOW CCOSS RESULTS SHOULD BE USED IN THE RATEMAKING PROCESS.**

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive certain costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records, as well as fundamental differences in opinions regarding the design or cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In this regard, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

**Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF KU'S CCOSS.**

A. The process in which I conducted my analysis in this case was identical to how I evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's CCOSS. Once the basic structure was understood, I reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed KU's selection of allocators to specific rate base, revenue and expense accounts. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

**Q. DID YOU FIND THE COMPANY'S STUDY TO BE MATHEMATICALLY ACCURATE?**

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to

the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. Seelye's CCOSS to be mathematically accurate.

**Q. DID YOUR EXAMINATION RESULT IN ANY DISAGREEMENTS WITH THE ASSUMPTIONS OR METHODOLOGIES USED BY MR. SEELYE?**

A. Yes. I have two material disagreements with Mr. Seelye's CCOSS.

**Q. PLEASE OUTLINE YOUR TWO MATERIAL DISAGREEMENTS.**

A. The two substantial disagreements that I have with Mr. Seelye are his "Modified Base-Intermediate-Peak" method to allocate generation costs and his classification of distribution plant between customer-related and demand-related.

**A. <u>Generation</u>**

**Q. YOU INDICATE THAT ONE OF YOUR DISAGREEMENTS WITH MR. SEELYE IS HIS USE OF WHAT HE REFERS TO AS A MODIFIED BASE-INTERMEDIATE-PEAK METHOD TO ALLOCATE GENERATION COSTS. ARE THERE OTHER METHODOLOGIES WHICH MAY BE USED TO ALLOCATE GENERATION- RELATED PLANT AND EXPENSES?**

A. Yes. There are several demand allocation methods utilized in the electric industry. The current National Association of Regulatory Utility Commissioners ("NARUC") <u>Electric Utility Cost Allocation Manual</u> discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright noted the existence of at least 29 demand allocation methods in his treatise, <u>Principles of Public Utilities Rates</u>.

**Q. WHY DO SO MANY GENERATION ALLOCATION METHODS EXIST FOR THE ELECTRIC INDUSTRY?**

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate throughout the year, there would be no disagreement as to the proper assignment of generation-related costs: all analysts would agree that energy usage in terms of kWh would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that KU experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy/capacity trade-off relating to generation costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity (KW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investments per KW, whereas smaller units with higher variable production costs generally require significantly less investment per KW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

**Q. PLEASE EXPLAIN.**

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to classes each and every hour of the year. This would result in 8,760 hourly allocations during non-leap years. Although such an analysis is certainly possible with today's technology, the time and cost necessary for such an undertaking would likely exceed the additional benefits obtained over simpler methods. This is because the analyst does not know precise class loads each and every hour, and subjective decisions must still be made regarding the assignment of fixed investment (capacity costs) to individual hours. With this practical constraint in mind, each method has its strengths and weaknesses regarding its reasonableness in reflecting cost causation as well as the cost and effort required to produce a study.

**Q. BRIEFLY, DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON PRODUCTION COST ALLOCATION METHODOLOGIES.**

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

**Single Coincident Peak ("1-CP")** -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, the sole criterion for assigning one hundred percent of fixed capacity costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of

generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility had a peak load of 15,000 MW and its actual optimal generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 15,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs at all and enjoy a free ride on the assignment of generation costs that this class requires.

**Summer and Winter Coincident Peak ("S/W Peak")** -- The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this characteristic. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method. However, it is my understanding that KU is consistently a summer peaking utility. Therefore, this methodology is likely not well suited in this instance.

**Twelve Monthly Coincident Peak ("12-CP")** -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to

how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to a small extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain on-going load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

**Peak and Average ("P&A")** -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between Peak and Average demands should be performed, many P&A studies use class contributions to coincident-peak demand for the "peak" portion, while some studies weight the Peak and Average loads based on the system coincident load factor and others give equal weight to energy usage and peak demand.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer to some degree of arbitrariness.

**Average and Excess ("A&E")** -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is

much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for many utilities. This is because no class will receive a free-ride under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during cheap off-peak periods.

**Equivalent Peaker ("EP")** -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy- or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant amount of data.

**Base-Intermediate-Peak ("BIP")** -- The BIP method is an accepted allocation approach that attempts to recognize the capacity/energy trade-off that actually exists within a utility's portfolio of generation assets. A utility's base load units tend to run during all periods of the year; i.e., both peak load periods as well as to satisfy energy requirements in the most efficient manner possible during minimum demand periods (e.g., during the middle of the night). Because base load units operate regardless of peak requirements, they are most appropriately classified as energy-related. At the opposite end of the spectrum are peaking units, such as combustion turbines. These units operate with high variable costs and are only utilized to help meet peak period demands. As such, peakers are classified as peak demand-related. Intermediate plants (e.g., many combined cycle units) are not as efficient as large base load plants but more efficient than peaking units. For this reason, Intermediate plants are not called upon (dispatched) during periods of minimum (base) load but are dispatched before, and more frequently, than peaker units. Therefore, Intermediate plants can be said to serve a dual purpose: partially energy-related and partially demand-related. Intermediate plants are typically classified as partially energy-related and partially demand-related based on their respective capacity factors.[2] In my opinion, the BIP method is an excellent cost allocation approach for many utilities as it captures the actual differences in the capacity/energy trade-off that exist across a utility's generation mix. The BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

**Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?**

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate Generation plant

[2] Capacity factor is the ratio of average utilization (output) over a year to peak hour output.

investment. Generation investment costs vary from a low of a few hundred dollars per KW of capacity for high running cost (energy cost) peakers to several thousand dollars per KW for base load nuclear facilities with low running costs. If a utility were only concerned with being able to meet peak load with no regard to running costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but running costs; i.e., variable fuel costs would be astronomical, and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

**Q. MR. SEELYE HAS USED WHAT HE REFERS TO AS A MODIFIED BIP METHOD TO ALLOCATE GENERATION COSTS. DID HE CALCULATE THE BIP METHOD IN A REASONABLE MANNER?**

A. Mr. Seelye's Modified BIP method does not follow the generally accepted BIP approach, and in fact, I have never seen Mr. Seelye's method used before. However, I would be reluctant to say his approach is totally unreasonable.

Whereas Mr. Seelye's Modified BIP method does allocate a portion of generation facilities based on energy and a portion on peak demands, his approach does not reflect the actual mix of supply resources utilized by KU. At this point, it should be noted that LG&E's and Kentucky Utilities' ("KU") generation resources are centrally dispatched. Both Mr. Seelye and I have recognized this combined central dispatch in our allocation studies. When I refer to KU's actual generation resources, I am referring to the joint resources of LG&E and KU and not the individual legal ownership of these plants for booking purposes.

The traditional BIP method is a supply-based approach that classifies generation plant between energy-related and demand-related; i.e., it considers the actual supply characteristics of a utility's generation portfolio. These supply based classifications are then allocated to classes based on demand-side criteria (kWh usage and peak demand).

Mr. Seelye's approach ignores the actually supply-side characteristics of EON's generation portfolio because it only considers relative differences in system usages and demands. In fact, given KU's customers combined usage and demand profiles, Mr. Seelye's approach would classify a utility's generation investment exactly the same

regardless of its actual portfolio mix of plants. Mr. Seelye's classification would be identical if KU's portfolio mix was comprised entirely of base load units or entirely of peaking units. In my opinion, this assumption (or result) is not consistent with the intent of the BIP method. Namely, to recognize the capacity/energy tradeoff actually present in a system.

**Q. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY USING A TRADITIONAL BIP APPROACH?**

A. Yes.

**Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR TRADITIONAL BIP METHOD.**

A. During the discovery phase of this proceeding, KU provided the hourly loads (output) of each EON generation unit during the test year. In other words, for each EON generating unit, I was provided hourly output during the test year. With this data, I examined the timing, frequency, and level of dispatch for each EON generating unit. This examination revealed clear and distinct patterns for individual generating units. Many units are clearly base load in nature, others are clearly peaker facilities, and some units are neither base load or clearly peaker, but intermediate plants. From this examination, I was able to classify each generating unit as base, intermediate, or peak. Base load plants were classified as 100% energy-related, peaker units were classified as 100% demand-related, and intermediate plants were classified as partially energy-related and partially demand-related based on their individual capacity factors. The results of my BIP generation classification is presented in my Schedule GAW_3. It should be noted that EON's hydroelectric facilities were classified as 100% energy-related as these facilities are largely run-of-river or flood control dams. My BIP classification study results in the following aggregate generation classification:

| | |
|---|---|
| Energy-related: | 82.78% |
| Demand-related: | 17.22% |

**Q. WHAT ARE THE CLASS RATES OF RETURN ON RATE BASE AT CURRENT RATES UTILIZING YOUR TRADITIONAL BIP METHOD TO CLASSIFY GENERATION PLANT?**

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Seelye's Modified BIP are presented below:

| Class | OAG Traditional BIP | Seelye Modified BIP |
|---|---|---|
| RS | 4.73% | 3.58% |
| GSS | 11.66% | 12.20% |
| GSP | 10.62% | 4.79% |
| AES | 9.48% | 6.32% |
| LPS | 9.49% | 11.53% |
| LPP | 8.99% | 11.82% |
| LPT | 10.10% | 10.07% |
| STODS | 4.80% | 6.73% |
| STODP | 5.42% | 6.92% |
| LCIP | 6.09% | 8.55% |
| LCIT | 3.64% | 5.54% |
| MPP | 14.97% | 12.88% |
| MPT | 13.95% | 13.35% |
| LMPP | 11.20% | 11.42% |
| LMPT | 10.57% | 13.40% |
| LITOD | 18.39% | 25.00% |
| SL | 5.04% | 4.51% |
| SLDEC | 7.86% | 6.87% |
| POL | 10.04% | 13.27% |
| OL | 14.89% | 16.28% |
| TOTAL COMPANY | 7.15% | 7.15% |

**B. <u>Distribution</u>**

**Q. AS WE MOVE DOWNSTREAM FROM GENERATION THROUGH TRANSMISSION, TO THE DISTRIBUTION SYSTEM, HOW HAS THE COMPANY ASSIGNED DISTRIBUTION COSTS TO RATE SCHEDULES AND CUSTOMER CLASSES?**

A. Mr. Seelye has allocated Distribution plant and expenses partially on the basis of number of customers and partially on the basis of peak demand. I concur with Mr.

Seelye's selection of customer and demand allocators for Distribution plant. However, there is often controversy regarding the portion of Distribution plant that should be allocated on number of customers and the portion that should be allocated on demand. This separation between customer-related and demand-related Distribution plant is referred to as the classification of Distribution plant.

**Q. PLEASE EXPLAIN THE TERM "CLASSIFICATION OF DISTRIBUTION PLANT."**

A. In the broadest sense, an embedded CCOSS is undertaken using a three-tiered approach. First, costs are functionalized as Production, Transmission, Distribution, General, and/or customer. These functionalized costs are then classified as energy, demand, or customer-related. Finally, classified costs are then allocated to individual classes. With respect to the classification of Distribution plant, it is generally recognized that there are no energy-related costs. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility Distribution plant often is classified as partially demand-related and partially customer-related.

**Q. WHY IS THE CLASSIFICATION OF DISTRIBUTION PLANT IMPORTANT IN CCOSS ANALYSES?**

A. The classification of Distribution plant may be the single most important factor affecting class rates of return. To illustrate the importance of this issue, consider the Residential class: whereas this class may account for only 40% to 50% of peak demand, it is responsible for a much higher percentage of the number of customers. Therefore, given the level of investment associated with Distribution plant, wide variations in class rates of return can result from different customer/demand classifications.

**Q. WHY ARE THE DIFFERENCES IN CUSTOMER DENSITIES IMPORTANT IN THE ASSIGNMENT OF DISTRIBUTION COSTS TO INDIVIDUAL CLASSES?**

A. Possibly the best way to answer this question is by way of example. Consider two different electric utilities: one similar to KU with urban, suburban, and rural service

areas and one similar to Consolidated Edison Company, which is mainly urban. With respect to the utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban utility. For the urban utility, it may be fair and reasonable to allocate Distribution plant solely on the basis of peak demands. However, with respect to the utility with a rural service area, such an allocation may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, many utilities classify Distribution plant as partially demand- related and partially customer-related. In this manner, a portion of Distribution plant is allocated based on a peak demand, and a portion allocated based on number of customers.

**Q. HOW DOES ONE DETERMINE HOW MUCH DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS DEMAND-RELATED AND HOW MUCH AS CUSTOMER-RELATED?**

A. Once the decision is made that Distribution plant should be allocated considering both peak demand and number of customers, there are two generally accepted methods for determining the portions or percentages that should be allocated on each basis. These two methods are known as the minimum size and zero-intercept approaches. Under both methods, a study is conducted for each major plant account within the distribution system. That is, each account is studied and assigned its own customer and demand components.

The minimum size method rests on the premise that the minimum, or smallest size, installed equipment makes up the distribution network to connect customers to the distribution system, and that all larger sizes of equipment serve peak demands. In practice, the cost per unit of the smallest sized installed equipment is determined. This minimum cost per unit is then multiplied by the total number units in the system to arrive at a total customer amount. The total customer amount is then divided by the total cost for the account to determine the customer percentage. As the compliment, one minus the customer percentage equals the demand percentage.

The zero-intercept method is similar to the minimum size method, except for the determination of the minimum cost per unit. The zero-intercept method recognizes that even the smallest installed piece of equipment has a demand component, because it too is designed and installed to meet the peak load placed on that equipment. The zero-intercept method attempts to arrive at the "theoretical" cost of a piece of plant or equipment capable of carrying zero load. This is accomplished using statistical regression techniques whereby the per unit costs of various sizes of equipment are determined and a best fitting line is fitted into an equation form. The point at which the fitted line intersects the cost axis at zero size is called the zero-intercept. The zero-intercept cost then serves as the minimum, or zero size, cost per unit.

**Q. IS ONE METHOD PREFERRED OVER THE OTHER?**

A. In general, I prefer to use the zero-intercept method when possible and appropriate. However, as with most aspects of ratemaking where there is not a universally accepted formula, each approach has its advantages and disadvantages. The major criticisms I have regarding the minimum size method is that this method tends to overstate the customer percentage because even the smallest installed size is used to meet some level of peak demand. The primary weaknesses of the zero-intercept method are that more data and a good working knowledge of statistical linear regression analyses are required, and sometimes there is no strong correlation between costs and sizes (capacity) of distribution equipment.

**Q. HOW APPROPRIATE IS EITHER METHOD FROM A DESIGN OR OPERATIONAL PERSPECTIVE?**

A. First and foremost, the classification of Distribution plant as partially customer-related and partially demand-related results from the view that the allocation of these plant items based solely on peak demands would not be equitable to some classes. I emphasize this point, because many analysts "lose sight of the forest for the trees". When classifying individual accounts within Distribution plant, analysts sometimes ignore (or do not understand) how a distribution system is designed and connected.

There are three major factors the analyst should keep in mind when classifying Distribution plant. First, there are often alternatives across plant and equipment. For example, the need for a particular transformer may be erased if a larger size conductor is used. Alternatively, fewer and smaller poles may be required if lighter conductors are used. Second, and more importantly, is the fact that purchasing economies are usually present. For example, there are dozens of various types of overhead conductors manufactured. However, due to purchasing economies, a utility may only purchase a few different sizes of conductor. This may result in some "over capacity", yet, the total installed cost is less than if every segment of the system is optimally designed. Third, most components of the distribution system are somewhat oversized for other reasons such as safety, reliability, and growth uncertainty.

Although, these three factors are reflective of how distribution systems are actually designed and installed, neither the minimum size nor the zero-intercept method account for these factors. In fact, the presence of these three factors can seriously skew the results of either method. If the weakness is not captured or recognized, inequitable class allocations may result.

**Q. HOW DID MR. SEELYE CLASSIFY DISTRIBUTION PLANT BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?**

A. My Seelye claims to have conducted a zero-intercept analysis to develop customer/demand classifications for distribution Overhead lines, underground lines, and transformers. I take exception to Mr. Seelye's reference to his proposed classifications as a "zero-intercept" derived study, and I disagree with his approach.

**Q. PLEASE EXPLAIN HOW AN INDUSTRY ACCEPTED ZERO-INTERCEPT STUDY IS CONDUCTED.**

A. Under accepted industry practices, which are well documented in various cost allocation manuals,[3] the zero-intercept method is very straight-forward. First, various types of equipment are separated by size and type. Next, historical accounting costs are

[3] See for example the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual, 1992, pages 92 through 94.

trended by vintage year to reflect cost differences over time. For each size and type of equipment, the total dollars and total units (feet or number of units) are considered as well as the capacity (size) of each type of equipment. Because the overall objective is to estimate the cost of a "zero-size" piece of equipment, total costs are divided by total units (feet or unit) for each type of equipment to derive an average cost per foot or per unit. A regression model is then developed based on the following form:

$$\text{cost/unit} = a + b\ (\text{size})$$

The resulting intercept (a) produces the estimated cost per unit of a "zero-size" piece of equipment. This estimated zero-size cost per unit is then multiplied by the total units in the system to estimate a zero-size total cost. The ratio of total zero size costs to trended total actual costs represents the percentage of zero-size equipment and serves as the customer percentage.

The above industry standard is in stark contrast to Mr. Seelye's method presented in his Seelye Exhibits 20, 21, and 22. Mr. Seelye refers to his approach as a "weighted regression analysis." Although this "weighted regression analysis" is a clever arithmetic exercise, it violates theoretical statistical principles of linear regression and skews his results. Moreover, on page 64 of his direct testimony, Mr. Seelye states:

> "Like most electric utilities, the number of feet of conductors on KU's system is not uniformly distributed over all sizes of wire. For example, KU has over 20.9 million feet of #2 copper overhead conductor, but only 660 feet of 556 MCM overhead conductor. 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."

It is interesting at best that Mr. Seelye finds KU's system to be typical of other utilities, yet, his approach varies dramatically from the industry practice that has been used by countless utilities, Commissions, and analysts for decades.

To understand the bias in Mr. Seelye's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead conductors as an example, consider Mr. Seelye's analysis presented in his Exhibit 20. Although not shown in his exhibit, Mr. Seelye's equation for Overhead conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 1.5562(\text{feet}^{0.5}) + 0.00244(\text{capacity x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if capacity is set to zero, the second term [0.00244(capacity x $feet^{0.5}$)] becomes zero. If we then ask what is the cost for a foot of a zero capacity conductor we see that $feet^{0.5} = 1^{0.5} = 1$, such that the cost for one foot becomes $1.5562. This is the zero-intercept used by Mr. Seelye.

To illustrate the bias in Mr. Seelye's analysis, consider the following hypothetical example of his approach for a system "not uniformly distributed over all sizes of wire":

| Total | Cost Per Foot (y) | Capacity (x) | Feet (n) | $y(n^{0.5})$ | $n^{0.5}$ | $x(n^{0.5})$ |
|---|---|---|---|---|---|---|
| 350.00 | 3.50 | 2.00 | 100 | 35 | 10.00 | 20.00 |
| 250.00 | 5.00 | 4.00 | 50 | 35.355339 | 7.07 | 28.28 |
| 62,500.00 | 6.25 | 6.00 | 10,000 | 625 | 100.00 | 600.00 |
| 164.00 | 8.20 | 8.00 | 20 | 36.671515 | 4.47 | 35.78 |
| 99.50 | 9.95 | 10.00 | 10 | 31.464663 | 3.16 | 31.62 |

Under the correct, and accepted zero-intercept method, the following regression equation results:

$$cost/feet = 1.75 + 0.805(size)$$

Therefore, a zero-size cost is estimated to be $1.75 per foot. Using the same data, the following equation is produced using Mr. Seelye's approach:

$$cost\ per\ foot \times feet^{0.5} = 0 + 1.9815(feet^{0.5}) + 0.7120(size \times feet^{0.5})$$

Mr. Seelye's approach results in a zero cost per foot of $1.9815 as compared to the industry accepted cost per foot of $1.75.

**Q. DO YOU HAVE ANY OTHER SIGNIFICANT DISAGREEMENTS WITH MR. SEELYE'S DISTRIBUTION PLANT CLASSIFICATION STUDIES?**

A. Yes. Because a utility's distribution plant is comprised of many different vintage years of equipment, it is necessary to trend original cost (booked) amounts to constant or current dollars. This is particularly important because certain types of equipment may have been installed as standard practice several years ago (and are still in service) but are not utilized today (with higher costs due to inflation). As such, the trending of equipment

costs is critical to measure various vintage years plant on a consistent (apples to apples) basis. Although Mr. Seelye utilized this required trending concept in his analyses for LG&E, distribution plant costs were not trended for his KU analyses.

**Q. WHAT ARE THE RESULTS OF MR. SEELYE'S CLASSIFICATION OF DISTRIBUTION PLANT?**

A. Mr. Seelye classifies distribution plant as follows:

| Account | Percentage | |
|---|---|---|
| | Customer | Demand |
| Overhead Conductors | 78.92% | 21.08% |
| Underground Conductors | 72.14% | 27.86% |
| Lines Transformers | 47.88% | 52.12% |

**Q. HAVE YOU CONDUCTED AN INDEPENDENT ANALYSIS TO CLASSIFY KU'S DISTRIBUTION PLANT?**

A. Yes. Because KU's distribution plant costs were not trended to constant dollars, I could not conduct a reasonable analysis for KU with the data available. As such, I utilized the constant dollar data for LG&E as used by Mr. Seelye in the LG&E case, and used my customer/demand percentages developed in that case as a surrogate for KU. The following are my estimated customer/demand classifications:

| Account | Percentage | |
|---|---|---|
| | Customer | Demand |
| Overhead Conductors | 39.3% | 60.7% |
| Underground Conductors | 20.1% | 79.9% |
| Line Transformers | 26.5% | 73.5% |

**Q. WHAT ARE YOUR CCOSS RESULTS USING THESE CUSTOMER/DEMAND CLASSIFICATIONS?**

A. My recommended distribution plant classifications coupled with a traditional BIP approach to classify generation resources are reflected in my recommended CCOSS. The detail of this CCOSS is provided in my Schedule GAW_4 and are summarized below:

| Class | ROR At Current Rates | |
|---|---|---|
| | OAG Recommended | Seelye |
| RS | 5.36% | 3.58% |
| GSS | 11.43% | 12.20% |
| GSP | 8.70% | 4.79% |
| AES | 7.68% | 6.32% |
| LPS | 8.48% | 11.53% |
| LPP | 8.01% | 11.82% |
| LPT | 10.10% | 10.07% |
| STODS | 3.95% | 6.73% |
| STODP | 4.72% | 6.92% |
| LCIP | 5.30% | 8.55% |
| LCIT | 3.64% | 5.54% |
| MPP | 13.17% | 12.88% |
| MPT | 13.96% | 13.35% |
| LMPP | 9.70% | 11.42% |
| LMPT | 10.57% | 13.40% |
| LITOD | 15.67% | 25.00% |
| SL | 6.13% | 4.51% |
| SLDEC | 8.71% | 6.87% |
| POL | 15.42% | 13.27% |
| OL | 19.06% | 16.28% |
| TOTAL COMPANY | 7.15% | 7.15% |

As can be seen above, my CCOSS study which is based on accepted industry practices, produces significantly different results than those obtained by Mr. Seelye.

**ELECTRIC CLASS REVENUE DISTRIBUTION**

**Q. PLEASE DESCRIBE KU'S PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL ELECTRIC REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.**

A. KU witness Seelye presents the Company's proposed distribution of its requested $19.57 million revenue increase to customer classes. In large part, Mr. Seelye proposes that the Residential and lighting classes should be responsible for the vast majority of the rate increase proposed by KU. According to Mr. Seelye, this proposed increase is based on his CCOSS results.

A summary of KU's proposed revenue increase for each customer class is shown below:

| Class | KU Proposed Electric Increase | | |
|---|---|---|---|
| | Amount | Percent | Percent of Avg. |
| RS | $17,329,356 | 4.47% | 233% |
| GSS | 0 | 0.00% | 0% |
| GSP | 446,784 | 16.04% | 837% |
| AES | 321,938 | 4.56% | 238% |
| LPS | 0 | 0.00% | 0% |
| LPP | 0 | 0.00% | 0% |
| LPT | -70,621 | -5.87% | -306% |
| STODS | 82,070 | 0.99% | 52% |
| STODP | 6,637 | 1.00% | 52% |
| LCIP | 0 | 0.00% | 0% |
| LCIT | -38,022 | -0.13% | -7% |
| MPP | 575,463 | 8.99% | 469% |
| MPT | 100,123 | 2.81% | 147% |
| LMPP | 29,196 | 0.67% | 35% |
| LMPT | 5,099 | 0.04% | 2% |
| LITOD | 0 | 0.00% | 0% |
| SL | 304,645 | 4.29% | 224% |
| SLDEC | 61,720 | 4.86% | 253% |
| POL | 195,020 | 4.89% | 255% |
| OL | 224,423 | 3.88% | 202% |
| TOTAL COMPANY | $19,573,831 | 1.92% | 100% |

**Q. MR. WATKINS, IN YOUR OPINION ARE KU'S PROPOSED CUSTOMER CLASS REVENUE INCREASES REASONABLE?**

A. No.

**Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. SEELYE?**

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering principles of gradualism, fairness and equity, I propose an equitable and cost based mechanism to assign class revenue increases at KU's requested overall revenue level. My proposed revenue distribution is presented in my Schedule GAW_5 and results in the following class increases:

| Class | OAG Proposed Electric Increase | | |
|---|---|---|---|
| | Amount | Percent | Percent of Avg. |
| RS | $9,723,431 | 2.51% | 131% |
| GSS | 1,247,416 | 0.96% | 50% |
| GSP | 40,057 | 1.44% | 75% |
| AES | 135,329 | 1.92% | 100% |
| LPS | 2,791,882 | 1.44% | 75% |
| LPP | 1,097,194 | 1.44% | 75% |
| LPT | 17,314 | 1.44% | 75% |
| STODS | 197,889 | 2.40% | 125% |
| STODP | 15,889 | 2.40% | 125% |
| LCIP | 2,799,307 | 2.40% | 125% |
| LCIT | 725,336 | 2.40% | 125% |
| MPP | 61,379 | 0.96% | 50% |
| MPT | 34,135 | 0.96% | 50% |
| LMPP | 62,624 | 1.44% | 75% |
| LMPT | 176,886 | 1.44% | 75% |
| LITOD | 199,504 | 0.96% | 50% |
| SL | 136,254 | 1.92% | 100% |
| SLDEC | 18,275 | 1.44% | 75% |
| POL | 38,266 | 0.96% | 50% |
| OL | 55,464 | 0.96% | 50% |
| TOTAL COMPANY | $19,573,831 | 1.92% | 100% |

My specific electric revenue allocation methodology is as follows, with the actual calculations provided in Schedule GAW_5.

First, I recognize class cost of service and the concept of gradualism. In doing so, I recommend a graduated scale of increases such that no class receives a rate decrease and that all class increases are limited to a range of 50% of the system average percentage increase to 150% of the system average increase. In order to recognize the higher than system average ROR's provided by certain classes, I increased these higher than average ROR classes less than the system average percentage. Similarly, those classes with low rates of return were increased by a higher percentage. Finally, due to its size relative to the system, the Residential class was treated as a residual.

**Q. MR. WATKINS, PLEASE PROVIDE YOUR RECOMMENDED SCALE BACK METHOD TO ASSIGN CLASS REVENUE INCREASES SHOULD THE COMMISSION AUTHORIZE AN OVERALL REVENUE REQUIREMENT INCREASE LESS THAN THAT PROPOSED BY KU OR AN OVERALL DECREASE AS RECOMMENDED BY THE OAG.**

A. I recommend that my customer class revenue increases be reduced proportionally downward.

**RESIDENTIAL ELECTRIC RATE DESIGN**

**Q. PLEASE DESCRIBE KU'S CURRENT RESIDENTIAL RATE STRUCTURE?**

A. Currently, Residential rates include a fixed monthly customer charge of $5.00 and a flat kWh energy charge.

**Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE OF $5.00, DOES KU PROPOSE AN INCREASE TO THIS FIXED MONTHLY RATE?**

A. Yes. KU proposes an increase to the monthly Residential customer charge from the current $5.00 level to $8.49.

**Q. DOES MR. SEELYE PROVIDE ANY JUSTIFICATION FOR THE LARGE INCREASE IN THE FIXED CUSTOMER CHARGE?**

A. As part of his CCOSS, Mr. Seelye functionalizes all costs that include an assignment of overheads to each functional and classification category. Within Mr. Seelye's CCOSS, these fully allocated costs that are classified as "customer" equate to a monthly residential "customer allocated cost" of $16.61.

**Q. DO YOU AGREE WITH MR. SEELYE'S "CUSTOMER COST" ANALYSIS?**

A. No. Mr. Seelye's customer cost analysis includes not only those costs that are directly attributable to customers but also assigns a significant level of corporate

overhead costs. In my opinion, any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs.

**Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?**

A. Yes. The results of my direct customer costs analysis are presented in my Schedule GAW_6 and result in a monthly Residential customer cost of $4.36.

**Q. WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER CHARGES IN THIS CASE?**

A. Given that my direct customer cost analysis results in a monthly customer cost of $4.36, I recommend maintaining the current monthly customer charge of $5.00 regardless of any increase or decrease in revenue requirement authorized by this Commission.

**Q. DOES KU'S PROPOSED 70% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE PROMOTE OR DISCOURAGE CONSERVATION?**

A. KU's proposed increased reliance on customer charge revenue will discourage conservation from its electric customers as a larger percentage of customers' bills will be collected from a fixed monthly charge that does not vary with usage. As such, the Company proposed 70% increase to the fixed customer charge would send a price signal to customers that is contrary to conservation efforts and encourage additional usage of electricity.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

# GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

## EDUCATION

| | |
|---|---|
| 1982 - 1988 | M.B.A., Virginia Commonwealth University, Richmond, Virginia |
| 1980 - 1982 | B.S., Economics; Virginia Commonwealth University |
| 1976 - 1980 | A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia |

## POSITIONS

| | |
|---|---|
| Jul. 1995-Present | Vice President/Senior Economist, Technical Associates, Inc. |
| Mar. 1993-1995 | Vice President/Senior Economist, C. W. Amos of Virginia |
| Apr. 1990-Mar. 1993 | Principal/Senior Economist, Technical Associates, Inc. |
| Aug. 1987-Apr. 1990 | Staff Economist, Technical Associates, Inc., Richmond, Virginia |
| Feb. 1987-Aug. 1987 | Economist, Old Dominion Electric Cooperative, Richmond, Virginia |
| May 1984-Jan. 1987 | Staff Economist, Technical Associates, Inc. |
| May 1982-May 1984 | Economic Analyst, Technical Associates, Inc. |
| Sep. 1980-May 1982 | Research Assistant, Technical Associates, Inc. |

## EXPERIENCE

### I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

## GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

### II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

### III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

# GLENN A. WATKINS

## IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

## MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

| | (1) OAG Test Year Adjustment to kWh | (2) Energy Rate | (3) OAG Test Year Revenue Adjustment (1) * (2) |
|---|---|---|---|
| Residential | (35,909,380) | $0.05774 | ($2,073,408) |
| General Service Rate GS | (3,964,088) | 0.06745 | (267,378) |
| Large Power Rate LP | | | |
| Secondary | (5,989,830) | 0.03282 | (196,586) |
| Primary | (1,571,891) | 0.03282 | (51,589) |
| Transmission | - | 0.03282 | 0 |
| Secondary Small Time of Day | (355,666) | 0.03879 | (13,796) |
| Primary Small Time of Day | - | 0.03879 | 0 |
| Total | (7,917,387) | | (261,972) |
| Large Power Rate LCTOD | - | | 0 |
| Primary | - | 0.03282 | 0 |
| Transmission | - | 0.03282 | 0 |
| Large Mine Power TOD | - | | 0 |
| Primary | - | 0.03082 | 0 |
| Transmission | - | 0.03082 | 0 |
| Street Lighting | - | | 0 |
| Total Company | (48,146,521) | | (2,602,757) |
| Variable Expenses | (48,146,521) | $0.02742 | ($1,320,178) |

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## Residential

| | Degree Days | | | Normal Weather Band | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Actual [1/] | 30-year Average [2/] | 30-year Std Dev[3/] | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Customer Per Degree Day[4/] | Average Customers | kWh Adjustment | Model R-square |
| **Cooling Season (CDD)** | | | | | | | | | | | |
| Cooling Month | | | | | | | | | | | |
| June | 284 | 242 | | | | | | | | | |
| July | 309 | 361 | | | | | | | | | |
| August | 496 | 332 | | | | | | | | | |
| September | 238 | 151 | | | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 1.62464 | 412,293 | (35,909,380) | 86.41634% |
| **Heating Season (HDD)** | | | | | | | | | | | |
| Heating Month | | | | | | | | | | | |
| November | 577 | 555 | | | | | | | | | |
| December | 765 | 883 | | | | | | | | | |
| January | 1,012 | 989 | | | | | | | | | |
| February | 849 | 801 | | | | | | | | | |
| March | 638 | 609 | | | | | | | | | |
| Seasonal Aggregate | 3,841 | 3,837 | 215 | 4,052 | 3,622 | No | 211 | | | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## General Service Secondary

| | Degree Days | | | Normal Weather Band | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual 1/ | 30-year Average 2/ | 30-year Std Dev 3/ | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Degree Day 4/ | kWh Adjustment |
| **Cooling Season (CDD)** | | | | | | | | | |
| Cooling Month | | | | | | | | | |
| June | 284 | 242 | | | | | | | |
| July | 309 | 361 | | | | | | | |
| August | 496 | 332 | | | | | | | |
| September | 238 | 151 | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 73,943.08 | -3,964,088 |
| **Heating Season (HDD)** | | | | | | | | | |
| Heating Month | | | | | | | | | |
| November | 577 | 555 | | | | | | | |
| December | 765 | 880 | | | | | | | |
| January | 1,012 | 1,001 | | | | | | | |
| February | 849 | 817 | | | | | | | |
| March | 638 | 615 | | | | | | | |
| Seasonal Aggregate | 3,483 | 3,615 | 215 | 3,830 | 3,400 | No | 347 | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## LP Secondary

| | Degree Days | | | Normal Weather Band | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual [1/] | 30-year Average [2/] | 30-year Std Dev[3/] | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Degree Day[4/] | kWh Adjustment |
| **Cooling Season (CDD)** | | | | | | | | | |
| Cooling Month | | | | | | | | | |
| June | 284 | 242 | | | | | | | |
| July | 309 | 361 | | | | | | | |
| August | 496 | 332 | | | | | | | |
| September | 238 | 151 | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 83,596.81 | -4,481,625 |
| **Heating Season (HDD)** | | | | | | | | | |
| Heating Month | | | | | | | | | |
| November | 577 | 555 | | | | | | | |
| December | 765 | 880 | | | | | | | |
| January | 1,012 | 1,001 | | | | | | | |
| February | 849 | 817 | | | | | | | |
| March | 638 | 615 | | | | | | | |
| Seasonal Aggregate | 3,483 | 3,615 | 215 | 3,830 | 3,400 | No | 347 | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## LP Secondary PF

| | Degree Days | | | Normal Weather Band | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual [1/] | 30-year Average [2/] | 30-year Std Dev[3/] | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Degree Day[4/] | kWh Adjustment |
| **Cooling Season (CDD)** | | | | | | | | | |
| **Cooling Month** | | | | | | | | | |
| June | 284 | 242 | | | | | | | |
| July | 309 | 361 | | | | | | | |
| August | 496 | 332 | | | | | | | |
| September | 238 | 151 | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 28,132.91 | -1,508,205 |
| **Heating Season (HDD)** | | | | | | | | | |
| **Heating Month** | | | | | | | | | |
| November | 577 | 555 | | | | | | | |
| December | 765 | 880 | | | | | | | |
| January | 1,012 | 1,001 | | | | | | | |
| February | 849 | 817 | | | | | | | |
| March | 638 | 615 | | | | | | | |
| Seasonal Aggregate | 3,483 | 3,615 | 215 | 3,830 | 3,400 | No | 347 | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## LP Primary

| | Degree Days | | | Normal Weather Band | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual [1/] | 30-year Average [2/] | 30-year Std Dev[3/] | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Degree Day[4/] | kWh Adjustment |
| **Cooling Season (CDD)** | | | | | | | | | |
| Cooling Month | | | | | | | | | |
| June | 284 | 242 | | | | | | | |
| July | 309 | 361 | | | | | | | |
| August | 496 | 332 | | | | | | | |
| September | 238 | 151 | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 7,085.19 | -379,837 |
| **Heating Season (HDD)** | | | | | | | | | |
| Heating Month | | | | | | | | | |
| November | 577 | 555 | | | | | | | |
| December | 765 | 880 | | | | | | | |
| January | 1,012 | 1,001 | | | | | | | |
| February | 849 | 817 | | | | | | | |
| March | 638 | 615 | | | | | | | |
| Seasonal Aggregate | 3,483 | 3,615 | 215 | 3,830 | 3,400 | No | 347 | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## LP Primary PF

| | Degree Days | | | Normal Weather Band | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual [1/] | 30-year Average [2/] | 30-year Std Dev[3/] | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Degree Day[4/] | kWh Adjustment |
| **Cooling Season (CDD)** | | | | | | | | | |
| Cooling Month | | | | | | | | | |
| June | 284 | 242 | | | | | | | |
| July | 309 | 361 | | | | | | | |
| August | 496 | 332 | | | | | | | |
| September | 238 | 151 | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 22,235.66 | -1,192,054 |
| **Heating Season (HDD)** | | | | | | | | | |
| Heating Month | | | | | | | | | |
| November | 577 | 555 | | | | | | | |
| December | 765 | 880 | | | | | | | |
| January | 1,012 | 1,001 | | | | | | | |
| February | 849 | 817 | | | | | | | |
| March | 638 | 615 | | | | | | | |
| Seasonal Aggregate | 3,483 | 3,615 | 215 | 3,830 | 3,400 | No | 347 | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

KENTUCKY UTILITIES

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

## LP Secondary STOD

| | Degree Days | | | Normal Weather Band | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Actual 1/ | 30-year Average 2/ | 30-year Std Dev 3/ | Upper Limit | Lower Limit | Adjustment | Boundary Limit less Actual | kWh Per Degree Day 4/ | kWh Adjustment |
| **Cooling Season (CDD)** | | | | | | | | | |
| Cooling Month | | | | | | | | | |
| June | 284 | 242 | | | | | | | |
| July | 309 | 361 | | | | | | | |
| August | 496 | 332 | | | | | | | |
| September | 238 | 151 | | | | | | | |
| Seasonal Aggregate | 1,327 | 1,085 | 188 | 1,273 | 897 | Yes | -54 | 6,634.32 | -355,666 |
| **Heating Season (HDD)** | | | | | | | | | |
| Heating Month | | | | | | | | | |
| November | 577 | 555 | | | | | | | |
| December | 765 | 880 | | | | | | | |
| January | 1,012 | 1,001 | | | | | | | |
| February | 849 | 817 | | | | | | | |
| March | 638 | 615 | | | | | | | |
| Seasonal Aggregate | 3,483 | 3,615 | 215 | 3,830 | 3,400 | No | 347 | | |

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and a binary variable for Weekdays and Holidays.

Schedule GAW_ 3

Eon Generation Unit Classification

| Unit | Type | Gross Plant | Percent Energy | Demand | Gross Plant Energy | Gross Plant Demand |
|---|---|---|---|---|---|---|
| Trimble 1 | Base | $598.442 | 100% | 0% | $598.442 | $0.000 |
| Mill Creek 3 | Base | $272.591 | 100% | 0% | $272.591 | $0.000 |
| Mill Creek 4 | Base | $494.022 | 100% | 0% | $494.022 | $0.000 |
| Mill Creek 1 | Base | $153.584 | 100% | 0% | $153.584 | $0.000 |
| Mill Creek 2 | Base | $121.972 | 100% | 0% | $121.972 | $0.000 |
| Ghent 1 | Base | $341.335 | 100% | 0% | $341.335 | $0.000 |
| Cane Run 6 | Base | $131.258 | 100% | 0% | $131.258 | $0.000 |
| Ghent 4 | Base | $365.800 | 100% | 0% | $365.800 | $0.000 |
| Ghent 3 | Base | $490.572 | 100% | 0% | $490.572 | $0.000 |
| Cane Run 5 | Base | $89.856 | 100% | 0% | $89.856 | $0.000 |
| Cane Run 4 | Base | $70.514 | 100% | 0% | $70.514 | $0.000 |
| Brown 2 | Base | $43.716 | 100% | 0% | $43.716 | $0.000 |
| Brown 3 | Base | $145.556 | 100% | 0% | $145.556 | $0.000 |
| Brown 1 | Base | $53.103 | 100% | 0% | $53.103 | $0.000 |
| Ghent 2 | Base | $148.052 | 100% | 0% | $148.052 | $0.000 |
| Green River 4 | Intermediate | $42.268 | 63% | 37% | $26.629 | $15.639 |
| Tyrone 3 | Intermediate | $24.555 | 69% | 31% | $16.943 | $7.612 |
| Green River 3 | Intermediate | $19.529 | 68% | 32% | $13.280 | $6.249 |
| Trimble 5 | Peak | $63.319 | 0% | 100% | $0.000 | $63.319 |
| Trimble 6 | Peak | $55.910 | 0% | 100% | $0.000 | $55.910 |
| Trimble 7 | Peak | $52.341 | 0% | 100% | $0.000 | $52.341 |
| Trimble 8 | Peak | $51.951 | 0% | 100% | $0.000 | $51.951 |
| Trimble 9 | Peak | $52.052 | 0% | 100% | $0.000 | $52.052 |
| Trimble 10 | Peak | $52.023 | 0% | 100% | $0.000 | $52.023 |
| Brown 6 | Peak | $58.868 | 0% | 100% | $0.000 | $58.868 |
| Brown 7 | Peak | $58.872 | 0% | 100% | $0.000 | $58.872 |
| Brown 8 | Peak | $35.458 | 0% | 100% | $0.000 | $35.458 |
| Brown 9 | Peak | $45.866 | 0% | 100% | $0.000 | $45.866 |
| Brown 10 | Peak | $28.591 | 0% | 100% | $0.000 | $28.591 |
| Brown 11 | Peak | $43.497 | 0% | 100% | $0.000 | $43.497 |
| Brown 5 | Peak | $45.189 | 0% | 100% | $0.000 | $45.189 |
| Paddys Run 13 | Peak | $64.098 | 0% | 100% | $0.000 | $64.098 |
| Paddys Run 11 | Peak | $1.826 | 0% | 100% | $0.000 | $1.826 |
| Cane Run 11 | Peak | $2.797 | 0% | 100% | $0.000 | $2.797 |
| Paddys Run 12 | Peak | $3.162 | 0% | 100% | $0.000 | $3.162 |
| Zorn 1 | Peak | $1.901 | 0% | 100% | $0.000 | $1.901 |
| Haefling 1,2 & 3 | Peak | $5.345 | 0% | 100% | $0.000 | $5.345 |
| Ohio Falls 1- 8 | Hydro | $29.739 | 100% | 0% | $29.739 | $0.000 |
| Dix Dam 1,2, &3 | Hydro | $11.033 | 100% | 0% | $11.033 | $0.000 |
| Total | | $4,370.563 | | | $3,617.997 | $752.566 |
| Percent | | | | | 82.78% | 17.22% |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Summary)**

| Cost of Service Summary -- Pro-Forma | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP | LCIP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| total Operating Revenue | $1,154,156,041 | $434,201,162 | $141,196,389 | $3,110,064 | $7,940,212 | $226,074,364 | $86,951,352 | $1,370,360 | $9,536,117 | $765,874 | $135,173,608 |
| Pro-Forma Adjustments: | | | | | | | | | | | |
| Eliminate Unbilled Revenue | -$6,878,000 | -$2,594,613 | -$846,156 | -$18,681 | -$47,381 | -$1,343,022 | -$515,139 | -$8,119 | -$56,155 | -$4,508 | -$801,974 |
| Mismatch in Fuel Cos Recovery | -$116,253,633 | -$40,731,777 | -$11,408,305 | -$265,407 | -$827,021 | -$23,801,704 | -$9,863,831 | -$154,207 | -$1,186,661 | -$96,213 | -$16,677,277 |
| To Reflect a Full Year of the FAC Roll- | $98,267 | $34,430 | $9,642 | $224 | $699 | $20,119 | $8,338 | $130 | $1,003 | $81 | $14,097 |
| Remove ECR Revenue | -$54,342,557 | -$20,626,185 | -$6,655,772 | -$150,005 | -$375,764 | -$10,481,263 | -$4,017,702 | -$63,714 | -$439,539 | -$35,499 | -$6,234,270 |
| To Reflect a full Year of the ECR Roll- | $21,935,653 | $8,325,866 | $2,686,637 | $60,550 | $151,679 | $4,230,816 | $1,621,766 | $25,718 | $177,422 | $14,329 | $2,516,495 |
| Remove Off-System ECR Revenues | -$371,295 | -$105,791 | -$37,805 | -$93 | -$2,090 | -$83,324 | -$35,459 | -$493 | -$4,186 | -$340 | -$60,397 |
| Eliminate Brokered Sales | $90,748 | $31,795 | $8,904 | $207 | $646 | $18,580 | $7,700 | $120 | $926 | $75 | $13,018 |
| Eliminate Rate Refund Acct | $17,682,129 | $6,670,295 | $2,175,319 | $48,026 | $121,809 | $3,452,674 | $1,324,332 | $20,872 | $144,364 | $11,586 | $2,061,735 |
| Eliminate DSM Revenue | -$4,429,150 | -$3,999,569 | -$123,092 | -$2,670 | $0 | -$240,135 | -$45,915 | -$2,128 | -$15,427 | -$215 | $0 |
| Year End Revenue Adjustment | -$4,243,045 | $843,080 | $1,130,662 | -$40,127 | $0 | -$6,373,654 | $0 | $0 | $0 | $0 | $0 |
| Adjustment for Merger Surecredit | $18,568,431 | $7,355,580 | $2,396,449 | $53,506 | $132,778 | $3,766,072 | $1,337,070 | $22,850 | $158,833 | $12,665 | $1,629,902 |
| Weather Normalized Electric Operating Revenues | -$8,721,229 | -$3,055,656 | -$855,689 | -$19,911 | -$62,042 | -$1,785,580 | -$739,975 | -$11,568 | -$89,022 | -$7,218 | -$1,251,112 |
| VDT Surecredit Revenues | $3,405,550 | $1,281,116 | $416,427 | $9,403 | $23,364 | $660,193 | $253,206 | $3,988 | $27,621 | $2,222 | $394,429 |
| Sub-Total | -$133,458,131 | -$46,571,429 | -$11,100,781 | -$324,977 | -$883,323 | -$31,960,228 | -$10,665,610 | -$166,550 | -$1,280,821 | -$103,031 | -$18,395,354 |
| Total Pro-Forma Operating Revenue | $1,020,697,910 | $387,629,753 | $130,095,608 | $2,785,088 | $7,056,889 | $194,114,135 | $76,285,742 | $1,203,810 | $8,255,296 | $662,844 | $116,778,254 |
| Operating Expenses | | | | | | | | | | | |
| Operation and Maintenance Expenses | $789,501,237 | $304,616,034 | $83,213,642 | $1,838,353 | $5,300,606 | $152,455,062 | $60,694,046 | $926,273 | $7,353,503 | $587,344 | $101,902,063 |
| Depreciation and Amortization Expenses | $109,736,123 | $46,776,559 | $13,144,361 | $293,559 | $730,284 | $18,873,622 | $7,037,078 | $101,167 | $882,131 | $65,691 | $11,644,544 |
| Regulatory Credits & Accretion Expense | -$255,374 | -$92,408 | -$25,620 | -$751 | -$1,803 | -$51,679 | -$21,112 | -$339 | -$2,576 | -$201 | -$35,332 |
| Property and Other Taxes | $17,237,030 | $7,353,896 | $2,066,602 | $46,085 | $114,671 | $2,961,609 | $1,103,529 | $15,851 | $138,360 | $10,300 | $1,825,902 |
| Gain on Disposition of Allowance | -$504,602 | -$208,908 | -$58,544 | -$1,367 | -$3,393 | -$89,744 | -$34,153 | -$504 | -$4,253 | -$320 | -$56,676 |
| State and Federal Income Taxes | $56,064,862 | $16,146,262 | $11,179,252 | $240,557 | $437,463 | $12,900,018 | $4,420,364 | $83,612 | $213,855 | $20,725 | $4,177,582 |
| Specific Assignment of Interruptible Credit | -$2,040,216 | | | | | | $430,293 | | | | -$644,684 |
| Allocation of Interruptible Credits | $2,040,216 | $985,796 | $184,843 | $13,076 | $20,667 | $336,251 | $128,995 | $2,705 | $16,413 | $1,328 | $213,147 |
| Adjustments to Operating Expenses: | | | | | | | | | | | |
| Eliminate mismatch in fuel cost recovery | -$96,155,056 | -$33,689,840 | -$9,434,319 | -$219,522 | -$684,041 | -$19,686,733 | -$8,158,517 | -$127,547 | -$981,505 | -$79,579 | -$13,794,017 |
| Remove ECR expenses | -$16,467,656 | -$6,250,440 | -$2,016,927 | -$45,457 | -$113,869 | -$3,176,182 | -$1,217,501 | -$19,307 | -$133,195 | -$10,757 | -$1,889,197 |
| Reflect full year of ECR roll-in | $8,506,554 | $3,228,736 | $1,041,866 | $23,481 | $58,821 | $1,640,693 | $628,914 | $9,973 | $68,804 | $5,557 | $975,886 |
| Eliminate brokered sales expenses | -$8,127 | -$2,847 | -$797 | -$19 | -$58 | -$1,664 | -$690 | -$11 | -$83 | -$7 | -$1,166 |
| Eliminate DSM Expenses | -$4,437,148 | -$4,006,791 | -$123,314 | -$2,674 | $0 | -$240,569 | -$45,997 | -$2,132 | -$15,455 | -$215 | $0 |
| Year end Expense adjustment | -$2,747,550 | $545,930 | $732,151 | -$25,984 | $0 | -$4,127,209 | $0 | $0 | $0 | $0 | $0 |
| Depreciation adjustment | $236,248 | $100,704 | $28,298 | $632 | $1,572 | $40,633 | $15,150 | $218 | $1,899 | $141 | $25,069 |
| Labor adjustment | $1,549,969 | $740,732 | $196,078 | $3,776 | $8,793 | $254,255 | $85,887 | $1,160 | $10,694 | $805 | $139,831 |
| Weather Normalization Expenses | -$4,355,146 | -$1,525,912 | -$427,308 | -$9,943 | -$30,982 | -$891,670 | -$369,523 | -$5,777 | -$44,455 | -$3,604 | -$624,772 |
| Storm damage adjustment | -$2,731,370 | -$1,869,618 | -$442,802 | -$3,448 | -$10,999 | -$218,611 | -$36,332 | -$4 | -$5,928 | -$291 | -$54,058 |
| Amortization of rate case expenses | $324,904 | $128,137 | $34,817 | $755 | $2,149 | $61,817 | $24,350 | $369 | $2,955 | $235 | $40,812 |
| Amortization of ESM audit expenses | -$37,986 | -$14,330 | -$4,673 | -$103 | -$262 | -$7,417 | -$2,845 | -$45 | -$310 | -$25 | -$4,429 |
| Adjustment for EKPC settlement charges | -$1,338,790 | -$469,072 | -$131,356 | -$3,056 | -$9,524 | -$274,103 | -$113,593 | -$1,776 | -$13,666 | -$1,108 | -$192,057 |
| Adjustment for MISO schedule 10 expenses | $1,961,979 | $709,658 | $196,747 | $5,770 | $13,855 | $397,177 | $162,284 | $2,604 | $19,801 | $1,541 | $271,593 |
| Adjustment to reflect reallocation of OVEC Demand Charges | $2,721,857 | $953,657 | $267,057 | $6,214 | $19,363 | $557,271 | $230,943 | $3,610 | $27,783 | $2,253 | $390,467 |
| Adjustment for Reserve Margin Demand Purchases | $1,199,403 | $499,185 | $132,753 | $7,320 | $8,170 | $229,529 | $86,909 | $1,597 | $11,440 | $700 | $137,042 |
| Adjustment for new credit facilities bank fees | $2,005,628 | $830,342 | $232,692 | $5,435 | $13,486 | $356,705 | $135,746 | $2,004 | $16,903 | $1,273 | $225,268 |
| Adjustment to reflect annualized vehicle fuel costs | $198,608 | $74,922 | $24,433 | $539 | $1,368 | $38,781 | $14,875 | $234 | $1,622 | $130 | $23,158 |
| Adjustment for Tyrone retirement | -$9,585 | -$3,467 | -$961 | -$28 | -$68 | -$1,940 | -$793 | -$13 | -$97 | -$8 | -$1,327 |
| Expense Adjustments | -$109,583,264 | -$40,020,315 | -$9,695,566 | -$256,311 | -$722,225 | -$25,049,237 | -$8,560,733 | -$134,840 | -$1,032,795 | -$82,957 | -$14,331,897 |
| Operating Expenses | $862,196,011 | $335,556,915 | $100,008,971 | $2,173,200 | $5,876,270 | $162,335,901 | $65,198,308 | $993,925 | $7,564,638 | $601,910 | $104,694,650 |
| rating Income -- Pro-Forma | $158,501,899 | $52,072,837 | $30,086,637 | $611,887 | $1,180,619 | $31,778,235 | $11,087,434 | $209,886 | $690,658 | $60,933 | $12,083,604 |
| al Cost Rate Base | $2,634,973,710 | $1,090,894,641 | $305,708,873 | $7,140,789 | $17,717,717 | $468,634,814 | $178,341,854 | $2,632,364 | $22,206,711 | $1,672,966 | $295,955,020 |
| s: ECR Rate Base | $415,886,486 | $118,496,647 | $42,345,211 | $103,900 | $2,340,527 | $93,330,868 | $39,717,814 | $551,821 | $4,688,442 | $380,401 | $67,650,270 |
| o Reflect Depreciation Reserve | -$236,248 | -$100,704 | -$28,298 | -$632 | -$1,572 | -$40,633 | -$15,150 | -$218 | -$1,899 | -$141 | -$25,069 |
| sh Working Capital | -$1,942,732 | -$766,182 | -$208,184 | -$4,515 | -$12,852 | -$369,631 | -$145,598 | -$2,205 | -$17,668 | -$1,407 | -$244,033 |
| ed Net Cost Rate Base | $2,216,908,244 | $971,531,108 | $263,127,180 | $7,031,742 | $15,362,765 | $374,893,682 | $138,463,292 | $2,078,119 | $17,498,701 | $1,291,016 | $228,035,647 |
| RoR | 7.15% | 5.36% | 11.43% | 8.70% | 7.68% | 8.48% | 8.01% | 10.10% | 3.95% | 4.72% | 5.30% |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Summary)**

| Cost of Service Summary -- Pro-Forma | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|
| total Operating Revenue | $35,809,536 | $6,896,875 | $3,993,096 | $4,916,425 | $13,992,126 | $23,247,719 | $7,371,816 | $1,376,780 | $4,131,161 | $6,100,984 |
| Pro-Forma Adjustments: | | | | | | | | | | |
| Eliminate Unbilled Revenue | -$210,613 | -$41,101 | -$23,857 | -$29,294 | -$82,773 | -$138,490 | -$45,208 | -$8,521 | -$25,204 | -$37,190 |
| Mismatch in Fuel Cos Recovery | -$4,974,499 | -$667,494 | -$408,130 | -$529,054 | -$1,584,982 | -$2,296,749 | -$262,670 | -$22,072 | -$196,691 | -$300,880 |
| To Reflect a Full Year of the FAC Roll- | $4,205 | $564 | $345 | $447 | $1,340 | $1,941 | $222 | $19 | $166 | $254 |
| Remove ECR Revenue | -$1,899,807 | -$322,310 | -$185,614 | -$226,786 | -$653,519 | -$1,074,407 | -$351,687 | -$62,947 | -$196,492 | -$289,276 |
| To Reflect a full Year of the ECR Roll- | $766,867 | $130,102 | $74,924 | $91,543 | $263,796 | $433,690 | $141,960 | $25,409 | $79,315 | $116,768 |
| Remove Off-System ECR Revenues | -$18,230 | -$1,949 | -$1,260 | -$1,750 | -$5,645 | -$8,956 | -$1,185 | -$100 | -$888 | -$1,358 |
| Eliminate Brokered Sales | $3,883 | $521 | $319 | $413 | $1,237 | $1,793 | $205 | $17 | $154 | $235 |
| Eliminate Rate Refund Acct | $541,449 | $105,663 | $61,332 | $75,310 | $212,785 | $356,034 | $116,222 | $21,906 | $64,794 | $95,609 |
| Eliminate DSM Revenue | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Year End Revenue Adjustment | $0 | $215,149 | $0 | $0 | $0 | $0 | $5,438 | -$87,075 | $65,957 | -$2,475 |
| Adjustment for Merger Surecredit | $488,942 | $115,118 | $67,819 | $82,168 | $232,283 | $388,337 | $127,483 | $24,581 | $70,952 | $105,042 |
| Weather Normalized Electric Operating Revenues | -$373,182 | -$50,075 | -$30,617 | -$39,690 | -$118,904 | -$172,300 | -$19,705 | -$1,656 | -$14,756 | -$22,572 |
| VDT Surecredit Revenues | $120,177 | $20,228 | $11,701 | $14,392 | $40,804 | $68,105 | $22,193 | $4,259 | $12,408 | $19,315 |
| Sub-Total | -$5,550,808 | -$495,583 | -$433,039 | -$562,310 | -$1,693,567 | -$2,441,001 | -$266,732 | -$106,179 | -$140,283 | -$316,526 |
| Total Pro-Forma Operating Revenue | $30,258,728 | $6,401,293 | $3,560,058 | $4,354,116 | $12,298,559 | $20,806,718 | $7,105,084 | $1,270,601 | $3,990,878 | $5,784,458 |
| Operating Expenses | | | | | | | | | | |
| Operation and Maintenance Expenses | $29,650,637 | $4,207,571 | $2,462,928 | $3,284,104 | $9,489,990 | $14,362,039 | $2,754,499 | $305,283 | $1,714,789 | $2,382,470 |
| Depreciation and Amortization Expenses | $3,100,490 | $531,586 | $274,858 | $394,525 | $1,018,632 | $1,750,492 | $1,729,255 | $305,989 | $475,507 | $605,794 |
| Regulatory Credits & Accretion Expense | -$10,386 | -$1,502 | -$920 | -$1,132 | -$3,412 | -$4,765 | -$486 | -$42 | -$359 | -$549 |
| Property and Other Taxes | $485,788 | $83,397 | $43,065 | $61,888 | $159,600 | $274,694 | $272,997 | $48,324 | $74,981 | $95,490 |
| Gain on Disposition of Allowance | -$15,474 | -$2,541 | -$1,368 | -$1,895 | -$5,079 | -$8,314 | -$6,568 | -$1,144 | -$1,900 | -$2,456 |
| State and Federal Income Taxes | $268,913 | $552,378 | $326,787 | $297,786 | $851,208 | $1,829,905 | $581,598 | $181,825 | $509,669 | $845,103 |
| Specific Assignment of Interruptible Credit | -$1,192,286 | | | | | -$633,539 | | | | |
| Allocation of Interruptible Credits | $61,185 | $13,758 | $7,652 | $8,618 | $21,319 | $22,241 | $746 | $63 | $559 | $854 |
| Adjustments to Operating Expenses: | | | | | | | | | | |
| Eliminate mismatch in fuel cost recovery | -$4,114,480 | -$552,094 | -$337,570 | -$437,597 | -$1,310,962 | -$1,899,674 | -$217,258 | -$18,256 | -$162,686 | -$248,862 |
| Remove ECR expenses | -$575,707 | -$97,671 | -$56,247 | -$68,724 | -$198,039 | -$325,582 | -$106,573 | -$19,075 | -$59,544 | -$87,660 |
| Reflect full year of ECR roll-in | $297,388 | $50,453 | $29,055 | $35,500 | $102,299 | $168,183 | $55,052 | $9,853 | $30,758 | $45,282 |
| Eliminate brokered sales expenses | -$348 | -$47 | -$29 | -$37 | -$111 | -$161 | -$18 | -$2 | -$14 | -$21 |
| Eliminate DSM Expenses | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Year end Expense adjustment | $0 | $139,318 | $0 | $0 | $0 | $0 | $3,521 | -$56,385 | $42,710 | -$1,603 |
| Depreciation adjustment | $6,675 | $1,144 | $592 | $849 | $2,193 | $3,769 | $3,723 | $659 | $1,024 | $1,304 |
| Labor adjustment | $36,053 | $6,535 | $3,143 | $4,826 | $11,742 | $21,876 | $10,657 | $1,432 | $5,449 | $6,245 |
| Weather Normalization Expenses | -$186,357 | -$25,006 | -$15,290 | -$19,820 | -$59,377 | -$86,042 | -$9,840 | -$827 | -$7,369 | -$11,272 |
| Storm damage adjustment | -$12 | -$4,111 | -$21 | -$2,788 | -$11 | -$16,154 | -$22,633 | -$2,614 | -$22,534 | -$18,402 |
| Amortization of rate case expenses | $11,795 | $1,697 | $981 | $1,321 | $3,777 | $5,792 | $1,236 | $142 | $747 | $1,019 |
| Amortization of ESM audit expenses | -$1,163 | -$227 | -$132 | -$162 | -$457 | -$765 | -$250 | -$47 | -$139 | -$205 |
| Adjustment for EKPC settlement charges | -$57,287 | -$7,687 | -$4,700 | -$6,093 | -$18,253 | -$26,450 | -$3,025 | -$254 | -$2,265 | -$3,465 |
| Adjustment for MISO schedule 10 expenses | $79,851 | $11,544 | $7,072 | $8,701 | $26,232 | $36,619 | $3,670 | $308 | $2,748 | $4,203 |
| Adjustment to reflect reallocation of OVEC Demand Charges | $116,468 | $15,628 | $9,556 | $12,387 | $37,109 | $53,774 | $6,150 | $517 | $4,605 | $7,045 |
| Adjustment for Reserve Margin Demand Purchases | $36,761 | $7,878 | $4,864 | $4,650 | $14,516 | $16,089 | $0 | $0 | $0 | $0 |
| Adjustment for new credit facilities bank fees | $61,504 | $10,100 | $5,439 | $7,531 | $20,188 | $33,045 | $26,106 | $4,546 | $7,553 | $9,763 |
| Adjustment to reflect annualized vehicle fuel costs | $6,082 | $1,187 | $689 | $846 | $2,390 | $3,999 | $1,305 | $246 | $728 | $1,074 |
| Adjustment for Tyrone retirement | -$390 | -$56 | -$35 | -$43 | -$128 | -$179 | -$18 | -$2 | -$13 | -$21 |
| Expense Adjustments | -$4,283,166 | -$441,414 | -$352,633 | -$458,651 | -$1,366,891 | -$2,011,861 | -$248,196 | -$79,758 | -$158,242 | -$295,576 |
| Operating Expenses | $28,065,701 | $4,943,234 | $2,760,368 | $3,585,243 | $10,165,368 | $15,580,893 | $5,083,845 | $760,540 | $2,615,003 | $3,631,130 |
| rating Income -- Pro-Forma | $2,193,027 | $1,458,059 | $799,689 | $768,873 | $2,133,191 | $5,225,825 | $2,021,239 | $510,062 | $1,375,875 | $2,153,328 |
| t Cost Rate Base | $80,803,283 | $13,269,079 | $7,145,932 | $9,894,085 | $26,522,617 | $43,414,754 | $34,297,253 | $5,972,091 | $9,922,639 | $12,826,229 |
| s: ECR Rate Base | $20,419,031 | $2,182,801 | $1,410,919 | $1,959,661 | $6,322,755 | $10,031,079 | $1,327,780 | $111,571 | $994,259 | $1,520,927 |
| o Reflect Depreciation Reserve | -$6,675 | -$1,144 | -$592 | -$849 | -$2,193 | -$3,769 | -$3,723 | -$659 | -$1,024 | -$1,304 |
| h Working Capital | -$70,529 | -$10,148 | -$5,867 | -$7,898 | -$22,585 | -$34,635 | -$7,390 | -$848 | -$4,465 | -$6,091 |
| d Net Cost Rate Base | $60,307,047 | $11,075,186 | $5,728,553 | $7,925,677 | $20,175,084 | $33,345,271 | $32,958,360 | $5,859,013 | $8,922,891 | $11,297,907 |
| RoR | 3.64% | 13.17% | 13.96% | 9.70% | 10.57% | 15.67% | 6.13% | 8.71% | 15.42% | 19.06% |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Rate Base)**

| | | | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RATE BASE** | | | | | | | | | | | | |
| **Plant-in-Service** | | | | | | | | | | | | |
| | **Intangible Plant** | | | | | | | | | | | |
| 301.00 | ORGANIZATION | PT&D | $38,811 | $16,568 | $4,653 | $104 | $258 | $6,668 | $2,485 | $36 | $312 | $23 |
| 302.00 | FRANCHISE AND CONSENTS | PT&D | $83,453 | $35,604 | $10,005 | $223 | $555 | $14,339 | $5,343 | $77 | $670 | $50 |
| 303.00 | SOFTWARE | PT&D | $22,294,019 | $9,511,378 | $2,672,901 | $59,606 | $148,313 | $3,830,484 | $1,427,282 | $20,501 | $178,952 | $13,322 |
| | Sub-total | | $22,416,283 | $9,563,540 | $2,687,560 | $59,932 | $149,126 | $3,851,491 | $1,435,110 | $20,614 | $179,933 | $13,395 |
| | **Production Plant** | | | | | | | | | | | |
| | Steam Production Generation | $1,434,800,591 | | | | | | | | | | |
| 330 | Hydro Baseload Generation | $9,546,697 | | | | | | | | | | |
| 340 | Other Production Generation | $428,799,376 | | | | | | | | | | |
| | Total Production | $1,873,146,664 | | | | | | | | | | |
| | Energy Related | | $1,550,590,809 | $543,280,385 | $152,137,280 | $3,539,999 | $11,030,799 | $317,467,101 | $131,563,764 | $2,056,811 | $15,827,689 | $1,283,286 |
| | Demand Related | | $322,555,856 | $134,246,074 | $35,701,266 | $1,968,605 | $2,197,241 | $61,727,413 | $23,372,584 | $429,560 | $3,076,488 | $188,244 |
| | Total Production Plant | | $1,873,146,664 | $677,526,459 | $187,838,546 | $5,508,604 | $13,228,040 | $379,194,514 | $154,936,348 | $2,486,371 | $18,904,177 | $1,471,531 |
| | **Transmission Plant** | | | | | | | | | | | |
| | KENTUCKY SYSTEM PROPERTY | | $410,409,382 | $148,447,113 | $41,155,721 | $1,206,944 | $2,898,284 | $83,082,115 | $33,946,798 | $544,768 | $4,141,935 | $322,415 |
| | VIRGINIA PROPERTY - 500 KV LINE | | $7,475,857 | $2,704,055 | $749,677 | $21,985 | $52,794 | $1,513,391 | $618,362 | $9,923 | $75,448 | $5,873 |
| | Total Transmission Plant | | $417,885,239 | $151,151,168 | $41,905,397 | $1,228,929 | $2,951,078 | $84,595,506 | $34,565,159 | $554,691 | $4,217,383 | $328,288 |
| | **Distribution Plant** | | | | | | | | | | | |
| 360-362 | TOTAL ACCTS 360-362 | | $102,616,477 | $52,269,797 | $10,767,237 | $602,883 | $1,080,951 | $16,511,923 | $6,485,042 | $0 | $720,711 | $51,755 |
| 364-365 | OVERHEAD LINES | 383,731,335 | | | | | | | | | | |
| | Primary | 312,674,484 | | | | | | | | | | |
| | Customer | | $122,881,072 | $96,871,453 | $18,412,257 | $16,830 | $72,463 | $2,035,287 | $81,112 | $468 | $11,921 | $468 |
| | Demand | | $189,793,412 | $96,675,148 | $19,914,450 | $1,115,057 | $1,999,264 | $30,539,483 | $11,994,354 | $0 | $1,332,984 | $95,723 |
| | Secondary | 71,056,850 | | | | | | | | | | |
| | Customer | | $27,925,342 | $22,036,365 | $4,188,429 | $0 | $16,484 | $462,988 | $0 | $0 | $2,712 | $106 |
| | Demand | | $43,131,508 | $26,240,535 | $13,230,190 | $0 | $264,408 | $3,184,048 | $0 | $0 | $177,560 | $0 |
| 366-367 | UNDERGROUND LINES | 86,588,726 | | | | | | | | | | |
| | Primary | 70,554,794 | | | | | | | | | | |
| | Customer | | $14,181,514 | $11,179,784 | $2,124,930 | $1,942 | $8,363 | $234,889 | $9,361 | $54 | $1,376 | $54 |
| | Demand | | $56,373,280 | $28,714,881 | $5,915,078 | $331,199 | $593,830 | $9,070,973 | $3,562,616 | $0 | $395,929 | $28,432 |
| | Secondary | 16,033,932 | | | | | | | | | | |
| | Customer | | $3,222,820 | $2,543,183 | $483,380 | $0 | $1,902 | $53,433 | $0 | $0 | $313 | $12 |
| | Demand | | $12,811,112 | $7,794,080 | $3,929,690 | $0 | $78,536 | $945,740 | $0 | $0 | $52,740 | $0 |
| 368 | TRANSFORMERS - POWER POOL | 5,372,853 | | | | | | | | | | |
| | Customer | | $1,421,119 | $1,121,430 | $213,149 | $0 | $839 | $23,561 | $0 | $0 | $138 | $5 |
| | Demand | | $3,951,733 | $2,404,173 | $1,212,157 | $0 | $24,225 | $291,724 | $0 | $0 | $16,268 | $0 |
| 368 | TRANSFORMERS - ALL OTHER | 230,038,518 | | | | | | | | | | |
| | Customer | | $60,845,188 | $48,013,979 | $9,125,967 | $0 | $35,916 | $1,008,783 | $0 | $0 | $5,909 | $232 |
| | Demand | | $169,193,330 | $102,934,576 | $51,898,486 | $0 | $1,037,203 | $12,490,167 | $0 | $0 | $696,521 | $0 |
| 369 | SERVICES | | $78,030,101 | $45,879,905 | $8,653,850 | $0 | $487,376 | $23,001,011 | $0 | $0 | $7,959 | $0 |
| 370 | METERS | | $61,476,425 | $38,269,497 | $16,884,059 | $40,882 | $130,884 | $4,855,300 | $195,373 | $1,107 | $14,447 | $553 |
| 371 | CUSTOMER INSTALLATION | | $17,415,370 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 373 | STREET LIGHTING | | $52,453,968 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Total Distribution Plant | | $1,017,723,772 | $582,948,784 | $166,953,311 | $2,108,793 | $5,832,645 | $104,709,311 | $22,327,858 | $1,628 | $3,437,488 | $177,340 |
| | **General Plant** | | | | | | | | | | | |
| | Total General Plant | | $88,658,922 | $37,824,877 | $10,629,600 | $237,039 | $589,811 | $15,233,079 | $5,676,020 | $81,530 | $711,656 | $52,978 |
| | TOTAL COMMON PLANT | | $0 | | | | | | | | | |
| 106 | COMPLETED CONSTR NOT CLASSIFIED | | $0 | | | | | | | | | |
| 105 | PLANT HELD FOR FUTURE USE | | $0 | | | | | | | | | |
| | OTHER | | $0 | | | | | | | | | |
| | Total General Plant | | $88,658,922 | $37,824,877 | $10,629,600 | $237,039 | $589,811 | $15,233,079 | $5,676,020 | $81,530 | $711,656 | $52,978 |
| | **Construction Work In Progress** | | | | | | | | | | | |
| | CWIP Production | | $850,877,946 | $307,766,783 | $85,325,767 | $2,502,287 | $6,008,846 | $172,249,326 | $70,379,925 | $1,129,435 | $8,587,233 | $668,444 |
| | CWIP Transmission | | $59,963,820 | $21,689,212 | $6,013,153 | $176,343 | $423,461 | $12,138,906 | $4,959,876 | $79,595 | $605,167 | $47,107 |
| | CWIP Distribution Plant | | $137,343,542 | $78,669,923 | $22,530,631 | $284,585 | $787,125 | $14,130,698 | $3,013,182 | $220 | $463,895 | $23,932 |
| | CWIP General Plant | | $27,677,464 | $11,806,137 | $3,318,339 | $73,999 | $184,127 | $4,755,449 | $1,771,935 | $25,452 | $222,164 | $16,539 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Rate Base)**

| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|
| RWIP | $0 | | | | | | | | | |
| Total CWIP | $1,075,862,772 | $419,934,054 | $117,187,890 | $3,037,214 | $7,403,557 | $203,274,380 | $80,124,918 | $1,234,701 | $9,878,459 | $756,022 |
| **TOTAL PLANT-IN-SERVICE** | **$3,419,830,880** | **$1,459,014,829** | **$410,014,415** | **$9,143,298** | **$22,750,700** | **$587,583,902** | **$218,940,495** | **$3,144,833** | **$27,450,637** | **$2,043,531** |
| **TOTAL UTILITY PLANT** | **$4,495,693,652** | **$1,878,948,883** | **$527,202,305** | **$12,180,512** | **$30,154,258** | **$790,858,282** | **$299,065,414** | **$4,379,534** | **$37,329,097** | **$2,799,553** |
| **Accumulated Reserve for Depreciation** | | | | | | | | | | |
| Steam Production | $801,561,442 | $289,928,758 | $80,380,324 | $2,357,255 | $5,660,575 | $162,265,832 | $66,300,736 | $1,063,974 | $8,089,521 | $629,701 |
| Hydraulic Production | $7,152,933 | $2,587,251 | $717,294 | $21,036 | $50,514 | $1,448,020 | $591,651 | $9,495 | $72,189 | $5,619 |
| Other Production | $105,179,005 | $38,043,769 | $10,547,317 | $309,313 | $742,767 | $21,292,140 | $8,699,826 | $139,612 | $1,061,488 | $82,628 |
| Transmission - Kentucky System Property | $254,442,507 | $92,033,120 | $25,515,413 | $748,272 | $1,796,856 | $51,508,622 | $21,046,079 | $337,741 | $2,567,886 | $199,888 |
| Transmission - Virginia Property | $4,333,686 | $1,567,516 | $434,581 | $12,745 | $30,604 | $877,299 | $358,459 | $5,752 | $43,736 | $3,405 |
| Distribution | $474,165,401 | $271,600,361 | $77,784,843 | $982,503 | $2,717,475 | $48,784,881 | $10,402,722 | $759 | $1,601,552 | $82,624 |
| General Plant | $44,717,082 | $19,077,811 | $5,361,273 | $119,556 | $297,484 | $7,683,139 | $2,862,826 | $41,121 | $358,940 | $26,721 |
| Intangible Plant | $16,103,542 | $6,870,312 | $1,930,705 | $43,055 | $107,130 | $2,766,857 | $1,030,962 | $14,809 | $129,262 | $9,623 |
| **TOTAL ACCUMULATED RESERVE FOR DEPRECIATION** | **$1,707,655,598** | **$721,708,898** | **$202,671,749** | **$4,593,736** | **$11,403,405** | **$296,626,789** | **$111,293,262** | **$1,613,262** | **$13,924,573** | **$1,040,208** |
| **Rate Base Adjustments and Working Capital** | | | | | | | | | | |
| **Working Capital Assets** | | | | | | | | | | |
| Cash Working Capital - Operation and Maintenance Expenses | $78,937,746 | $31,131,770 | $8,459,008 | $183,465 | $522,221 | $15,018,992 | $5,915,970 | $89,603 | $717,912 | $57,162 |
| Materials and Supplies | $74,430,157 | $31,754,407 | $8,923,669 | $198,997 | $495,153 | $12,788,341 | $4,765,082 | $68,445 | $597,443 | $44,476 |
| Prepayments | $1,461,220 | $623,405 | $175,190 | $3,907 | $9,721 | $251,062 | $93,549 | $1,344 | $11,729 | $873 |
| Sub-total | $154,829,123 | $63,509,583 | $17,557,867 | $386,369 | $1,027,095 | $28,058,395 | $10,774,600 | $159,392 | $1,327,085 | $102,511 |
| **Other Rate Base Items** | | | | | | | | | | |
| **Deferred Debits** | | | | | | | | | | |
| Total Production Plant | $143,326,414 | $51,841,877 | $14,372,727 | $421,498 | $1,012,162 | $29,014,594 | $11,855,170 | $190,248 | $1,446,479 | $112,596 |
| Total Transmission Plant | $24,426,563 | $8,835,209 | $2,449,488 | $71,834 | $172,499 | $4,944,844 | $2,020,430 | $32,423 | $246,518 | $19,189 |
| Total Distribution Plant | $82,470,281 | $47,238,702 | $13,528,903 | $170,884 | $472,643 | $8,485,020 | $1,809,317 | $132 | $278,554 | $14,371 |
| Total General Plant | $6,674,350 | $2,847,502 | $800,209 | $17,845 | $44,402 | $1,146,765 | $427,298 | $6,138 | $53,574 | $3,988 |
| Sub-total | $256,897,609 | $110,763,290 | $31,151,327 | $682,061 | $1,701,705 | $43,591,223 | $16,112,214 | $228,941 | $2,025,125 | $150,144 |
| **Accumulated Deferred Investment Tax Credits** | | | | | | | | | | |
| Production | $48,588,068 | $17,574,546 | $4,872,396 | $142,889 | $343,126 | $9,836,031 | $4,018,937 | $64,495 | $490,361 | $38,170 |
| Transmission | $74,169 | $26,827 | $7,436 | $218 | $524 | $15,014 | $6,135 | $98 | $749 | $58 |
| Transmission VA | $3,355 | $1,213 | $336 | $10 | $24 | $679 | $277 | $4 | $34 | $3 |
| Distribution VA | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Distribution Plant KY,FERC & TN | $101,221 | $57,979 | $16,605 | $210 | $580 | $10,414 | $2,221 | $0 | $342 | $18 |
| General | $16,235 | $6,926 | $1,946 | $43 | $108 | $2,789 | $1,039 | $15 | $130 | $10 |
| Sub-total | $48,783,047 | $17,667,492 | $4,898,721 | $143,370 | $344,361 | $9,864,928 | $4,028,609 | $64,613 | $491,615 | $38,259 |
| **Customer Advances** | | | | | | | | | | |
| Customer Advances | $2,405,862 | $1,493,972 | $348,860 | $7,494 | $15,526 | $238,002 | $80,042 | $3 | $10,106 | $638 |
| Sub-total | $2,405,862 | $1,493,972 | $348,860 | $7,494 | $15,526 | $238,002 | $80,042 | $3 | $10,106 | $638 |
| **Emission Allowance** | | | | | | | | | | |
| Emission Allowance | $193,051 | $69,828 | $19,359 | $568 | $1,363 | $39,081 | $15,968 | $256 | $1,948 | $152 |
| Sub-total | $193,051 | $69,828 | $19,359 | $568 | $1,363 | $39,081 | $15,968 | $256 | $1,948 | $152 |
| **TOTAL OTHER RATE BASE** | $303,274,794 | $126,936,809 | $35,701,188 | $817,938 | $2,030,540 | $53,218,149 | $20,060,781 | $293,551 | $2,506,635 | $187,765 |
| **TOTAL RATE BASE** | **$2,634,973,710** | **$1,090,894,641** | **$305,708,873** | **$7,140,789** | **$17,717,717** | **$468,634,814** | **$178,341,854** | **$2,632,364** | **$22,208,711** | **$1,672,966** |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Rate Base)**

| | | | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **RATE BASE** | | | | | | | | | | | | | |
| **Plant-in-Service** | | | | | | | | | | | | | |
| | **Intangible Plant** | | | | | | | | | | | | |
| 301.00 | ORGANIZATION | PT&D | $4,111 | $1,094 | $188 | $97 | $139 | $359 | $619 | $615 | $109 | $169 | $215 |
| 302.00 | FRANCHISE AND CONSENTS | PT&D | $8,840 | $2,352 | $404 | $209 | $300 | $773 | $1,330 | $1,322 | $234 | $363 | $462 |
| 303.00 | SOFTWARE | PT&D | $2,361,584 | $628,308 | $107,864 | $55,700 | $80,045 | $206,424 | $355,284 | $353,089 | $62,501 | $96,978 | $123,504 |
| | Sub-total | | $2,374,535 | $631,754 | $108,456 | $56,005 | $80,484 | $207,556 | $357,233 | $355,025 | $62,843 | $97,510 | $124,182 |
| | **Production Plant** | | | | | | | | | | | | |
| | Steam Production Generation | $1,434,800,591 | | | | | | | | | | | |
| 330 | Hydro Baseload Generation | $9,546,697 | | | | | | | | | | | |
| 340 | Other Production Generation | $428,799,376 | | | | | | | | | | | |
| | Total Production | $1,873,146,664 | | | | | | | | | | | |
| | Energy Related | | $222,441,504 | $66,349,867 | $8,903,030 | $5,443,637 | $7,056,659 | $21,140,491 | $30,634,031 | $3,503,492 | $294,392 | $2,623,459 | $4,013,131 |
| | Demand Related | | $36,854,681 | $9,886,133 | $2,118,677 | $1,308,093 | $1,250,395 | $3,903,686 | $4,326,714 | $0 | $0 | $0 | $0 |
| | Total Production Plant | | $259,296,185 | $76,236,001 | $11,021,707 | $6,751,731 | $8,307,055 | $25,044,177 | $34,960,746 | $3,503,492 | $294,392 | $2,623,459 | $4,013,131 |
| | **Transmission Plant** | | | | | | | | | | | | |
| | KENTUCKY SYSTEM PROPERTY | | $56,812,202 | $16,703,428 | $2,414,873 | $1,479,315 | $1,820,089 | $5,487,219 | $7,659,954 | $767,621 | $64,502 | $574,804 | $879,283 |
| | VIRGINIA PROPERTY - 500 KV LINE | | $1,034,869 | $304,263 | $43,988 | $26,947 | $33,154 | $99,953 | $139,531 | $13,983 | $1,175 | $10,470 | $16,017 |
| | Total Transmission Plant | | $57,847,071 | $17,007,691 | $2,458,862 | $1,506,261 | $1,853,243 | $5,587,172 | $7,799,485 | $781,603 | $65,677 | $585,274 | $895,300 |
| | **Distribution Plant** | | | | | | | | | | | | |
| 360-362 | TOTAL ACCTS 360-362 | | $9,802,396 | $0 | $736,478 | $0 | $505,177 | $0 | $2,932,830 | $50,128 | $4,212 | $37,536 | $57,420 |
| 364-365 | OVERHEAD LINES | 383,731,335 | | | | | | | | | | | |
| | Primary | 312,674,484 | | | | | | | | | | | |
| | Customer | | $9,350 | $1,636 | $7,246 | $2,805 | $701 | $1,403 | $234 | $1,832,026 | $212,611 | $1,832,026 | $1,478,773 |
| | Demand | | $18,129,936 | $0 | $1,362,147 | $0 | $934,345 | $0 | $5,424,391 | $92,714 | $7,791 | $69,425 | $106,200 |
| | Secondary | 71,056,850 | | | | | | | | | | | |
| | Customer | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $416,750 | $48,365 | $416,750 | $336,392 |
| | Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $11,673 | $981 | $8,741 | $13,371 |
| 366-367 | UNDERGROUND LINES | 86,588,726 | | | | | | | | | | | |
| | Primary | 70,554,794 | | | | | | | | | | | |
| | Customer | | $1,079 | $189 | $836 | $324 | $81 | $162 | $27 | $211,431 | $24,537 | $211,431 | $170,663 |
| | Demand | | $5,385,034 | $0 | $404,591 | $0 | $277,523 | $0 | $1,611,177 | $27,538 | $2,314 | $20,621 | $31,544 |
| | Secondary | 16,033,932 | | | | | | | | | | | |
| | Customer | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $48,096 | $5,582 | $48,096 | $38,822 |
| | Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,467 | $291 | $2,596 | $3,972 |
| 368 | TRANSFORMERS - POWER POOL | 5,372,853 | | | | | | | | | | | |
| | Customer | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $21,208 | $2,461 | $21,208 | $17,119 |
| | Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,069 | $90 | $801 | $1,225 |
| 368 | TRANSFORMERS - ALL OTHER | 230,038,518 | | | | | | | | | | | |
| | Customer | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $908,037 | $105,380 | $908,037 | $732,949 |
| | Demand | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $45,790 | $3,848 | $34,288 | $52,451 |
| 369 | SERVICES | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 370 | METERS | | $22,255 | $4,488 | $16,783 | $5,533 | $1,660 | $3,381 | $430 | $491,936 | $0 | $537,859 | $0 |
| 371 | CUSTOMER INSTALLATION | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $10,956,432 | $2,118,048 | $1,753,482 | $2,587,408 |
| 373 | STREET LIGHTING | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $33,000,064 | $6,379,424 | $5,281,374 | $7,793,106 |
| | Total Distribution Plant | | $33,350,049 | $6,313 | $2,528,081 | $8,662 | $1,719,488 | $4,946 | $9,969,089 | $48,118,361 | $8,915,935 | $11,184,273 | $13,421,416 |
| | **General Plant** | | | | | | | | | | | | |
| | Total General Plant | | $9,391,554 | $2,498,657 | $428,956 | $221,507 | $318,322 | $820,907 | $1,412,895 | $1,404,163 | $248,553 | $385,664 | $491,153 |
| | TOTAL COMMON PLANT | | | | | | | | | | | | |
| 106 | COMPLETED CONSTR NOT CLASSIFIED | | | | | | | | | | | | |
| 105 | PLANT HELD FOR FUTURE USE | | | | | | | | | | | | |
| | OTHER | | | | | | | | | | | | |
| | Total General Plant | | $9,391,554 | $2,498,657 | $428,956 | $221,507 | $318,322 | $820,907 | $1,412,895 | $1,404,163 | $248,553 | $385,664 | $491,153 |
| | **Construction Work In Progress** | | | | | | | | | | | | |
| | CWIP Production | | $117,785,441 | $34,630,247 | $5,006,617 | $3,066,978 | $3,773,484 | $11,376,332 | $15,880,939 | $1,591,463 | $133,728 | $1,191,708 | $1,822,967 |
| | CWIP Transmission | | $8,300,679 | $2,440,493 | $352,831 | $216,139 | $265,928 | $801,723 | $1,119,175 | $112,155 | $9,424 | $83,983 | $128,470 |
| | CWIP Distribution Plant | | $4,500,645 | $852 | $341,169 | $1,169 | $232,048 | $667 | $1,345,345 | $6,493,654 | $1,203,220 | $1,509,337 | $1,811,243 |
| | CWIP General Plant | | $2,931,847 | $780,028 | $133,911 | $69,150 | $99,373 | $256,270 | $441,076 | $438,351 | $77,593 | $120,396 | $153,328 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Rate Base)**

| | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RWIP | | | | | | | | | | | |
| Total CWIP | $133,518,613 | $37,851,621 | $5,834,527 | $3,353,435 | $4,370,834 | $12,434,992 | $18,786,536 | $8,635,623 | $1,423,965 | $2,905,424 | $3,916,007 |
| **TOTAL PLANT-IN-SERVICE** | **$362,259,395** | **$96,380,415** | **$16,546,062** | **$8,544,166** | **$12,278,591** | **$31,664,758** | **$54,499,447** | **$54,162,644** | **$9,587,400** | **$14,876,181** | **$18,945,181** |
| **TOTAL UTILITY PLANT** | **$495,778,008** | **$134,232,035** | **$22,380,590** | **$11,897,601** | **$16,649,424** | **$44,099,750** | **$73,285,983** | **$62,798,267** | **$11,011,365** | **$17,781,605** | **$22,861,188** |
| **Accumulated Reserve for Depreciation** | | | | | | | | | | | |
| Steam Production | $110,958,650 | $32,623,093 | $4,716,436 | $2,889,217 | $3,554,775 | $10,716,965 | $14,960,487 | $1,499,223 | $125,977 | $1,122,637 | $1,717,309 |
| Hydraulic Production | $990,167 | $291,120 | $42,088 | $25,783 | $31,722 | $95,636 | $133,504 | $13,379 | $1,124 | $10,018 | $15,325 |
| Other Production | $14,559,733 | $4,280,725 | $618,880 | $379,116 | $466,449 | $1,406,255 | $1,963,080 | $196,724 | $16,530 | $147,310 | $225,341 |
| Transmission - Kentucky System Property | $35,222,000 | $10,355,665 | $1,497,155 | $917,134 | $1,128,405 | $3,401,924 | $4,748,961 | $475,904 | $39,989 | $356,363 | $545,131 |
| Transmission - Virginia Property | $599,904 | $176,379 | $25,500 | $15,621 | $19,219 | $57,942 | $80,885 | $8,106 | $681 | $6,070 | $9,285 |
| Distribution | $15,538,047 | $2,941 | $1,177,853 | $4,036 | $801,123 | $2,304 | $4,644,676 | $22,418,718 | $4,154,003 | $5,210,840 | $6,253,142 |
| General Plant | $4,736,837 | $1,260,253 | $216,353 | $111,722 | $160,553 | $414,043 | $712,625 | $708,221 | $125,363 | $194,518 | $247,724 |
| Intangible Plant | $1,705,833 | $453,843 | $77,913 | $40,233 | $57,818 | $149,105 | $256,631 | $255,045 | $45,146 | $70,050 | $89,210 |
| **TOTAL ACCUMULATED RESERVE FOR DEPRECIATION** | **$184,311,170** | **$49,444,019** | **$8,372,177** | **$4,382,862** | **$6,220,064** | **$16,244,173** | **$27,500,847** | **$25,575,318** | **$4,508,814** | **$7,117,805** | **$9,102,466** |
| **Rate Base Adjustments and Working Capital** | | | | | | | | | | | |
| **Working Capital Assets** | | | | | | | | | | | |
| Cash Working Capital - Operation and Maintenance Expenses | $9,915,650 | $2,865,771 | $412,330 | $238,400 | $320,896 | $917,667 | $1,407,303 | $300,273 | $34,449 | $181,424 | $247,479 |
| Materials and Supplies | $7,884,315 | $2,097,650 | $360,113 | $185,958 | $267,235 | $689,161 | $1,186,141 | $1,178,811 | $208,663 | $323,769 | $412,328 |
| Prepayments | $154,786 | $41,181 | $7,070 | $3,651 | $5,246 | $13,530 | $23,286 | $23,143 | $4,096 | $6,356 | $8,095 |
| Sub-total | $17,954,751 | $5,004,603 | $779,513 | $428,009 | $593,377 | $1,620,358 | $2,616,731 | $1,502,227 | $247,208 | $511,549 | $667,902 |
| **Other Rate Base Items** | | | | | | | | | | | |
| **Deferred Debits** | | | | | | | | | | | |
| Total Production Plant | $19,840,407 | $5,833,303 | $843,341 | $516,618 | $635,626 | $1,916,290 | $2,675,070 | $268,075 | $22,526 | $200,738 | $307,070 |
| Total Transmission Plant | $3,381,323 | $994,147 | $143,727 | $88,045 | $108,327 | $326,586 | $455,902 | $45,687 | $3,839 | $34,211 | $52,333 |
| Total Distribution Plant | $2,702,490 | $512 | $204,861 | $702 | $139,337 | $401 | $807,836 | $3,899,226 | $722,494 | $906,307 | $1,087,592 |
| Total General Plant | $707,008 | $188,102 | $32,292 | $16,675 | $23,964 | $61,799 | $106,364 | $105,707 | $18,711 | $29,033 | $36,975 |
| Sub-total | $26,631,228 | $7,016,064 | $1,224,222 | $622,040 | $907,254 | $2,305,075 | $4,045,172 | $4,318,694 | $767,570 | $1,170,289 | $1,483,969 |
| **Accumulated Deferred Investment Tax Credits** | | | | | | | | | | | |
| Production | $6,725,955 | $1,977,507 | $285,895 | $175,135 | $215,479 | $649,628 | $906,856 | $90,878 | $7,636 | $68,051 | $104,098 |
| Transmission | $10,267 | $3,019 | $436 | $267 | $329 | $992 | $1,384 | $139 | $12 | $104 | $159 |
| Transmission VA | $464 | $137 | $20 | $12 | $15 | $45 | $63 | $6 | $1 | $5 | $7 |
| Distribution VA | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Distribution Plant KY,FERC & TN | $3,317 | $1 | $251 | $1 | $171 | $0 | $992 | $4,786 | $887 | $1,112 | $1,335 |
| General | $1,720 | $458 | $79 | $41 | $58 | $150 | $259 | $257 | $46 | $71 | $90 |
| Sub-total | $6,741,723 | $1,981,120 | $286,681 | $175,456 | $216,052 | $650,815 | $909,554 | $96,066 | $8,581 | $69,342 | $105,689 |
| **Customer Advances** | | | | | | | | | | | |
| Customer Advances | $120,341 | $9 | $9,079 | $16 | $6,203 | $8 | $35,991 | $13,523 | $1,547 | $13,350 | $11,150 |
| Sub-total | $120,341 | $9 | $9,079 | $16 | $6,203 | $8 | $35,991 | $13,523 | $1,547 | $13,350 | $11,150 |
| **Emission Allowance** | | | | | | | | | | | |
| Emission Allowance | $26,724 | $7,857 | $1,136 | $696 | $856 | $2,581 | $3,603 | $361 | $30 | $270 | $414 |
| Sub-total | $26,724 | $7,857 | $1,136 | $696 | $856 | $2,581 | $3,603 | $361 | $30 | $270 | $414 |
| **TOTAL OTHER RATE BASE** | $33,252,610 | $8,997,175 | $1,501,824 | $797,480 | $1,117,103 | $2,955,883 | $4,918,734 | $4,401,237 | $774,604 | $1,226,281 | $1,578,508 |
| **TOTAL RATE BASE** | **$295,955,020** | **$80,603,283** | **$13,269,079** | **$7,145,932** | **$9,894,085** | **$26,522,617** | **$43,414,754** | **$34,297,253** | **$5,972,091** | **$9,922,639** | **$12,826,229** |

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|
| **O & M Expenses** | | | | | | | | | | |
| **Steam Production O&M** | | | | | | | | | | |
| 500 OPERATION SUPERVISION & ENGINEERING | $3,348,315 | $1,204,814 | $334,568 | $9,482 | $23,674 | $679,101 | $278,137 | $4,444 | $33,856 | $2,654 |
| 501 FUEL | $359,943,470 | $126,113,366 | $35,316,100 | $821,751 | $2,560,614 | $73,694,626 | $30,540,306 | $477,454 | $3,674,131 | $297,893 |
| 502 STEAM EXPENSES | $9,025,021 | $3,264,395 | $905,026 | $26,541 | $63,734 | $1,827,000 | $746,500 | $11,980 | $91,082 | $7,090 |
| 505 ELECTRIC EXPENSES | $4,886,361 | $1,767,421 | $490,003 | $14,370 | $34,507 | $989,181 | $404,173 | $6,486 | $49,314 | $3,839 |
| 506 MISC. STEAM POWER EXPENSES | $6,423,607 | $2,323,451 | $644,157 | $18,891 | $45,363 | $1,300,377 | $531,325 | $8,527 | $64,828 | $5,046 |
| 507 RENTS | $1,911,917 | $691,550 | $191,726 | $5,623 | $13,502 | $387,043 | $158,143 | $2,538 | $19,295 | $1,502 |
| 510 MAINTENANCE SUPERVISION & ENGINEERING | $4,677,355 | $1,646,278 | $460,349 | $11,112 | $33,240 | $956,121 | $395,455 | $6,205 | $47,668 | $3,843 |
| 511 MAINTENANCE OF STRUCTURES | $4,477,790 | $1,619,639 | $449,031 | $13,168 | $31,622 | $906,471 | $370,378 | $5,944 | $45,191 | $3,518 |
| 512 MAINTENANCE OF BOILER PLANT | $24,647,620 | $8,635,785 | $2,418,318 | $56,271 | $175,342 | $5,046,340 | $2,091,289 | $32,694 | $251,591 | $20,399 |
| 513 MAINTENANCE OF ELECTRIC PLANT | $9,390,527 | $3,290,158 | $921,358 | $21,439 | $66,804 | $1,922,611 | $796,763 | $12,456 | $95,854 | $7,772 |
| 514 MAINTENANCE OF MISC STEAM PLANT | $991,695 | $347,460 | $97,301 | $2,264 | $7,055 | $203,039 | $84,143 | $1,315 | $10,123 | $821 |
| Sub-total | $429,723,678 | $150,904,317 | $42,227,937 | $1,000,911 | $3,055,456 | $87,911,910 | $36,396,613 | $570,043 | $4,382,934 | $354,376 |
| **Hydraulic Production O&M** | | | | | | | | | | |
| 535 OPERATION SUPERVISION & ENGINEERING | $7,220 | $2,611 | $724 | $21 | $51 | $1,462 | $597 | $10 | $73 | $6 |
| 536 WATER FOR POWER | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 537 HYDRAULIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 538 ELECTRIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 539 MISC. HYDRAULIC POWER EXPENSES | $36,018 | $13,028 | $3,612 | $106 | $254 | $7,291 | $2,979 | $48 | $364 | $28 |
| 540 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 541 MAINTENANCE SUPERVISION & ENGINEERING | $104,232 | $36,905 | $10,300 | $260 | $740 | $21,262 | $8,771 | $138 | $1,060 | $85 |
| 542 MAINTENANCE OF STRUCTURES | $135,839 | $49,133 | $13,622 | $399 | $959 | $27,499 | $11,236 | $180 | $1,371 | $107 |
| 543 MAINT. OF RESERVES, DAMS, AND WATERWAYS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 544 MAINTENANCE OF ELECTRIC PLANT | $136,478 | $47,818 | $13,391 | $312 | $971 | $27,942 | $11,580 | $181 | $1,393 | $113 |
| 545 MAINTENANCE OF MISC HYDRAULIC PLANT | $5,457 | $1,912 | $535 | $12 | $39 | $1,117 | $463 | $7 | $56 | $5 |
| Sub-total | $425,244 | $151,408 | $42,184 | $1,111 | $3,014 | $86,574 | $35,626 | $564 | $4,316 | $343 |
| **Other Power Generation Operation Expense** | | | | | | | | | | |
| 546 OPERATION SUPERVISION & ENGINEERING | $99,030 | $35,820 | $9,931 | $291 | $699 | $20,047 | $8,191 | $131 | $999 | $78 |
| 547 FUEL | $50,197,106 | $17,587,556 | $4,925,124 | $114,600 | $357,099 | $10,277,328 | $4,259,099 | $66,585 | $512,388 | $41,544 |
| 548 GENERATION EXPENSE | $1,459,910 | $528,057 | $146,399 | $4,293 | $10,310 | $295,540 | $120,756 | $1,938 | $14,734 | $1,147 |
| 549 MISC OTHER POWER GENERATION | $114,052 | $41,253 | $11,437 | $335 | $805 | $23,088 | $9,434 | $151 | $1,151 | $90 |
| 550 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 551 MAINTENANCE SUPERVISION & ENGINEERING | $33,775 | $12,216 | $3,387 | $99 | $239 | $6,837 | $2,794 | $45 | $341 | $27 |
| 552 MAINTENANCE OF STRUCTURES | $143,980 | $52,078 | $14,438 | $423 | $1,017 | $29,147 | $11,909 | $191 | $1,453 | $113 |
| 553 MAINTENANCE OF GENERATING & ELEC PLANT | $2,313,971 | $836,975 | $232,044 | $6,805 | $16,341 | $468,434 | $191,399 | $3,072 | $23,353 | $1,818 |
| 554 MAINTENANCE OF MISC OTHER POWER GEN PLT | $247,222 | $89,422 | $24,791 | $727 | $1,746 | $50,047 | $20,449 | $328 | $2,495 | $194 |
| Sub-total | $54,609,046 | $19,183,377 | $5,367,551 | $127,575 | $388,256 | $11,170,468 | $4,624,031 | $72,441 | $556,914 | $45,010 |
| **Other Power Supply Expense** | | | | | | | | | | |
| 555 PURCHASED POWER | | | | | | | | | | |
| 'Demand | $15,031,259 | $5,436,881 | $1,507,330 | $44,204 | $106,150 | $3,042,886 | $1,243,303 | $19,952 | $151,699 | $11,808 |
| 'Energy | $142,211,384 | $49,826,592 | $13,953,167 | $324,669 | $1,011,682 | $29,116,280 | $12,066,281 | $188,639 | $1,451,626 | $117,696 |
| 555 PURCHASED POWER OPTIONS | $0 | | | | | | | | | |
| 555 BROKERAGE FEES | $0 | | | | | | | | | |
| 555 MISO TRANSMISSION EXPENSES | $0 | | | | | | | | | |
| 556 SYSTEM CONTROL AND LOAD DISPATCH | $1,341,969 | $485,397 | $134,572 | $3,947 | $9,477 | $271,664 | $111,000 | $1,781 | $13,543 | $1,054 |
| 557 OTHER EXPENSES | $1,040,935 | $376,512 | $104,385 | $3,061 | $7,351 | $210,724 | $86,100 | $1,382 | $10,505 | $818 |
| Sub-total | $159,625,548 | $56,125,382 | $15,699,454 | $375,881 | $1,134,660 | $32,641,554 | $13,506,685 | $211,754 | $1,627,373 | $131,376 |
| **Transmission Expenses** | | | | | | | | | | |
| 560 OPERATION SUPERVISION AND ENG | $888,516 | $321,381 | $89,100 | $2,613 | $6,275 | $179,869 | $73,493 | $1,179 | $8,967 | $698 |
| 561 LOAD DISPATCHING | $842,754 | $304,828 | $84,511 | $2,478 | $5,951 | $170,605 | $69,708 | $1,119 | $8,505 | $662 |
| 562 STATION EXPENSES | $361,025 | $130,585 | $36,204 | $1,062 | $2,550 | $73,085 | $29,862 | $479 | $3,644 | $284 |
| 563 OVERHEAD LINE EXPENSES | $335,766 | $121,448 | $33,670 | $987 | $2,371 | $67,971 | $27,773 | $446 | $3,389 | $264 |
| 565 TRANSMISSION OF ELECTRICITY BY OTHERS | $4,617,906 | $1,670,320 | $463,082 | $13,580 | $32,611 | $934,836 | $381,968 | $6,130 | $46,605 | $3,628 |
| 566 MISC. TRANSMISSION EXPENSES | $4,624,059 | $1,672,545 | $463,699 | $13,599 | $32,655 | $936,082 | $382,477 | $6,138 | $46,667 | $3,633 |
| 567 RENTS | $88,823 | $32,128 | $8,907 | $261 | $627 | $17,981 | $7,347 | $118 | $896 | $70 |
| 568 MAINTENACE SUPERVISION AND ENG | $0 | | | | | | | | | |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|
| 569 STRUCTURES | $0 | | | | | | | | | |
| 570 MAINT OF STATION EQUIPMENT | $915,531 | $331,152 | $91,809 | $2,692 | $6,465 | $185,337 | $75,728 | $1,215 | $9,240 | $719 |
| 571 MAINT OF OVERHEAD LINES | $3,300,624 | $1,193,852 | $330,986 | $9,707 | $23,309 | $668,169 | $273,009 | $4,381 | $33,311 | $2,593 |
| 572 UNDERGROUND LINES | $0 | | | | | | | | | |
| 573 MISC PLANT | $175,179 | $63,363 | $17,567 | $515 | $1,237 | $35,463 | $14,490 | $233 | $1,768 | $138 |
| 575 MISO DAY 1&2 EXPENSE | $10,185 | $3,684 | $1,021 | $30 | $72 | $2,062 | $842 | $14 | $103 | $8 |
| Sub-total | $16,160,369 | $5,845,286 | $1,620,557 | $47,525 | $114,123 | $3,271,459 | $1,336,696 | $21,451 | $163,094 | $12,695 |
| **Distribution Expense - Operating** | | | | | | | | | | |
| 580 OPERATION SUPERVISION AND ENGI | $1,284,074 | $763,721 | $243,914 | $2,965 | $6,700 | $128,728 | $29,910 | $9 | $3,747 | $231 |
| 581 LOAD DISPATCHING | $610,159 | $310,797 | $64,022 | $3,585 | $6,427 | $98,180 | $38,560 | $0 | $4,285 | $308 |
| 582 STATION EXPENSES | $1,001,284 | $510,024 | $105,062 | $5,883 | $10,547 | $161,116 | $63,278 | $0 | $7,032 | $505 |
| 583 OVERHEAD LINE EXPENSES | $3,030,139 | $1,909,562 | $440,194 | $8,938 | $18,577 | $286,026 | $95,354 | $4 | $12,044 | $760 |
| 584 UNDERGROUND LINE EXPENSES | $72,494 | $42,055 | $10,426 | $279 | $572 | $8,628 | $2,991 | $0 | $377 | $24 |
| 585 STREET LIGHTING EXPENSE | $10,832 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 586 METER EXPENSES | $6,096,249 | $3,794,957 | $1,674,291 | $4,054 | $12,979 | $481,471 | $19,374 | $110 | $1,433 | $55 |
| 586 METER EXPENSES - LOAD MANAGEMENT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 587 CUSTOMER INSTALLATIONS EXPENSE | -$73,416 | -$42,053 | -$12,044 | -$152 | -$421 | -$7,553 | -$1,611 | $0 | -$248 | -$13 |
| 588 MISCELLANEOUS DISTRIBUTION EXP | $4,379,334 | $2,508,468 | $718,411 | $9,074 | $25,098 | $450,571 | $96,078 | $7 | $14,792 | $763 |
| 588 MISC DISTR EXP – MAPPIN | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 589 RENTS | $12,654 | $7,248 | $2,076 | $26 | $73 | $1,302 | $278 | $0 | $43 | $2 |
| 590 MAINTENANCE SUPERVISION AND EN | $6,387 | $3,978 | $919 | $20 | $40 | $621 | $209 | $0 | $26 | $2 |
| 591 STRUCTURES | $628 | $320 | $66 | $4 | $7 | $101 | $40 | $0 | $4 | $0 |
| 592 MAINTENANCE OF STATION EQUIPME | $856,534 | $436,293 | $89,873 | $5,032 | $9,023 | $137,824 | $54,130 | $0 | $6,016 | $432 |
| 593 MAINTENANCE OF OVERHEAD LINES | $20,706,877 | $13,049,259 | $3,008,125 | $61,079 | $126,952 | $1,954,598 | $651,615 | $25 | $82,302 | $5,196 |
| 594 MAINTENANCE OF UNDERGROUND LIN | $590,308 | $342,450 | $84,897 | $2,271 | $4,654 | $70,253 | $24,352 | $0 | $3,070 | $194 |
| 595 MAINTENANCE OF LINE TRANSFORME | $110,444 | $72,472 | $29,298 | $0 | $515 | $6,481 | $0 | $0 | $337 | $0 |
| 596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS | $55,955 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 597 MAINTENANCE OF METERS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 598 MISCELLANEOUS DISTRIBUTION EXPENSES | $7,695 | $4,407 | $1,262 | $16 | $44 | $792 | $169 | $0 | $26 | $1 |
| Sub-total | $38,758,632 | $23,713,959 | $6,460,794 | $103,073 | $221,788 | $3,779,138 | $1,074,727 | $155 | $135,286 | $8,461 |
| **Customer Accounts Expense** | | | | | | | | | | |
| 901 SUPERVISION/CUSTOMER ACCTS | $1,853,549 | $1,256,875 | $261,678 | $2,221 | $931 | $271,345 | $10,647 | $61 | $3,103 | $122 |
| 902 METER READING EXPENSES | $4,126,623 | $2,798,228 | $582,583 | $4,944 | $2,072 | $604,106 | $23,704 | $135 | $6,908 | $271 |
| 903 RECORDS AND COLLECTION | $11,300,549 | $7,662,805 | $1,595,373 | $13,539 | $5,675 | $1,654,312 | $64,911 | $371 | $18,917 | $742 |
| 904 UNCOLLECTIBLE ACCOUNTS | $3,133,404 | $2,124,734 | $442,363 | $3,754 | $1,574 | $458,706 | $17,999 | $103 | $5,245 | $206 |
| 905 MISC CUST ACCOUNTS | $227,523 | $154,282 | $32,121 | $273 | $114 | $33,308 | $1,307 | $7 | $381 | $15 |
| Sub-total | $20,641,648 | $13,996,924 | $2,914,117 | $24,730 | $10,366 | $3,021,777 | $118,567 | $678 | $34,554 | $1,355 |
| **Customer Service & Information Expense** | | | | | | | | | | |
| 907 SUPERVISION | $217,872 | $173,269 | $32,795 | $31 | $128 | $3,741 | $147 | $1 | $21 | $1 |
| 908 CUSTOMER ASSISTANCE EXPENSES | $4,733,193 | $3,764,216 | $712,455 | $665 | $2,788 | $81,265 | $3,189 | $18 | $465 | $18 |
| 908 CUSTOMER ASSISTANCE EXP-INCENTIVES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 909 INFORMATIONAL AND INSTRUCTIONA | $449,354 | $357,363 | $67,638 | $63 | $265 | $7,715 | $303 | $2 | $44 | $2 |
| 909 INFORM AND INSTRUC -LOAD MGMT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 910 MISCELLANEOUS CUSTOMER SERVICE | $785,960 | $625,059 | $118,305 | $110 | $463 | $13,494 | $529 | $3 | $77 | $3 |
| 911 DEMONSTRATION AND SELLING EXP | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 912 DEMONSTRATION AND SELLING EXP | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 913 ADVERTISING EXPENSES | $66,555 | $52,930 | $10,018 | $9 | $39 | $1,143 | $45 | $0 | $7 | $0 |
| 915 MDSE-JOBBING-CONTRACT | $0 | | | | | | | | | |
| 916 MISC SALES EXPENSE | $0 | | | | | | | | | |
| Sub-total | $6,252,934 | $4,972,836 | $941,211 | $879 | $3,683 | $107,358 | $4,212 | $24 | $614 | $24 |
| **General Expenses** | | | | | | | | | | |
| 920 ADMIN. & GEN. SALARIES- | $14,199,205 | $6,785,813 | $1,796,263 | $34,590 | $80,551 | $2,329,220 | $786,803 | $10,631 | $97,963 | $7,379 |
| 921 OFFICE SUPPLIES AND EXPENSES | $6,808,062 | $3,253,579 | $861,250 | $16,585 | $38,622 | $1,116,786 | $377,247 | $5,097 | $46,970 | $3,538 |
| 922 ADMINISTRATIVE EXPENSES TRANSFERRED | -$1,409,208 | -$673,462 | -$178,271 | -$3,433 | -$7,994 | -$231,165 | -$78,087 | -$1,055 | -$9,722 | -$732 |
| 923 OUTSIDE SERVICES EMPLOYED | $9,557,040 | $4,567,319 | $1,209,008 | $23,281 | $54,217 | $1,567,725 | $529,572 | $7,155 | $65,936 | $4,966 |
| 924 PROPERTY INSURANCE | $2,804,917 | $1,196,672 | $336,290 | $7,499 | $18,660 | $481,931 | $179,573 | $2,579 | $22,515 | $1,676 |
| 925 INJURIES AND DAMAGES - INSURAN | $1,723,528 | $823,676 | $218,034 | $4,199 | $9,778 | $282,725 | $95,504 | $1,290 | $11,891 | $896 |
| 926 EMPLOYEE BENEFITS | $20,838,595 | $9,958,784 | $2,636,175 | $50,763 | $118,216 | $3,418,337 | $1,154,703 | $15,601 | $143,770 | $10,829 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|
| 928 REGULATORY COMMISSION FEES | $529,026 | $225,700 | $63,427 | $1,414 | $3,519 | $90,896 | $33,869 | $486 | $4,246 | $316 |
| 929 DUPLICATE CHARGES | -$2,928 | -$1,399 | -$370 | -$7 | -$17 | -$480 | -$162 | -$2 | -$20 | -$2 |
| 930 MISCELLANEOUS GENERAL EXPENSES | $1,240,888 | $593,022 | $156,978 | $3,023 | $7,040 | $203,554 | $68,760 | $929 | $8,561 | $645 |
| 931 RENTS AND LEASES | $1,396,179 | $595,657 | $167,392 | $3,733 | $9,288 | $239,887 | $89,385 | $1,284 | $11,207 | $834 |
| 932 MAINTENANCE OF GENERAL PLANT | $0 | | | | | | | | | |
| 935 MAINTENANCE OF GENERAL PLANT | $5,618,834 | $2,397,183 | $673,660 | $15,023 | $37,380 | $965,409 | $359,723 | $5,167 | $45,102 | $3,358 |
| Sub-total | $63,304,138 | $29,722,545 | $7,939,837 | $156,669 | $369,260 | $10,464,824 | $3,596,889 | $49,163 | $448,418 | $33,703 |
| **TOTAL O & M EXPENSES** | **$789,501,237** | **$304,616,034** | **$83,213,642** | **$1,838,353** | **$5,300,606** | **$152,455,062** | **$60,694,046** | **$926,273** | **$7,353,603** | **$587,344** |
| **TOTAL O&M EXPENSE Less PURCHASED POWER** | **$632,258,594** | **$249,352,560** | **$67,753,145** | **$1,469,480** | **$4,182,774** | **$120,295,896** | **$47,384,462** | **$717,682** | **$5,750,178** | **$457,840** |
| **Depreciation Expense** | | | | | | | | | | |
| Steam Production | $41,922,608 | $15,163,616 | $4,203,986 | $123,287 | $296,055 | $8,486,694 | $3,467,607 | $55,647 | $423,091 | $32,934 |
| Hydraulic Production | $150,640 | $54,487 | $15,106 | $443 | $1,064 | $30,495 | $12,460 | $200 | $1,520 | $118 |
| Other Production | $14,711,364 | $5,321,174 | $1,475,251 | $43,264 | $103,891 | $2,978,127 | $1,216,843 | $19,528 | $148,470 | $11,557 |
| Transmission - Kentucky System Property | $12,173,047 | $4,403,052 | $1,220,709 | $35,799 | $85,965 | $2,464,277 | $1,006,887 | $16,158 | $122,853 | $9,563 |
| Transmission - Virginia Property | $216,042 | $78,144 | $21,665 | $635 | $1,526 | $43,735 | $17,870 | $287 | $2,180 | $170 |
| Distribution | $30,450,891 | $17,442,169 | $4,995,341 | $63,096 | $174,516 | $3,132,964 | $668,063 | $49 | $102,852 | $5,306 |
| General Plant | $4,599,109 | $1,962,135 | $551,402 | $12,296 | $30,596 | $790,204 | $294,439 | $4,229 | $36,917 | $2,748 |
| Intangible Plant | $5,512,422 | $2,351,784 | $660,902 | $14,738 | $36,672 | $947,126 | $352,910 | $5,069 | $44,248 | $3,294 |
| **TOTAL DEPRECIATION EXPENSES** | **$109,736,123** | **$46,776,559** | **$13,144,361** | **$293,559** | **$730,284** | **$18,873,622** | **$7,037,078** | **$101,167** | **$882,131** | **$65,691** |
| **Other Expenses** | | | | | | | | | | |
| Regulatory Credits and Accretion Expense | | | | | | | | | | |
| Production | -$255,036 | -$92,248 | -$25,575 | -$750 | -$1,801 | -$51,629 | -$21,095 | -$339 | -$2,574 | -$200 |
| Transmission | -$156 | -$56 | -$16 | $0 | -$1 | -$32 | -$13 | $0 | -$2 | $0 |
| Distribution | -$182 | -$104 | -$30 | $0 | -$1 | -$19 | -$4 | $0 | -$1 | $0 |
| Property Taxes & Other | $10,473,065 | $4,468,162 | $1,255,649 | $28,001 | $69,673 | $1,799,447 | $670,495 | $9,631 | $84,066 | $6,258 |
| Other Taxes | $6,763,965 | $2,885,735 | $810,953 | $18,084 | $44,998 | $1,162,162 | $433,035 | $6,220 | $54,294 | $4,042 |
| Gain on Disposition of Allowances | -$504,602 | -$208,908 | -$58,544 | -$1,367 | -$3,393 | -$89,744 | -$34,153 | -$504 | -$4,253 | -$320 |
| Interest | $56,236,895 | $23,282,406 | $6,524,588 | $152,402 | $378,140 | $10,001,833 | $3,806,259 | $56,181 | $473,946 | $35,705 |
| Other Expenses | $0 | | | | | | | | | |
| **Total Other Expenses** | $72,713,948 | $30,334,985 | $8,507,026 | $196,369 | $487,615 | $12,822,018 | $4,854,523 | $71,189 | $605,478 | $45,484 |
| **TOTAL EXPENSES** | $971,951,308 | $381,727,578 | $104,865,029 | $2,328,281 | $6,518,505 | $184,150,702 | $72,585,648 | $1,098,629 | $8,841,111 | $698,519 |
| **Calculation of Taxable Income and Allocation of Income Taxes:** | | | | | | | | | | |
| Total Operating Revenue | $1,154,156,041 | $434,201,182 | $141,196,389 | $3,110,064 | $7,940,212 | $226,074,364 | $86,951,352 | $1,370,360 | $9,536,117 | $765,874 |
| Operating Expenses | $915,714,413 | $358,445,172 | $98,340,441 | $2,175,879 | $6,140,365 | $174,148,869 | $68,779,389 | $1,042,448 | $8,367,165 | $662,814 |
| Interest Expense | $56,236,895 | $23,282,406 | $6,524,588 | $152,402 | $378,140 | $10,001,833 | $3,806,259 | $56,181 | $473,946 | $35,705 |
| **Taxable Income** | **$182,204,733** | **$52,473,604** | **$36,331,360** | **$781,783** | **$1,421,707** | **$41,923,662** | **$14,365,704** | **$271,731** | **$695,006** | **$67,355** |
| Income Taxes | | | | | | | | | | |
| State & Federal Income Taxes | $56,064,862 | $16,146,262 | $11,179,252 | $240,557 | $437,463 | $12,900,018 | $4,420,364 | $83,612 | $213,855 | $20,725 |

Kentucky Utilities
Electric Cost of Service Study
(Expenses)

| | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL |
|---|---|---|---|---|---|---|---|---|---|---|
| **O & M Expenses** | | | | | | | | | | |
| **Steam Production O&M** | | | | | | | | | | |
| 500 OPERATION SUPERVISION & ENGINEERING | $466,290 | $137,434 | $19,623 | $12,017 | $14,914 | $44,914 | $63,099 | $6,478 | $544 | $4,851 |
| 501 FUEL | $51,636,039 | $15,402,001 | $2,066,688 | $1,263,648 | $1,638,084 | $4,907,408 | $7,111,173 | $813,276 | $68,338 | $608,992 |
| 502 STEAM EXPENSES | $1,249,317 | $367,313 | $53,104 | $32,531 | $40,024 | $120,666 | $168,445 | $16,880 | $1,418 | $12,640 |
| 505 ELECTRIC EXPENSES | $676,410 | $198,872 | $28,752 | $17,613 | $21,670 | $65,331 | $91,200 | $9,139 | $768 | $6,844 |
| 506 MISC. STEAM POWER EXPENSES | $889,208 | $261,437 | $37,797 | $23,154 | $28,487 | $85,884 | $119,891 | $12,015 | $1,010 | $8,997 |
| 507 RENTS | $264,663 | $77,814 | $11,250 | $6,891 | $8,479 | $25,563 | $35,684 | $3,576 | $300 | $2,678 |
| 510 MAINTENANCE SUPERVISION & ENGINEERING | $667,679 | $198,766 | $26,950 | $16,483 | $21,210 | $63,596 | $91,687 | $10,312 | $866 | $7,722 |
| 511 MAINTENANCE OF STRUCTURES | $619,852 | $182,244 | $26,348 | $16,140 | $19,858 | $59,869 | $83,574 | $8,375 | $704 | $6,271 |
| 512 MAINTENANCE OF BOILER PLANT | $3,535,848 | $1,054,673 | $141,519 | $86,530 | $112,170 | $336,041 | $486,947 | $55,690 | $4,680 | $41,702 |
| 513 MAINTENANCE OF ELECTRIC PLANT | $1,347,127 | $401,821 | $53,918 | $32,967 | $42,736 | $128,029 | $185,523 | $21,217 | $1,783 | $15,888 |
| 514 MAINTENANCE OF MISC STEAM PLANT | $142,265 | $42,435 | $5,694 | $3,482 | $4,513 | $13,521 | $19,592 | $2,241 | $188 | $1,678 |
| Sub-total | $61,494,698 | $18,324,810 | $2,471,641 | $1,511,456 | $1,952,146 | $5,850,821 | $8,456,817 | $959,200 | $80,600 | $718,261 |
| **Hydraulic Production O&M** | | | | | | | | | | |
| 535 OPERATION SUPERVISION & ENGINEERING | $999 | $294 | $42 | $26 | $32 | $97 | $135 | $14 | $1 | $10 |
| 536 WATER FOR POWER | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 537 HYDRAULIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 538 ELECTRIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 539 MISC. HYDRAULIC POWER EXPENSES | $4,986 | $1,466 | $212 | $130 | $160 | $482 | $672 | $67 | $6 | $50 |
| 540 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 541 MAINTENANCE SUPERVISION & ENGINEERING | $14,782 | $4,389 | $603 | $369 | $470 | $1,412 | $2,022 | $222 | $19 | $166 |
| 542 MAINTENANCE OF STRUCTURES | $18,804 | $5,529 | $799 | $490 | $602 | $1,816 | $2,535 | $254 | $21 | $190 |
| 543 MAINT. OF RESERVES, DAMS, AND WATERWAYS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 544 MAINTENANCE OF ELECTRIC PLANT | $19,579 | $5,840 | $784 | $479 | $621 | $1,861 | $2,696 | $308 | $26 | $231 |
| 545 MAINTENANCE OF MISC HYDRAULIC PLANT | $783 | $234 | $31 | $19 | $25 | $74 | $108 | $12 | $1 | $9 |
| Sub-total | $59,932 | $17,751 | $2,472 | $1,513 | $1,911 | $5,742 | $8,169 | $878 | $74 | $657 |
| **Other Power Generation Operation Expense** | | | | | | | | | | |
| 546 OPERATION SUPERVISION & ENGINEERING | $13,708 | $4,030 | $583 | $357 | $439 | $1,324 | $1,848 | $185 | $16 | $139 |
| 547 FUEL | $7,201,074 | $2,147,937 | $288,217 | $176,226 | $228,444 | $684,379 | $991,712 | $113,418 | $9,530 | $84,929 |
| 548 GENERATION EXPENSE | $202,093 | $59,417 | $8,590 | $5,262 | $6,474 | $19,519 | $27,248 | $2,731 | $229 | $2,045 |
| 549 MISC OTHER POWER GENERATION | $15,788 | $4,642 | $671 | $411 | $506 | $1,525 | $2,129 | $213 | $18 | $160 |
| 550 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 551 MAINTENANCE SUPERVISION & ENGINEERING | $4,675 | $1,375 | $199 | $122 | $150 | $452 | $630 | $63 | $5 | $47 |
| 552 MAINTENANCE OF STRUCTURES | $19,931 | $5,860 | $847 | $519 | $639 | $1,925 | $2,687 | $269 | $23 | $202 |
| 553 MAINTENANCE OF GENERATING & ELEC PLANT | $320,319 | $94,177 | $13,616 | $8,341 | $10,262 | $30,938 | $43,188 | $4,328 | $364 | $3,241 |
| 554 MAINTENANCE OF MISC OTHER POWER GEN PLT | $34,223 | $10,062 | $1,455 | $891 | $1,096 | $3,305 | $4,614 | $462 | $39 | $346 |
| Sub-total | $7,811,811 | $2,327,500 | $314,177 | $192,129 | $248,011 | $743,367 | $1,074,057 | $121,670 | $10,224 | $91,108 |
| **Other Power Supply Expense** | | | | | | | | | | |
| 555 PURCHASED POWER | | | | | | | | | | |
| 'Demand | $2,080,749 | $611,764 | $88,445 | $54,180 | $66,661 | $200,970 | $280,546 | $28,114 | $2,362 | $21,052 |
| 'Energy | $20,401,072 | $6,085,233 | $816,535 | $499,260 | $647,197 | $1,938,886 | $2,809,579 | $321,320 | $27,000 | $240,609 |
| 555 PURCHASED POWER OPTIONS | | | | | | | | | | |
| 555 BROKERAGE FEES | | | | | | | | | | |
| 555 MISO TRANSMISSION EXPENSES | | | | | | | | | | |
| 556 SYSTEM CONTROL AND LOAD DISPATCH | $185,766 | $54,617 | $7,896 | $4,837 | $5,951 | $17,942 | $25,047 | $2,510 | $211 | $1,880 |
| 557 OTHER EXPENSES | $144,095 | $42,365 | $6,125 | $3,752 | $4,616 | $13,917 | $19,428 | $1,947 | $164 | $1,458 |
| Sub-total | $22,811,682 | $6,793,980 | $919,001 | $562,029 | $724,425 | $2,171,715 | $3,134,600 | $353,891 | $29,737 | $264,998 |
| **Transmission Expenses** | | | | | | | | | | |
| 560 OPERATION SUPERVISION AND ENG | $122,996 | $36,162 | $5,228 | $3,203 | $3,940 | $11,880 | $16,583 | $1,662 | $140 | $1,244 |
| 561 LOAD DISPATCHING | $116,661 | $34,300 | $4,959 | $3,038 | $3,737 | $11,268 | $15,729 | $1,576 | $132 | $1,180 |
| 562 STATION EXPENSES | $49,976 | $14,694 | $2,124 | $1,301 | $1,601 | $4,827 | $6,738 | $675 | $57 | $506 |
| 563 OVERHEAD LINE EXPENSES | $46,479 | $13,665 | $1,976 | $1,210 | $1,489 | $4,489 | $6,267 | $628 | $53 | $470 |
| 565 TRANSMISSION OF ELECTRICITY BY OTHERS | $639,248 | $187,946 | $27,172 | $16,645 | $20,480 | $61,742 | $86,189 | $8,637 | $726 | $6,468 |
| 566 MISC. TRANSMISSION EXPENSES | $640,100 | $188,197 | $27,208 | $16,667 | $20,507 | $61,824 | $86,304 | $8,649 | $727 | $6,476 |
| 567 RENTS | $12,296 | $3,615 | $523 | $320 | $394 | $1,188 | $1,658 | $166 | $14 | $124 |
| 568 MAINTENACE SUPERVISION AND ENG | | | | | | | | | | |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL |
|---|---|---|---|---|---|---|---|---|---|---|
| 569 STRUCTURES | | | | | | | | | | |
| 570 MAINT OF STATION EQUIPMENT | $126,735 | $37,262 | $5,387 | $3,300 | $4,060 | $12,241 | $17,088 | $1,712 | $144 | $1,282 |
| 571 MAINT OF OVERHEAD LINES | $456,899 | $134,334 | $19,421 | $11,897 | $14,638 | $44,130 | $61,603 | $6,173 | $519 | $4,623 |
| 572 UNDERGROUND LINES | | | | | | | | | | |
| 573 MISC PLANT | $24,250 | $7,130 | $1,031 | $631 | $777 | $2,342 | $3,270 | $328 | $28 | $245 |
| 575 MISO DAY 1&2 EXPENSE | $1,410 | $415 | $60 | $37 | $45 | $136 | $190 | $19 | $2 | $14 |
| Sub-total | $2,237,050 | $657,718 | $95,089 | $58,250 | $71,668 | $216,066 | $301,620 | $30,226 | $2,540 | $22,634 |
| **Distribution Expense - Operating** | | | | | | | | | | |
| 580 OPERATION SUPERVISION AND ENGI | $42,988 | $36 | $3,353 | $46 | $2,220 | $28 | $12,811 | $22,920 | $3,445 | $9,840 |
| 581 LOAD DISPATCHING | $58,285 | $0 | $4,379 | $0 | $3,004 | $0 | $17,439 | $298 | $25 | $223 |
| 582 STATION EXPENSES | $95,647 | $0 | $7,186 | $0 | $4,929 | $0 | $28,617 | $489 | $41 | $366 |
| 583 OVERHEAD LINE EXPENSES | $143,237 | $13 | $10,813 | $22 | $7,384 | $11 | $42,836 | $18,582 | $2,130 | $18,375 |
| 584 UNDERGROUND LINE EXPENSES | $4,509 | $0 | $339 | $0 | $232 | $0 | $1,349 | $243 | $27 | $237 |
| 585 STREET LIGHTING EXPENSE | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,815 | $1,317 | $1,091 |
| 586 METER EXPENSES | $2,207 | $445 | $1,664 | $549 | $165 | $335 | $43 | $48,782 | $0 | $53,336 |
| 586 METER EXPENSES - LOAD MANAGEMENT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 587 CUSTOMER INSTALLATIONS EXPENSE | -$2,406 | $0 | -$182 | -$1 | -$124 | $0 | -$719 | -$3,471 | -$643 | -$807 |
| 588 MISCELLANEOUS DISTRIBUTION EXP | $143,508 | $27 | $10,879 | $37 | $7,399 | $21 | $42,898 | $207,057 | $38,366 | $48,127 |
| 588 MISC DISTR EXP – MAPPIN | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 589 RENTS | $415 | $0 | $31 | $0 | $21 | $0 | $124 | $598 | $111 | $139 |
| 590 MAINTENANCE SUPERVISION AND EN | $314 | $0 | $24 | $0 | $16 | $0 | $94 | $47 | $6 | $38 |
| 591 STRUCTURES | $60 | $0 | $5 | $0 | $3 | $0 | $18 | $0 | $0 | $0 |
| 592 MAINTENANCE OF STATION EQUIPME | $81,820 | $0 | $6,147 | $0 | $4,217 | $0 | $24,480 | $418 | $35 | $313 |
| 593 MAINTENANCE OF OVERHEAD LINES | $978,831 | $88 | $73,895 | $151 | $50,457 | $76 | $292,723 | $126,981 | $14,556 | $125,566 |
| 594 MAINTENANCE OF UNDERGROUND LIN | $36,719 | $1 | $2,764 | $2 | $1,893 | $1 | $10,984 | $1,981 | $223 | $1,928 |
| 595 MAINTENANCE OF LINE TRANSFORME | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $458 | $52 | $452 |
| 596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $35,203 | $6,805 | $5,634 |
| 597 MAINTENANCE OF METERS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 598 MISCELLANEOUS DISTRIBUTION EXPENSES | $252 | $0 | $19 | $0 | $13 | $0 | $75 | $364 | $67 | $85 |
| Sub-total | $1,586,386 | $611 | $121,317 | $807 | $81,828 | $472 | $473,771 | $467,766 | $66,566 | $264,943 |
| **Customer Accounts Expense** | | | | | | | | | | |
| 901 SUPERVISION/CUSTOMER ACCTS | $2,373 | $426 | $913 | $304 | $183 | $426 | $61 | $17,844 | $2,291 | $7,374 |
| 902 METER READING EXPENSES | $5,283 | $948 | $2,032 | $677 | $406 | $948 | $135 | $39,727 | $5,100 | $16,417 |
| 903 RECORDS AND COLLECTION | $14,466 | $2,596 | $5,564 | $1,855 | $1,113 | $2,596 | $371 | $108,791 | $13,965 | $44,956 |
| 904 UNCOLLECTIBLE ACCOUNTS | $4,011 | $720 | $1,543 | $514 | $309 | $720 | $103 | $30,166 | $3,872 | $12,465 |
| 905 MISC CUST ACCOUNTS | $291 | $52 | $112 | $37 | $22 | $52 | $7 | $2,190 | $281 | $905 |
| Sub-total | $26,424 | $4,743 | $10,163 | $3,388 | $2,033 | $4,743 | $678 | $198,719 | $25,509 | $82,116 |
| **Customer Service & Information Expense** | | | | | | | | | | |
| 907 SUPERVISION | $16 | $3 | $13 | $4 | $1 | $3 | $0 | $3,280 | $421 | $1,355 |
| 908 CUSTOMER ASSISTANCE EXPENSES | $355 | $64 | $273 | $91 | $27 | $64 | $9 | $71,253 | $9,147 | $29,436 |
| 908 CUSTOMER ASSISTANCE EXP-INCENTIVES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 909 INFORMATIONAL AND INSTRUCTIONA | $34 | $6 | $26 | $9 | $3 | $6 | $1 | $6,765 | $868 | $2,795 |
| 909 INFORM AND INSTRUC -LOAD MGMT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 910 MISCELLANEOUS CUSTOMER SERVICE | $59 | $11 | $45 | $15 | $5 | $11 | $2 | $11,832 | $1,519 | $4,888 |
| 911 DEMONSTRATION AND SELLING EXP | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 912 DEMONSTRATION AND SELLING EXP | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 913 ADVERTISING EXPENSES | $5 | $1 | $4 | $1 | $0 | $1 | $0 | $1,002 | $129 | $414 |
| 915 MDSE-JOBBING-CONTRACT | | | | | | | | | | |
| 916 MISC SALES EXPENSE | | | | | | | | | | |
| Sub-total | $469 | $84 | $361 | $120 | $36 | $84 | $12 | $94,131 | $12,084 | $38,887 |
| **General Expenses** | | | | | | | | | | |
| 920 ADMIN. & GEN. SALARIES- | $1,280,983 | $330,284 | $59,869 | $28,793 | $44,213 | $107,565 | $200,403 | $97,632 | $13,122 | $49,918 |
| 921 OFFICE SUPPLIES AND EXPENSES | $614,190 | $158,361 | $28,705 | $13,805 | $21,199 | $51,574 | $96,087 | $46,811 | $6,292 | $23,934 |
| 922 ADMINISTRATIVE EXPENSES TRANSFERRED | -$127,132 | -$32,779 | -$5,942 | -$2,858 | -$4,388 | -$10,675 | -$19,889 | -$9,690 | -$1,302 | -$4,954 |
| 923 OUTSIDE SERVICES EMPLOYED | $862,189 | $222,304 | $40,296 | $19,379 | $29,758 | $72,399 | $134,885 | $65,713 | $8,832 | $33,598 |
| 924 PROPERTY INSURANCE | $297,122 | $79,050 | $13,571 | $7,008 | $10,071 | $25,971 | $44,700 | $44,424 | $7,864 | $12,201 |
| 925 INJURIES AND DAMAGES - INSURAN | $155,488 | $40,091 | $7,267 | $3,495 | $5,367 | $13,056 | $24,325 | $11,851 | $1,593 | $6,059 |
| 926 EMPLOYEE BENEFITS | $1,879,956 | $484,722 | $87,863 | $42,256 | $64,886 | $157,861 | $294,109 | $143,284 | $19,258 | $73,259 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL |
|---|---|---|---|---|---|---|---|---|---|---|
| 928 REGULATORY COMMISSION FEES | $56,039 | $14,909 | $2,560 | $1,322 | $1,899 | $4,898 | $8,431 | $8,379 | $1,483 | $2,301 |
| 929 DUPLICATE CHARGES | -$264 | -$68 | -$12 | -$6 | -$9 | -$22 | -$41 | -$20 | -$3 | -$10 |
| 930 MISCELLANEOUS GENERAL EXPENSES | $111,947 | $28,864 | $5,232 | $2,516 | $3,884 | $9,400 | $17,513 | $8,532 | $1,147 | $4,362 |
| 931 RENTS AND LEASES | $147,896 | $39,348 | $6,755 | $3,488 | $5,013 | $12,927 | $22,250 | $22,112 | $3,914 | $6,073 |
| 932 MAINTENANCE OF GENERAL PLANT | | | | | | | | | | |
| 935 MAINTENANCE OF GENERAL PLANT | $595,198 | $158,354 | $27,185 | $14,038 | $20,174 | $52,026 | $89,543 | $88,990 | $15,752 | $24,442 |
| Sub-total | $5,873,612 | $1,523,441 | $273,350 | $133,237 | $202,047 | $496,981 | $912,315 | $528,018 | $77,951 | $231,183 |
| **TOTAL O & M EXPENSES** | **$101,902,063** | **$29,650,637** | **$4,207,571** | **$2,462,928** | **$3,284,104** | **$9,489,990** | **$14,362,039** | **$2,754,499** | **$305,283** | **$1,714,789** |
| **TOTAL O&M EXPENSE Less PURCHASED POWER** | **$79,420,243** | **$22,953,640** | **$3,302,590** | **$1,909,488** | **$2,570,247** | **$7,350,135** | **$11,271,913** | **$2,405,065** | **$275,920** | **$1,453,128** |
| **Depreciation Expense** | | | | | | | | | | |
| Steam Production | $5,803,268 | $1,706,226 | $246,675 | $151,109 | $185,919 | $560,510 | $782,451 | $78,411 | $6,589 | $58,715 |
| Hydraulic Production | $20,853 | $6,131 | $886 | $543 | $668 | $2,014 | $2,812 | $282 | $24 | $211 |
| Other Production | $2,036,467 | $598,744 | $86,563 | $53,027 | $65,242 | $196,693 | $274,576 | $27,516 | $2,312 | $20,604 |
| Transmission - Kentucky System Property | $1,685,092 | $495,436 | $71,627 | $43,878 | $53,985 | $162,755 | $227,200 | $22,768 | $1,913 | $17,049 |
| Transmission - Virginia Property | $29,906 | $8,793 | $1,271 | $779 | $958 | $2,889 | $4,032 | $404 | $34 | $303 |
| Distribution | $997,853 | $189 | $75,642 | $259 | $51,448 | $148 | $298,281 | $1,439,730 | $266,770 | $334,640 |
| General Plant | $487,179 | $129,616 | $22,252 | $11,490 | $16,513 | $42,584 | $73,293 | $72,840 | $12,893 | $20,006 |
| Intangible Plant | $583,926 | $155,355 | $26,671 | $13,772 | $19,792 | $51,040 | $87,848 | $87,305 | $15,454 | $23,979 |
| **TOTAL DEPRECIATION EXPENSES** | **$11,644,544** | **$3,100,490** | **$531,586** | **$274,858** | **$394,525** | **$1,018,632** | **$1,750,492** | **$1,729,255** | **$305,989** | **$475,507** |
| **Other Expenses** | | | | | | | | | | |
| Regulatory Credits and Accretion Expense | | | | | | | | | | |
| Production | -$35,304 | -$10,380 | -$1,501 | -$919 | -$1,131 | -$3,410 | -$4,760 | -$477 | -$40 | -$357 |
| Transmission | -$22 | -$6 | -$1 | -$1 | -$1 | -$2 | -$3 | $0 | $0 | $0 |
| Distribution | -$6 | $0 | $0 | $0 | $0 | $0 | -$2 | -$9 | -$2 | -$2 |
| Property Taxes & Other | $1,109,402 | $295,160 | $50,672 | $26,166 | $37,603 | $96,972 | $166,902 | $165,870 | $29,361 | $45,558 |
| Other Taxes | $716,500 | $190,627 | $32,726 | $16,899 | $24,285 | $62,629 | $107,793 | $107,126 | $18,963 | $29,423 |
| Gain on Disposition of Allowances | -$56,676 | -$15,474 | -$2,541 | -$1,368 | -$1,895 | -$5,079 | -$8,314 | -$6,568 | -$1,144 | -$1,900 |
| Interest | $6,316,416 | $1,724,543 | $283,195 | $152,512 | $211,164 | $566,059 | $926,579 | $731,989 | $127,459 | $211,774 |
| Other Expenses | | | | | | | | | | |
| **Total Other Expenses** | **$8,050,311** | **$2,184,471** | **$362,549** | **$193,289** | **$270,026** | **$717,168** | **$1,188,195** | **$997,932** | **$174,597** | **$284,495** |
| **TOTAL EXPENSES** | **$121,595,918** | **$34,935,598** | **$5,101,706** | **$2,931,074** | **$3,948,655** | **$11,225,791** | **$17,300,725** | **$5,481,686** | **$785,869** | **$2,474,791** |
| **Calculation of Taxable Income and Allocation of Income Taxes:** | | | | | | | | | | |
| Total Operating Revenue | $135,173,608 | $35,809,536 | $6,896,875 | $3,993,096 | $4,916,425 | $13,992,126 | $23,247,719 | $7,371,816 | $1,376,780 | $4,131,161 |
| Operating Expenses | $115,280,501 | $33,211,055 | $4,818,511 | $2,778,562 | $3,737,490 | $10,659,732 | $16,374,146 | $4,749,697 | $658,410 | $2,263,017 |
| Interest Expense | $6,316,416 | $1,724,543 | $283,195 | $152,512 | $211,164 | $566,059 | $926,579 | $731,989 | $127,459 | $211,774 |
| **Taxable Income** | **$13,576,691** | **$873,938** | **$1,795,169** | **$1,062,022** | **$967,771** | **$2,766,335** | **$5,946,994** | **$1,890,130** | **$590,911** | **$1,656,370** |
| Income Taxes | | | | | | | | | | |
| State & Federal Income Taxes | $4,177,582 | $268,913 | $552,378 | $326,787 | $297,786 | $851,208 | $1,829,905 | $581,598 | $181,825 | $509,669 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | | OL |
|---|---|---|
| **O & M Expenses** | | |
| | **Steam Production O&M** | |
| 500 | OPERATION SUPERVISION & ENGINEERING | $7,421 |
| 501 | FUEL | $931,581 |
| 502 | STEAM EXPENSES | $19,336 |
| 505 | ELECTRIC EXPENSES | $10,469 |
| 506 | MISC. STEAM POWER EXPENSES | $13,762 |
| 507 | RENTS | $4,096 |
| 510 | MAINTENANCE SUPERVISION & ENGINEERING | $11,812 |
| 511 | MAINTENANCE OF STRUCTURES | $9,593 |
| 512 | MAINTENANCE OF BOILER PLANT | $53,791 |
| 513 | MAINTENANCE OF ELECTRIC PLANT | $24,304 |
| 514 | MAINTENANCE OF MISC STEAM PLANT | $2,567 |
| | Sub-total | $1,098,731 |
| | **Hydraulic Production O&M** | |
| 535 | OPERATION SUPERVISION & ENGINEERING | $15 |
| 536 | WATER FOR POWER | $0 |
| 537 | HYDRAULIC EXPENSES | $0 |
| 538 | ELECTRIC EXPENSES | $0 |
| 539 | MISC. HYDRAULIC POWER EXPENSES | $77 |
| 540 | RENTS | $0 |
| 541 | MAINTENANCE SUPERVISION & ENGINEERING | $255 |
| 542 | MAINTENANCE OF STRUCTURES | $291 |
| 543 | MAINT. OF RESERVES, DAMS, AND WATERWAYS | $0 |
| 544 | MAINTENANCE OF ELECTRIC PLANT | $353 |
| 545 | MAINTENANCE OF MISC HYDRAULIC PLANT | $14 |
| | Sub-total | $1,006 |
| | **Other Power Generation Operation Expense** | |
| 546 | OPERATION SUPERVISION & ENGINEERING | $212 |
| 547 | FUEL | $129,917 |
| 548 | GENERATION EXPENSE | $3,128 |
| 549 | MISC OTHER POWER GENERATION | $244 |
| 550 | RENTS | $0 |
| 551 | MAINTENANCE SUPERVISION & ENGINEERING | $72 |
| 552 | MAINTENANCE OF STRUCTURES | $308 |
| 553 | MAINTENANCE OF GENERATING & ELEC PLANT | $4,958 |
| 554 | MAINTENANCE OF MISC OTHER POWER GEN PLT | $530 |
| | Sub-total | $139,369 |
| | **Other Power Supply Expense** | |
| 555 | PURCHASED POWER | |
| | 'Demand | $32,204 |
| | 'Energy | $368,062 |
| 555 | PURCHASED POWER OPTIONS | |
| 555 | BROKERAGE FEES | |
| 555 | MISO TRANSMISSION EXPENSES | |
| 556 | SYSTEM CONTROL AND LOAD DISPATCH | $2,875 |
| 557 | OTHER EXPENSES | $2,230 |
| | Sub-total | $405,371 |
| **Transmission Expenses** | | |
| 560 | OPERATION SUPERVISION AND ENG | $1,904 |
| 561 | LOAD DISPATCHING | $1,806 |
| 562 | STATION EXPENSES | $773 |
| 563 | OVERHEAD LINE EXPENSES | $719 |
| 565 | TRANSMISSION OF ELECTRICITY BY OTHERS | $9,894 |
| 566 | MISC. TRANSMISSION EXPENSES | $9,907 |
| 567 | RENTS | $190 |
| 568 | MAINTENACE SUPERVISION AND ENG | |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | | OL |
|---|---|---|
| 569 | STRUCTURES | |
| 570 | MAINT OF STATION EQUIPMENT | $1,961 |
| 571 | MAINT OF OVERHEAD LINES | $7,071 |
| 572 | UNDERGROUND LINES | |
| 573 | MISC PLANT | $375 |
| 575 | MISO DAY 1&2 EXPENSE | $22 |
| | Sub-total | $34,623 |
| | **Distribution Expense - Operating** | |
| 580 | OPERATION SUPERVISION AND ENGI | $6,462 |
| 581 | LOAD DISPATCHING | $341 |
| 582 | STATION EXPENSES | $560 |
| 583 | OVERHEAD LINE EXPENSES | $15,278 |
| 584 | UNDERGROUND LINE EXPENSES | $205 |
| 585 | STREET LIGHTING EXPENSE | $1,609 |
| 586 | METER EXPENSES | $0 |
| 586 | METER EXPENSES - LOAD MANAGEMENT | $0 |
| 587 | CUSTOMER INSTALLATIONS EXPENSE | -$968 |
| 588 | MISCELLANEOUS DISTRIBUTION EXP | $57,753 |
| 588 | MISC DISTR EXP -- MAPPIN | $0 |
| 589 | RENTS | $167 |
| 590 | MAINTENANCE SUPERVISION AND EN | $33 |
| 591 | STRUCTURES | $0 |
| 592 | MAINTENANCE OF STATION EQUIPME | $479 |
| 593 | MAINTENANCE OF OVERHEAD LINES | $104,402 |
| 594 | MAINTENANCE OF UNDERGROUND LIN | $1,670 |
| 595 | MAINTENANCE OF LINE TRANSFORME | $377 |
| 596 | MAINTENANCE OF ST LIGHTS & SIG SYSTEMS | $8,313 |
| 597 | MAINTENANCE OF METERS | $0 |
| 598 | MISCELLANEOUS DISTRIBUTION EXPENSES | $101 |
| | Sub-total | $196,784 |
| | **Customer Accounts Expense** | |
| 901 | SUPERVISION/CUSTOMER ACCTS | $14,373 |
| 902 | METER READING EXPENSES | $32,000 |
| 903 | RECORDS AND COLLECTION | $87,630 |
| 904 | UNCOLLECTIBLE ACCOUNTS | $24,298 |
| 905 | MISC CUST ACCOUNTS | $1,764 |
| | Sub-total | $160,066 |
| | **Customer Service & Information Expense** | |
| 907 | SUPERVISION | $2,642 |
| 908 | CUSTOMER ASSISTANCE EXPENSES | $57,396 |
| 908 | CUSTOMER ASSISTANCE EXP-INCENTIVES | $0 |
| 909 | INFORMATIONAL AND INSTRUCTIONA | $5,449 |
| 909 | INFORM AND INSTRUC -LOAD MGMT | $0 |
| 910 | MISCELLANEOUS CUSTOMER SERVICE | $9,531 |
| 911 | DEMONSTRATION AND SELLING EXP | $0 |
| 912 | DEMONSTRATION AND SELLING EXP | $0 |
| 913 | ADVERTISING EXPENSES | $807 |
| 915 | MDSE-JOBBING-CONTRACT | |
| 916 | MISC SALES EXPENSE | |
| | Sub-total | $75,825 |
| | **General Expenses** | |
| 920 | ADMIN. & GEN. SALARIES- | $57,211 |
| 921 | OFFICE SUPPLIES AND EXPENSES | $27,431 |
| 922 | ADMINISTRATIVE EXPENSES TRANSFERRED | -$5,678 |
| 923 | OUTSIDE SERVICES EMPLOYED | $38,507 |
| 924 | PROPERTY INSURANCE | $15,539 |
| 925 | INJURIES AND DAMAGES - INSURAN | $6,944 |
| 926 | EMPLOYEE BENEFITS | $83,962 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Expenses)**

| | | OL |
|---|---|---|
| 928 | REGULATORY COMMISSION FEES | $2,931 |
| 929 | DUPLICATE CHARGES | -$12 |
| 930 | MISCELLANEOUS GENERAL EXPENSES | $5,000 |
| 931 | RENTS AND LEASES | $7,735 |
| 932 | MAINTENANCE OF GENERAL PLANT | |
| 935 | MAINTENANCE OF GENERAL PLANT | $31,127 |
| | Sub-total | $270,696 |
| | **TOTAL O & M EXPENSES** | **$2,382,470** |
| | **TOTAL O&M EXPENSE Less PURCHASED POWER** | **$1,982,205** |
| | **Depreciation Expense** | |
| | Steam Production | $89,817 |
| | Hydraulic Production | $323 |
| | Other Production | $31,518 |
| | Transmission - Kentucky System Property | $26,080 |
| | Transmission - Virginia Property | $463 |
| | Distribution | $401,577 |
| | General Plant | $25,478 |
| | Intangible Plant | $30,538 |
| | **TOTAL DEPRECIATION EXPENSES** | **$605,794** |
| | **Other Expenses** | |
| | Regulatory Credits and Accretion Expense | |
| | Production | -$546 |
| | Transmission | $0 |
| | Distribution | -$2 |
| | Property Taxes & Other | $58,019 |
| | Other Taxes | $37,471 |
| | Gain on Disposition of Allowances | -$2,456 |
| | Interest | $273,744 |
| | Other Expenses | |
| | **Total Other Expenses** | $366,228 |
| **TOTAL EXPENSES** | | $3,354,492 |

**Calculation of Taxable Income and Allocation of Income Taxes:**

| | |
|---|---|
| Total Operating Revenue | $6,100,984 |
| Operating Expenses | $3,080,749 |
| Interest Expense | $273,744 |
| **Taxable Income** | **$2,746,492** |
| Income Taxes | |
| State & Federal Income Taxes | $845,103 |

Kentucky Utilities
Electric Cost of Service Study
(Salaries and Wages)

| | | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP | LCIP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | **Labor O & M Expenses** | | | | | | | | | | | |
| 6 | | | | | | | | | | | | |
| 7 | **Labor Expenses** | | | | | | | | | | | |
| 8 | | | | | | | | | | | | |
| 9 | **Steam Power Generation Operation Expenses** | | | | | | | | | | | |
| | 500 OPERATION SUPERVISION & ENGINEERING | $2,086,714 | $750,856 | $208,507 | $5,909 | $14,754 | $423,224 | $173,339 | $2,770 | $21,099 | $1,654 | $290,598 |
| 10 | 501 FUEL | $1,737,173 | $608,653 | $170,444 | $3,966 | $12,358 | $355,666 | $147,395 | $2,304 | $17,732 | $1,438 | $249,208 |
| 1 | 502 STEAM EXPENSES | $5,091,499 | $1,841,620 | $510,574 | $14,973 | $35,956 | $1,030,709 | $421,141 | $6,758 | $51,384 | $4,000 | $704,807 |
| 2 | 505 ELECTRIC EXPENSES | $3,433,990 | $1,242,091 | $344,359 | $10,099 | $24,251 | $695,167 | $284,041 | $4,558 | $34,657 | $2,698 | $475,361 |
| | 506 MISC. STEAM POWER EXPENSES | $222,596 | $80,514 | $22,322 | $655 | $1,572 | $45,062 | $18,412 | $295 | $2,246 | $175 | $30,813 |
| 3 | 507 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | | | | | | | | | | | | |
| | Total Steam Power Operation Expenses | $12,571,972 | $4,523,735 | $1,256,206 | $35,602 | $88,891 | $2,549,830 | $1,044,327 | $16,686 | $127,119 | $9,964 | $1,750,787 |
| 5 | | | | | | | | | | | | |
| 6 | **Steam Power Generation Maintenance Expenses** | | | | | | | | | | | |
| 7 | 510 MAINTENANCE SUPERVISION & ENGINEERING | $3,205,656 | $1,128,288 | $315,503 | $7,616 | $22,781 | $655,284 | $271,028 | $4,253 | $32,670 | $2,634 | $457,599 |
| 8 | 511 MAINTENANCE OF STRUCTURES | $787,400 | $284,807 | $78,960 | $2,316 | $5,561 | $159,399 | $65,129 | $1,045 | $7,947 | $619 | $108,998 |
| | 512 MAINTENANCE OF BOILER PLANT | $3,487,689 | $1,221,981 | $342,197 | $7,962 | $24,811 | $714,068 | $295,922 | $4,626 | $35,601 | $2,886 | $500,330 |
| 9 | 513 MAINTENANCE OF ELECTRIC PLANT | $1,206,726 | $422,800 | $118,399 | $2,755 | $8,585 | $247,064 | $102,388 | $1,601 | $12,318 | $999 | $173,112 |
| 10 | 514 MAINTENANCE OF MISC STEAM PLANT | $103,934 | $36,415 | $10,198 | $237 | $739 | $21,279 | $8,819 | $138 | $1,061 | $86 | $14,910 |
| | Total Steam Power Generation Maintenance Expense | $8,791,406 | $3,094,291 | $865,257 | $20,886 | $62,477 | $1,797,094 | $743,285 | $11,663 | $89,596 | $7,224 | $1,254,949 |
| 11 | Total Steam Power Generation Expense | $21,363,377 | $7,618,026 | $2,121,462 | $56,488 | $151,368 | $4,346,924 | $1,787,612 | $28,349 | $216,715 | $17,188 | $3,005,736 |
| 12 | | | | | | | | | | | | |
| | **Hydraulic Power Generation Operation Expenses** | | | | | | | | | | | |
| 13 | 535 OPERATION SUPERVISION & ENGINEERING | $5,529 | $2,000 | $554 | $16 | $39 | $1,119 | $457 | $7 | $56 | $4 | $765 |
| 14 | 536 WATER FOR POWER | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 537 HYDRAULIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 538 ELECTRIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15 | 539 MISC. HYDRAULIC POWER EXPENSES | $2,262 | $818 | $227 | $7 | $16 | $458 | $187 | $3 | $23 | $2 | $313 |
| | 540 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Total Hydraulic Power Operation Expenses | $7,791 | $2,818 | $781 | $23 | $55 | $1,577 | $644 | $10 | $79 | $6 | $1,078 |
| 16 | | | | | | | | | | | | |
| | **Hydraulic Power Generation Maintenance Expenses** | | | | | | | | | | | |
| 18 | 541 MAINTENANCE SUPERVISION & ENGINEERING | $61,207 | $21,672 | $6,049 | $153 | $434 | $12,486 | $5,151 | $81 | $622 | $50 | $8,680 |
| 19 | 542 MAINTENANCE OF STRUCTURES | $29,661 | $10,729 | $2,974 | $87 | $209 | $6,005 | $2,453 | $39 | $299 | $23 | $4,106 |
| 20 | 543 MAINT. OF RESERVES, DAMS, AND WATERWAYS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 544 MAINTENANCE OF ELECTRIC PLANT | $58,637 | $20,545 | $5,753 | $134 | $417 | $12,005 | $4,975 | $78 | $599 | $49 | $8,412 |
| | 545 MAINTENANCE OF MISC HYDRAULIC PLANT | $2,568 | $900 | $252 | $6 | $18 | $526 | $218 | $3 | $26 | $2 | $368 |
| | Total Hydraulic Power Generation Maint. Expense | $152,074 | $53,845 | $15,028 | $380 | $1,079 | $31,021 | $12,797 | $202 | $1,547 | $124 | $21,566 |
| | Total Hydraulic Power Generation Expense | $159,865 | $56,663 | $15,810 | $403 | $1,134 | $32,598 | $13,442 | $212 | $1,625 | $130 | $22,645 |
| | **Other Power Generation Operation Expense** | | | | | | | | | | | |
| | 546 OPERATION SUPERVISION & ENGINEERING | $68,700 | $24,849 | $6,889 | $202 | $485 | $13,907 | $5,683 | $91 | $693 | $54 | $9,510 |
| | 547 FUEL | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 548 GENERATION EXPENSE | $315,655 | $114,174 | $31,654 | $928 | $2,229 | $63,900 | $26,109 | $419 | $3,186 | $248 | $43,696 |
| | 549 MISC OTHER POWER GENERATION | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 550 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Total Other Power Generation Expenses | $384,355 | $139,023 | $38,543 | $1,130 | $2,714 | $77,808 | $31,792 | $510 | $3,879 | $302 | $53,206 |
| | **Other Power Generation Maintenance Expense** | | | | | | | | | | | |
| | 551 MAINTENANCE SUPERVISION & ENGINEERING | $23,508 | $8,503 | $2,357 | $69 | $166 | $4,759 | $1,944 | $31 | $237 | $18 | $3,254 |

**Kentucky Utilities**
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| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP | LCIP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 552 MAINTENANCE OF STRUCTURES | $68,736 | $24,862 | $6,893 | $202 | $485 | $13,915 | $5,685 | $91 | $694 | $54 | $9,515 |
| 553 MAINTENANCE OF GENERATING & ELEC PLANT | $299,702 | $108,404 | $30,054 | $881 | $2,116 | $60,671 | $24,790 | $398 | $3,025 | $235 | $41,487 |
| 554 MAINTENANCE OF MISC OTHER POWER GEN PLT | $64,527 | $23,340 | $6,471 | $190 | $456 | $13,063 | $5,337 | $86 | $651 | $51 | $8,932 |
| Total Other Power Generation Maintenance Expense | $456,473 | $165,108 | $45,775 | $1,342 | $3,224 | $92,407 | $37,757 | $606 | $4,607 | $359 | $63,189 |
| Total Other Power Generation Expense | $840,828 | $304,132 | $84,318 | $2,473 | $5,938 | $170,215 | $69,549 | $1,116 | $8,486 | $661 | $116,394 |
| Total Production Expense | $22,364,070 | $7,978,821 | $2,221,590 | $59,363 | $158,440 | $4,549,737 | $1,870,603 | $29,677 | $226,826 | $17,978 | $3,144,775 |
| **Purchased Power** | | | | | | | | | | | |
| 555 PURCHASED POWER | $0 | | | | | | | | | | |
| 556 SYSTEM CONTROL AND LOAD DISPATCH | $940,689 | $340,252 | $94,332 | $2,766 | $6,643 | $190,430 | $77,809 | $1,249 | $9,494 | $739 | $130,218 |
| 557 OTHER EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Purchased Power Labor | $940,689 | $340,252 | $94,332 | $2,766 | $6,643 | $190,430 | $77,809 | $1,249 | $9,494 | $739 | $130,218 |
| **Transmission Labor Expenses** | | | | | | | | | | | |
| 560 OPERATION SUPERVISION AND ENG | $576,280 | $208,443 | $57,789 | $1,695 | $4,070 | $116,660 | $47,667 | $765 | $5,816 | $453 | $79,773 |
| 561 LOAD DISPATCHING | $636,176 | $230,108 | $63,796 | $1,871 | $4,493 | $128,786 | $52,621 | $844 | $6,420 | $500 | $88,065 |
| 562 STATION EXPENSES | $145,235 | $52,532 | $14,564 | $427 | $1,026 | $29,401 | $12,013 | $193 | $1,466 | $114 | $20,105 |
| 563 OVERHEAD LINE EXPENSES | $26,006 | $9,406 | $2,608 | $76 | $184 | $5,265 | $2,151 | $35 | $262 | $20 | $3,600 |
| 566 MISC. TRANSMISSION EXPENSES | $163,103 | $58,995 | $16,356 | $480 | $1,152 | $33,018 | $13,491 | $216 | $1,646 | $128 | $22,578 |
| 568 MAINTENACE SUPERVISION AND ENG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 570 MAINT OF STATION EQUIPMENT | $331,101 | $119,761 | $33,203 | $974 | $2,338 | $67,027 | $27,387 | $439 | $3,342 | $260 | $45,834 |
| 571 MAINT OF OVERHEAD LINES | $74,028 | $26,776 | $7,423 | $218 | $523 | $14,986 | $6,123 | $98 | $747 | $58 | $10,247 |
| 572 UNDERGROUND LINES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 573 MISC PLANT | $44,250 | $16,005 | $4,437 | $130 | $312 | $8,958 | $3,660 | $59 | $447 | $35 | $6,125 |
| Total Transmission Labor Expenses | $1,996,178 | $722,028 | $200,176 | $5,870 | $14,097 | $404,101 | $165,113 | $2,650 | $20,146 | $1,568 | $276,327 |
| **Distribution Operation Labor Expense** | | | | | | | | | | | |
| 580 OPERATION SUPERVISION AND ENGI | $797,280 | $474,193 | $151,446 | $1,841 | $4,160 | $79,927 | $18,571 | $6 | $2,327 | $143 | $26,691 |
| 581 LOAD DISPATCHING | $476,728 | $242,831 | $50,022 | $2,801 | $5,022 | $76,710 | $30,128 | $0 | $3,348 | $240 | $45,539 |
| 582 STATION EXPENSES | $467,882 | $238,325 | $49,093 | $2,749 | $4,929 | $75,286 | $29,569 | $0 | $3,286 | $236 | $44,694 |
| 583 OVERHEAD LINE EXPENSES | $1,687,045 | $1,063,158 | $245,080 | $4,976 | $10,343 | $159,246 | $53,089 | $2 | $6,705 | $423 | $79,748 |
| 584 UNDERGROUND LINE EXPENSES | $40,998 | $23,784 | $5,896 | $158 | $323 | $4,879 | $1,691 | $0 | $213 | $13 | $2,550 |
| 585 STREET LIGHTING EXPENSE | $6,061 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 586 METER EXPENSES | $2,458,791 | $1,530,614 | $675,289 | $1,635 | $5,235 | $194,191 | $7,814 | $44 | $578 | $22 | $890 |
| 586 METER EXPENSES - LOAD MANAGEMENT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 587 CUSTOMER INSTALLATIONS EXPENSE | $2,638 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 588 MISCELLANEOUS DISTRIBUTION EXP | $1,891,059 | $1,083,192 | $310,220 | $3,918 | $10,838 | $194,563 | $41,488 | $3 | $6,387 | $330 | $61,969 |
| 589 RENTS | $0 | | | | | | | | | | |
| Total Distribution Operation Labor Expense | $7,828,482 | $4,656,098 | $1,487,047 | $18,078 | $40,850 | $784,803 | $182,350 | $55 | $22,845 | $1,408 | $262,082 |
| **Distribution Maintenance Labor Expense** | | | | | | | | | | | |
| 590 MAINTENANCE SUPERVISION AND EN | $4,720 | $2,939 | $679 | $14 | $30 | $459 | $154 | $0 | $19 | $1 | $232 |
| 591 MAINTENANCE OF STRUCTURES | $348 | $177 | $37 | $2 | $4 | $56 | $22 | $0 | $2 | $0 | $33 |
| 592 MAINTENANCE OF STATION EQUIPME | $310,795 | $158,310 | $32,611 | $1,826 | $3,274 | $50,010 | $19,641 | $0 | $2,183 | $157 | $29,689 |
| 593 MAINTENANCE OF OVERHEAD LINES | $4,678,164 | $2,948,131 | $679,605 | $13,799 | $28,681 | $441,589 | $147,215 | $6 | $18,594 | $1,174 | $221,141 |
| 594 MAINTENANCE OF UNDERGROUND LIN | $105,012 | $60,920 | $15,103 | $404 | $828 | $12,498 | $4,332 | $0 | $546 | $35 | $6,532 |
| 595 MAINTENANCE OF LINE TRANSFORME | $42,160 | $27,665 | $11,184 | $0 | $197 | $2,474 | $0 | $0 | $129 | $0 | $0 |
| 596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS | $36,321 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| SW. 597 MAINTENANCE OF METERS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 598 MAINTENANCE OF MISC DISTR PLANT | $56 | $32 | $9 | $0 | $0 | $6 | $1 | $0 | $0 | $0 | $2 |

**Kentucky Utilities**
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| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP | LCIP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SWP Total Distribution Maintenance Labor Expense | $5,177,577 | $3,198,174 | $739,228 | $16,046 | $33,014 | $507,091 | $171,366 | $6 | $21,474 | $1,367 | $257,628 |
| Total Distribution Operation and Maintenance Labor Expenses | $13,006,059 | $7,854,272 | $2,226,275 | $34,124 | $73,863 | $1,291,894 | $353,716 | $61 | $44,318 | $2,775 | $519,710 |
| Transmission and Distribution Labor Expenses | $15,002,237 | $8,576,300 | $2,426,451 | $39,994 | $87,960 | $1,695,995 | $518,828 | $2,710 | $64,464 | $4,343 | $796,037 |
| Production, Transmission and Distribution Labor Expenses | $38,306,996 | $16,895,373 | $4,742,373 | $102,124 | $253,043 | $6,436,163 | $2,467,240 | $33,636 | $300,783 | $23,060 | $4,071,030 |
| **Customer Accounts Expense** | | | | | | | | | | | |
| 901 SUPERVISION/CUSTOMER ACCTS | $1,329,439 | $901,481 | $187,686 | $1,593 | $668 | $194,620 | $7,636 | $44 | $2,225 | $87 | $1,702 |
| 902 METER READING EXPENSES | $484,456 | $328,505 | $68,394 | $580 | $243 | $70,921 | $2,783 | $16 | $811 | $32 | $620 |
| 903 RECORDS AND COLLECTION | $4,753,471 | $3,223,288 | $671,079 | $5,695 | $2,387 | $695,871 | $27,304 | $156 | $7,957 | $312 | $6,085 |
| 904 UNCOLLECTIBLE ACCOUNTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 905 MISC CUST ACCOUNTS | $111,733 | $75,765 | $15,774 | $134 | $56 | $16,357 | $642 | $4 | $187 | $7 | $143 |
| Total Customer Accounts Labor Expense | $6,679,098 | $4,529,039 | $942,932 | $8,002 | $3,354 | $977,768 | $38,365 | $219 | $11,181 | $438 | $8,550 |
| **Customer Service Expense** | | | | | | | | | | | |
| 907 SUPERVISION | $107,651 | $85,613 | $16,204 | $15 | $63 | $1,848 | $73 | $0 | $11 | $0 | $8 |
| 908 CUSTOMER ASSISTANCE EXPENSES | $106,916 | $85,028 | $16,093 | $15 | $63 | $1,836 | $72 | $0 | $10 | $0 | $8 |
| 908 CUSTOMER ASSISTANCE EXP-LOAD MGMT | $0 | | | | | | | | | | |
| 909 INFORMATIONAL AND INSTRUCTIONA | $0 | | | | | | | | | | |
| 909 INFORM AND INSTRUC -LOAD MGMT | $0 | | | | | | | | | | |
| 910 MISCELLANEOUS CUSTOMER SERVICE | $20,122 | $16,003 | $3,029 | $3 | $12 | $345 | $14 | $0 | $2 | $0 | $2 |
| 911 DEMONSTRATION AND SELLING EXP | $0 | | | | | | | | | | |
| 912 DEMONSTRATION AND SELLING EXP | $0 | | | | | | | | | | |
| 913 WATER HEATER - HEAT PUMP PROGRAM | $0 | | | | | | | | | | |
| 915 MDSE-JOBBING-CONTRACT | $0 | | | | | | | | | | |
| 916 MISC SALES EXPENSE | $0 | | | | | | | | | | |
| Total Customer Service Labor Expense | $234,689 | $186,644 | $35,326 | $33 | $138 | $4,029 | $158 | $1 | $23 | $1 | $18 |
| Sub-Total Labor Exp | $45,220,783 | $21,611,056 | $5,720,631 | $110,159 | $256,536 | $7,417,960 | $2,505,763 | $33,856 | $311,987 | $23,500 | $4,079,597 |
| **Administrative and General Expense** | | | | | | | | | | | |
| 920 ADMIN. & GEN. SALARIES- | $10,799,153 | $5,160,925 | $1,366,141 | $26,307 | $61,263 | $1,771,479 | $598,400 | $8,085 | $74,505 | $5,612 | $974,247 |
| 921 OFFICE SUPPLIES AND EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 922 ADMIN. EXPENSES TRANSFERRED - CREDIT | -$933,756 | -$446,243 | -$118,124 | -$2,275 | -$5,297 | -$153,172 | -$51,741 | -$699 | -$6,442 | -$485 | -$84,239 |
| 923 OUTSIDE SERVICES EMPLOYED | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 924 PROPERTY INSURANCE | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 925 INJURIES AND DAMAGES - INSURAN | $79,180 | $37,840 | $10,017 | $193 | $449 | $12,989 | $4,388 | $59 | $546 | $41 | $7,143 |
| 926 EMPLOYEE BENEFITS | $0 | | | | | | | | | | |
| 928 REGULATORY COMMISSION FEES | $0 | | | | | | | | | | |
| 929 DUPLICATE CHARGES-CR | $0 | | | | | | | | | | |
| 930 MISCELLANEOUS GENERAL EXPENSES | $0 | | | | | | | | | | |
| 931 RENTS AND LEASES | $0 | | | | | | | | | | |
| 932 MAINTENANCE OF GENERAL PLANT | $0 | | | | | | | | | | |
| 935 MAINTENANCE OF GENERAL PLANT | $0 | | | | | | | | | | |
| Total Administrative and General Expense | $9,944,577 | $4,752,523 | $1,258,033 | $24,225 | $56,415 | $1,631,296 | $551,046 | $7,445 | $68,610 | $5,168 | $897,151 |
| Total Operation and Maintenance Expenses | $55,165,360 | $26,363,578 | $6,978,665 | $134,384 | $312,951 | $9,049,256 | $3,056,810 | $41,301 | $380,597 | $28,668 | $4,976,748 |
| Operation and Maintenance Expenses Less Purchase Power | $55,165,360 | $26,363,578 | $6,978,665 | $134,384 | $312,951 | $9,049,256 | $3,056,810 | $41,301 | $380,597 | $28,668 | $4,976,748 |

**Kentucky Utilities**
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**(Salaries and Wages)**

| | | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | **Labor O & M Expenses** | | | | | | | | | | |
| 6 | | | | | | | | | | | |
| 7 | **Labor Expenses** | | | | | | | | | | |
| 8 | | | | | | | | | | | |
| 9 | **Steam Power Generation Operation Expenses** | | | | | | | | | | |
| | 500 OPERATION SUPERVISION & ENGINEERING | $85,651 | $12,229 | $7,489 | $9,294 | $27,991 | $39,324 | $4,037 | $339 | $3,023 | $4,625 |
| 10 | 501 FUEL | $74,334 | $9,974 | $6,099 | $7,906 | $23,684 | $34,320 | $3,925 | $330 | $2,939 | $4,496 |
| 1 | 502 STEAM EXPENSES | $207,221 | $29,959 | $18,352 | $22,580 | $68,074 | $95,029 | $9,523 | $800 | $7,131 | $10,908 |
| 2 | 505 ELECTRIC EXPENSES | $139,761 | $20,206 | $12,378 | $15,229 | $45,913 | $64,093 | $6,423 | $540 | $4,810 | $7,357 |
| | 506 MISC. STEAM POWER EXPENSES | $9,060 | $1,310 | $802 | $987 | $2,976 | $4,155 | $416 | $35 | $312 | $477 |
| 3 | 507 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 4 | | | | | | | | | | | |
| | Total Steam Power Operation Expenses | $516,027 | $73,678 | $45,120 | $55,996 | $168,638 | $236,920 | $24,325 | $2,044 | $18,215 | $27,863 |
| 5 | | | | | | | | | | | |
| 6 | **Steam Power Generation Maintenance Expenses** | | | | | | | | | | |
| 7 | 510 MAINTENANCE SUPERVISION & ENGINEERING | $136,225 | $18,470 | $11,296 | $14,536 | $43,586 | $62,839 | $7,067 | $594 | $5,292 | $8,095 |
| 8 | 511 MAINTENANCE OF STRUCTURES | $32,047 | $4,633 | $2,838 | $3,492 | $10,528 | $14,696 | $1,473 | $124 | $1,103 | $1,887 |
| | 512 MAINTENANCE OF BOILER PLANT | $149,238 | $20,025 | $12,244 | $15,872 | $47,551 | $68,904 | $7,880 | $662 | $5,901 | $9,027 |
| 9 | 513 MAINTENANCE OF ELECTRIC PLANT | $51,636 | $6,929 | $4,236 | $5,492 | $16,452 | $23,841 | $2,727 | $229 | $2,042 | $3,123 |
| 10 | 514 MAINTENANCE OF MISC STEAM PLANT | $4,447 | $597 | $365 | $473 | $1,417 | $2,053 | $235 | $20 | $176 | $269 |
| | Total Steam Power Generation Maintenance Expense | $373,594 | $50,654 | $30,980 | $39,865 | $119,534 | $172,333 | $19,382 | $1,629 | $14,513 | $22,201 |
| 11 | Total Steam Power Generation Expense | $889,620 | $124,332 | $76,100 | $95,862 | $288,172 | $409,253 | $43,706 | $3,673 | $32,728 | $50,064 |
| 12 | | | | | | | | | | | |
| | **Hydraulic Power Generation Operation Expenses** | | | | | | | | | | |
| 13 | 535 OPERATION SUPERVISION & ENGINEERING | $225 | $33 | $20 | $25 | $74 | $103 | $10 | $1 | $8 | $12 |
| 14 | 536 WATER FOR POWER | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 537 HYDRAULIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 538 ELECTRIC EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15 | 539 MISC. HYDRAULIC POWER EXPENSES | $92 | $13 | $8 | $10 | $30 | $42 | $4 | $0 | $3 | $5 |
| | 540 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Total Hydraulic Power Operation Expenses | $317 | $46 | $28 | $35 | $104 | $145 | $15 | $1 | $11 | $17 |
| 16 | | | | | | | | | | | |
| | **Hydraulic Power Generation Maintenance Expenses** | | | | | | | | | | |
| 18 | 541 MAINTENANCE SUPERVISION & ENGINEERING | $2,577 | $354 | $217 | $276 | $829 | $1,187 | $131 | $11 | $98 | $150 |
| 19 | 542 MAINTENANCE OF STRUCTURES | $1,207 | $175 | $107 | $132 | $397 | $554 | $55 | $5 | $42 | $64 |
| 20 | 543 MAINT. OF RESERVES, DAMS, AND WATERWAYS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 544 MAINTENANCE OF ELECTRIC PLANT | $2,509 | $337 | $206 | $267 | $799 | $1,158 | $132 | $11 | $99 | $152 |
| | 545 MAINTENANCE OF MISC HYDRAULIC PLANT | $110 | $15 | $9 | $12 | $35 | $51 | $6 | $0 | $4 | $7 |
| | Total Hydraulic Power Generation Maint. Expense | $6,403 | $880 | $539 | $686 | $2,060 | $2,950 | $324 | $27 | $243 | $371 |
| | Total Hydraulic Power Generation Expense | $6,721 | $926 | $567 | $721 | $2,164 | $3,096 | $339 | $28 | $254 | $388 |
| | **Other Power Generation Operation Expense** | | | | | | | | | | |
| | 546 OPERATION SUPERVISION & ENGINEERING | $2,796 | $404 | $248 | $305 | $919 | $1,282 | $128 | $11 | $96 | $147 |
| | 547 FUEL | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 548 GENERATION EXPENSE | $12,847 | $1,857 | $1,138 | $1,400 | $4,220 | $5,891 | $590 | $50 | $442 | $676 |
| | 549 MISC OTHER POWER GENERATION | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | 550 RENTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Total Other Power Generation Expenses | $15,643 | $2,262 | $1,385 | $1,705 | $5,139 | $7,174 | $719 | $60 | $538 | $823 |
| | **Other Power Generation Maintenance Expense** | | | | | | | | | | |
| | 551 MAINTENANCE SUPERVISION & ENGINEERING | $957 | $138 | $85 | $104 | $314 | $439 | $44 | $4 | $33 | $50 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Salaries and Wages)**

| | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|
| 552 MAINTENANCE OF STRUCTURES | $2,798 | $404 | $246 | $305 | $919 | $1,283 | $129 | $11 | $96 | $147 |
| 553 MAINTENANCE OF GENERATING & ELEC PLANT | $12,198 | $1,763 | $1,080 | $1,329 | $4,007 | $5,594 | $561 | $47 | $420 | $642 |
| 554 MAINTENANCE OF MISC OTHER POWER GEN PLT | $2,626 | $380 | $233 | $286 | $863 | $1,204 | $121 | $10 | $90 | $138 |
| Total Other Power Generation Maintenance Expense | $18,578 | $2,686 | $1,645 | $2,024 | $6,103 | $8,520 | $854 | $72 | $639 | $978 |
| Total Other Power Generation Expense | $34,221 | $4,947 | $3,031 | $3,729 | $11,242 | $15,693 | $1,573 | $132 | $1,178 | $1,801 |
| Total Production Expense | $930,562 | $130,205 | $79,698 | $100,311 | $301,578 | $428,042 | $45,618 | $3,833 | $34,159 | $52,254 |
| **Purchased Power** | | | | | | | | | | |
| 555 PURCHASED POWER | | | | | | | | | | |
| 556 SYSTEM CONTROL AND LOAD DISPATCH | $38,286 | $5,535 | $3,391 | $4,172 | $12,577 | $17,557 | $1,759 | $148 | $1,317 | $2,015 |
| 557 OTHER EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Purchased Power Labor | $38,286 | $5,535 | $3,391 | $4,172 | $12,577 | $17,557 | $1,759 | $148 | $1,317 | $2,015 |
| **Transmission Labor Expenses** | | | | | | | | | | |
| 560 OPERATION SUPERVISION AND ENG | $23,454 | $3,391 | $2,077 | $2,556 | $7,705 | $10,756 | $1,078 | $91 | $807 | $1,235 |
| 561 LOAD DISPATCHING | $25,892 | $3,743 | $2,293 | $2,821 | $8,506 | $11,874 | $1,190 | $100 | $891 | $1,363 |
| 562 STATION EXPENSES | $5,911 | $855 | $523 | $644 | $1,942 | $2,711 | $272 | $23 | $203 | $311 |
| 563 OVERHEAD LINE EXPENSES | $1,058 | $153 | $94 | $115 | $348 | $485 | $49 | $4 | $36 | $56 |
| 566 MISC. TRANSMISSION EXPENSES | $6,638 | $960 | $588 | $723 | $2,181 | $3,044 | $305 | $26 | $228 | $349 |
| 568 MAINTENACE SUPERVISION AND ENG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 570 MAINT OF STATION EQUIPMENT | $13,476 | $1,948 | $1,193 | $1,468 | $4,427 | $6,180 | $619 | $52 | $464 | $709 |
| 571 MAINT OF OVERHEAD LINES | $3,013 | $436 | $267 | $328 | $990 | $1,382 | $138 | $12 | $104 | $159 |
| 572 UNDERGROUND LINES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 573 MISC PLANT | $1,801 | $260 | $159 | $196 | $592 | $826 | $83 | $7 | $62 | $95 |
| Total Transmission Labor Expenses | $81,243 | $11,746 | $7,195 | $8,853 | $26,689 | $37,257 | $3,734 | $314 | $2,796 | $4,277 |
| **Distribution Operation Labor Expense** | | | | | | | | | | |
| 580 OPERATION SUPERVISION AND ENGI | $23 | $2,082 | $28 | $1,378 | $17 | $7,954 | $14,231 | $2,139 | $6,109 | $4,012 |
| 581 LOAD DISPATCHING | $0 | $3,421 | $0 | $2,347 | $0 | $13,625 | $233 | $20 | $174 | $267 |
| 582 STATION EXPENSES | $0 | $3,358 | $0 | $2,303 | $0 | $13,372 | $229 | $19 | $171 | $262 |
| 583 OVERHEAD LINE EXPENSES | $7 | $6,020 | $12 | $4,111 | $6 | $23,849 | $10,345 | $1,186 | $10,230 | $8,506 |
| 584 UNDERGROUND LINE EXPENSES | $0 | $192 | $0 | $131 | $0 | $763 | $138 | $15 | $134 | $116 |
| 585 STREET LIGHTING EXPENSE | $0 | $0 | $0 | $0 | $0 | $0 | $3,813 | $737 | $610 | $900 |
| 586 METER EXPENSES | $179 | $671 | $221 | $66 | $135 | $17 | $19,675 | $0 | $21,512 | $0 |
| 586 METER EXPENSES - LOAD MANAGEMENT | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 587 CUSTOMER INSTALLATIONS EXPENSE | $0 | $0 | $0 | $0 | $0 | $0 | $1,660 | $321 | $266 | $392 |
| 588 MISCELLANEOUS DISTRIBUTION EXP | $12 | $4,697 | $16 | $3,195 | $9 | $18,524 | $89,410 | $16,567 | $20,782 | $24,939 |
| 589 RENTS | | | | | | | | | | |
| Total Distribution Operation Labor Expense | $221 | $20,443 | $278 | $13,532 | $168 | $78,105 | $139,733 | $21,004 | $59,989 | $39,393 |
| **Distribution Maintenance Labor Expense** | | | | | | | | | | |
| 590 MAINTENANCE SUPERVISION AND EN | $0 | $18 | $0 | $12 | $0 | $69 | $35 | $5 | $28 | $24 |
| 591 MAINTENANCE OF STRUCTURES | $0 | $3 | $0 | $2 | $0 | $10 | $0 | $0 | $0 | $0 |
| 592 MAINTENANCE OF STATION EQUIPME | $0 | $2,231 | $0 | $1,530 | $0 | $8,883 | $152 | $13 | $114 | $174 |
| 593 MAINTENANCE OF OVERHEAD LINES | $20 | $16,695 | $34 | $11,399 | $17 | $66,133 | $28,688 | $3,289 | $28,368 | $23,587 |
| 594 MAINTENANCE OF UNDERGROUND LIN | $0 | $492 | $0 | $337 | $0 | $1,954 | $352 | $40 | $343 | $297 |
| 595 MAINTENANCE OF LINE TRANSFORME | $0 | $0 | $0 | $0 | $0 | $0 | $175 | $20 | $173 | $144 |
| 596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS | $0 | $0 | $0 | $0 | $0 | $0 | $22,850 | $4,417 | $3,657 | $5,396 |
| 597 MAINTENANCE OF METERS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 598 MAINTENANCE OF MISC DISTR PLANT | $0 | $0 | $0 | $0 | $0 | $1 | $3 | $0 | $1 | $1 |

SW.

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Salaries and Wages)**

| | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|
| SWP Total Distribution Maintenance Labor Expense | $20 | $19,437 | $35 | $13,280 | $17 | $77,050 | $52,255 | $7,783 | $32,684 | $29,623 |
| Total Distribution Operation and Maintenance Labor Expenses | $241 | $39,880 | $313 | $26,812 | $185 | $155,154 | $191,988 | $28,788 | $92,672 | $69,017 |
| Transmission and Distribution Labor Expenses | $81,485 | $51,625 | $7,508 | $35,665 | $26,874 | $192,411 | $195,722 | $29,101 | $95,468 | $73,294 |
| Production, Transmission and Distribution Labor Expenses | $1,050,332 | $187,366 | $90,596 | $140,148 | $341,029 | $638,011 | $243,099 | $33,082 | $130,945 | $127,563 |
| **Customer Accounts Expense** | | | | | | | | | | |
| 901 SUPERVISION/CUSTOMER ACCTS | $305 | $655 | $218 | $131 | $305 | $44 | $12,799 | $1,643 | $5,289 | $10,309 |
| 902 METER READING EXPENSES | $111 | $239 | $80 | $48 | $111 | $16 | $4,664 | $599 | $1,927 | $3,757 |
| 903 RECORDS AND COLLECTION | $1,092 | $2,340 | $780 | $468 | $1,092 | $156 | $45,762 | $5,874 | $18,910 | $36,861 |
| 904 UNCOLLECTIBLE ACCOUNTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 905 MISC CUST ACCOUNTS | $26 | $55 | $18 | $11 | $26 | $4 | $1,076 | $138 | $444 | $866 |
| Total Customer Accounts Labor Expense | $1,535 | $3,288 | $1,096 | $658 | $1,535 | $219 | $64,300 | $8,254 | $26,571 | $51,793 |
| **Customer Service Expense** | | | | | | | | | | |
| 907 SUPERVISION | $1 | $6 | $2 | $1 | $1 | $0 | $1,621 | $208 | $669 | $1,305 |
| 908 CUSTOMER ASSISTANCE EXPENSES | $1 | $6 | $2 | $1 | $1 | $0 | $1,609 | $207 | $665 | $1,296 |
| 908 CUSTOMER ASSISTANCE EXP-LOAD MGMT | | | | | | | | | | |
| 909 INFORMATIONAL AND INSTRUCTIONA | | | | | | | | | | |
| 909 INFORM AND INSTRUC -LOAD MGMT | | | | | | | | | | |
| 910 MISCELLANEOUS CUSTOMER SERVICE | $0 | $1 | $0 | $0 | $0 | $0 | $303 | $39 | $125 | $244 |
| 911 DEMONSTRATION AND SELLING EXP | | | | | | | | | | |
| 912 DEMONSTRATION AND SELLING EXP | | | | | | | | | | |
| 913 WATER HEATER - HEAT PUMP PROGRAM | | | | | | | | | | |
| 915 MDSE-JOBBING-CONTRACT | | | | | | | | | | |
| 916 MISC SALES EXPENSE | | | | | | | | | | |
| Total Customer Service Labor Expense | $3 | $14 | $5 | $1 | $3 | $0 | $3,533 | $454 | $1,460 | $2,846 |
| Sub-Total Labor Exp | $1,051,870 | $190,668 | $91,697 | $140,807 | $342,567 | $638,230 | $310,932 | $41,790 | $158,975 | $182,202 |
| **Administrative and General Expense** | | | | | | | | | | |
| 920 ADMIN. & GEN. SALARIES- | $251,197 | $45,533 | $21,898 | $33,626 | $81,808 | $152,415 | $74,254 | $9,980 | $37,965 | $43,512 |
| 921 OFFICE SUPPLIES AND EXPENSES | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 922 ADMIN. EXPENSES TRANSFERRED - CREDIT | -$21,720 | -$3,937 | -$1,893 | -$2,907 | -$7,074 | -$13,179 | -$6,420 | -$863 | -$3,283 | -$3,762 |
| 923 OUTSIDE SERVICES EMPLOYED | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 924 PROPERTY INSURANCE | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 925 INJURIES AND DAMAGES - INSURAN | $1,842 | $334 | $161 | $247 | $600 | $1,118 | $544 | $73 | $278 | $319 |
| 926 EMPLOYEE BENEFITS | | | | | | | | | | |
| 928 REGULATORY COMMISSION FEES | | | | | | | | | | |
| 929 DUPLICATE CHARGES-CR | | | | | | | | | | |
| 930 MISCELLANEOUS GENERAL EXPENSES | | | | | | | | | | |
| 931 RENTS AND LEASES | | | | | | | | | | |
| 932 MAINTENANCE OF GENERAL PLANT | | | | | | | | | | |
| 935 MAINTENANCE OF GENERAL PLANT | | | | | | | | | | |
| Total Administrative and General Expense | $231,318 | $41,930 | $20,165 | $30,965 | $75,334 | $140,354 | $68,378 | $9,190 | $34,961 | $40,068 |
| Total Operation and Maintenance Expenses | $1,283,189 | $232,598 | $111,862 | $171,772 | $417,902 | $778,585 | $379,310 | $50,980 | $193,936 | $222,270 |
| Operation and Maintenance Expenses Less Purchase Power | $1,283,189 | $232,598 | $111,862 | $171,772 | $417,902 | $778,585 | $379,310 | $50,980 | $193,936 | $222,270 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Revenues)**

| | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 **REVENUE** | | | | | | | | | | |
| Sales | $1,112,461,756 | $419,658,059 | $136,859,016 | $3,021,554 | $7,663,577 | $217,223,150 | $83,319,633 | $1,313,122 | $9,082,579 | $729,069 |
| Accrued Revenues | -$17,682,129 | -$6,670,295 | -$2,175,319 | -$48,026 | -$121,809 | -$3,452,674 | -$1,324,332 | -$20,872 | -$144,364 | -$11,588 |
| Intercompany Sales | $41,161,612 | $14,421,791 | $4,038,600 | $93,972 | $292,821 | $8,427,406 | $3,492,460 | $54,600 | $420,158 | $34,066 |
| Off-System Sales | $6,327,778 | $1,802,945 | $644,289 | $1,581 | $35,611 | $1,420,044 | $604,313 | $8,396 | $71,335 | $5,788 |
| Brokered Sales | -$90,748 | -$31,795 | -$8,904 | -$207 | -$646 | -$18,580 | -$7,700 | -$120 | -$926 | -$75 |
| Redundant Capacity | $10,854 | $0 | $0 | $0 | $0 | $7,793 | $3,061 | $0 | $0 | $0 |
| Misc Service Revenues | $1,578,059 | $760,286 | $343,576 | $7,585 | $4,405 | $305,527 | $117,190 | $1,847 | $19,622 | $1,575 |
| Rent From Electric Property | $1,994,812 | $282,465 | $339,262 | $7,490 | $3,710 | $506,649 | $194,334 | $3,063 | $16,405 | $1,317 |
| Other Electric Revenue | $2,585,939 | $1,383,113 | $309,712 | $7,434 | $15,161 | $340,842 | $128,036 | $2,206 | $15,153 | $1,215 |
| Unbilled Revenue | $6,878,000 | $2,594,613 | $846,156 | $18,681 | $47,381 | $1,343,022 | $515,139 | $8,119 | $56,155 | $4,508 |
| Merger Surcredit Amortization | -$1,069,892 | $0 | $0 | $0 | $0 | -$28,815 | -$90,782 | $0 | $0 | $0 |
| **TOTAL REVENUE** | **$1,154,156,041** | **$434,201,182** | **$141,196,389** | **$3,110,064** | **$7,940,212** | **$226,074,364** | **$86,951,352** | **$1,370,360** | **$9,536,117** | **$765,874** |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Revenues)**

| | | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 **REVENUE** | | | | | | | | | | | | |
| | Sales | $129,712,936 | $34,065,000 | $6,647,734 | $3,858,665 | $4,738,074 | $13,387,914 | $22,399,700 | $7,312,068 | $1,378,192 | $4,076,500 | $6,015,214 |
| | Accrued Revenues | -$2,061,735 | -$541,449 | -$105,663 | -$61,332 | -$75,310 | -$212,795 | -$356,034 | -$116,222 | -$21,906 | -$64,794 | -$95,609 |
| | Intercompany Sales | $5,904,879 | $1,761,308 | $236,338 | $144,505 | $187,324 | $561,190 | $813,204 | $93,003 | $7,815 | $69,642 | $106,532 |
| | Off-System Sales | $1,029,309 | $310,679 | $33,209 | $21,467 | $29,817 | $96,202 | $152,624 | $20,202 | $1,698 | $15,128 | $23,141 |
| | Brokered Sales | -$13,018 | -$3,883 | -$521 | -$319 | -$413 | -$1,237 | -$1,793 | -$205 | -$17 | -$154 | -$235 |
| | Redundant Capacity | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | Misc Service Revenues | $12,234 | $3,213 | $200 | $0 | $0 | $339 | $458 | $0 | $0 | $0 | $0 |
| | Rent From Electric Property | $378,299 | $99,348 | $33,370 | $0 | $0 | $57,364 | $71,737 | $0 | $0 | $0 | $0 |
| | Other Electric Revenue | $206,683 | $57,050 | $11,108 | $6,252 | $7,639 | $20,376 | $29,333 | $17,762 | $2,478 | $9,635 | $14,751 |
| | Unbilled Revenue | $801,974 | $210,613 | $41,101 | $23,857 | $29,294 | $82,773 | $138,490 | $45,208 | $8,521 | $25,204 | $37,190 |
| | Merger Surcredit Amortization | -$797,953 | -$152,342 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | **TOTAL REVENUE** | **$135,173,608** | **$35,809,536** | **$6,896,875** | **$3,993,096** | **$4,916,425** | **$13,992,126** | **$23,247,719** | **$7,371,816** | **$1,376,780** | **$4,131,161** | **$6,100,984** |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Amounts)**

| Alloc No. | Allocator Description | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy (Loss Adjusted) | $20,156,276,125 | $7,062,152,956 | $1,977,646,848 | $46,016,783 | $143,390,395 | $4,126,784,782 | $1,710,209,770 | $26,736,679 | $205,745,622 | $16,681,560 |
| 2 | Energy | $18,783,418,257 | $6,497,809,251 | $1,819,611,111 | $43,720,684 | $131,931,925 | $3,797,009,283 | $1,624,875,433 | $26,100,266 | $189,304,284 | $15,849,200 |
| 3 | Customers (Monthly Bills) | $7,996,703 | $4,958,111 | $938,420 | $672 | $3,668 | $107,045 | $4,202 | $24 | $612 | $24 |
| 4 | Average Customers (Bills/12) | $666,393 | $413,176 | $78,202 | $73 | $306 | $8,920 | $350 | $2 | $51 | $2 |
| 5 | Average Customers (Lighting = Lights) | $666,393 | $413,176 | $78,202 | $73 | $306 | $8,920 | $350 | $2 | $51 | $2 |
| 6 | Weighted Average Customers (Lighting =9 Lights per Cust) | $609,322 | $413,176 | $86,022 | $730 | $306 | $89,200 | $3,500 | $20 | $1,020 | $40 |
| 7 | Street Lighting | $69,869,338 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 8 | Average Customers | $666,393 | $413,176 | $78,202 | $73 | $306 | $8,920 | $350 | $2 | $51 | $2 |
| 9 | Average Customers (Lighting = 9 Lights per Cust) | $519,535 | $413,176 | $78,202 | $73 | $306 | $8,920 | $350 | $2 | $51 | $2 |
| 10 | Average Secondary Customers | $519,012 | $413,176 | $78,202 | $0 | $306 | $8,920 | $0 | $0 | $51 | $0 |
| 11 | Average Primary Customers | $519,536 | $413,176 | $78,202 | $73 | $306 | $8,920 | $350 | $2 | $51 | $2 |
| 12 | Year End Customers | $502,777 | $414,418 | $78,768 | $72 | $310 | $8,707 | $347 | $2 | $51 | $2 |
| 13 | Year End Customers (Lighting = Lights) | $708,973 | $414,418 | $78,768 | $72 | $310 | $8,707 | $347 | $2 | $51 | $2 |
| 14 | Weighted Year End Customers (Lighting =9 Lights per Cust) | $612,466 | $414,418 | $86,645 | $720 | $310 | $87,070 | $3,470 | $20 | $1,020 | $40 |
| 15 | Street Lighting | $52,453,988 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16 | Year End Customers | $708,973 | $414,418 | $78,768 | $72 | $310 | $8,707 | $347 | $2 | $51 | $2 |
| 17 | Year End Customers (Lighting = 9 Lights per Cust) | $525,667 | $414,418 | $78,768 | $72 | $310 | $8,707 | $347 | $2 | $51 | $2 |
| 18 | Year End Secondary Customers | $525,167 | $414,418 | $78,768 | $0 | $310 | $8,707 | $0 | $0 | $51 | $2 |
| 19 | Year End Primary Customers | $525,688 | $414,418 | $78,768 | $72 | $310 | $8,707 | $347 | $2 | $51 | $2 |
| 20 | Maximum Class Non-Coincident Peak Demands | $4,667,350 | $2,277,441 | $469,138 | $26,268 | $47,098 | $719,439 | $282,559 | $5,128 | $31,402 | $2,255 |
| 21 | Primary Distribution Plant -- Average Number of Customers | 1.00000 | 0.79528 | 0.15052 | 0.00014 | 0.00059 | 0.01717 | 0.00067 | 0.00000 | 0.00010 | 0.00000 |
| 22 | Customer Services -- Weighted cost of Services | 1.00000 | 0.58798 | 0.11090 | 0.00000 | 0.00625 | 0.29477 | 0.00000 | 0.00000 | 0.00010 | 0.00000 |
| 23 | Meter Costs -- Weighted Cost of Meters | 1.00000 | 0.62251 | 0.27464 | 0.00067 | 0.00213 | 0.07898 | 0.00318 | 0.00002 | 0.00024 | 0.00001 |
| 24 | Lighting Systems -- Lighting Customers | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 25 | Meter Reading and Billing -- Weighted Cost | 1.00000 | 0.67809 | 0.14118 | 0.00120 | 0.00050 | 0.14639 | 0.00574 | 0.00003 | 0.00167 | 0.00007 |
| 26 | Marketing/Economic Development | 1.00000 | 0.79528 | 0.15052 | 0.00014 | 0.00059 | 0.01717 | 0.00067 | 0.00000 | 0.00010 | 0.00000 |
| 27 | Rev | 1112462089.000 | 419658185.000 | 136859057.000 | 3021555.000 | 7663579.000 | 217223215.000 | 83319658.000 | 1313122.000 | 9082582.000 | 729069.000 |
| 28 | Maximum Class Demands (Primary) | $4,471,090 | $2,277,441 | $469,138 | $26,268 | $47,098 | $719,439 | $282,559 | $0 | $31,402 | $2,255 |
| 29 | Sum of the Individual Customer Demands (Secondary) | $8,070,265 | $4,909,823 | $2,475,479 | $0 | $49,473 | $595,762 | $0 | $0 | $33,223 | $0 |
| 30 | Summer Peak Period Demand Allocator | $3,555,506 | $1,479,783 | $393,532 | $21,700 | $24,220 | $680,416 | $257,634 | $4,735 | $33,912 | $2,075 |
| 31 | Winter Peak Period Demand Allocator | $3,594,667 | $1,896,227 | $277,905 | $23,766 | $44,306 | $529,267 | $205,311 | $4,751 | $25,365 | $2,500 |
| 32 | Base Demand Allocator | $2,294,658 | $803,979 | $225,142 | $5,239 | $16,324 | $469,807 | $194,696 | $3,044 | $23,423 | $1,899 |
| 33 | Production Residual Winter Demand Allocator | $2,279,717 | $803,979 | $225,142 | $5,239 | $16,324 | $469,807 | $194,696 | $3,044 | $23,423 | $1,899 |
| 34 | **Production Winter Demand Allocator** | **$1** | **$1** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 35 | Production Residual Summer Demand Allocator | $3,555,506 | $1,479,783 | $393,532 | $21,700 | $24,220 | $680,416 | $257,634 | $4,735 | $33,912 | $2,075 |
| 36 | Production Summer Demand Allocator | $1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 37 | Production Residual Summer Demand Allocator | $3,555,506 | $1,479,783 | $393,532 | $21,700 | $24,220 | $680,416 | $257,634 | $4,735 | $33,912 | $2,075 |
| 38 | Production Summer Demand Total | $18,189,248 | $7,570,271 | $2,013,230 | $111,012 | $123,905 | $3,480,871 | $1,318,003 | $24,223 | $173,486 | $10,615 |
| 39 | Distribution O&M | $916,133,794 | $627,091,863 | $148,521,175 | $1,156,512 | $3,689,346 | $73,324,792 | $12,186,074 | $1,189 | $1,988,306 | $97,509 |
| 40 | Total Other Revenue allocator | $6,158,810 | $3,294,095 | $737,627 | $17,706 | $36,109 | $811,767 | $304,936 | $5,254 | $36,089 | $2,894 |
| 41 | Customer Specific Assignment | $0 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 42 | Misc Service Revenue Allocator | $3,260,775 | $1,570,995 | $709,938 | $15,674 | $9,102 | $631,317 | $242,152 | $3,816 | $40,546 | $3,255 |
| 43 | Off-System Sales Allocator | $6,327,778 | $1,802,945 | $644,289 | $1,581 | $35,611 | $1,420,044 | $604,313 | $8,396 | $71,335 | $5,788 |
| 44 | Interruptible Credit Allocator | $1,285,910,033 | $621,329,040 | $116,503,314 | $8,241,533 | $13,026,103 | $211,932,756 | $81,303,247 | $1,704,712 | $10,344,505 | $837,030 |
| 45 | Operation and Maintenance Less Fuel | $180,545,747 | $101,747,472 | $22,563,362 | $553,014 | $1,013,169 | $23,812,729 | $7,145,379 | $118,553 | $924,581 | $70,491 |
| 46 | Base Rate Revenue | $958,043,947 | $364,691,143 | $121,479,709 | $2,654,163 | $6,648,873 | $186,103,586 | $70,244,702 | $1,110,048 | $7,580,016 | $607,081 |
| 47 | VDT Revenue | -$3,405,552 | -$1,281,117 | -$416,427 | -$9,403 | -$23,364 | -$660,193 | -$253,206 | -$3,988 | -$27,621 | -$2,222 |
| 48 | Merger Surcerdit Revenue | -$17,498,536 | -$6,931,759 | -$2,258,368 | -$50,423 | -$125,127 | -$3,549,075 | -$1,260,029 | -$21,533 | -$149,681 | -$11,935 |
| 49 | Remove ECR Revenues | $54,342,066 | $20,625,999 | $6,655,712 | $150,004 | $375,761 | $10,481,169 | $4,017,666 | $63,713 | $439,535 | $35,498 |
| 50 | Customer Specific Assignment | $0 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 51 | Gross Production Plant | $1,873,146,664 | $677,526,459 | $187,838,546 | $5,508,604 | $13,228,040 | $379,194,514 | $154,936,348 | $2,486,371 | $18,904,177 | $1,471,531 |
| 52 | Gross Transmission Plant | $417,885,239 | $151,151,168 | $41,905,397 | $1,228,929 | $2,951,078 | $84,595,506 | $34,565,159 | $554,691 | $4,217,383 | $328,288 |
| 53 | Gross Distribution Plant | $1,017,723,772 | $582,948,784 | $166,953,311 | $2,108,793 | $5,832,645 | $104,709,311 | $22,327,858 | $1,628 | $3,437,488 | $177,340 |
| 54 | Total Prod.,Ttrans., Distrib Plant | $3,308,755,675 | $1,411,626,412 | $396,697,255 | $8,846,326 | $22,011,764 | $568,499,332 | $211,829,366 | $3,042,690 | $26,559,048 | $1,977,158 |
| 55 | Dist. Overhead Lines Gross Plant | $383,731,334 | $241,823,501 | $55,745,327 | $1,131,887 | $2,352,620 | $36,221,807 | $12,075,466 | $468 | $1,525,178 | $96,296 |
| 56 | Gross Intangible Plant | $22,416,283 | $9,563,540 | $2,687,560 | $59,932 | $149,126 | $3,851,491 | $1,435,110 | $20,614 | $179,933 | $13,395 |
| 57 | Gross Total Plant in Service | $3,419,830,880 | $1,459,014,829 | $410,014,415 | $9,143,298 | $22,750,700 | $587,583,902 | $218,940,495 | $3,144,833 | $27,450,637 | $2,043,531 |
| 58 | Dist. Underground Lines Gross Plant | $86,588,726 | $50,231,927 | $12,453,078 | $333,141 | $682,631 | $10,305,035 | $3,571,977 | $54 | $450,357 | $28,498 |
| 59 | Gross General Plant | $88,658,922 | $37,824,877 | $10,629,600 | $237,039 | $589,811 | $15,233,079 | $5,676,020 | $81,530 | $711,656 | $52,978 |
| 60 | Labor Accts 501-507 | $10,485,257 | $3,772,879 | $1,047,699 | $29,693 | $74,137 | $2,126,605 | $870,988 | $13,916 | $106,020 | $8,310 |
| 61 | Labor Accts 511-514 | $5,585,749 | $1,966,004 | $549,754 | $13,270 | $39,696 | $1,141,810 | $472,257 | $7,410 | $56,926 | $4,590 |
| 62 | Labor Accts 536-540 | $2,262 | $818 | $227 | $7 | $16 | $458 | $187 | $3 | $23 | $2 |
| 63 | Labor Accts 542-545 | $90,866 | $32,173 | $8,980 | $227 | $645 | $18,536 | $7,647 | $121 | $924 | $74 |
| 64 | Labor Accts 581-588 | $7,031,202 | $4,181,905 | $1,335,601 | $16,237 | $36,689 | $704,876 | $163,779 | $49 | $20,518 | $1,265 |
| 65 | Labor Accts 591-598 | $22,328,441 | $13,905,201 | $3,213,522 | $68,402 | $141,194 | $2,170,049 | $730,306 | $26 | $91,755 | $5,824 |
| 66 | Labor Accts 500-916 | $45,220,783 | $21,611,056 | $5,720,631 | $110,159 | $256,536 | $7,417,960 | $2,505,763 | $33,856 | $311,987 | $23,500 |
| 67 | O&M less Purchased Power | $632,258,594 | $249,352,560 | $67,753,145 | $1,469,480 | $4,182,774 | $120,295,896 | $47,384,462 | $717,682 | $5,750,178 | $457,840 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Amounts)**

| Alloc No. | Allocator Description | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 68 | Dist. Lines Gross Plant | $470,320,060 | $292,055,429 | $68,198,405 | $1,465,028 | $3,035,251 | $46,526,842 | $15,647,443 | $521 | $1,975,535 | $124,795 |
| 69 | Rate Base | $2,634,973,710 | $1,090,894,641 | $305,708,873 | $7,140,789 | $17,717,717 | $468,634,814 | $178,341,854 | $2,632,364 | $22,206,711 | $1,672,966 |
| 70 | Gross Transformer Plant | $235,411,371 | $154,474,157 | $62,449,760 | $0 | $1,098,183 | $13,814,235 | $0 | $0 | $718,836 | $237 |
| 71 | Dpreciation Expense | $109,736,123 | $46,776,559 | $13,144,361 | $293,559 | $730,284 | $18,873,622 | $7,037,078 | $101,167 | $882,131 | $65,691 |
| 72 | Total Labor | $55,165,360 | $26,363,578 | $6,978,665 | $134,384 | $312,951 | $9,049,256 | $3,056,810 | $41,301 | $380,597 | $28,668 |
| 73 | Distribution O&M | $38,758,632 | $23,713,959 | $6,460,794 | $103,073 | $221,788 | $3,779,138 | $1,074,727 | $155 | $135,286 | $8,461 |
| 74 | Sales Revenue | $1,112,461,756 | $419,658,059 | $136,859,016 | $3,021,554 | $7,663,577 | $217,223,150 | $83,319,633 | $1,313,122 | $9,082,579 | $729,069 |
| 75 | Distribution Poles, Lines, Transform & Services | $783,761,532 | $492,409,491 | $139,302,015 | $1,465,028 | $4,620,810 | $83,342,089 | $15,647,443 | $521 | $2,702,330 | $125,032 |
| 76 | | | | | | | | | | | |
| 77 | | | | | | | | | | | |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Amounts)**

| Alloc No. | Allocator Description | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy (Loss Adjusted) | $2,891,538,085 | $862,488,183 | $115,731,325 | $70,762,356 | $91,730,180 | $274,807,237 | $398,214,663 | $45,542,217 | $3,826,828 | $34,102,592 | $52,167,064 |
| 2 | Energy | $2,747,259,009 | $841,958,377 | $109,956,679 | $69,078,000 | $87,153,119 | $268,266,000 | $388,735,959 | $41,902,893 | $3,521,022 | $31,377,420 | $47,998,342 |
| 3 | Customers (Monthly Bills) | $466 | $79 | $364 | $123 | $39 | $82 | $12 | $844,691 | $108,454 | $348,991 | $680,424 |
| 4 | Average Customers (Bills/12) | $39 | $7 | $30 | $10 | $3 | $7 | $1 | $70,391 | $9,038 | $29,083 | $56,702 |
| 5 | Average Customers (Lighting = Lights) | $39 | $7 | $30 | $10 | $3 | $7 | $1 | $70,391 | $9,038 | $29,083 | $56,702 |
| 6 | Weighted Average Customers (Lighting =9 Lights per Cust) | $780 | $140 | $300 | $100 | $60 | $140 | $20 | $5,866 | $753 | $2,424 | $4,725 |
| 7 | Street Lighting | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $43,956,496 | $8,497,472 | $7,034,856 | $10,380,514 |
| 8 | Average Customers | $39 | $7 | $30 | $10 | $3 | $7 | $1 | $70,391 | $9,038 | $29,083 | $56,702 |
| 9 | Average Customers (Lighting = 9 Lights per Cust) | $39 | $7 | $30 | $10 | $3 | $7 | $1 | $7,821 | $1,004 | $3,231 | $6,300 |
| 10 | Average Secondary Customers | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $7,821 | $1,004 | $3,231 | $6,300 |
| 11 | Average Primary Customers | $39 | $7 | $30 | $10 | $3 | $7 | $1 | $7,821 | $1,004 | $3,231 | $6,300 |
| 12 | Year End Customers | $40 | $7 | $31 | $12 | $3 | $6 | $1 | $0 | $0 | $0 | $0 |
| 13 | Year End Customers (Lighting = Lights) | $40 | $7 | $31 | $12 | $3 | $6 | $1 | $70,537 | $8,186 | $70,537 | $56,936 |
| 14 | Weighted Year End Customers (Lighting =9 Lights per Cust) | $800 | $140 | $310 | $120 | $60 | $120 | $20 | $5,878 | $682 | $5,878 | $4,745 |
| 15 | Street Lighting | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $33,000,064 | $6,379,424 | $5,281,374 | $7,793,106 |
| 16 | Year End Customers | $40 | $7 | $31 | $12 | $3 | $6 | $1 | $70,537 | $8,186 | $70,537 | $56,936 |
| 17 | Year End Customers (Lighting = 9 Lights per Cust) | $40 | $7 | $31 | $12 | $3 | $6 | $1 | $7,837 | $910 | $7,837 | $6,326 |
| 18 | Year End Secondary Customers | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $7,837 | $910 | $7,837 | $6,326 |
| 19 | Year End Primary Customers | $40 | $7 | $31 | $12 | $3 | $6 | $1 | $7,837 | $910 | $7,837 | $6,326 |
| 20 | Maximum Class Non-Coincident Peak Demands | $427,099 | $121,476 | $32,089 | $17,176 | $22,011 | $52,480 | $127,786 | $2,184 | $184 | $1,635 | $2,502 |
| 21 | Primary Distribution Plant – Average Number of Customers | 0.00008 | 0.00001 | 0.00006 | 0.00002 | 0.00001 | 0.00001 | 0.00000 | 0.01505 | 0.00193 | 0.00622 | 0.01214 |
| 22 | Customer Services – Weighted cost of Services | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| 23 | Meter Costs – Weighted Cost of Meters | 0.00036 | 0.00007 | 0.00027 | 0.00009 | 0.00003 | 0.00006 | 0.00001 | 0.00800 | 0.00000 | 0.00875 | 0.00000 |
| 24 | Lighting Systems – Lighting Customers | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.62912 | 0.12162 | 0.10069 | 0.14857 |
| 25 | Meter Reading and Billing – Weighted Cost | 0.00128 | 0.00023 | 0.00049 | 0.00016 | 0.00010 | 0.00023 | 0.00003 | 0.00964 | 0.00124 | 0.00398 | 0.00775 |
| 26 | Marketing/Economic Development | 0.00008 | 0.00001 | 0.00006 | 0.00002 | 0.00001 | 0.00001 | 0.00000 | 0.01505 | 0.00193 | 0.00623 | 0.01213 |
| 27 | Rev | 129712975.000 | 34065011.000 | 6647736.000 | 3858666.000 | 4738075.000 | 13387918.000 | 22399707.000 | 7312070.000 | 1378192.000 | 4076501.000 | 6015216.000 |
| 28 | Maximum Class Demands (Primary) | $427,099 | $0 | $32,089 | $0 | $22,011 | $0 | $127,786 | $2,184 | $184 | $1,635 | $2,502 |
| 29 | Sum of the Individual Customer Demands (Secondary) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,184 | $184 | $1,635 | $2,502 |
| 30 | Summer Peak Period Demand Allocator | $406,246 | $108,974 | $23,354 | $14,419 | $13,783 | $43,030 | $47,693 | $0 | $0 | $0 | $0 |
| 31 | Winter Peak Period Demand Allocator | $352,268 | $106,233 | $24,657 | $12,756 | $16,011 | $33,629 | $33,210 | $2,184 | $184 | $1,635 | $2,502 |
| 32 | Base Demand Allocator | $329,182 | $98,189 | $13,175 | $8,056 | $10,443 | $31,285 | $45,334 | $5,185 | $436 | $3,882 | $5,939 |
| 33 | Production Residual Winter Demand Allocator | $329,182 | $98,189 | $13,175 | $8,056 | $10,443 | $31,285 | $45,334 | $5,185 | $436 | $3,882 | $5,939 |
| 34 | **Production Winter Demand Allocator** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** |
| 35 | Production Residual Summer Demand Allocator | $406,246 | $108,974 | $23,354 | $14,419 | $13,783 | $43,030 | $47,693 | $0 | $0 | $0 | $0 |
| 36 | Production Summer Demand Allocator | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 37 | Production Residual Summer Demand Allocator | $406,246 | $108,974 | $23,354 | $14,419 | $13,783 | $43,030 | $47,693 | $0 | $0 | $0 | $0 |
| 38 | Production Summer Demand Total | $2,078,272 | $557,489 | $119,474 | $73,765 | $70,511 | $220,133 | $243,988 | $0 | $0 | $0 | $0 |
| 39 | Distribution O&M | $18,131,624 | $4,162 | $1,378,920 | $7,136 | $934,991 | $3,568 | $5,418,374 | $7,591,249 | $876,755 | $7,558,078 | $6,172,171 |
| 40 | Total Other Revenue allocator | $492,246 | $135,872 | $26,455 | $14,691 | $18,194 | $48,529 | $69,861 | $42,302 | $5,902 | $22,948 | $35,133 |
| 41 | Customer Specific Assignment | $0 | $0 | $0 | $0 | | | $0 | $0 | $0 | | |
| 42 | Misc Service Revenue Allocator | $25,280 | $6,639 | $414 | $0 | $0 | $701 | $946 | $0 | $0 | $0 | $0 |
| 43 | Off-System Sales Allocator | $1,029,309 | $310,679 | $33,209 | $21,467 | $29,817 | $95,202 | $152,624 | $20,202 | $1,698 | $15,128 | $23,141 |
| 44 | Interruptible Credit Allocator | $134,342,697 | $38,563,883 | $8,671,502 | $4,822,695 | $5,431,805 | $13,436,745 | $14,018,131 | $470,179 | $39,508 | $352,076 | $538,574 |
| 45 | Operation and Maintenance Less Fuel | $11,502,465 | $3,042,676 | $664,235 | $330,812 | $441,152 | $1,026,993 | $1,544,680 | $1,981,562 | $306,385 | $642,981 | $1,013,046 |
| 46 | Base Rate Revenue | $107,887,035 | $32,985,640 | $5,800,666 | $3,326,359 | $4,055,754 | $11,352,111 | $14,042,852 | $6,845,722 | $1,321,287 | $3,767,361 | $5,539,838 |
| 47 | VDT Revenue | -$394,429 | -$120,177 | -$20,228 | -$11,701 | -$14,392 | -$40,804 | -$68,105 | -$22,193 | -$4,259 | -$12,408 | -$19,315 |
| 48 | Merger Surcerdit Revenue | -$1,535,989 | -$460,770 | -$108,485 | -$63,911 | -$77,434 | -$218,699 | -$365,961 | -$120,138 | -$23,165 | -$66,864 | -$98,990 |
| 49 | Remove ECR Revenues | $6,234,214 | $1,899,790 | $322,307 | $185,612 | $226,784 | $653,513 | $1,074,397 | $351,684 | $62,946 | $196,490 | $289,273 |
| 50 | Customer Specific Assignment | $0 | $0 | $0 | $0 | | | $0 | $0 | $0 | | |
| 51 | Gross Production Plant | $259,296,185 | $76,236,001 | $11,021,707 | $6,751,731 | $8,307,055 | $25,044,177 | $34,960,746 | $3,503,492 | $294,392 | $2,623,459 | $4,013,131 |
| 52 | Gross Transmission Plant | $57,847,071 | $17,007,591 | $2,458,862 | $1,506,261 | $1,853,243 | $5,587,172 | $7,799,485 | $781,603 | $65,677 | $585,274 | $895,300 |
| 53 | Gross Distribution Plant | $33,350,049 | $6,313 | $2,528,081 | $8,662 | $1,719,488 | $4,946 | $9,969,089 | $48,118,361 | $8,915,935 | $11,184,273 | $13,421,416 |
| 54 | Total Prod.,Ttrans., Distrib Plant | $350,493,305 | $93,250,004 | $16,008,651 | $8,266,654 | $11,879,785 | $30,636,295 | $52,729,320 | $52,403,456 | $9,276,003 | $14,393,006 | $18,329,846 |
| 55 | Dist. Overhead Lines Gross Plant | $18,139,286 | $1,636 | $1,369,393 | $2,805 | $935,047 | $1,403 | $5,424,625 | $2,353,163 | $269,748 | $2,326,942 | $1,934,737 |
| 56 | Gross Intangible Plant | $2,374,535 | $631,754 | $108,456 | $56,005 | $80,484 | $207,556 | $357,233 | $355,025 | $62,843 | $97,510 | $124,182 |
| 57 | Gross Total Plant In Service | $362,259,395 | $96,380,415 | $16,546,062 | $8,544,166 | $12,278,591 | $31,664,758 | $54,499,447 | $54,162,644 | $9,587,400 | $14,876,181 | $18,945,181 |
| 58 | Dist. Underground Lines Gross Plant | $5,386,113 | $189 | $405,427 | $324 | $277,604 | $162 | $1,611,204 | $290,533 | $32,724 | $282,745 | $245,001 |
| 59 | Gross General Plant | $9,391,554 | $2,498,657 | $428,956 | $221,507 | $318,322 | $820,907 | $1,412,895 | $1,404,163 | $248,553 | $385,664 | $491,153 |
| 60 | Labor Accts 501-507 | $1,460,189 | $430,376 | $61,449 | $37,631 | $46,702 | $140,647 | $197,596 | $20,287 | $1,705 | $15,191 | $23,238 |
| 61 | Labor Accts 511-514 | $797,350 | $237,368 | $32,184 | $19,684 | $25,329 | $75,948 | $109,494 | $12,314 | $1,035 | $9,221 | $14,106 |
| 62 | Labor Accts 536-540 | $313 | $92 | $13 | $8 | $10 | $30 | $42 | $4 | $0 | $3 | $5 |
| 63 | Labor Accts 542-545 | $12,886 | $3,826 | $526 | $322 | $410 | $1,231 | $1,763 | $194 | $16 | $145 | $222 |
| 64 | Labor Accts 581-588 | $235,390 | $199 | $18,361 | $250 | $12,154 | $151 | $70,150 | $125,502 | $18,865 | $53,879 | $35,382 |
| 65 | Labor Accts 591-598 | $1,097,682 | $90 | $82,830 | $154 | $56,582 | $77 | $328,281 | $165,405 | $21,740 | $133,978 | $115,344 |
| 66 | Labor Accts 500-916 | $4,079,597 | $1,051,870 | $190,668 | $91,697 | $140,807 | $342,567 | $638,230 | $310,932 | $41,790 | $158,975 | $182,202 |
| 67 | O&M less Purchased Power | $79,420,243 | $22,953,640 | $3,302,590 | $1,909,488 | $2,570,247 | $7,350,135 | $11,271,913 | $2,405,065 | $275,920 | $1,453,128 | $1,982,205 |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Amounts)**

| Alloc No. | Allocator Description | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 68 | Dist. Lines Gross Plant | $23,525,399 | $1,825 | $1,774,820 | $3,129 | $1,212,651 | $1,564 | $7,035,828 | $2,643,696 | $302,472 | $2,609,687 | $2,179,738 |
| 69 | Rate Base | $295,955,020 | $80,803,283 | $13,269,079 | $7,145,932 | $9,894,085 | $26,522,617 | $43,414,754 | $34,297,253 | $5,972,091 | $9,922,639 | $12,826,229 |
| 70 | Gross Transformer Plant | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $976,105 | $111,779 | $964,334 | $803,744 |
| 71 | Dpreciation Expense | $11,644,544 | $3,100,490 | $531,586 | $274,858 | $394,525 | $1,018,632 | $1,750,492 | $1,729,255 | $305,989 | $475,507 | $605,794 |
| 72 | Total Labor | $4,976,748 | $1,283,189 | $232,598 | $111,862 | $171,772 | $417,902 | $778,585 | $379,310 | $50,980 | $193,936 | $222,270 |
| 73 | Distribution O&M | $1,586,386 | $611 | $121,317 | $807 | $81,828 | $472 | $473,771 | $467,766 | $66,566 | $264,943 | $196,784 |
| 74 | Sales Revenue | $129,712,936 | $34,065,000 | $6,647,734 | $3,658,665 | $4,738,074 | $13,387,914 | $22,399,700 | $7,312,068 | $1,378,192 | $4,076,500 | $6,015,214 |
| 75 | Distribution Poles, Lines, Transform & Services | $23,525,399 | $1,825 | $1,774,820 | $3,129 | $1,212,651 | $1,564 | $7,035,828 | $3,619,801 | $414,251 | $3,574,022 | $2,983,482 |
| 76 | | | | | | | | | | | | |
| 77 | | | | | | | | | | | | |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Percents)**

| Alloc No. | Allocator Description | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy (Loss Adjusted) | 100.0000% | 35.0370% | 9.8116% | 0.2283% | 0.7114% | 20.4739% | 8.4848% | 0.1326% | 1.0208% | 0.0828% |
| 2 | Energy | 100.0000% | 34.5933% | 9.6873% | 0.2328% | 0.7024% | 20.2147% | 8.6506% | 0.1390% | 1.0078% | 0.0844% |
| 3 | Customers (Monthly Bills) | 100.0000% | 62.0019% | 11.7351% | 0.0109% | 0.0459% | 1.3386% | 0.0525% | 0.0003% | 0.0077% | 0.0003% |
| 4 | Average Customers (Bills/12) | 100.0000% | 62.0019% | 11.7351% | 0.0110% | 0.0459% | 1.3385% | 0.0525% | 0.0003% | 0.0077% | 0.0003% |
| 5 | Average Customers (Lighting = Lights) | 100.0000% | 62.0019% | 11.7351% | 0.0110% | 0.0459% | 1.3385% | 0.0525% | 0.0003% | 0.0077% | 0.0003% |
| 6 | Weighted Average Customers (Lighting =9 Lights per Cust) | 100.0000% | 67.8091% | 14.1177% | 0.1198% | 0.0502% | 14.6392% | 0.5744% | 0.0033% | 0.1674% | 0.0066% |
| 7 | Street Lighting | 100.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 8 | Average Customers | 100.0000% | 62.0019% | 11.7351% | 0.0110% | 0.0459% | 1.3385% | 0.0525% | 0.0003% | 0.0077% | 0.0003% |
| 9 | Average Customers (Lighting = 9 Lights per Cust) | 100.0000% | 79.5280% | 15.0523% | 0.0141% | 0.0589% | 1.7169% | 0.0674% | 0.0004% | 0.0098% | 0.0004% |
| 10 | Average Secondary Customers | 100.0000% | 79.6082% | 15.0675% | 0.0000% | 0.0590% | 1.7186% | 0.0000% | 0.0000% | 0.0098% | 0.0000% |
| 11 | Average Primary Customers | 100.0000% | 79.5279% | 15.0523% | 0.0141% | 0.0589% | 1.7169% | 0.0674% | 0.0004% | 0.0098% | 0.0004% |
| 12 | Year End Customers | 100.0000% | 82.4258% | 15.6666% | 0.0143% | 0.0617% | 1.7318% | 0.0690% | 0.0004% | 0.0101% | 0.0004% |
| 13 | Year End Customers (Lighting = Lights) | 100.0000% | 58.4533% | 11.1102% | 0.0102% | 0.0437% | 1.2281% | 0.0489% | 0.0003% | 0.0072% | 0.0003% |
| 14 | Weighted Year End Customers (Lighting =9 Lights per Cust) | 100.0000% | 67.6638% | 14.1469% | 0.1176% | 0.0506% | 14.2163% | 0.5666% | 0.0033% | 0.1665% | 0.0065% |
| 15 | Street Lighting | 100.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 16 | Year End Customers | 100.0000% | 58.4533% | 11.1102% | 0.0102% | 0.0437% | 1.2281% | 0.0489% | 0.0003% | 0.0072% | 0.0003% |
| 17 | Year End Customers (Lighting = 9 Lights per Cust) | 100.0000% | 78.8336% | 14.9838% | 0.0137% | 0.0590% | 1.6563% | 0.0660% | 0.0004% | 0.0097% | 0.0004% |
| 18 | Year End Secondary Customers | 100.0000% | 78.9117% | 14.9987% | 0.0000% | 0.0590% | 1.6579% | 0.0000% | 0.0000% | 0.0097% | 0.0004% |
| 19 | Year End Primary Customers | 100.0000% | 78.8335% | 14.9838% | 0.0137% | 0.0590% | 1.6563% | 0.0660% | 0.0004% | 0.0097% | 0.0004% |
| 20 | Maximum Class Non-Coincident Peak Demands | 100.0000% | 48.7952% | 10.0515% | 0.5628% | 1.0091% | 15.4143% | 6.0539% | 0.1099% | 0.6728% | 0.0483% |
| 21 | Primary Distribution Plant -- Average Number of Customers | 100.0000% | 79.5280% | 15.0520% | 0.0140% | 0.0590% | 1.7170% | 0.0670% | 0.0000% | 0.0100% | 0.0000% |
| 22 | Customer Services -- Weighted cost of Services | 100.0000% | 58.7977% | 11.0904% | 0.0000% | 0.6246% | 29.4771% | 0.0000% | 0.0000% | 0.0102% | 0.0000% |
| 23 | Meter Costs -- Weighted Cost of Meters | 100.0000% | 62.2507% | 27.4643% | 0.0665% | 0.2129% | 7.8978% | 0.3178% | 0.0018% | 0.0235% | 0.0009% |
| 24 | Lighting Systems -- Lighting Customers | 100.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 25 | Meter Reading and Billing -- Weighted Cost | 100.0000% | 67.8090% | 14.1180% | 0.1200% | 0.0500% | 14.6390% | 0.5740% | 0.0030% | 0.1670% | 0.0070% |
| 26 | Marketing/Economic Development | 100.0000% | 79.5280% | 15.0520% | 0.0140% | 0.0590% | 1.7170% | 0.0670% | 0.0000% | 0.0100% | 0.0000% |
| 27 | Rev | 100.0000% | 37.7234% | 12.3024% | 0.2716% | 0.6889% | 19.5263% | 7.4897% | 0.1180% | 0.8164% | 0.0655% |
| 28 | Maximum Class Demands (Primary) | 100.0000% | 50.9370% | 10.4927% | 0.5875% | 1.0534% | 16.0909% | 6.3197% | 0.0000% | 0.7023% | 0.0504% |
| 29 | Sum of the Individual Customer Demands (Secondary) | 100.0000% | 60.8384% | 30.6741% | 0.0000% | 0.6130% | 7.3822% | 0.0000% | 0.0000% | 0.4117% | 0.0000% |
| 30 | Summer Peak Period Demand Allocator | 100.0000% | 41.6195% | 11.0682% | 0.6103% | 0.6812% | 19.1370% | 7.2461% | 0.1332% | 0.9538% | 0.0584% |
| 31 | Winter Peak Period Demand Allocator | 100.0000% | 52.7511% | 7.7310% | 0.6612% | 1.2325% | 14.7237% | 5.7115% | 0.1322% | 0.7056% | 0.0695% |
| 32 | Base Demand Allocator | 100.0000% | 35.0370% | 9.8116% | 0.2283% | 0.7114% | 20.4739% | 8.4848% | 0.1326% | 1.0208% | 0.0828% |
| 33 | Production Residual Winter Demand Allocator | 100.6554% | 35.2666% | 9.8759% | 0.2298% | 0.7161% | 20.6081% | 8.5404% | 0.1335% | 1.0274% | 0.0833% |
| 34 | Production Winter Demand Allocator | 100.0000% | 52.7511% | 7.7310% | 0.6612% | 1.2325% | 14.7237% | 5.7115% | 0.1322% | 0.7056% | 0.0695% |
| 35 | Production Residual Summer Demand Allocator | 100.0000% | 41.6195% | 11.0682% | 0.6103% | 0.6812% | 19.1370% | 7.2461% | 0.1332% | 0.9538% | 0.0584% |
| 36 | Production Summer Demand Allocator | 100.0000% | 41.6195% | 11.0682% | 0.6103% | 0.6812% | 19.1370% | 7.2461% | 0.1332% | 0.9538% | 0.0584% |
| 37 | Production Residual Summer Demand Allocator | 100.0000% | 41.6195% | 11.0682% | 0.6103% | 0.6812% | 19.1370% | 7.2461% | 0.1332% | 0.9538% | 0.0584% |
| 38 | Production Summer Demand Total | 100.0000% | 41.6195% | 11.0682% | 0.6103% | 0.6812% | 19.1370% | 7.2461% | 0.1332% | 0.9538% | 0.0584% |
| 39 | Distribution O&M | 100.0000% | 68.4498% | 16.2117% | 0.1262% | 0.4027% | 8.0037% | 1.3302% | 0.0001% | 0.2170% | 0.0106% |
| 40 | Total Other Revenue allocator | 100.0000% | 53.4859% | 11.9768% | 0.2875% | 0.5863% | 13.1806% | 4.9512% | 0.0853% | 0.5860% | 0.0470% |
| 41 | Customer Specific Assignment | | | | | | | | | | |
| 42 | Misc Service Revenue Allocator | 100.0000% | 48.1786% | 21.7721% | 0.4807% | 0.2791% | 19.3609% | 7.4262% | 0.1170% | 1.2434% | 0.0998% |
| 43 | Off-System Sales Allocator | 100.0000% | 28.4925% | 10.1819% | 0.0250% | 0.5628% | 22.4414% | 9.5502% | 0.1327% | 1.1273% | 0.0915% |
| 44 | Interruptible Credit Allocator | 100.0000% | 48.3182% | 9.0600% | 0.6409% | 1.0130% | 16.4811% | 6.3226% | 0.1326% | 0.8045% | 0.0651% |
| 45 | Operation and Maintenance Less Fuel | 100.0000% | 56.3555% | 12.5527% | 0.3063% | 0.5612% | 13.1893% | 3.9577% | 0.0657% | 0.5121% | 0.0390% |
| 46 | Base Rate Revenue | 100.0000% | 38.0662% | 12.6800% | 0.2770% | 0.6940% | 19.4254% | 7.3321% | 0.1159% | 0.7912% | 0.0634% |
| 47 | VDT Revenue | 100.0000% | 37.6185% | 12.2279% | 0.2761% | 0.6861% | 19.3858% | 7.4351% | 0.1171% | 0.8111% | 0.0652% |
| 48 | Merger Surcerdit Revenue | 100.0000% | 39.6134% | 12.9060% | 0.2882% | 0.7151% | 20.2821% | 7.2008% | 0.1231% | 0.8554% | 0.0682% |
| 49 | Remove ECR Revenues | 100.0000% | 37.9559% | 12.2478% | 0.2760% | 0.6915% | 19.2874% | 7.3933% | 0.1172% | 0.8088% | 0.0653% |
| 50 | Customer Specific Assignment | | | | | | | | | | |
| 51 | Gross Production Plant | 100.0000% | 36.1705% | 10.0280% | 0.2941% | 0.7062% | 20.2437% | 8.2714% | 0.1327% | 1.0092% | 0.0786% |
| 52 | Gross Transmission Plant | 100.0000% | 36.1705% | 10.0280% | 0.2941% | 0.7062% | 20.2437% | 8.2714% | 0.1327% | 1.0092% | 0.0786% |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Percents)**

| Alloc No. | Allocator Description | Total | Rate RS | GSS | GSP | AES | LPS | LPP | LPT | STODS | STODP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 53 | Gross Distribution Plant | 100.0000% | 57.2797% | 16.4046% | 0.2072% | 0.5731% | 10.2886% | 2.1939% | 0.0002% | 0.3378% | 0.0174% |
| 54 | Total Prod.,Ttrans., Distrib Plant | 100.0000% | 42.6634% | 11.9893% | 0.2674% | 0.6653% | 17.1817% | 6.4021% | 0.0920% | 0.8027% | 0.0598% |
| 55 | Dist. Overhead Lines Gross Plant | 100.0000% | 63.0190% | 14.5272% | 0.2950% | 0.6131% | 9.4394% | 3.1469% | 0.0001% | 0.3975% | 0.0251% |
| 56 | Gross Intangible Plant | 100.0000% | 42.6634% | 11.9893% | 0.2674% | 0.6653% | 17.1817% | 6.4021% | 0.0920% | 0.8027% | 0.0598% |
| 57 | Gross Total Plant in Service | 100.0000% | 42.6634% | 11.9893% | 0.2674% | 0.6653% | 17.1817% | 6.4021% | 0.0920% | 0.8027% | 0.0598% |
| 58 | Dist. Underground Lines Gross Plant | 100.0000% | 58.0121% | 14.3819% | 0.3847% | 0.7884% | 11.9011% | 4.1252% | 0.0001% | 0.5201% | 0.0329% |
| 59 | Gross General Plant | 100.0000% | 42.6634% | 11.9893% | 0.2674% | 0.6653% | 17.1817% | 6.4021% | 0.0920% | 0.8027% | 0.0598% |
| 60 | Labor Accts 501-507 | 100.0000% | 35.9827% | 9.9921% | 0.2832% | 0.7071% | 20.2819% | 8.3068% | 0.1327% | 1.0111% | 0.0793% |
| 61 | Labor Accts 511-514 | 100.0000% | 35.1968% | 9.8421% | 0.2376% | 0.7107% | 20.4415% | 8.4547% | 0.1327% | 1.0191% | 0.0822% |
| 62 | Labor Accts 536-540 | 100.0000% | 36.1705% | 10.0280% | 0.2941% | 0.7062% | 20.2437% | 8.2714% | 0.1327% | 1.0092% | 0.0786% |
| 63 | Labor Accts 542-545 | 100.0000% | 35.4070% | 9.8822% | 0.2498% | 0.7097% | 20.3988% | 8.4151% | 0.1327% | 1.0170% | 0.0814% |
| 64 | Labor Accts 581-588 | 100.0000% | 59.4764% | 18.9953% | 0.2309% | 0.5218% | 10.0250% | 2.3293% | 0.0007% | 0.2918% | 0.0180% |
| 65 | Labor Accts 591-598 | 100.0000% | 62.2757% | 14.3921% | 0.3063% | 0.6324% | 9.7188% | 3.2707% | 0.0001% | 0.4109% | 0.0261% |
| 66 | Labor Accts 500-916 | 100.0000% | 47.7901% | 12.6504% | 0.2436% | 0.5673% | 16.4039% | 5.5412% | 0.0749% | 0.6899% | 0.0520% |
| 67 | O&M less Purchased Power | 100.0000% | 39.4384% | 10.7160% | 0.2324% | 0.6616% | 19.0264% | 7.4945% | 0.1135% | 0.9095% | 0.0724% |
| 68 | Dist. Lines Gross Plant | 100.0000% | 62.0972% | 14.5004% | 0.3115% | 0.6454% | 9.8926% | 3.3270% | 0.0001% | 0.4200% | 0.0265% |
| 69 | Rate Base | 100.0000% | 41.4006% | 11.6020% | 0.2710% | 0.6724% | 17.7852% | 6.7683% | 0.0999% | 0.8428% | 0.0635% |
| 70 | Gross Transformer Plant | 100.0000% | 65.6188% | 26.5279% | 0.0000% | 0.4665% | 5.8681% | 0.0000% | 0.0000% | 0.3054% | 0.0001% |
| 71 | Dpreciation Expense | 100.0000% | 42.6264% | 11.9782% | 0.2675% | 0.6655% | 17.1991% | 6.4127% | 0.0922% | 0.8039% | 0.0599% |
| 72 | Total Labor | 100.0000% | 47.7901% | 12.6504% | 0.2436% | 0.5673% | 16.4039% | 5.5412% | 0.0749% | 0.6899% | 0.0520% |
| 73 | Distribution O&M | 100.0000% | 61.1837% | 16.6693% | 0.2659% | 0.5722% | 9.7504% | 2.7729% | 0.0004% | 0.3490% | 0.0218% |
| 74 | Sales Revenue | 100.0000% | 37.7234% | 12.3024% | 0.2716% | 0.6889% | 19.5263% | 7.4897% | 0.1180% | 0.8164% | 0.0655% |
| 75 | Distribution Poles, Lines, Transform & Services | 100.0000% | 62.8264% | 17.7735% | 0.1869% | 0.5896% | 10.6336% | 1.9965% | 0.0001% | 0.3448% | 0.0160% |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Percents)**

| Alloc No. | Allocator Description | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Energy (Loss Adjusted) | 14.3456% | 4.2790% | 0.5742% | 0.3511% | 0.4551% | 1.3634% | 1.9756% | 0.2259% | 0.0190% | 0.1692% | 0.2588% |
| 2 | Energy | 14.6260% | 4.4825% | 0.5854% | 0.3678% | 0.4640% | 1.4282% | 2.0696% | 0.2231% | 0.0187% | 0.1670% | 0.2555% |
| 3 | Customers (Monthly Bills) | 0.0058% | 0.0010% | 0.0046% | 0.0015% | 0.0005% | 0.0010% | 0.0002% | 10.5630% | 1.3562% | 4.3642% | 8.5088% |
| 4 | Average Customers (Bills/12) | 0.0059% | 0.0011% | 0.0045% | 0.0015% | 0.0005% | 0.0011% | 0.0002% | 10.5630% | 1.3563% | 4.3642% | 8.5088% |
| 5 | Average Customers (Lighting = Lights) | 0.0059% | 0.0011% | 0.0045% | 0.0015% | 0.0005% | 0.0011% | 0.0002% | 10.5630% | 1.3563% | 4.3642% | 8.5088% |
| 6 | Weighted Average Customers (Lighting =9 Lights per Cust) | 0.1280% | 0.0230% | 0.0492% | 0.0164% | 0.0098% | 0.0230% | 0.0033% | 0.9627% | 0.1236% | 0.3978% | 0.7755% |
| 7 | Street Lighting | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 62.9124% | 12.1619% | 10.0686% | 14.8570% |
| 8 | Average Customers | 0.0059% | 0.0011% | 0.0045% | 0.0015% | 0.0005% | 0.0011% | 0.0002% | 10.5630% | 1.3563% | 4.3642% | 8.5088% |
| 9 | Average Customers (Lighting = 9 Lights per Cust) | 0.0075% | 0.0013% | 0.0058% | 0.0019% | 0.0006% | 0.0013% | 0.0002% | 1.5054% | 0.1932% | 0.6219% | 1.2126% |
| 10 | Average Secondary Customers | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 1.5069% | 0.1935% | 0.6226% | 1.2139% |
| 11 | Average Primary Customers | 0.0075% | 0.0013% | 0.0058% | 0.0019% | 0.0006% | 0.0013% | 0.0002% | 1.5054% | 0.1933% | 0.6220% | 1.2127% |
| 12 | Year End Customers | 0.0080% | 0.0014% | 0.0062% | 0.0024% | 0.0006% | 0.0012% | 0.0002% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 13 | Year End Customers (Lighting = Lights) | 0.0056% | 0.0010% | 0.0044% | 0.0017% | 0.0004% | 0.0008% | 0.0001% | 9.9492% | 1.1546% | 9.9492% | 8.0308% |
| 14 | Weighted Year End Customers (Lighting =9 Lights per Cust) | 0.1306% | 0.0229% | 0.0506% | 0.0196% | 0.0098% | 0.0196% | 0.0033% | 0.9597% | 0.1114% | 0.9597% | 0.7747% |
| 15 | Street Lighting | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 62.9124% | 12.1619% | 10.0686% | 14.8570% |
| 16 | Year End Customers | 0.0056% | 0.0010% | 0.0044% | 0.0017% | 0.0004% | 0.0008% | 0.0001% | 9.9492% | 1.1546% | 9.9492% | 8.0308% |
| 17 | Year End Customers (Lighting = 9 Lights per Cust) | 0.0076% | 0.0013% | 0.0059% | 0.0023% | 0.0006% | 0.0011% | 0.0002% | 1.4908% | 0.1731% | 1.4908% | 1.2034% |
| 18 | Year End Secondary Customers | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 1.4924% | 0.1732% | 1.4924% | 1.2046% |
| 19 | Year End Primary Customers | 0.0076% | 0.0013% | 0.0059% | 0.0023% | 0.0006% | 0.0011% | 0.0002% | 1.4909% | 0.1730% | 1.4909% | 1.2034% |
| 20 | Maximum Class Non-Coincident Peak Demands | 9.1508% | 2.6027% | 0.6875% | 0.3680% | 0.4716% | 1.1244% | 2.7379% | 0.0468% | 0.0039% | 0.0350% | 0.0536% |
| 21 | Primary Distribution Plant -- Average Number of Customers | 0.0080% | 0.0010% | 0.0060% | 0.0020% | 0.0010% | 0.0010% | 0.0000% | 1.5050% | 0.1930% | 0.6220% | 1.2140% |
| 22 | Customer Services -- Weighted cost of Services | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 23 | Meter Costs -- Weighted Cost of Meters | 0.0362% | 0.0073% | 0.0273% | 0.0090% | 0.0027% | 0.0055% | 0.0007% | 0.8002% | 0.0000% | 0.8749% | 0.0000% |
| 24 | Lighting Systems -- Lighting Customers | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 62.9120% | 12.1620% | 10.0690% | 14.8570% |
| 25 | Meter Reading and Billing -- Weighted Cost | 0.1280% | 0.0230% | 0.0490% | 0.0160% | 0.0100% | 0.0230% | 0.0030% | 0.9640% | 0.1240% | 0.3980% | 0.7750% |
| 26 | Marketing/Economic Development | 0.0080% | 0.0010% | 0.0060% | 0.0020% | 0.0010% | 0.0010% | 0.0000% | 1.5050% | 0.1930% | 0.6230% | 1.2130% |
| 27 | Rev | 11.6600% | 3.0621% | 0.5976% | 0.3469% | 0.4259% | 1.2034% | 2.0135% | 0.6573% | 0.1239% | 0.3664% | 0.5407% |
| 28 | Maximum Class Demands (Primary) | 9.5525% | 0.0000% | 0.7177% | 0.0000% | 0.4923% | 0.0000% | 2.8581% | 0.0488% | 0.0041% | 0.0366% | 0.0560% |
| 29 | Sum of the Individual Customer Demands (Secondary) | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0271% | 0.0023% | 0.0203% | 0.0310% |
| 30 | Summer Peak Period Demand Allocator | 11.4258% | 3.0649% | 0.6568% | 0.4055% | 0.3877% | 1.2102% | 1.3414% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 31 | Winter Peak Period Demand Allocator | 9.7997% | 2.9553% | 0.6859% | 0.3549% | 0.4454% | 0.9355% | 0.9239% | 0.0608% | 0.0051% | 0.0455% | 0.0696% |
| 32 | Base Demand Allocator | 14.3456% | 4.2790% | 0.5742% | 0.3511% | 0.4551% | 1.3634% | 1.9756% | 0.2259% | 0.0190% | 0.1692% | 0.2588% |
| 33 | Production Residual Winter Demand Allocator | 14.4396% | 4.3070% | 0.5779% | 0.3534% | 0.4581% | 1.3723% | 1.9886% | 0.2274% | 0.0191% | 0.1703% | 0.2605% |
| 34 | Production Winter Demand Allocator | 9.7997% | 2.9553% | 0.6859% | 0.3549% | 0.4454% | 0.9355% | 0.9239% | 0.0608% | 0.0051% | 0.0455% | 0.0696% |
| 35 | Production Residual Summer Demand Allocator | 11.4258% | 3.0649% | 0.6568% | 0.4055% | 0.3877% | 1.2102% | 1.3414% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 36 | Production Summer Demand Allocator | 11.4258% | 3.0649% | 0.6568% | 0.4055% | 0.3877% | 1.2102% | 1.3414% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 37 | Production Residual Summer Demand Allocator | 11.4258% | 3.0649% | 0.6568% | 0.4055% | 0.3877% | 1.2102% | 1.3414% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 38 | Production Summer Demand Total | 11.4258% | 3.0649% | 0.6568% | 0.4055% | 0.3877% | 1.2102% | 1.3414% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 39 | Distribution O&M | 1.9791% | 0.0005% | 0.1505% | 0.0008% | 0.1021% | 0.0004% | 0.5914% | 0.8286% | 0.0957% | 0.8250% | 0.6737% |
| 40 | Total Other Revenue allocator | 7.9926% | 2.2061% | 0.4296% | 0.2418% | 0.2954% | 0.7880% | 1.1343% | 0.6869% | 0.0958% | 0.3726% | 0.5704% |
| 41 | Customer Specific Assignment | | | | | | | | | | | |
| 42 | Misc Service Revenue Allocator | 0.7753% | 0.2036% | 0.0127% | 0.0000% | 0.0000% | 0.0215% | 0.0290% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| 43 | Off-System Sales Allocator | 16.2665% | 4.9098% | 0.5248% | 0.3393% | 0.4712% | 1.5203% | 2.4120% | 0.3193% | 0.0268% | 0.2391% | 0.3657% |
| 44 | Interruptible Credit Allocator | 10.4473% | 2.9990% | 0.6743% | 0.3750% | 0.4224% | 1.0449% | 1.0901% | 0.0366% | 0.0031% | 0.0274% | 0.0419% |
| 45 | Operation and Maintenance Less Fuel | 6.3709% | 1.6853% | 0.3679% | 0.1832% | 0.2443% | 0.5688% | 0.8556% | 1.0975% | 0.1697% | 0.3561% | 0.5611% |
| 46 | Base Rate Revenue | 11.2612% | 3.4430% | 0.6055% | 0.3472% | 0.4233% | 1.1849% | 1.4658% | 0.7146% | 0.1379% | 0.3932% | 0.5782% |
| 47 | VDT Revenue | 11.5819% | 3.5289% | 0.5940% | 0.3436% | 0.4226% | 1.1982% | 1.9998% | 0.6517% | 0.1251% | 0.3643% | 0.5672% |
| 48 | Merger Surcerdit Revenue | 8.7778% | 2.6332% | 0.6200% | 0.3652% | 0.4425% | 1.2510% | 2.0914% | 0.6866% | 0.1324% | 0.3821% | 0.5657% |
| 49 | Remove ECR Revenues | 11.4722% | 3.4960% | 0.5931% | 0.3416% | 0.4173% | 1.2026% | 1.9771% | 0.6472% | 0.1158% | 0.3616% | 0.5323% |
| 50 | Customer Specific Assignment | | | | | | | | | | | |
| 51 | Gross Production Plant | 13.8428% | 4.0699% | 0.5884% | 0.3604% | 0.4435% | 1.3370% | 1.8664% | 0.1870% | 0.0157% | 0.1401% | 0.2142% |
| 52 | Gross Transmission Plant | 13.8428% | 4.0699% | 0.5884% | 0.3604% | 0.4435% | 1.3370% | 1.8664% | 0.1870% | 0.0157% | 0.1401% | 0.2142% |

**Kentucky Utilities**
**Electric Cost of Service Study**
**(Allocator Percents)**

| Alloc No. | Allocator Description | LCIP | LCIT | MPP | MPT | LMPP | LMPT | LITOD | SL | SLDEC | POL | OL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 53 | Gross Distribution Plant | 3.2769% | 0.0006% | 0.2484% | 0.0009% | 0.1690% | 0.0005% | 0.9795% | 4.7280% | 0.8761% | 1.0989% | 1.3188% |
| 54 | Total Prod.,Ttrans., Distrib Plant | 10.5929% | 2.8183% | 0.4838% | 0.2498% | 0.3590% | 0.9259% | 1.5936% | 1.5838% | 0.2803% | 0.4350% | 0.5540% |
| 55 | Dist. Overhead Lines Gross Plant | 4.7271% | 0.0004% | 0.3569% | 0.0007% | 0.2437% | 0.0004% | 1.4137% | 0.6132% | 0.0703% | 0.6064% | 0.5042% |
| 56 | Gross Intangible Plant | 10.5929% | 2.8183% | 0.4838% | 0.2498% | 0.3590% | 0.9259% | 1.5936% | 1.5838% | 0.2803% | 0.4350% | 0.5540% |
| 57 | Gross Total Plant in Service | 10.5929% | 2.8183% | 0.4838% | 0.2498% | 0.3590% | 0.9259% | 1.5936% | 1.5838% | 0.2803% | 0.4350% | 0.5540% |
| 58 | Dist. Underground Lines Gross Plant | 6.2203% | 0.0002% | 0.4682% | 0.0004% | 0.3206% | 0.0002% | 1.8608% | 0.3355% | 0.0378% | 0.3265% | 0.2829% |
| 59 | Gross General Plant | 10.5929% | 2.8183% | 0.4838% | 0.2498% | 0.3590% | 0.9259% | 1.5936% | 1.5838% | 0.2803% | 0.4350% | 0.5540% |
| 60 | Labor Accts 501-507 | 13.9261% | 4.1046% | 0.5860% | 0.3589% | 0.4454% | 1.3414% | 1.8845% | 0.1935% | 0.0163% | 0.1449% | 0.2216% |
| 61 | Labor Accts 511-514 | 14.2747% | 4.2495% | 0.5762% | 0.3524% | 0.4535% | 1.3597% | 1.9602% | 0.2205% | 0.0185% | 0.1651% | 0.2525% |
| 62 | Labor Accts 536-540 | 13.8428% | 4.0699% | 0.5884% | 0.3604% | 0.4435% | 1.3370% | 1.8664% | 0.1870% | 0.0157% | 0.1401% | 0.2142% |
| 63 | Labor Accts 542-545 | 14.1815% | 4.2108% | 0.5788% | 0.3541% | 0.4513% | 1.3548% | 1.9400% | 0.2132% | 0.0179% | 0.1597% | 0.2443% |
| 64 | Labor Accts 581-588 | 3.3478% | 0.0028% | 0.2611% | 0.0036% | 0.1729% | 0.0021% | 0.9977% | 1.7849% | 0.2683% | 0.7663% | 0.5032% |
| 65 | Labor Accts 591-598 | 4.9161% | 0.0004% | 0.3710% | 0.0007% | 0.2534% | 0.0003% | 1.4702% | 0.7408% | 0.0974% | 0.6000% | 0.5166% |
| 66 | Labor Accts 500-916 | 9.0215% | 2.3261% | 0.4216% | 0.2028% | 0.3114% | 0.7575% | 1.4114% | 0.6876% | 0.0924% | 0.3516% | 0.4029% |
| 67 | O&M less Purchased Power | 12.5614% | 3.6304% | 0.5223% | 0.3020% | 0.4065% | 1.1625% | 1.7828% | 0.3804% | 0.0436% | 0.2298% | 0.3135% |
| 68 | Dist. Lines Gross Plant | 5.0020% | 0.0004% | 0.3774% | 0.0007% | 0.2578% | 0.0003% | 1.4960% | 0.5621% | 0.0643% | 0.5549% | 0.4635% |
| 69 | Rate Base | 11.2318% | 3.0666% | 0.5036% | 0.2712% | 0.3755% | 1.0066% | 1.6476% | 1.3016% | 0.2266% | 0.3766% | 0.4868% |
| 70 | Gross Transformer Plant | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.4146% | 0.0475% | 0.4096% | 0.3414% |
| 71 | Dpreciation Expense | 10.6114% | 2.8254% | 0.4844% | 0.2505% | 0.3595% | 0.9283% | 1.5952% | 1.5758% | 0.2788% | 0.4333% | 0.5520% |
| 72 | Total Labor | 9.0215% | 2.3261% | 0.4216% | 0.2028% | 0.3114% | 0.7575% | 1.4114% | 0.6876% | 0.0924% | 0.3516% | 0.4029% |
| 73 | Distribution O&M | 4.0930% | 0.0016% | 0.3130% | 0.0021% | 0.2111% | 0.0012% | 1.2224% | 1.2069% | 0.1717% | 0.6836% | 0.5077% |
| 74 | Sales Revenue | 11.6600% | 3.0621% | 0.5976% | 0.3469% | 0.4259% | 1.2034% | 2.0135% | 0.6573% | 0.1239% | 0.3664% | 0.5407% |
| 75 | Distribution Poles, Lines, Transform & Services | 3.0016% | 0.0002% | 0.2264% | 0.0004% | 0.1547% | 0.0002% | 0.8977% | 0.4618% | 0.0529% | 0.4560% | 0.3807% |

Schedule GAW_5

Kentucky Utilities
OAG Proosed Revenue Distribution

| Class | Total Revenue @ Current rates 1/ | KU Proposed ROR @ Current Rates | KU Proposed Indexed ROR | KU Proposed Increase Amount 1/ | KU Proposed Increase Percent | KU Proposed Percent Of System Average | OAG Proposed ROR @ Current Rates | OAG Proposed Indexed ROR | OAG Proposed Increase Amount | OAG Proposed Increase Percent | OAG Proposed Percent Of System Average |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate RS | $387,629,753 | 3.58% | 50% | $17,329,356 | 4.47% | 233% | 5.36% | 75% | $9,723,431 | 2.51% | 131% |
| GSS | $130,095,608 | 12.20% | 171% | $0 | 0.00% | 0% | 11.43% | 160% | $1,247,416 | 0.96% | 50% |
| GSP | $2,785,088 | 4.79% | 67% | $446,784 | 16.04% | 837% | 8.70% | 122% | $40,057 | 1.44% | 75% |
| AES | $7,056,889 | 6.32% | 88% | $321,938 | 4.56% | 238% | 7.68% | 107% | $135,329 | 1.92% | 100% |
| LPS | $194,114,135 | 11.53% | 161% | $0 | 0.00% | 0% | 8.48% | 119% | $2,791,882 | 1.44% | 75% |
| LPP | $76,285,742 | 11.82% | 165% | $0 | 0.00% | 0% | 8.01% | 112% | $1,097,194 | 1.44% | 75% |
| LPT | $1,203,810 | 10.07% | 141% | ($70,621) | -5.87% | -306% | 10.10% | 141% | $17,314 | 1.44% | 75% |
| STODS | $8,255,296 | 6.73% | 94% | $82,070 | 0.99% | 52% | 3.95% | 55% | $197,889 | 2.40% | 125% |
| STODP | $662,844 | 6.92% | 97% | $6,637 | 1.00% | 52% | 4.72% | 66% | $15,889 | 2.40% | 125% |
| LCIP | $116,778,254 | 8.55% | 120% | $0 | 0.00% | 0% | 5.30% | 74% | $2,799,307 | 2.40% | 125% |
| LCIT | $30,258,728 | 5.54% | 77% | ($38,022) | -0.13% | -7% | 3.64% | 51% | $725,336 | 2.40% | 125% |
| MPP | $6,401,293 | 12.88% | 180% | $575,463 | 8.99% | 469% | 13.17% | 184% | $61,379 | 0.96% | 50% |
| MPT | $3,560,058 | 13.35% | 187% | $100,123 | 2.81% | 147% | 13.96% | 195% | $34,135 | 0.96% | 50% |
| LMPP | $4,354,116 | 11.42% | 160% | $29,196 | 0.67% | 35% | 9.70% | 136% | $62,624 | 1.44% | 75% |
| LMPT | $12,298,559 | 13.40% | 187% | $5,099 | 0.04% | 2% | 10.57% | 148% | $176,886 | 1.44% | 75% |
| LITOD | $20,806,718 | 25.00% | 350% | $0 | 0.00% | 0% | 15.67% | 219% | $199,504 | 0.96% | 50% |
| SL | $7,105,084 | 4.51% | 63% | $304,645 | 4.29% | 224% | 6.13% | 86% | $136,254 | 1.92% | 100% |
| SLDEC | $1,270,601 | 6.87% | 96% | $61,720 | 4.86% | 253% | 8.71% | 122% | $18,275 | 1.44% | 75% |
| POL | $3,990,878 | 13.27% | 186% | $195,020 | 4.89% | 255% | 15.42% | 216% | $38,266 | 0.96% | 50% |
| OL | $5,784,458 | 16.28% | 228% | $224,423 | 3.88% | 202% | 19.06% | 267% | $55,464 | 0.96% | 50% |
| Total Company | ********** | 7.15% | 100% | $19,573,831 | 1.92% | 100% | 7.15% | 100% | $19,573,831 | 1.92% | 100% |

1/ Per Seelye Exhibit 19

**Kentucky Utilities**
**Customer Cost Analysis**

| | | Residential |
|---|---|---|
| **Gross Plant** | | |
| | 369 Services | $45,879,905 |
| | 370 Meters | $38,269,497 |
| | Total Gross Plant | $84,149,401 |
| **Depreciation Reserve** | | |
| | Services (OVHD & UNGD) | 21,375,804 |
| | Meters | 17,830,055 |
| | Total Depreciation Reserve | $39,205,859 |
| **Total Net Plant** | | $44,943,542 |
| **Operation & Maintenance Expenses** | | |
| | Dist Oper - Meter | $3,794,957 |
| | Dist Oper - Cust Installations | -$42,053 |
| | Meter Reading | $2,798,228 |
| | Records & Collections | $7,662,805 |
| | Dist Maint - Meters | $0 |
| | Total O & M Expenses | $14,213,937 |
| **Depreciation Expense** | | |
| | Services | $1,372,754 |
| | Meters | $1,145,046 |
| | Total Depreciation Expense | $2,517,799 |
| **Revenue Requirement** | | |
| | Interest | $1,074,151 |
| | Equity return | $2,367,626 |
| | Income Tax | $1,426,646 |
| | Revenue For Return | 4,868,423 |
| | O & M Expenses | $14,213,937 |
| | Depreciation Expense | $2,517,799 |
| | Total Customer Revenue Requirement | $21,600,159 |
| | Number of Bills | $4,958,111 |
| | Monthly Cost | $4.36 |

| | PCT | Cost | WGHT Cost |
|---|---|---|---|
| Debt | 47.37% | 5.05% | 2.39% |
| Common | 52.68% | 10.00% | 5.27% |
| Total | 100.00% | | 7.66% |