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	236	151									
Seasonal Aggregate	1,327	1,085	188	1,273	897	Yes	-54	1.62464	412,293	(35,909,380)	66.41634%
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	$434,201,182	$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	-$6,876,000	-$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	-$285,407	-$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	$4,230,818	$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	$11,588	$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	-$8,373,654	$0	$0	$0	$0	$0
Adjustment for Merger Surecredit	$18,568,431	$7,355,580	$2,396,449	$53,506	$132,778	$3,786,072	$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	$394,428
Sub-Total	-$133,456,131	-$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	$1,839,353	$5,300,608	$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	$85,691	$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	$48,085	$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	$18,413	$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	-$880	-$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	$81,817	$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	$162,264	$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	$498,185	$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	$13,488	$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	-$66	-$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	$7,564,538	$601,910	$104,594,650
rating Income -- Pro-Forma	$158,501,898	$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	$1,090,884,641	$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	-$208,164	-$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	$6,696,875	$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	-$351,667	-$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	-$6,956	-$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	$486,942	$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	-$495,563	-$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	$12,296,559	$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	$14,382,039	$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	$851,206	$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	-$7,667	-$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	$12,367	$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	$14,518	$16,089	$0	$0	$0	$0
Adjustment for new credit facilities bank fees	$61,504	$10,100	$5,439	$7,531	$20,186	$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	$2,182,601	$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
sh Working Capital	-$70,529	-$10,148	-$5,867	-$7,898	-$22,585	-$34,635	-$7,380	-$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	$38,611	$16,558	$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	$2,698,284	$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	$1,060,951	$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	$4,168,429	$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	$28,714,861	$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		$189,193,330	$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	$61,530	$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	$172,249,328	$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	$222,184	$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	$1,075,882,772	$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	$60,380,324	$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	$474,185,401	$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	$7,883,139	$2,862,826	$41,121	$358,940	$26,721
Intangible Plant	$16,103,542	$8,870,312	$1,930,705	$43,055	$107,130	$2,786,857	$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**	**$11,403,406**	**$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	$175,180	$3,907	$9,721	$251,062	$93,549	$1,344	$11,729	$873
Sub-total	$154,829,123	$63,509,583	$17,557,887	$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	$1,148,765	$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	$7,438	$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	$16,805	$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	$8,640	$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	$4,328,714	$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	$2,414,673	$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	$2,458,662	$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	312,674,464											
	Customer		$9,350	$1,836	$7,246	$2,805	$701	$1,403	$234	$1,832,026	$212,611	$1,832,026	$1,478,773
	Demand		$16,129,936	$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	$636	$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	$21,206	$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	$6,662	$1,719,488	$4,946	$9,969,089	$48,118,361	$6,915,935	$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	$34,830,247	$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		$4,500,845	$852	$341,169	$1,169	$232,048	$687	$1,345,345	$8,493,654	$1,203,220	$1,509,337	$1,811,243
	CWIP General Plant		$2,931,647	$780,028	$133,911	$89,150	$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	$3,918,007
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	$95,638	$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	$4,738,837	$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**	**$25,575,316**	**$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	$206,663	$323,769	$412,328
Prepayments	$154,766	$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	$3,361,323	$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	$38,975
Sub-total	$26,631,228	$7,016,064	$1,224,222	$822,040	$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	$867	$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	$6,488	$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	$908,471	$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 HYORAULIC 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	$871	$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	$888,518	$321,381	$89,100	$2,613	$8,275	$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
589 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	$273,008	$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 MISD 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	$25,096	$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	$20,706,677	$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	$6,785,613	$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	$461,931	$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	$5,616,834	$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	$158,669	$369,260	$10,464,624	$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**	**$162,455,062**	**$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**	**$717,662**	**$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	$1,084	$30,495	$12,460	$200	$1,520	$118
Other Production	$14,711,384	$5,321,174	$1,475,251	$43,264	$103,891	$2,978,127	$1,218,843	$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	$4,895,341	$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**	**$48,776,559**	**$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	$4,466,162	$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	$8,220	$54,294	$4,042
Gain on Disposition of Allowances	-$504,602	-$208,908	-$58,544	-$1,367	-$3,383	-$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	$473,948	$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**	**$695,008**	**$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	$486,290	$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	$1,838,084	$4,907,408	$7,111,173	$813,276	$68,338	$608,992
502 STEAM EXPENSES	$1,246,317	$367,313	$53,104	$32,531	$40,024	$120,668	$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	$86,661	$200,970	$280,548	$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	$11,860	$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	$8,267	$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	$66,304	$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	$657,716	$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	$10,679	$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	$80	$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	$1,586,388	$611	$121,317	$807	$81,828	$472	$473,771	$467,766	$68,568	$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	$8,765	$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	$11,632	$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	$49,916
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	**$101,902,083**	**$29,650,637**	**$4,207,571**	**$2,462,928**	**$3,284,104**	**$9,489,990**	**$14,362,039**	**$2,764,499**	**$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	$51,446	$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	$26,871	$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	-$8	-$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	-$1,366	-$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	$6,318,416	$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	$2,587
	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	**$2,362,470**
	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	$206,507	$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	$12,356	$355,668	$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	$1,126,286	$315,503	$7,616	$22,781	$655,284	$271,028	$4,253	$32,670	$2,634	$457,599
8	511 MAINTENANCE OF STRUCTURES	$767,400	$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	$1,208,726	$422,800	$118,399	$2,755	$8,585	$247,064	$102,388	$1,801	$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	$11,863	$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	$246	$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
Electric Cost of Service Study
(Salaries and Wages)

	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	$128,788	$52,621	$844	$6,420	$500	$88,085
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	$119,781	$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	$8,125
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	$1,063,156	$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	$4,676,164	$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
Electric Cost of Service Study
(Salaries and Wages)

	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	$1,387	$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	$194,820	$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	$5,720,831	$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	$28,307	$61,283	$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	$9,049,258	$3,056,810	$41,301	$380,597	$28,668	$4,976,748

Kentucky Utilities
Electric Cost of Service Study
(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	$85,851	$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	$20,208	$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	$12,647	$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	$248	$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	$2,628	$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	$18,695	$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
SW. 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

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	$32,884	$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	$46	$111	$16	$4,684	$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	$1,078	$138	$444	$866
Total Customer Accounts Labor Expense	$1,535	$3,268	$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	$206	$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	$91,897	$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	$1,283,169	$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**	**$86,961,352**	**$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	$1,977,848,848	$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	$8,497,809,251	$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	$4,956,111	$938,420	$872	$3,668	$107,045	$4,202	$24	$612	$24
4	Average Customers (Bills/12)	$666,393	$413,176	$78,202	$73	$308	$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	$78,788	$72	$310	$8,707	$347	$2	$51	$2
17	Year End Customers (Lighting = 9 Lights per Cust)	$525,687	$414,418	$78,788	$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	83319858.000	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	$44,308	$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	$16,189,248	$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	$12,188,074	$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	$844,289	$1,581	$35,811	$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	$211,932,758	$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	$118,563	$924,581	$70,491
46	Base Rate Revenue	$958,043,947	$364,691,143	$121,479,709	$2,654,163	$6,848,873	$186,103,586	$70,244,702	$1,110,048	$7,580,018	$607,081
47	VDT Revenue	-$3,405,552	-$1,281,117	-$418,427	-$9,403	-$23,364	-$860,193	-$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	$4,017,866	$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	$10,829,600	$237,039	$589,811	$15,233,079	$5,676,020	$81,530	$711,856	$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	$1,988,004	$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	$456	$187	$3	$23	$2
63	Labor Accts 542-545	$90,888	$32,173	$8,980	$227	$845	$18,536	$7,847	$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	$258,536	$7,417,960	$2,505,763	$33,856	$311,987	$23,500
67	O&M less Purchased Power	$632,258,594	$249,352,560	$87,753,145	$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	$7,140,769	$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	$55,691
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	$8,460,794	$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	$3,626,828	$34,102,592	$52,167,064
2	Energy	$2,747,259,009	$841,958,377	$109,956,679	$69,078,000	$87,153,119	$266,266,000	$388,735,959	$41,902,693	$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	$660,424
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	$6,497,472	$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	$8,379,424	$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	$52,460	$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	6847736.000	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	$6,056	$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	$1,379,920	$7,136	$934,991	$3,568	$5,418,374	$7,591,249	$876,755	$7,556,078	$8,172,171
40	Total Other Revenue allocator	$492,246	$135,872	$26,455	$14,891	$18,194	$48,529	$89,861	$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	$8,639	$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	$6,671,502	$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	-$218,899	-$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	$76,238,001	$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	$17,007,691	$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	$9,989,089	$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	$30,636,285	$52,729,320	$52,403,456	$9,276,003	$14,393,006	$18,329,846
55	Dist. Overhead Lines Gross Plant	$18,139,266	$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	$58,005	$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	$14,676,181	$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	$1,480,189	$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	$6	$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	$62,830	$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	$2,609,887	$2,179,736
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%	15.6686%	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%	0.8246%	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%	9.8118%	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%	46.1786%	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%	0.6428%	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%	0.5898%	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	0.0078%	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%	0.8588%	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 Allocetor	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%	0.8743%	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%	1.1649%	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%	4.7260%	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%	0.0376%	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%	0.4580%	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%	3.84%	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%	88%	$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%	188%	$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	4,888,423
	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%