COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

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

DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

MARCH 3, 2017

TABLE OF CONTENTS

PAGE

I. INTRODUCTION 1

II. CLASS COST OF SERVICE 2

- **A. Generation Plant** 7
  - **1. Probability of Dispatch Method** 22
  - **2. Base-Intermediate Peak (“BIP”) Method** 25
- **B. Distribution Plant** 28

III. CLASS REVENUE DISTRIBUTION 45

IV. RESIDENTIAL RATE DESIGN 51

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia 23229.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. 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 36-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have provided testimony relating to class cost of service and rate design before this Commission on numerous occasions including previous Kentucky Utilities ("KU") and Louisville Gas & Electric ("LG&E") rate cases.

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

A. Technical Associates has been retained by the Kentucky Office of the Attorney General ("OAG") to assist in its evaluation of the accuracy and reasonableness of KU's jurisdictional class cost of service study, proposed distribution of revenues by class and residential rate design. 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.

II. <u>CLASS COST OF SERVICE</u>

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the Kentucky Public Service Commission, KU has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED 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 individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In these regards, 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 only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the FERC), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1] 324 U.S. 581, 65 S. Ct. 829.

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

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

A. In conducting my independent analysis, I reviewed the structure and organization of the Company's CCOSS and 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. I then verified the accuracy of KU's CCOSS model by replicating its results using my own computer model. 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. NOTWITHSTANDING ANY CONCEPTUAL DISAGREEMENTS ON HOW INDIVIDUAL COSTS SHOULD BE ALLOCATED ACROSS CLASSES, DID YOU FIND THE COMPANY'S STUDY TO BE ACCURATE?

A. As part of my detailed examination of Company witness William Seeyle's CCOSS, I discovered a few minor errors within his model. These minor errors relate to: (1) a formula error within his functionalization/classification process concerning

Distribution O&M Labor expenses;[2] (2) his assignment of meter reading expenses to the Lighting classes that are not metered;[3] (3) an inconsistency in the allocation of advertising expenses wherein Mr. Seeyle first allocated advertising expenses (Account 913) based on weighted number of customers and then deducted the Company's proforma advertising expense adjustment based on sales revenues; and, (4) the calculation and assignment of income tax expense to individual rate classes.[4]

Q. PLEASE PROVIDE A SUMMARY OF CLASS RATES OF RETURN UNDER MR. SEEYLE'S AS-FILED CCOSS AND THOSE OBTAINED WITH THE MINOR CORRECTIONS YOU DISCUSSED ABOVE.

A. Although Mr. Seeyle conducted CCOSS analyses using two different methodologies, the table below provides a comparison of his as-filed "Modified Base-Intermediate-Peak" method to those obtained with the corrections described above:

---

[2] This error can be seen in Mr. Seeyle's Modified BIP electronic (Excel) model in the tab: "Functional Assignment," row 481.

[3] Mr. Seeyle classifies meter reading expenses (Account 902) as "Customer Accounts Expense." He then allocates his classified "Customer Accounts Expense" based on a weighted customer basis (Allocator CUST05), which includes street lighting customers. Street lighting is not metered such that this class should not be assigned any meter reading expenses.

[4] Mr. Seeyle calculates class income tax expense before the Company's proposed proforma adjustments to reduce revenue for Off System ECR revenues and advertising expenses and then effectively allocates the income tax effect of these combined adjustments based on taxable income before the adjustments. The error relates to the fact that some classes (such as the Residential class) are assigned a much larger percentage of the reduced ECR revenues but do not receive the full benefit of the reduced tax expense associated with this reduction in revenues.

Seeyle Modified Base-Intermediate-Peak
Rate of Return ("ROR") At Current Rates
As-Filed and Corrected

Class	As-Filed	Corrected
Residential	4.16%	4.15%
General Service	9.10%	9.04%
All Electric Schools	5.27%	5.25%
Pwr Svc-Secondary	9.61%	9.57%
Pwr Svc-Primary	11.83%	11.63%
TOD-Secondary	6.42%	6.43%
TOD-Primary	4.48%	4.45%
Retail Transmission	4.55%	4.51%
Fluctuating Load	1.50%	1.50%
Outdoor Lighting	7.67%	8.60%
Lighting Energy	9.83%	9.83%
Traffic Energy	10.02%	8.07%
TOTAL	5.56%	5.56%

As indicated above, these corrections can be characterized as minor in nature wherein the only material differences relate to Outdoor Lighting and Traffic Energy.

Q. ARE THERE CERTAIN ASPECTS OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TEND TO BE MORE CONTROVERSIAL THAN OTHERS?

A. Yes. For decades, cost allocation experts and to some degree, utility commissions, have disagreed on how generation and certain distribution plant accounts should be allocated across classes. Beyond a doubt, these two issue areas are the most contentious and often have the largest impact on the results of achieved class RORs.

Q. WHAT METHODS DID MR. SEEYLE UTILIZE TO CONDUCT HIS CCOSS?

A. With regard to the allocation of generation (production) plant, Mr. Seeyle utilized two separate approaches: Modified Base-Intermediate-Peak ("Modified BIP"); and, Loss of Load Probability ("LOLP"). With regard to distribution plant, Mr. Seeyle classified both the primary and secondary voltage systems as partially customer-related and partially demand-related. As a result, Mr. Seeyle allocates individual distribution plant accounts based partially on number of customers and partially on peak demands. I will explain each of these approaches in more detail later in my testimony.

A. <u>Generation Plant</u>

Q. BEFORE WE DISCUSS SPECIFIC COST ALLOCATION METHODOLOGIES, PLEASE EXPLAIN HOW GENERATION/PRODUCTION-RELATED COSTS ARE INCURRED; I.E., PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO GENERATION/PRODUCTION RESOURCES.

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 (load) 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 kilowatt-hour ("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 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 further complicate matters, the electric utility industry is unique in that there is a distinct energy/capacity trade-off relating to production 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 kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment 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.

The investment (capacity) costs of generation facilities are fixed in nature and are considered sunk investment costs. At the same time, the energy cost of running generation plants tends to be almost all variable in nature such that base load units tend to have low variable running costs whereas peaking units tend to have much higher variable running costs per kWh. As a result, generation assets tend to be dispatched based upon the variable running costs of each unit wherein lower variable cost units are dispatched before higher cost units. As such, total system production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes each and every hour of the year. This would result in 8,760 hourly allocations. Although such an analysis is certainly possible with today's technology, hourly supply (generation) and demand (customer load) data is required to conduct such hour-by-hour analyses. While most utilities can and do record hourly production output, they often do not estimate class loads on an hourly basis (at least not for every hour of the year). With these constraints in mind, several allocation methodologies have been developed to allocate electric utility generation plant investment and attendant costs. Each of these methods has strengths and weaknesses regarding the reasonableness in reflecting cost causation.

Q. APPROXIMATELY HOW MANY COST ALLOCATION METHODOLOGIES EXIST RELATING TO THE ALLOCATION OF GENERATION PLANT?

A. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[5]

---

[5] Principles of Public Utility Rates, Second Edition, page 495.

Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION 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, under this method, the sole criterion for assigning one hundred percent of fixed generation 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 such as KU had a peak load of 6,500 mW and its actual optimal generation mix included an assortment of 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 6,500 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 and will, therefore, enjoy a “free ride” on the assignment of generation costs that this class requires.

<u>4-CP</u> -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

<u>Summer and Winter Coincident Peak (“S/W Peak”)</u> -- 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. 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 no more reasonable than the 1-CP method.

<u>12-CP</u> -- 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 than does the 1-CP or 4-CP methods.

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 some 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 ongoing 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 generation facilities are designed and 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, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on some arbitrary factor such as system coincident load factor.

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 some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

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 the 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 some 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 off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method that explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors tend to run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods.

Finally, wind and solar generating facilities may only produce energy when environmental conditions are present; i.e., wind or sunshine. As a result, their reliability factors are such that they may not be relied upon to meet peak loads at all times. For example, many utilities experience peak demands in the early morning and evening hours when there is either no sunlight present or minimal sunlight available for solar generation. As such, wind and solar generating units are classified as energy-related.

Probability of Dispatch -- The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year (8,760 hours). Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only those few peak hours. The hourly capacity costs for each generating asset are summed to develop hourly investment cost responsibilities. These hourly investments are then assigned to individual rate classes based on class contributions to system load for each hour of the year. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

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 level of assumptions regarding the current (or future) costs of various generating alternatives.

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 investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily 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. WHAT METHODOLOGIES DID MR. SEEYLE UTILIZE TO ALLOCATE GENERATION PLANT COSTS WITHIN HIS CCOSS?

A. As mentioned earlier, Mr. Seeyle prepared CCOSS utilizing two different methods to allocate generation-related costs: "Modified BIP"; and, LOLP.

Q. PLEASE EXPLAIN MR. SEEYLE'S MODIFIED BIP APPROACH TO ALLOCATE GENERATION-RELATED COSTS.

A. Mr. Seeyle's Modified BIP method does not follow the generally accepted BIP approach. However, I would be reluctant to say his approach is totally unreasonable. Indeed, Mr. Seeyle's so-called Modified BIP is a variant of the Peak & Average method.

Whereas Mr. Seeyle's Modified BIP method does allocate a portion of generation facilities based on energy (34.38%) and a portion on peak demands (36.02% on winter peak and 29.60% on summer peak), his approach does not reflect the actual mix of supply resources utilized by KU. As a result, Mr. Seeyle's approach is a version of the P&A method using summer and winter peak demands; i.e., 34.38% is allocated on average demand (energy) and 65.62% is allocated on the average of winter and summer peak demands.

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 kW peak demand).

Mr. Seeyle's approach ignores the actual supply-side characteristics of KU's and LG&E's combined generation portfolio because it only considers relative differences in system usages and demands. In fact, given KU's and LG&E's retail customers combined usages and demand profiles, Mr. Seeyle's approach would classify a utility's generation investment exactly the same regardless of its actual portfolio mix of generation resources. Mr. Seeyle's classification would be identical if the Companies' 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 KU's and LG&E's generation resources.

Q. PLEASE EXPLAIN MR. SEEYLE'S LOLP APPROACH TO ALLOCATE GENERATION-RELATED COSTS.

A. In simple terms, KU personnel calculated a probability of the Company not being able to meet its load requirements with its own generation for each and every hour of the forecasted test year (8,760 hours). As might be imagined, for hours in which the total system load is relatively low, the probability of not meeting the total system load (LOLP) is zero. Likewise, KU calculates that there is a probability of not meeting the system load (LOLP) during hours in which system demand is at, or near, the annual peak. With this framework, Mr. Seeyle then multiplies each class' percentage contribution to total jurisdictional load by the calculated system LOLP for each hour of the year. This results in a weighting across classes based on the hourly system LOLPs. These hourly weightings are then added for all hours in which LOLP is greater than zero to develop his class allocation factors for generation plant.

Q. IS THE CONCEPTUAL FRAMEWORK UTILIZED BY MR. SEEYLE REASONABLE?

A. From a conceptual standpoint, Mr. Seeyle's approach to allocate costs is reasonable. However, no credibility can be given to the hourly system LOLPs which serve as the foundation for Mr. Seeyle's calculations.

Q. PLEASE EXPLAIN WHY NO CREDIBILITY CAN BE GIVEN TO THE HOURLY SYSTEM LOLPs THAT WERE CALCULATED BY THE COMPANY.

A. There are a host of reasons. First, the hourly system LOLPs developed by KU/LG&E personnel are black box results from an algorithm in which it is impossible to determine the inputs, assumptions and most importantly, specific methods used to calculate each hourly LOLP. In Confidential response to OAG data request 1-276, the Company indicated that the methodology utilized to calculate hourly LOLPs is embedded within their Power System Production Simulation Software ("PROSYM") such that the hourly LOLP results are simply provided as output. In OAG data request 1-277, the Company was asked to provide all analyses, workpapers, spreadsheets, etc. showing how the hourly system LOLPs were calculated. Although the Company provided numerous input files presumably used to calculate LOLPs, they were unable to show how each hourly LOLP was determined. As a result (and because PROSYM calculated system LOLPs for 8,760 hours), in OAG data request 2-58, the Company was asked to show how the LOLP was developed for a single hour. The Company's response to OAG data request 2-58 was as follows:

> The hourly LOLPs were produced by PROSYM, which is the software provided by ABB that the Companies also use to develop the generation forecast. The attachment to the response to AG 1-276 documents the LOLP calculations performed in PROSYM. However, the LOLP calculations are performed within the software. The Companies do not have access to the underlying proprietary code that performs the LOLP calculations or the calculations' intermediate components.

In short, it is impossible to determine exactly how the Companies' PROSYM model calculates hourly LOLPs such that it is also impossible to verify the results or evaluate the reasonableness of the assumptions that go into the determination of each hourly LOLP. As will be explained later in my testimony, I have serious concerns relating to the inputs, assumptions, and perhaps methodology utilized to develop these black box hourly LOLPs.

The next concern I have is frankly, a matter of common sense. KU and LG&E have more than sufficient installed capacity and indeed, the Companies' acknowledge that they have no plans to build or install additional capacity for the next several years. Therefore, given the significant amount of excess capacity that KU and LG&E already have, there is very little realistic probability that the Companies will not be able to meet its load requirements each and every hour of the year. Indeed, for all intents and purposes, the Companies' hourly loss of load probabilities reflect this reality.

In response to OAG data request 1-277(a), the Company provided hourly system LOLPs. The largest LOLP during the entire forecasted test year is 0.126%, which means that there is roughly one-tenth of one percent probability that the Companies will not be able to meet it load requirements during this hour. It should be noted that this highest LOLP also coincides with the Companies' forecasted annual peak load demand. All other hours have lower LOLPs than 0.126%. What this means is there is about one-tenth of one percent probability that the Companies will not be able to meet its load requirements during the peak hour of the year (given all other assumptions within the calculation of LOLP). As a result, the Company estimates that in the hour with the highest LOLP (i.e., annual peak load), it would not be able to meet 232 kW of demand. This minimal level of 232 kW equates to the demands of only about 15 to 20 residential households. In other words, even with this exceptionally low LOLP during the annual peak hour and given all other assumptions used to develop this maximum LOLP, the Company will be able to serve all residential, commercial, and industrial customer's load requirements of 6,807,000 kW, but for 232 kW (0.0034%) which must be therefore made up with purchased power or some other resource.

Q. NOTWITHSTANDING THE EXCEPTIONALLY LOW CALCULATED PROBABILITY OF THE COMPANIES NOT BEING ABLE TO MEET ALL OF ITS ANNUAL PEAK LOAD REQUIREMENTS GIVEN ITS PORTFOLIO OF GENERATION AND SUPPLY ASSETS, HAVE YOU INVESTIGATED THE REASONABLENESS OF THESE BLACK BOX LOLP RESULTS?

A. Yes. First and foremost, the Companies' LOLP methodology and calculations do not consider a very valuable capacity resource, that being interruptible loads available from the Curtailable Service Rider ("CSR"). In other words, the Companies' LOLP calculations do not consider or reflect the fact that there is more than 130 mW of interruptible load available as a capacity resource.[6] In response to OAG data request 1-274(c), the Company was asked to provide a detailed explanation of how curtailable load or curtailable load credits are reflected within the class hourly loads as used to develop the LOLP study. The Company responded that "the impact of curtailable loads is not reflected in the hourly class load profiles." This is most important and troubling since the Companies have more than 130 mW of load that could be interrupted, yet, for LOLP purposes, they ignore this important resource. Indeed, had the Companies considered curtailable load within their LOLP, there would be virtually no probability of not meeting its load requirements (even with all other assumptions that will be explained below). In other words, the Companies' own calculations show that under a worst case scenario, the Company will be able to meet all but 0.23 mW of load before a single curtailable service customer is interrupted.

[6] Per Company response to KIUC 1-55.

Q. IN ADDITION TO THE COMPANIES FAILURE TO CONSIDER CURTAILABLE SERVICE AS A CAPACITY RESOURCE, HAVE YOU DISCOVERED OTHER UNREASONABLE ASSUMPTIONS WITHIN THE COMPANIES' CALCULATED BLACK BOX HOURLY LOLPs?

A. Yes. As indicated earlier, the maximum LOLP during the forecasted test year is 0.126% during the annual peak hour. The Company forecasts that the six highest hourly LOLPs will occur on the same day during the consecutive afternoon and early evening of August 9th from 2:00 p.m. through 7:59 p.m. (6 hours). During this period, the Companies' calculated LOLPs range from a low of 0.031% to a high of 0.126%. During this six hour period, I evaluated the assumed level of output for every generation and production asset within KU's and LG&E's portfolio of assets. I observed that the following generating units were assumed to be offline (or unavailable) during the entire six hour period:

Unit	Capacity (mW)[7]	Fuel Source
Unavailable for all 6 hours of peak day		
Brown 8	126	Gas/Oil
Brown 9	126	Gas/Oil
Brown 10	126	Gas/Oil
Brown 11	126	Gas/Oil
Cane Run 11	16	Gas
Haefling	42	Gas/Oil
Paddy's Run 11	16	Gas
Paddy's Run 12	33	Gas
Zorn 1	18	Gas
Unavailable 4 of 6 hours including the peak hour		
Trimble 8	199	Gas
Unavailable 3 of 6 hours		
Trimble 10	199	Gas
Total Unavailable Capacity:	1,027	--

[7] Per response to OAG data request 1-285.

Remembering that even during the hour of the highest loss of load probability, the Company expects to meet all but 0.23 mW of its load requirements. However, as we can see above, the Companies' LOLP procedures have modeled more than 1,000 mW of generation capacity that is not dispatched or utilized during this period. Indeed, if only one of these eleven unused generating units are dispatched and utilized, the LOLP becomes zero. The above discussion is limited to the highest LOLPs for six hours of the year. I examined the availability of generating units for other hours in which there is an LOLP and observed that there is a significant amount of unused capacity from the Companies' generating units for each hour in which there is at least some miniscule LOLP. While it is reasonable to model situations in which some units may not be available due to forced outage rates, clearly, the unavailability of eleven gas-fired generating units is unrealistic.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. SEEYLE'S PROPOSED CCOSS UTILIZING HIS LOLP APPROACH?

A. No credibility can be given to this method such that it should not be considered in this case.

Q. HAVE YOU CONDUCTED ALTERNATIVE STUDIES THAT MORE ACCURATELY REPRESENT THE CAPACITY AND ENERGY TRADE-OFFS EXHIBITED IN KU'S GENERATION PLANT INVESTMENT?

A. Yes. As indicated earlier, there is no single, or absolute, correct method to allocate joint generation costs. While some methods are superior to others, it is my opinion that the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

In my opinion, the Probability of Dispatch and BIP methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. This is particularly true and important for KU given the fact that the preponderance of its investment in generation plant is associated with base load generation facilities.[8] As such, I have conducted alternative CCOSS utilizing these two allocation methodologies.

1. Probability of Dispatch Method

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, KU provided both of these critical data sets. As such, I was able to conduct a CCOSS utilizing the Probability of Dispatch method.

The first step in conducting the Probability of Dispatch method is to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the NARUC: Electric Utility Cost Allocation Manual,[9] each plant's total gross investment and accumulated depreciation was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour. My Schedule GAW-2 provides these hourly assignments. It should be noted that this exercise actually assigns costs to 8,760 hours; however, my Schedule GAW-2 only encompasses several of the first hours in the test year to avoid attachments exceeding 125 pages each. The electronic Excel spreadsheet containing the details of this assignment for each and every hour of the test year are provided to the parties with my filed testimony (Completed 4 Probability of Dispatch KU – Using Gross Plt.xls). In addition, an hourly analysis was conducted for depreciation reserve due to differences in the net book value of KU's various generation facilities. The electronic Excel spreadsheet containing the details of the depreciation reserve for each and every hour of the test year are provided to the parties with my filed testimony (Completed 2 Probability of Dispatch KU – Using Depreciation Reserve.xls).

---

8 It is recognized that KU and LG&E jointly dispatch their combined generating assets based on the system load of both utilities. As such, my analyses (as well as Mr. Seeyle's) reflects this joint dispatch of generating assets.

9 1992 Edition, page 62.

Once hourly investment costs are known, these costs were then assigned to individual rate classes on an hour-by-hour basis. As indicated earlier, KU provided individual class loads for each hour of the test year. As such, each class' relative contribution to the total system load in a given hour, is multiplied by the hourly generation investment cost. The hourly class investment costs were then summed for all hours of the year to develop class responsibility for KU's net generation plant. Schedule GAW-3 provides summaries of the hourly assignment of generation costs to individual rate classes. The class assignment to each and every hour of the test year are provided in an Excel spreadsheet filed with my testimony (Completed 4 Probability of Dispatch KU – Using Gross Plt.xls and Completed 2 Probability of Dispatch KU – Using Depreciation Reserve.xls).

In addition to assigning fixed investment costs on an hour-by-hour basis, I have also conducted a similar analyses with regard to variable fuel costs. That is, I conducted a time differentiated fuel cost analysis for each hour of the year.

Q. PLEASE EXPLAIN YOUR TIME DIFFERENTIATED FUEL COST ANALYSIS AND YOUR CONCLUSIONS AS A RESULT OF THIS ANALYSIS.

A. As discussed earlier, KU provided each generation plant's hourly output during the forecasted test year. In addition, the Company provided forecasted test year monthly fuel costs (per kWh) for each generating unit. With this data, I was able to calculate hourly fuel costs by individual generating unit. These hourly fuel costs were then assigned to individual rate classes on an hour-by-hour basis based on class hourly loads as discussed previously. The end result of this analysis yielded very similar hourly fuel costs across all classes such that all classes' fuel costs are within 3.6% of the system average annual fuel cost as shown below[10]:

[10] My hourly fuel cost analysis by rate class reflects line losses such that the fuel cost reflect cost per kWh at the meter. The details of this analysis are provided in an Excel spreadsheet filed with my testimony (Hourly Fuel Cost KU and LG&E – With Source & Meter-Adjusted.xls).

KU Class Hourly Fuel Costs
(Annual Weighted Average)

Class	Fuel Cost Per mWh	Deviation From Sys. Average
Residential	$23.217	1.2%
General Service	$23.200	1.2%
All Electric Schools	$23.254	1.4%
Pwr Svc-Secondary	$23.136	0.9%
Pwr Svc-Primary	$22.597	-1.5%
TOD-Secondary	$23.175	1.1%
TOD-Primary	$22.587	-1.5%
Retail Transmission	$22.106	-3.6%
Fluctuating Load	$22.162	-3.4%
Outdoor Lighting	$22.980	0.2%
Lighting Energy	$22.959	0.1%
Traffic Energy	$23.135	0.9%
TOTAL	$22.931	--

Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OBTAINED UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. First it should be noted that the following summary and comparison utilizes all other classification and procedures used by Mr. Seeyle in conducting his CCOSS. The following table provides a comparison of Mr. Seeyle's (as-corrected) Modified BIP results to those obtained utilizing the Probability of Dispatch method (which also incorporates time differentiated fuel costs):

CCOSS Comparison Utilizing KU's Procedures
Except for the Allocation of Generation Plant and Fuel Costs
(ROR At Current Rates)

Class	Modified BIP (As Corrected)	Probability Of Dispatch
Residential	4.15%	4.72%
General Service	9.04%	9.70%
All Electric Schools	5.25%	5.45%
Pwr Svc-Secondary	9.57%	9.23%
Pwr Svc-Primary	11.63%	10.48%
TOD-Secondary	6.43%	5.69%
TOD-Primary	4.45%	3.54%
Retail Transmission	4.51%	3.67%
Fluctuating Load	1.50%	1.03%
Outdoor Lighting	8.60%	7.40%
Lighting Energy	9.83%	3.91%
Traffic Energy	8.07%	6.55%
TOTAL	5.56%	5.56%

As can be seen in the table above, there are material differences for some classes and minimal differences for other classes. For example, the residential ROR increases from 4.15% to 4.72%, while the lighting classes RORs are significantly reduced. A summary of my Probability of Dispatch CCOSS results are provided in my Schedule GAW-4, while the details are provided in Excel format filed with my testimony (TAI Prob Dispatch with Time Fuel & Customer-Demand Split.xls).

2. <u>Base-Intermediate-Peak ("BIP") Method</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. In order to reflect the capacity/energy trade-off inherent in KU's mix of generating resources, each plant's owned capacity (mW) and output (mWh) during the test year is required.[11] Schedule GAW-5 provides the classification between energy and demand for KU's generation plant under the BIP method. The BIP method evaluates each plant based on its capacity factor and variable fuel costs to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements.

Q. DOES SCHEDULE GAW-5 HELP EXPLAIN THE CAPACITY/ENERGY TRADE-OFF CONSIDERATION USED BY ELECTRIC UTILITIES IN DEVELOPING A PARTICULAR MIX OF GENERATING FACILITIES?

A. Yes. As can be seen in Schedule GAW-5, KU's larger, more expensive, generating plants have high capacity factors and lower fuel costs. The large base load units run most hours of the year supplying energy to all customers. In contrast, the smaller, high operating (fuel) cost plants tend to have lower capacity factors meaning they are primarily used to meet peak loads. Because the vast preponderance of KU's investment in generation plant is associated with its base load units, a very large percentage (83.6%) of generation plant is classified as energy-related under the BIP method.

Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. The following summary and comparison utilizes all other allocations and procedures used by Mr. Seeyle in conducting his CCOSS analysis. The following table provides a comparison of Mr. Seeyle's Modified BIP (as corrected) results to those obtained utilizing the true BIP method:

[11] KU and LG&E own 75% of Trimble Unit 1 and Trimble Unit 2 wherein a non-affiliate owns the remaining 25% of these units. As such, the available capacity (mW) and energy output (mWh) reflects KU's and LG&E's 75% entitlement.

CCOSS Comparison Utilizing KU's Procedures
Except for the Allocation of Generation Plant and Fuel Costs
(ROR At Current Rates)

Class	Modified BIP (As Corrected)	True BIP
Residential	4.15%	4.71%
General Service	9.04%	9.62%
All Electric Schools	5.25%	5.53%
Pwr Svc-Secondary	9.57%	9.27%
Pwr Svc-Primary	11.63%	10.47%
TOD-Secondary	6.43%	5.69%
TOD-Primary	4.45%	3.61%
Retail Transmission	4.51%	3.58%
Fluctuating Load	1.50%	0.95%
Outdoor Lighting	8.60%	7.52%
Lighting Energy	9.83%	4.23%
Traffic Energy	8.07%	6.68%
TOTAL	5.56%	5.56%

As can be seen in the table above, there are material differences for some classes and minimal differences for other classes. For example, the residential ROR increases from 4.15% to 4.71%, while some of the lighting classes RORs are significantly reduced. A summary of my BIP CCOSS results are provided in my Schedule GAW-6, while the details are provided in Excel format filed with my testimony (TAI BIP with Customer-Demand Split.xls).

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PROPER ALLOCATION OF KU'S GENERATION PLANT?

A. KU's and LG&E's combined portfolio of generating assets is comprised predominately of large base load units that serve the energy needs of KU and LG&E throughout the entire year. While the Companies do indeed rely upon intermediate and peaker units to some degree, the dollar investment in these facilities pale in comparison to its base load investments. The Probability of Dispatch and BIP methods are very detailed approaches that are theoretically sound and reasonably reflect the capacity/energy trade-off in generation facilities specific to KU's investment. As such, these two methods are the most "accurate" methods from a cost causation perspective. It is my opinion that each of these methods should be considered in evaluating class profitability.

B. Distribution Plant

Q. PLEASE EXPLAIN THE PHRASE "CLASSIFICATION OF DISTRIBUTION PLANT."

A. It is generally recognized that there are no energy-related costs associated with distribution plant. 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 sometimes is classified as partially demand-related and partially customer-related.

Q. WHY IS DISTRIBUTION PLANT SOMETIMES CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Even though investment is made in distribution plant and equipment to meet the needs of customers at their required power levels, there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. Therefore, if one were to allocate distribution plant investment based simply on class contributions to peak demand, an inequitable allocation of these costs may result.

As a hypothetical, suppose a utility serves both an urban area and a rural area. In this situation, many customers' electrical needs are served with relatively few miles of conductors, few poles, etc. in the urban area, while many more miles of conductors, more poles, etc. are required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that commercial and industrial customers are predominately clustered in the more densely populated urban area, while the less dense (rural) portion of the service territory consists almost entirely of residential customers, it may be unreasonable to allocate the total Company's distribution investments based solely on demand; i.e., a large investment in many miles of line is required to serve predominately residential customers in the rural area while the commercial and industrial electrical needs are met with much fewer miles of lines in the urban area. Under this circumstance, an allocation of costs based on a weighting of customers and demand can be considered equitable and appropriate.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THE CONCEPTS OF DENSITY AND CLASS CUSTOMER MIX AS THEY RELATE TO COST ALLOCATIONS.

A. As a starting point, it is important to understand absolute and relative class relationships of an electric utility's number of customers, energy requirements, and maximum loads (demands). In terms of simple customer counts, the number of residential accounts make-up the majority of any retail electric utility's number of customers. However, because residential customers tend to be small volume users compared to commercial and industrial customers, the residential class is responsible for a significantly smaller percentage of total kWH energy supplied or peak loads on the system. For example, in KU's system, the following characteristics are exhibited:

	Percentage of Total Jurisdictional Distribution System[12]		
Category	Customers	kWh	Peak Demand (NCP)
Residential	82.8%	37.7%	47.8%
Comm./Ind. Distribution Voltage	17.2%	62.3%	52.2%

While the table above shows the relative class differences between number of customers, energy usage, and peak demands, the following table illustrates the absolute size differences between KU's different types of customers:

[12] Excludes lighting classes.

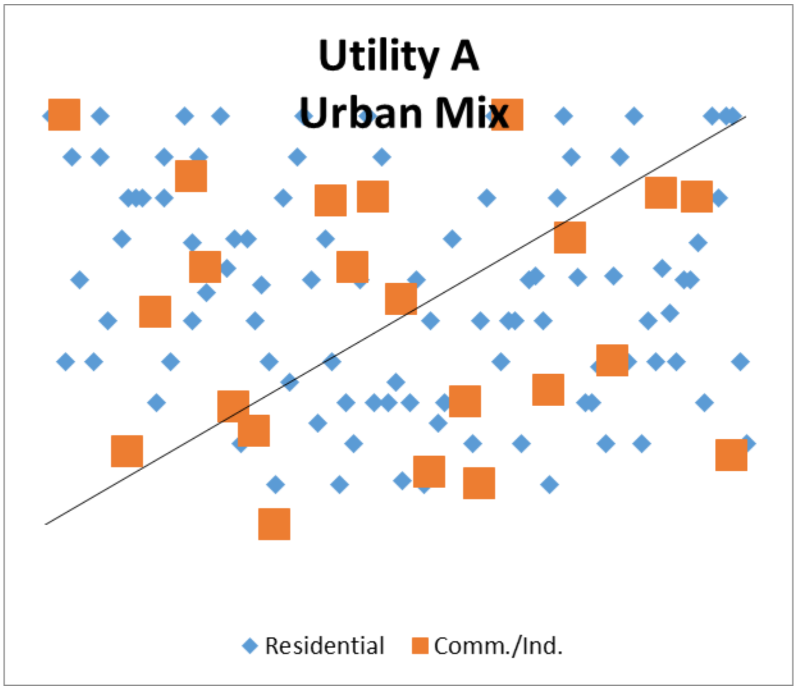
Category	Average Annual kWh Per Customer (kWh)
Residential	14,145
Comm./Ind. Distribution Voltage	112,578

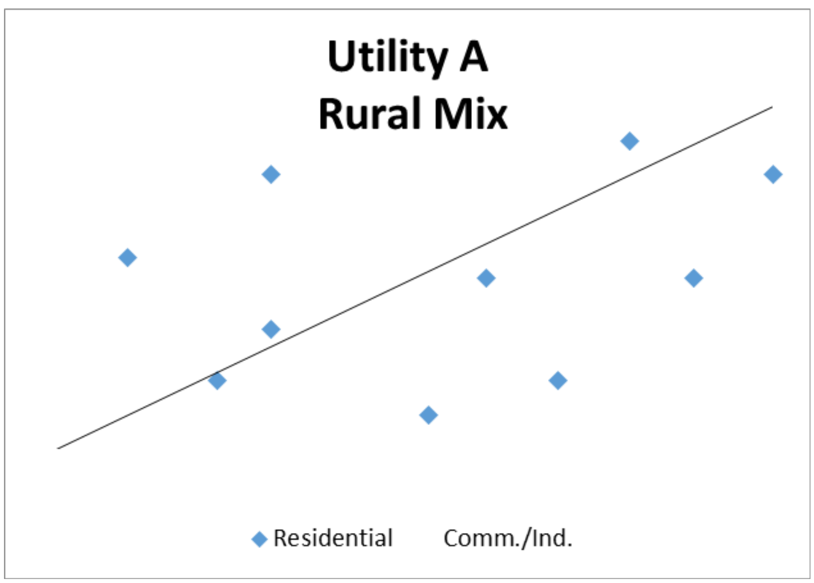
With the above relationships explained, in order to understand the concepts of density and class customer mix, consider examples of two hypothetical electric utilities each of which are comprised of only two distribution lines: one line serving a densely populated area (urban) and another line serving a sparsely populated area (rural). Furthermore, for simplicity and explanatory purposes, assume there are only two classes of customers for each utility: Residential and Commercial/Industrial with the following characteristics:

	Absolute			Relative	
Class	Number of Customers	Peak Load	Peak Load Per Customer	Number of Customers	Peak Load
Residential	110	550	5	83%	33%
Comm./Ind.	22	1,100	50	17%	67%
Total	132	1,650	--	100%	100%

Utility A:

For Utility A, assume all commercial/industrial customers are located on the urban (densely populated) distribution line such that the rural line only serves residential customers as shown graphically below:



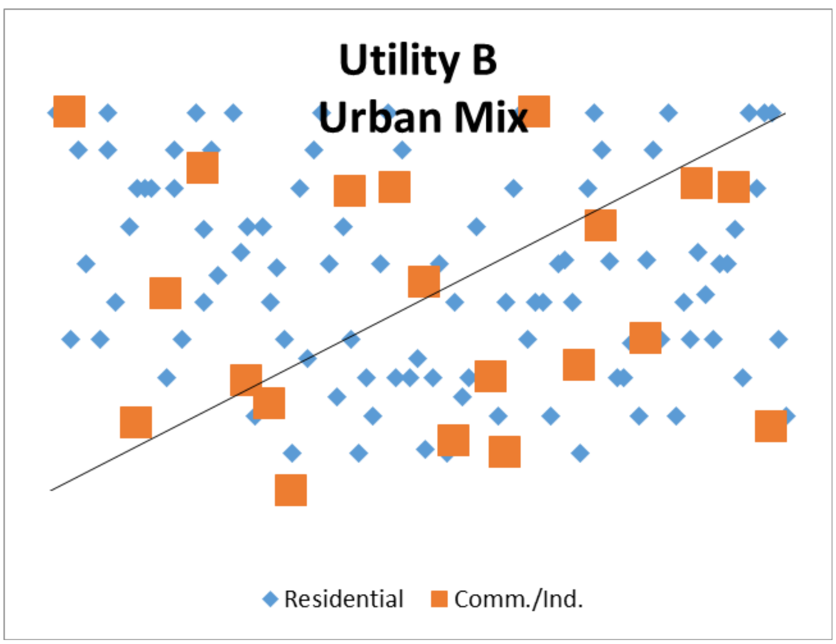


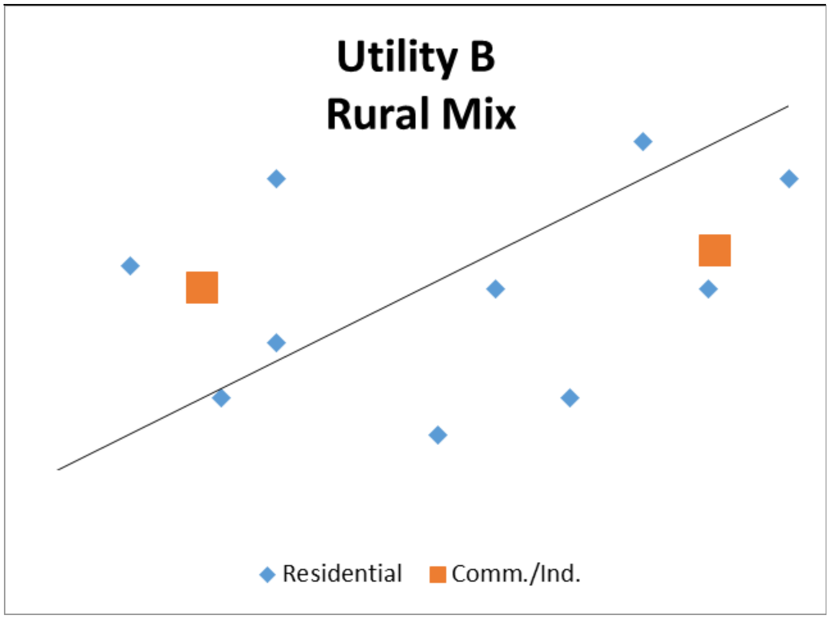
Because the urban line is much shorter in total distance, yet, serves the majority of customers (and loads) <u>and</u> many more miles of line are required to serve relatively few residential only customers in rural areas, it would be unfair, and inconsistent with cost causation to allocate total system line costs only on utilization (kW) because commercial/industrial customers arguably do not cause costs to be incurred for the rural portion of the system. As such, some weighting of relative number of customers and utilization is appropriate to allocate total system line costs.

<u>Utility B</u>:

For Utility B, assume that the relative mix of customers is evenly distributed between the urban and rural lines. In other words, this utility's configuration of customers is as follows:

	Number of Customers			
	Urban Line		Rural Line	
Class	Amount	Percent	Amount	Percent
Residential	100	83%	10	83%
Comm./Ind.	20	17%	2	17%
Total	120	100%	12	100%





As can be seen in the above table and charts, the relative imposition of costs across the two classes for Utility B is the same for the urban and rural lines. That is, while there are more absolute residential customers than commercial/industrial customers on both the urban and rural lines, the proportion (mix) of customers is the same between urban and rural. As such, an allocation of total system lines costs based on utilization (maximum loads) is appropriate such that no consideration of customer counts is needed or desired. Indeed, if distribution costs are classified and allocated partially on number of customers, the Residential class will be over burdened with cost responsibility creating a subsidy for commercial/industrial customers.

Q. DOES THE CLASSIFICATION OF DISTRIBUTION PLANT INVESTMENT AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED REFLECT ANY RELATIVE COST (PER MILE) DIFFERENCES BETWEEN URBAN AND RURAL AREAS?

A. No. It is generally more expensive to install a mile of distribution circuit in an urban area than in a rural area. However, although this cost difference may be substantial, this cost difference is usually ignored due to record keeping limitations, in that all costs are simply assumed to be uniform (averaged) across the rural and urban portions of a service area.

Q. DO YOUR EXAMPLES DISCUSSED ABOVE IMPLY THAT IT COSTS MORE TO SERVE RURAL CUSTOMERS THAN URBAN CUSTOMERS AND THAT PERHAPS A UTILITY'S RURAL CUSTOMERS SHOULD PAY MORE PER UNIT THAN URBAN CUSTOMERS?

A. While it is possible that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has generally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences. Rather, regulatory policy has been such that classes of customers with similar usage and/or load characteristics are established for pricing purposes. In fact, during my 36-plus years practicing utility costing and pricing across the Country, I have never seen an electric rate structure that discriminates based on customer densities or other geographic characteristics.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR EXPLANATION AND CONCEPTS REGARDING CUSTOMER DENSITIES AND CLASS CUSTOMER MIXES?

A. Yes. In the well-known and often referenced, treatise <u>Principles of Public Utility Rates</u>, Professor James Bonbright states that there:

> is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[13]

Q. BEFORE WE CONTINUE, IS KU's DISTRIBUTION SYSTEM COMPRISED OF VARIOUS SUB-SYSTEMS?

A. Yes. As is the case with virtually every electric utility, KU's overall distribution system is comprised of a primary voltage system and a secondary voltage system. The

---

[13] Bonbright, <u>Principles of Public Utility Rates</u>, Second Edition, page 491.

primary system operates at higher voltage levels than the secondary system and generally consists of plant and equipment between the substations and transformers. The lower voltage secondary system can be thought of as operating downstream from the primary system and delivers electricity to small end-users.

Q. BRIEFLY DESCRIBE THE TYPES OF INVESTMENT (EQUIPMENT) UTILIZED IN KU's DISTRIBUTION SYSTEM.

A. For accounting purposes, KU's distribution plant is grouped into various accounts. These accounts include: Land and Land Rights (Account 360); Structures and Improvements (Account 361); Station Equipment (Account 362); Poles, Towers and Fixtures (Account 364); Overhead Conductors (Account 365); Underground Conduit (Account 366); Underground Conductors (Account 367); Line Transformers (Account 368); Meters (Account 370); Area Lighting (Account 371) and Street Lighting (Account 373).

Q. DID MR. SEEYLE MAKE AN *A PRIORI* ASSUMPTION THAT DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Yes.

Q. WHAT RELATIVE CUSTOMER/DEMAND PERCENTAGES DID MR. SEEYLE USE IN THIS CASE?

A. The following are Mr. Seeyle's customer/demand percentages used for each distribution plant account:

Classification of Distribution Plant

Account	Percent Customer	Percent Demand
Poles (Primary Voltage)	59.19%	40.81%
Poles (Secondary Voltage)	59.19%	40.81%
Overhead Lines (Primary Voltage)	59.19%	40.81%
Overhead Lines (Secondary Voltage)	59.19%	40.81%
Underground Lines (Primary Voltage)	79.61%	20.39%
Underground Lines (Secondary Voltage)	79.61%	20.39%

Q. HAVE YOU CONDUCTED ANALYSES TO DETERMINE IF A CLASSIFICATION OF DISTRIBUTION PLANT AS PARTIALLY CUSTOMER-RELATED IS APPROPRIATE FOR KU?

A. Yes, I have.

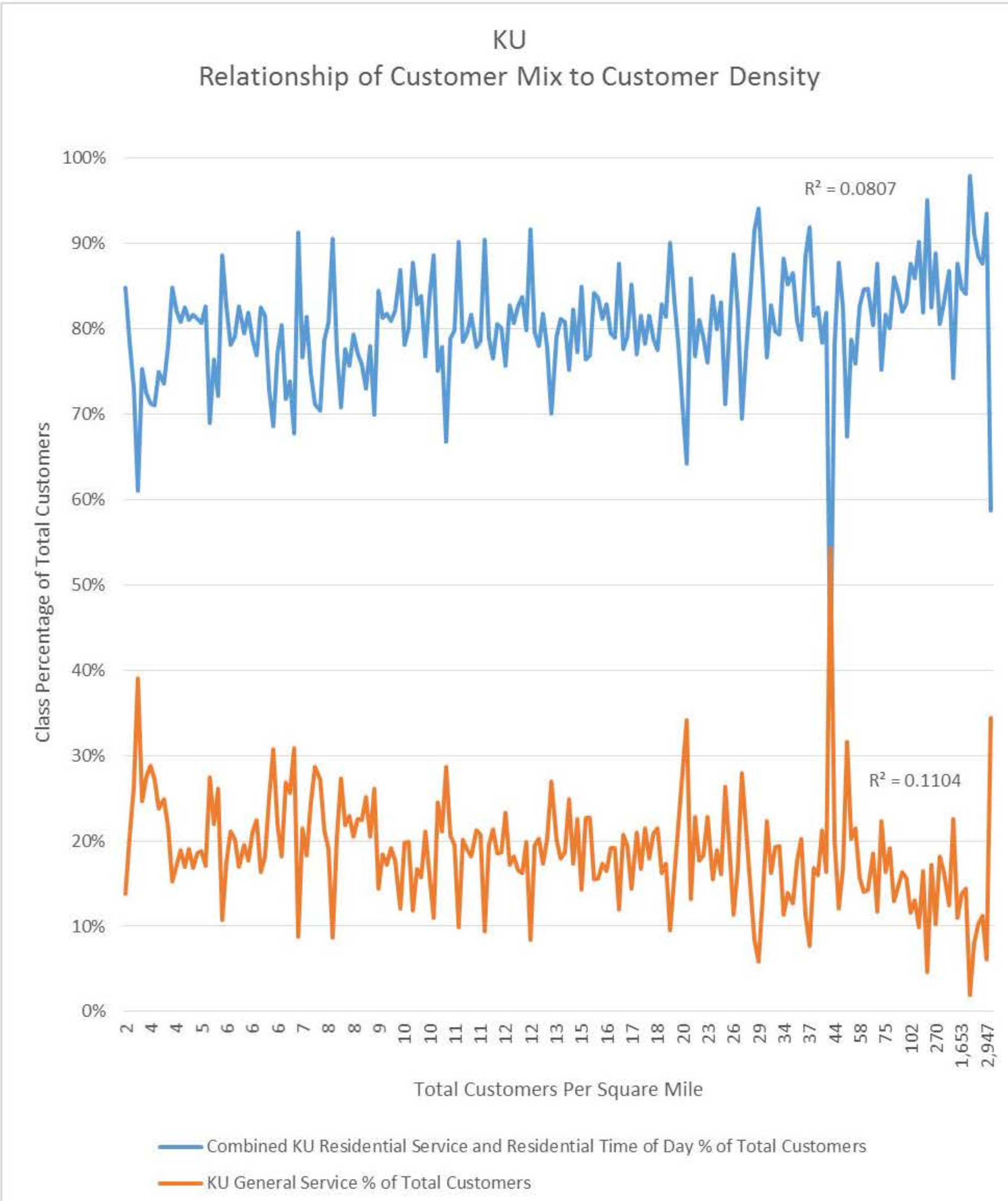
Q. PLEASE EXPLAIN.

A. My. Seeyle has made an *a priori* assumption that it is appropriate to allocate a portion of its distribution plant based on customer counts and a portion based on demand levels. As indicated earlier, the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than peak demand, is due to the possibility that the mix of customers varies significantly across the customer density levels within KU's service territory. In this regard, I evaluated this assumption by conducting an analysis of the distribution, or mix, of KU's customer classes across its service area.

Through discovery, the Company provided a data base of the number of customers by rate schedule for each postal zip-code within its service area. I then evaluated the mix of customers by rate class for each postal zip-code within the KU service area. In order to evaluate whether any differences exist in the distribution of customers across various customer density areas, I calculated the number of total KU distribution customers (excluding lighting customers) per square mile for each non-Post Office Box zip-code to serve as a measure of density for relatively small geographic areas. I was then able to readily compare KU's mix of customers throughout its service area and delineate between sparsely populated and densely populated areas (in terms of number of KU customers). As a further refinement, I also evaluated the distribution of customers on a stratified basis. That is, for each customer group (Residential, General Service, Power Service, Time of Day, and All Electric Schools) I separated small geographical areas (zip codes) into four separate strata (lowest to highest customer densities). I examined each stratum (by customer group) to determine if any significant differences in customer mix occur within each stratum.

This analysis of the distribution of the various customer groups by density provided a basis to determine whether: (a) utilization alone (demand) is an appropriate and fair method to allocate distribution costs; or, (b) whether a weighting of customers and utilization (demand) is appropriate in order to reasonably reflect the imposition or causation of costs.

If there is any basis for a customer classification of distribution plant, this analysis should show a negative correlation between the residential customer mix (residential percentage of total customers) and density across KU's service area. In other words, the percentage of residential customers (by zip-code) should decline as customer density per square mile increases from the least dense areas to the most dense areas of KU's service territory. Similarly, if Mr. Seeyle's assumption is correct, you should see a distinct positive correlation between non-residential customer mixes and customer densities by zip-code. The graph below shows the percentage of total customers by rate group (Y axis) compared to total customers per square mile (X axis):


KU
Relationship of Customer Mix to Customer Density
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Class Percentage of Total Customers
R² = 0.0807
R² = 0.1104
2 4 4 5 6 6 6 7 8 8 9 10 10 11 11 12 12 13 15 16 17 18 20 23 26 29 34 37 44 58 75 102 270 1,653 2,947
Total Customers Per Square Mile
Combined KU Residential Service and Residential Time of Day % of Total Customers
KU General Service % of Total Customers

As can be seen in the graph above, there is absolutely no correlation or trend between the distribution of customers (customer mix) and density levels for any of the three customer groups. Indeed, and as shown in the graph, the correlation coefficients for all three customer groups are essentially zero.

As discussed earlier, I also analyzed this data on a stratified basis. A summary of the approach and data utilized for the stratification analysis is provided below:[14]

			Percent of Total Distribution Customers[15]		
Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Percent Of Strata	Number	% of Class
Residential					
Strata 1	2 Min to 8 Max	52	77.5%	21,471	5.1%
Strata 2	8.1 Min to 14 Max	52	79.4%	40,094	9.6%
Strata 3	14.1 Min to 33 Max	51	79.1%	81,343	19.4%
Strata 4	33.1 Min to 3,700 Max	51	85.1%	276,199	65.9%
Total		206		419,107	100.0%
General Service					
Strata 1	2 Min to 8 Max	52	21.4%	5,945	7.4%
Strata 2	8.1 Min to 14 Max	52	19.4%	9,789	12.2%
Strata 3	14.1 Min to 33 Max	51	19.6%	20,176	25.2%
Strata 4	33.1 Min to 3,700 Max	51	13.6%	44,231	55.2%
Total		206		80,141	100.0%
Power Service					
Strata 1	2 Min to 8 Max	52	0.7%	207	4.3%
Strata 2	8.1 Min to 14 Max	52	0.9%	446	9.3%
Strata 3	14.1 Min to 33 Max	51	0.9%	946	19.7%
Strata 4	33.1 Min to 3,700 Max	51	1.0%	3,205	66.7%
Total		206		4,804	100.0%
Time of Day					
Strata 1	2 Min to 8 Max	52	0.5%	39	4.3%
Strata 2	8.1 Min to 14 Max	52	2.5%	77	8.5%
Strata 3	14.1 Min to 33 Max	51	0.5%	202	22.3%
Strata 4	33.1 Min to 3,700 Max	51	0.2%	587	64.9%
Total		206		905	100.0%
All Electric Schools					
Strata 1	2 Min to 8 Max	52	0.2%	54	9.3%
Strata 2	8.1 Min to 14 Max	52	0.2%	107	18.4%
Strata 3	14.1 Min to 33 Max	51	0.2%	162	27.8%
Strata 4	33.1 Min to 3,700 Max	51	0.1%	260	44.6%
Total		206		583	100.0%

14 The data and details of this analysis are provided in Excel format filed with my testimony (KU Zip Code Analysis.xls).

15 Excludes Lighting.

Q. WHAT ARE YOUR FINDINGS AS A RESULT OF THIS ANALYSIS?

A. KU's customers are dispersed in a reasonably proportional manner throughout its service area. In fact, the distribution of residential customers is somewhat greater in the more densely populated zip codes than the less densely populated zip codes, which is contrary to the hypothesis and is opposite of what would be expected if one were to accept the notion that distribution investment should be classified as partially customer-related. As important is the fact that in the less dense areas of KU's service territory (which requires more miles of distribution lines and number of poles to serve fewer customers), the Company actually serves a larger percentage of General Service customers than in the more densely populated areas within KU's service territory.

As a result of these analyses, it cannot be said that the less populated portions of KU's service area (which require significant investment to serve few customers) are disproportionately required to serve any one class of customers. As such, with respect to KU's primary voltage distribution system, plant and expenses should be assigned to classes based only on utilization (peak demand) and any consideration of customer counts is improper for the allocation of distribution plant. Therefore, my studies indicate that KU's primary voltage distribution system costs should be classified as 100% demand-related.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE CLASSIFICATION OF KU'S SECONDARY VOLTAGE DISTRIBUTION SYSTEM?

A. In conducting the analysis discussed above, I recognize that the Company's primary voltage distribution system serves more customers and provides more power and energy than does its secondary voltage system. In other words, KU's secondary voltage system can be thought of as serving customers downstream from the primary voltage system. As such, the secondary voltage system serves smaller individual geographical areas such as individual neighborhoods, etc. The smallest geographical area in which I have data available to evaluate customer densities and customers mixes is on a zip code basis. Because an individual neighborhood (or secondary voltage circuit) may encompass a relatively small geographical area, I cannot reasonably opine as to whether it is inappropriate to classify a portion of the Company's secondary system based partially on customers and based partially on demand. Therefore, I have accepted Mr. Seeyle's classification of secondary voltage distribution plant as partially customer-related and partially demand-related.

Q. DOES THE NARUC ELECTRIC COST ALLOCATION MANUAL INDICATE IF AN *A PRIORI* ASSUMPTION IS APPROPRIATE REGARDING WHETHER DISTRIBUTION COSTS MUST BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. No. In fact, the NARUC Manual (published in 1992) states the following:

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.
>
> Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. (page 89)

Q. HAS NARUC PROVIDED MORE RECENT GUIDANCE CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT THAN WHAT WAS PUBLISHED IN THE 1992 NARUC ELECTRIC COST ALLOCATION MANUAL?

A. Yes. The 1992 NARUC Manual was written in an era when all retail utility services were bundled (generation, transmission and distribution). Subsequent to the unbundling of retail rates in the mid to late 1990's by several state jurisdictions, NARUC commissioned a study to examine the costing and pricing of electric distribution service in further detail. In December 2000, NARUC published a report entitled: <u>Charging For Distribution Services: Issues in Rate Design</u>. As part of the Executive Summary this report states:

> The usefulness of cost analyses of the distribution system in designing rate structures and setting rate levels depends in large measure upon the manner in which the studies are undertaken. Cost studies (both marginal and embedded) are intended, among other things, to determine the nature and causes of costs, so that they can then be reformulated into rates that cost-causers can pay. Such studies must of necessity rely on a host of simplifying assumptions in order to produce workable results; this is

> especially true of embedded cost studies. Moreover, it is often the case that many of the costs (*e.g.,* administrative and general) that distribution rates recover are not caused by provision of distribution service, but are assigned to it arbitrarily. Too great dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design. (page 67)

With specific regard to classification and allocation of certain distribution plant (poles, wires and transformers), Chapter IV of this report is devoted to the costing of distribution services. With respect to embedded cost analyses this updated NARUC report states:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.
>
> Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related. However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).

> Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access. (pages 29 & 30)

In summary, when all of the facts and guidelines are known, it is clear to me that: (a) data and analysis specific to each utility is more appropriate and preferred over an *a priori* assumption that distribution plant must be partially customer-related; and, (b) many (if not most) state regulatory commissions endorse a method in which all distribution plant from substations through line transformers is classified and allocated based solely on demand. A copy of the entire Chapter (IV) from the 2000 NARUC Publication discussing costing studies is provided in my Schedule GAW-7.

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. WHAT ARE YOUR RECOMMENDATIONS CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT IN THIS CASE?

A. Based on my customer density/mix analysis of KU's distribution system, it is apparent that KU's primary voltage distribution system costs should be classified as 100% demand-related. With regard to the Company's secondary voltage distribution system, I have accepted Mr. Seeyle's customer/demand classifications.

Q. WHAT ARE THE CCOSS RESULTS UTILIZING THE GENERATION ALLOCATION METHODS YOU DISCUSSED EARLIER AND ALSO CLASSIFIES PRIMARY VOLTAGE DISTRIBUTION PLANT AS 100% DEMAND-RELATED?

A. The following provides a summary of my CCOSS results at current rates under each allocation method wherein primary voltage distribution costs are classified as 100% demand-related:

100% Primary Voltage Demand Distribution Plant
ROR At Current Rates

Class	Modified BIP (As Corrected)	Probability Of Dispatch	True BIP
Residential	4.73%	5.37%	5.35%
General Service	9.36%	10.06%	9.97%
All Electric Schools	4.21%	4.37%	4.44%
Pwr Svc-Secondary	8.45%	8.16%	8.20%
Pwr Svc-Primary	10.22%	9.24%	9.23%
TOD-Secondary	5.40%	4.78%	4.76%
TOD-Primary	3.53%	2.77%	2.81%
Retail Transmission	4.51%	3.67%	3.58%
Fluctuating Load	1.50%	1.03%	0.95%
Outdoor Lighting	9.82%	8.43%	8.58%
Lighting Energy	7.32%	2.85%	3.05%
Traffic Energy	9.55%	7.73%	7.89%
TOTAL	5.56%	5.56%	5.56%

A summary of these CCOSS results are provided in my Schedules GAW-8 and GAW-9. Furthermore, in accordance with the Commission's directive regarding CCOSS, I am providing the functionalization and classification of costs along with the detailed allocation of specific accounts utilizing the Probability of Dispatch method in my Schedules GAW-10 (Class Allocation), GAW-11 (Functionalization/Classification), and GAW-12 (Demand, Energy, Customer costs). The Excel spreadsheet containing this model are provided with my filed testimony (TAI Prob Dispatch with 100% Demand.xls).

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CLASS COST ALLOCATIONS RELATING TO THIS CASE?

A. As can be seen in the table above, while absolute class RORs vary across allocation methodologies, there are relative consistencies across several classes. The TOD-Primary and Fluctuating Load RORs at current rates are considerably lower than the system average regardless of allocation approach, while the General Service, Power Service-Primary and Power Service-Secondary classes RORs tend to be significantly greater than the system average ROR. These profitability patterns across methodologies can then be used as a tool in evaluating reasonable individual class increases.

III. <u>CLASS REVENUE DISTRIBUTION</u>

Q. WHAT ARE THE GENERAL CRITERIA THAT SHOULD BE CONSIDERED IN ESTABLISHING CLASS REVENUE RESPONSIBILITY FOR ELECTRIC UTILITY RATES?

A. There are several criteria that should be considered in evaluating class or rate revenue responsibility. First, class cost allocation results should be considered, but as discussed in detail earlier in my testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure;

affordability of electricity across various classes as well as a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria to be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. In this regard, there is no universal mathematical methodology that can be applied across all utilities or across all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases. These include: some movement towards allocated cost of service; and, maximum/minimum percentage changes across individual rate classes.

Q. DID KU WITNESS SEEYLE CONSIDER AND REFLECT THE VARIOUS SUBJECTIVE CRITERIA AS WELL AS THE BROAD PARAMETERS DISCUSSED ABOVE WITHIN HIS CLASS REVENUE DISTRIBUTION PROPOSAL?

A. Yes. While Mr. Seeyle did consider his CCOSS results, he also recognized other important criteria in developing his proposed class revenue distribution (increases).

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S PROPOSED CLASS REVENUE INCREASE.

A. The following table provides a summary of current and KU proposed revenue by rate class:

KU's Proposed Class Revenue Increases
($000)

Class	Revenue At Present Rates	Proposed Increase	% Increase	% of System Average
Residential (RS)	$622,810	$37,000	5.94%	92%
General Service (GS)	$239,171	$12,094	5.06%	78%
All Electric Schools (AES)	$14,562	$777	5.34%	83%
Pwr Serv-Sec (PS-Sec)	$187,147	$9,478	5.06%	79%
Pwr Serv-Prim (PS-Pri)	$14,972	$706	4.71%	73%
Time of Day-Sec (TOU-Sec)	$123,708	$6,866	5.55%	86%
Time of Day-Pri (TOU-Pri)	$262,429	$17,336	6.61%	102%
Retail Trans (RTS)	$89,718	$6,023	6.71%	104%
Fluctuating Load (FLS)	$30,815	$2,235	7.25%	112%
Outdoor Lighting (ST & POL)	$30,390	$1,866	6.14%	95%
Lighting Energy (LE)	$35	$0	0.00%	0%
Traffic Energy (TE)	$173	$8	4.71%	73%
Curtailable Service Riders (CSR)	-$17,396	$8,688	49.95%	--
TOTAL	$1,598,534	$103,078	6.45%	100%

Q. HAVE YOU CONDUCTED ANALYSES TO EVALUATE THE REASONABLENESS OF MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES?

A. Yes. I have evaluated Mr. Seeyle's proposed class revenue increases both in terms of relative class magnitudes as well as in terms of whether his proposed changes reflect a reasonable movement towards allocated cost of providing service.

Q. PLEASE EXPLAIN YOUR EVALUATION OF MR. SEEYLE'S PROPOSED CLASS REVENUE DISTRIBUTION IN TERMS OF RELATIVE MAGNITUDES.

A. A common technique utilized in the industry is to evaluate class percentage increases relative to the overall system increases. While there are no hard and fast rules, a common practice is that no class should receive an increase greater than approximately 150% of the system average percentage increase. Furthermore, I am of the opinion that no class should receive a rate decrease when there is a significant overall increase to the total Company's revenue requirement. In this regard, Mr. Seeyle's proposed revenue distribution fulfills this criteria however, as will be shown below, he has limited individual class increases somewhat too narrowly.

Q. PLEASE EXPLAIN WHY IT IS YOUR OPINION THAT MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES ARE LIMITED TOO NARROWLY.

A. As indicated several times earlier in my testimony, class cost of service studies cannot be considered surgically precise such that the results obtained from other reasonable methods and approaches may yield somewhat different results. In this regard, it is beneficial to consider the results of multiple CCOSS in conjunction with the concept of gradualism and the other subjective criteria discussed earlier.

My Schedule GAW-13 provides a summary comparison of class rates of return at current rates under each of the CCOSS that should be considered in this case. The following table provides the average indexed ROR at current rates of all methods as well as the average indexed ROR of the methods in which primary voltage distribution plant is classified as 100% demand-related:

Average Indexed ROR Under Multiple Methods and KU Proposed
Percent Increases as a Percent of System Average Percent Increase

Class	Average (All Methods)	Average Primary Distribution 100% Demand	Seeyle Proposed Pct. Of Sys. Average Increase
Residential	87%	93%	92%
General Service	173%	176%	78%
All Electric Schools	88%	78%	83%
Pwr Svc-Secondary	159%	149%	79%
Pwr Svc-Primary	184%	172%	73%
TOD-Secondary	98%	90%	86%
TOD-Primary	62%	55%	102%
Retail Transmission	70%	70%	104%
Fluctuating Load	21%	21%	112%
Outdoor Lighting	151%	161%	95%
Lighting Energy	93%	79%	0%
Traffic Energy	139%	151%	73%
TOTAL	100%	100%	100%

As indicated in the table above, the cost studies indicate that the TOD-Primary, Retail Transmission, and Fluctuating Load classes are contributing significantly less to profits than the system as a whole which indicates that larger percentage increases are warranted for these classes. However, Mr. Seeyle proposes very modest increases (above the system average percentage increase) to these classes of 102%, 104%, and 112%, respectively. At the same time, the General Service and Power Service-Primary classes are contributing significantly more to profits than the system average. Although Mr. Seeyle proposes to increase these classes by a lower percentage rate than the system average percentage, there will be little movement towards allocated cost of service with his recommended narrow bands. Finally, although the Lighting Energy class is somewhat below the system average ROR (indexed ROR less than 100%), Mr. Seeyle proposes no increase to this class. Under Mr. Seeyle's proposal of no increase to Lighting Energy, this class will move further away from the allocated cost of providing service.

As a result, I recommend that Mr. Seeyle's narrow band of class increases be expanded somewhat in order to move these classes closer to allocated cost of service.

Q. PLEASE EXPLAIN AND PROVIDE YOUR RECOMMENDED MODIFICATIONS TO MR. SEEYLE'S CLASS REVENUE DISTRIBUTION PROPOSAL.

A. I recommend somewhat larger percentage increases to the TOD-Primary, Retail Transmission, and Fluctuating Load classes and somewhat smaller percentage increases to the General Service and Power Service-Primary classes. I also recommend that the Lighting class be increased at the system average percentage increase. The table below provides my recommended class revenue increases at the Company's proposed overall increase of $103 million:

OAG Proposed Class Revenue Distribution
At the Company's Proposed Overall Increase
($000)

Class	Proposed Increase	Percent Increase	Percent Of Sys. Average Percent Increase
Residential	$37,000	5.94%	92%
General Service	$10,286	4.30%	67%
All Electric Schools	$777	5.34%	83%
Pwr Svc-Secondary	$9,478	5.06%	79%
Pwr Svc-Primary	$644	4.30%	67%
TOD-Secondary	$6,866	5.55%	86%
TOD-Primary	$18,614	7.09%	110%
Retail Transmission	$6,364	7.09%	110%
Fluctuating Load	$2,484	8.06%	125%
Outdoor Lighting	$1,866	6.14%	95%
Lighting Energy	$2	6.13%	95%
Traffic Energy	$8	4.71%	73%
Curtailable Service Rider	$8,688	49.95%	--
TOTAL	$103,078	6.45%	100%

Q. PLEASE PROVIDE A COMPARISON OF MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES TO THOSE YOU RECOMMEND.

A. The following table provides a comparison of the Company's and my recommended class revenue increases at the Company's overall requested $103 million increase:

Comparison of KU and OAG
Class Revenue Distribution

Class	KU Proposed Increase	OAG Recommended Increase
Residential	$37,000	$37,000
General Service	$12,094	$10,286
All Electric Schools	$777	$777
Pwr Svc-Secondary	$9,478	$9,478
Pwr Svc-Primary	$706	$644
TOD-Secondary	$6,866	$6,866
TOD-Primary	$17,336	$18,614
Retail Transmission	$6,023	$6,364
Fluctuating Load	$2,235	$2,484
Outdoor Lighting	$1,866	$1,866
Lighting Energy	$0	$2
Traffic Energy	$8	$8
Curtailable Service Rider	$8,688	$8,688
TOTAL	$103,078	$103,078

Q. IN THE EVENT THE COMMISSION AUTHORIZES AN OVERALL REVENUE INCREASE LESS THAN THE $103 MILLION REQUESTED BY KU, HOW SHOULD THE ULTIMATE INCREASE BE DISTRIBUTED ACROSS RATE SCHEDULES?

A. I recommend that any overall increase be distributed to rate classes in proportion to the class increases I recommend above.

IV. RESIDENTIAL RATE DESIGN

Q. PLEASE EXPLAIN KU'S CURRENT RESIDENTIAL RATE STRUCTURE.

A. KU offers three different rate schedules for Residential service. Rate RS is the standard Residential rate that serves all but 25 customers. This rate structure is comprised of a fixed monthly customer charge and a flat energy charge per kWh. The Company also offers two Residential Time of Day rates. These Time of Day rates include a fixed monthly charge plus time differentiated rates for demand charges (RTOD-Demand) and another that incorporates time differentiated energy charges (RTOD-

Energy). Currently, there are approximately 25 customers subscribed to the RTOD-Demand rate and no customers have elected the RTOD-Energy rate.

Q. DOES KU PROPOSE SIGNIFICANT INCREASES TO FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. KU witnesses Robert Conroy and William Seeyle propose to increase all residential customer charges from $10.75 to $22.00 per month, or by more than 100%.

Q. MR. WATKINS, HAVE YOU IDENTIFIED A COMMON OBJECTIVE IN KU'S RESIDENTIAL RATE DESIGN PROPOSAL?

A. Yes. It is clear from the testimonies of Messrs. Conroy and Seeyle that the primary objective of KU's residential rate design is to guarantee revenue collection and profitability associated with fixed monthly customer charges. Moreover, and as will be discussed later in my testimony, the witnesses are clearly opening the door for even more revenue stability by proposing to differentiate energy charges between "fixed" and "variable" components as well as advocate the possibility of demand-based rates for all residential customers and the possibility of revenue decoupling in the future.

Q. WHY DOES KU DESIRE MORE RESIDENTIAL REVENUE COLLECTED FROM FIXED CHARGES?

A. Fixed monthly customer charges represent guaranteed revenue to KU. This guarantee of revenue obviously reduces the risks of KU's operations and provides much more assurances of net income available to shareholders.

Q. HOW DOES KU SUPPORT THIS EXCEPTIONALLY LARGE INCREASE TO THE FIXED MONTHLY CUSTOMER CHARGES?

A. Messrs. Conroy and Seeyle offer three rationale for high customer charges. First, Mr. Conroy observes that a residential rate design that recovers a larger portion of revenue from fixed charges will stabilize customers' monthly bills. Second, Mr. Seeyle is of the opinion that because the majority of KU's total costs of providing service are "fixed" in nature, a large portion of its revenues should be collected from fixed charges.

Third, Mr. Seeyle claims that higher fixed charges will help eliminate intra-class subsidies within the Residential class.

Q. IS MR. CONROY CORRECT IN HIS ASSERTION THAT THE COLLECTION OF A HIGHER PROPORTION OF TOTAL REVENUES FROM FIXED CHARGES WILL TEND TO STABILIZE CUSTOMERS' MONTHLY BILLS?

A. Mathematically, Mr. Conroy is absolutely correct. However, this certainly is not an objective of proper economic rate design or accepted public policy. If a rate structure is reconfigured such that a larger proportion of customers' bills are comprised of non-avoidable fixed charges and a smaller proportion of customers' bills are comprised of volumetrically-based (energy) charges, customers' abilities to make rational economic decisions are reduced. In other words, the ability of individuals to control their total electric bill is diminished with rate structures that are comprised largely of fixed charges. This reduced ability to control bills leads to uneconomic decisions relating to the consumption of electricity and clearly hampers incentives to conserve energy.

Q. IS MR. SEEYLE'S ASSERTION THAT FIXED COSTS SHOULD BE COLLECTED FROM FIXED CHARGES IN ACCORDANCE WITH SOUND ECONOMIC PRINCIPLES OR ACCEPTED PRICING PRACTICES?

A. No. Mr. Seeyle has a profound misunderstanding of sound economic principles that are contrary to accepted pricing practices. First, I will discuss the theoretical aspects of sound economic pricing principles and then I will discuss accepted pricing practices in our economy.

The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[16] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

[16] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[17] It is well known that costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS KU.

A. Due to KU's investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive

---

[17] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity usage, i.e., the level of kWh consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. IS THE ELECTRIC UTILITY INDUSTRY UNIQUE IN ITS COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing, agricultural, and transportation industries are comprised of cost structures predominated with "fixed" costs. Obvious examples of these industries include: automobile and truck manufacturing; petroleum production; farming; airline; rail transportation; and shipping transportation. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated.

Accordingly, KU's position that its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Company's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHAT EFFICIENT PRICING STRUCTURES AND PRACTICES PREVAIL IN COMPETITIVE ELECTRICITY MARKETS?

A. Yes. In several States, the provision of electricity to retail customers has been unbundled wherein distribution service remains regulated, but customers have the ability to shop for transmission and generation service in a competitive marketplace. In every instance in which I am aware, residential customers pay for competitively-based transmission and generation service entirely on a volumetric basis; i.e., no fixed charges are imposed. In this regard, there is no question that the total cost of transmission and generation service is largely "fixed" in nature due to the large capital investments required to provide service.

Q. ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. Yes. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[18] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

---

[18] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[19] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[20]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[21]

Recently, some public utilities have begun to advocate SFV residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. ARE CONSERVATION AND EFFICIENCY GAINS A NEW RISK TO PUBLIC UTILITIES?

A. No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average residential electric usage per appliance has been declining, utilities have remained financially healthy and have

---

[19] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.
[20] *Id.* p. 8 (alteration in original).
[21] *Id.* pp. 128-129.

continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

Q. DOES KU HAVE ANY APPROVED PLANS TO COMPENSATE THE COMPANY FOR CONSERVATION EFFORTS?

A. Yes. KU has an approved Demand Side Management Cost Recovery Mechanism wherein the Company is compensated for not only the cost of implementing its conservation programs but also provides compensation for diminished revenues resulting from its conservation programs. In addition, the Company is provided an incentive bonus (up to 5% of program expenditures) of 15% on the expected net resource savings for each approved DSM program.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. A CUSTOMER'S TOTAL ELECTRIC BILL IS COMPRISED OF A BASE RATE COMPONENT, A FUEL ADJUSTMENT CLAUSE ("FAC") RIDER; AND VARIOUS OTHER RIDERS. THESE FUEL AND OTHER RIDERS ARE VOLUMETRICALLY PRICED AND REPRESENT A SIGNIFICANT PORTION OF A CUSTOMER'S BILL. DOES THE VOLUMETRIC PRICING OF THESE COMPONENTS ELIMINATE THE NEED FOR A PROPER PRICING SIGNAL FROM BASE RATES?

A. No, certainly not. The fact that significant revenue may be collected volumetrically through riders does not lessen the need for reasonable design of the underlying base rates.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. PLEASE RESPOND TO MR. SEEYLE'S ASSERTION THAT HIGHER FIXED CUSTOMER CHARGES HELP REDUCE INTRA-CLASS SUBSIDIES.

A. Although I have already explained why the notion that fixed costs should be recovered from fixed charges does not comport with accepted economic theory and practice, the genesis of Mr. Seeyle's rationale relating to intra-class subsidies rests on the premise that the revenue derived from small volume customers does not sufficiently recover the total costs to provide service, such that the revenue generated from large volume customers subsidize the small volume customers. Mr. Seeyle's rationale and opinion is incorrect and fails to consider two important aspects of cost causation and ratemaking principles and practices.

First, one must compare the "cost causation" of "small volume and large volume" customers within a particular rate class particularly as it relates to residential customers. Based on the seasonal nature of the demand for electricity, residential customers use much more electricity in the winter and summer months than during the spring and fall months due to the use of electricity for heating and air conditioning. Some residential customers do not use electricity for space heating purposes and may not have air conditioning (or use in a limited fashion). As such, these annual small volume customers use electricity at a much more constant rate throughout the year than do residential large volume customers; i.e., small volume customer's usage is more constant throughout the year.

To illustrate, KU's average residential customer used about 1,537 kWh during the winter months of January and February and about 1,335 kWh during the summer months of July and August. However, during the spring and fall months of April, May, October, and November, the average residential customer used only about 842 kWh.[22] As a result, the load factor of small volume (non-heating/air conditioning customers) tends to be much higher than that for large volume (heating/air conditioning customers). As a matter of cost causation, KU must plan and install relatively more capacity for heating/air conditioning customers than for small volume customers. This additional capacity obviously comes at a cost such that the cost to serve a high load factor (low annual volume) customer is significantly less than that for a low load factor (high annual volume) customer.

The second aspect concerns the pricing structure of goods and services generally, and public utility rates specifically. That is, taken to the extreme, it could be argued that every consumer of a good or service (whether competitive or regulated) imposes a different cost upon the good or service provided such that a different price could

[22] Per KU response to CAC data request 1-8.

theoretically be calculated for every individual customer. This of course is not done in practice as it is not practical or reasonable. For example, if two customers purchase gasoline from a gas station at the same time, one driving a very large vehicle with a large fuel tank and the other driving a very small car with a small fuel tank, the customer purchasing a small amount of gasoline does not pay more per gallon than the customer purchasing significantly more gasoline. This is true even though the ultimate delivered price of gasoline includes a significant level of “fixed” costs such as the cost of the store, gas pumps, labor, etc.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH KU’S RESIDENTIAL CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer’s account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO KU’S RESIDENTIAL CLASS?

A. Yes. I conducted a direct customer cost analysis for KU’s Residential class. The details of this analysis are provided in my Schedule GAW-14. As indicated in this Schedule, the Residential direct customer cost is at most $6.13 per month. It should be noted that my customer cost analyses is based on the Company’s proposed return on equity of 10.23%. If a lower cost of equity is used, the resulting customer costs are somewhat reduced.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all electric utilities, KU is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to KU's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. MR. SEEYLE CLAIMS THAT HIS "COST-BASED" RESIDENTIAL CUSTOMER CHARGE IS $23.93 PER MONTH. PLEASE EXPLAIN HOW MR. SEEYLE ARRIVED AT THIS LEVEL.

A. Mr. Seeyle's figure of $23.93 per residential customer per month includes the majority of distribution plant investment costs associated with poles and overhead lines (59%), underground conductors and conduit (80%), and transformers (47%). In addition, Mr. Seeyle's calculated residential customer cost of $23.93 per month includes $12.5 million in administrative and general expenses plus additional other overhead expenses. Finally, Mr. Seeyle's customer cost analysis includes the entire amount of uncollectible expense assigned to the Residential class ($3.6 million). These costs should not be reflected within the determination of an appropriate fixed monthly customer charge.

Q. SHOULD ANY DISTRIBUTION OVERHEAD LINES, UNDERGROUND LINES, OR TRANSFORMER COSTS BE CONSIDERED IN DETERMINING THE LEVEL, OR REASONABLENESS, OF FIXED MONTHLY CHARGES?

A. No. Every electric utility's investment in distribution lines and transformers reflects the back bone of the company's distribution system and indeed, serves as the infrastructure supporting the company's entire existence. In other words, distribution lines and transformers are the conduit to move electricity from the transmission system to individual customers. Residential electric customers do not subscribe to KU's service simply to be "connected," rather, they rely upon KU to distribute their energy requirements throughout the year.

Q. WHY THEN ARE DISTRIBUTION COSTS SOMETIMES CLASSIFIED AND ALLOCATED BASED PARTIALLY ON PEAK DEMANDS AND PARTIALLY ON NUMBER OF CUSTOMERS?

A. I provided a detailed discussion of this topic earlier in my testimony. In short, the reason that some analysts classify distribution plant as partially customer-related and partially demand-related has nothing to do with cost causation but rather, is a means to equitably allocate costs due to differences in customer densities and the mix of customers across classes.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT DISTRIBUTION POLES, LINES, AND TRANSFORMERS SHOULD NOT BE CONSIDERED AS "CUSTOMER-RELATED" COSTS FOR PURPOSES OF DETERMINING THE REASONABLENESS OF FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. In his well-known treatise <u>Principles of Public Utility Rates</u>, Professor James C. Bonbright states:

> . . . if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customers costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories. (Second Edition, page 492)

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR KU'S RESIDENTIAL CUSTOMERS?

A. Although my residential customer cost analysis indicates a maximum monthly customer charge of $6.13 per month, I recommend maintaining the current customer charge of $10.75 per month. In this regard, I recognize that the current rate of $10.75 is 75% greater than the direct customer cost. In the interest of rate continuity and rate stability, my recommendation of maintaining the current monthly customer charge is in the best public interest.

Q. PLEASE BRIEFLY SUMMARIZE WHY YOUR RECOMMENDATION TO MAINTAIN THE CURRENT LEVEL OF CUSTOMER CHARGES IS APPROPRIATE.

A. It must be remembered that my proposed rate design will allow the Company a reasonable opportunity to recover all of its costs and earn a fair rate of return. Utilities advocate higher fixed customer charges in order to minimize their risks by guaranteeing revenue recovery through fixed charges. Whether electricity rates are largely volumetric priced or largely based on fixed charges, the reality is the utility will collect its required revenues. This is particularly relevant in this case since the Company is using a forecasted test year that reflects energy usages (kWh) under normal weather conditions. Rate designs structured largely based on volumetric charges promote conservation, are efficient, and are in accordance with pricing practices in competitive markets.

Finally, no cross-subsidization issues are created across customers within the same class as long as the fixed customer charge recovers the incremental cost of connecting and maintaining each customer's account. Indeed, the incremental cost of connecting and maintaining a residential customer's account is slightly above $6.00 per month. My recommendation to maintain the current residential customer charge of $10.75 is considerably higher than this incremental cost. At the same time, my recommendation to maintain the current rate level adheres to the accepted ratemaking principles of rate continuity and rate stability.

Q. DOES THE COMPANY PROPOSE ANY STRUCTURAL CHANGES TO THE MANNER IN WHICH ENERGY CHARGES ARE PRESENTED ON CUSTOMER'S BILLS?

A. Yes. Messrs. Conroy and Seeyle propose a change in the way residential customers' bills are presented. Currently, a customer's bill simply shows that month's kWh energy charges. The Company is proposing to bifurcate this energy charge into a "variable cost" component and a "fixed cost" component. Mr. Seeyle testifies that this proposal is solely for educational and informational purposes at this point in time.

Q. WHAT IS THE COMPANY'S RATIONALE FOR PROPOSING THIS "EDUCATIONAL AND INFORMATIONAL" BIFURCATION OF ENERGY CHARGES?

A. Mr. Seeyle indicates that the Company wants customers, stakeholders, and employees to be aware that two types of costs are included in the energy charge. Mr. Seeyle opines that "it is important for customers, stakeholders, and employees to understand that not all costs are automatically reduced when customers use less energy."

Similarly, Mr. Conroy testifies that:

> splitting the energy charge solely on the tariff sheets as proposed will allow the Commission and interested customers to see how much fixed-cost recovery versus truly variable-cost recovery is embedded in the Company's volumetric energy rate for those rate schedules. The Company plans to provide additional educational material on this issue to customers periodically by discussing it in bill inserts or customer newsletters enclosed in customers' bills.

Q. DO YOU SUPPORT THIS PROPOSED BIFURCATION OF ENERGY CHARGES WITHIN CUSTOMERS' BILLS?

A. No. First, even for those customers that understand the concepts of fixed versus variable costs, they could care less about the cost structure for ratemaking purposes within their energy charges. What the customer is interested in is what those variable charges are in total. As an analogy, when consumers purchase gasoline, they could care less how much of the total cost per gallon is associated with the fixed cost of producing, transporting, and delivering that gallon of gasoline versus the variable cost of gasoline at the wellhead. Second, in my practice throughout the United States, I have not seen such a proposal, let alone such a bifurcation of rates between “fixed” and “variable” costs. This could lead to additional customer confusion as they may not understand the distinction between “fixed” and “variable” costs, and perhaps more importantly, may disagree with the Company’s determination of what is and what is not a fixed cost. The point of this is that such a distinction is unnecessary, will not assist consumers in their efficient utilization of electricity, nor assist in making decisions on how to control their electricity bills. Indeed, it is clear that this proposal is nothing more than a campaign by KU to advocate the collection of so-called “fixed” costs from non-avoidable charges.

Q. MR. SEEYLE DISCUSSES THE POTENTIAL RATE DESIGN PROBLEMS CREATED BY DISTRIBUTED GENERATION. PLEASE RESPOND TO THESE POTENTIAL RATE DESIGN PROBLEMS ESPOUSED BY MR. SEEYLE.

A. While Mr. Seeyle acknowledges that distributed generation has not created any significant problems for KU, it is creating problems with the erosion of fixed cost recovery for utilities in western States. As a result, Mr. Seeyle believes it is important for KU to be aware of what is going on in other jurisdictions in order to begin educating its customers, stakeholders, and employees about the kinds of costs that are fixed and those that are variable and thus, avoidable.

In this regard, it is clear that Mr. Seeyle is attempting to again make a case for collecting more (or virtually all) fixed costs through either unavoidable customer charges or inelastic demand charges. I am well aware of the situation involving distributed generation in the desert States of Arizona, New Mexico, and Nevada. Given the climate and typography of these western States, distributed generation (solar) has become increasingly prevalent and has indeed created issues for the utilities in these States. There are a myriad of reasons for this including the fact that these desert States experience intense sunshine for most days thereby making solar generation more practical and affordable. Similarly, there are few trees to block sunlight in the desert or open plains. Finally, many western residential customers are extremely rural in nature, wherein sustained outages present numerous concerns and problems to these very rural customers. None of these situations exist in Kentucky, nor are they likely to prevail in the foreseeable future. Indeed, Mr. Seeyle's distributed generation argument is nothing more than the gnat on the mule's back driving the plow.

Q. MR. SEEYLE ALSO ASSERTS THAT SOME UTILITIES ARE CONSIDERING THE IMPLEMENTATION OF THREE- AND MULTI-PART RATES FOR RESIDENTIAL, SMALL COMMERCIAL AND INDUSTRIAL CUSTOMERS. PLEASE COMMENT ON THIS ASSERTION.

A. Mr. Seeyle claims that some of these approaches are being <u>adopted</u> by utilities. In this regard, Mr. Seeyle is referring to mandatory demand charges. While Mr. Seeyle is correct that mandatory demand charges have been proposed by a handful of utilities throughout the United States, not a single one has been approved. Typical residential customers do not understand the concept of power versus energy usage and therefore, do not understand the concept of demand charges. As a result and universally, residential customers have expressed nothing short of outrage over utilities' proposals to implement mandatory demand charges. Indeed, this Commission needs to look no further than Glasgow, Kentucky as it relates to the mandatory residential demand charge initially implemented by the Glasgow Electric Plant Board. This utility initially implemented mandatory residential demand charges (which is not subject to this Commission's jurisdiction). Almost immediately, there was public outcry relating to these mandatory demand charges. As a result, the utility was forced to continue offering energy only-based rates. Other examples include mandatory demand charge proposals in Arizona that were supported by the Commission Staff. Once again, there was much public outcry against this change as has ever been seen. Ultimately, the Arizona Corporation Commission denied the utilities request for mandatory residential demand charges.

Q. WHY ARE SOME UTILITIES ADVOCATING MANDATORY RESIDENTIAL DEMAND CHARGES?

A. Maximum peak load (demand) is considerably more inelastic than energy consumption; i.e., a customer's total demand will not vary as much as its energy consumption regardless of a consumer's attempts to reduce consumption or engage in conservation practices. As a result, this creates more guarantee of revenue recovery to the utility, which in turn, reduces the utility's risks.

Q. DOES KU CURRENTLY HAVE ALTERNATIVE RESIDENTIAL RATE DESIGN OPTIONS AVAILABLE TO ITS CUSTOMERS?

A. Yes. As discussed earlier, the Company offers an optional Time of Day energy-based rate schedule as well as an optional demand-based rate schedule. Currently, there are only about 25 customers subscribed to the demand-based rate schedule and no customers have opted for the Time of Day energy-based rate schedule. This lack of participation is evidence of the fact that residential customers do not like or do not want demand-based rates. In this regard, this is a very important public policy issue. That is, in competitive markets, consumers (the market) dictate how pricing structures are developed. However, with respect to public utilities, they are monopolists and consumers have no other option for these public goods and services. Under the tried and true energy only-based rates, utilities have, and will continue to have, the realistic opportunity to recover their costs and provide a reasonable profit to their shareholders. As such, these proposals advocated by KU and other utilities are nothing more than a red herring in that the utilities are using these rate design approaches to reduce their risk and increase shareholder value at the expense of the consuming public.

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

Mar. 1993-Present	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as 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. <u>Anti-Trust and Commercial Business Damage Litigation</u>

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 AND LOUISVILLE GAS & ELECTRIC
Assignment of Gross Plant to Hours Based on Dispatch

Total Output By Plant All Periods					76,552		270,295		585,272		14,495		5,361,923			3,029,956			33,262,127
Plant Investment					$ 84,714,614.68		$ 65,243,803.70		$ 959,593,510.85		$ 23,887,880		$ 411,976,847.50			$ 732,470,921.67			6,096,514,525
						$ Investment Allocation Test Factor		$ Investment Allocation Test Factor		$ Investment Allocation Test Factor		$ Investment Allocation Test Factor		% Test Factor	$ Investment Allocation Test Factor		% Test Factor	$ Investment Allocation Test Factor	
						$ 84,714,614.68		$ 65,243,803.70		$ 959,593,510.85		$ 23,887,879.64		100%	$ 411,976,847.50		100%	$ 732,470,921.67	
Month	Day	Year	Hour	Adjusted Hour	Brown 1	Brown 1 Plant Investment Allocation	Brown 2	Brown 2 Plant Investment Allocation	Brown 3	Brown 3 Plant Investment Allocation	Brown 5	Brown 5 Plant Investment Allocation	Cane Run 7	Cane Run 7 Hour %	Cane Run 7 Plant Investment Allocation	Ghent 1	Ghent 1 Hour %	Ghent 1 Plant Investment Allocation	Total Investment by Hour
7	1	2017	1	0	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	497	0.00927%	$ 38,190.24	334	0.01102%	$ 80,742.19	$ 734,145.84
7	1	2017	2	1	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	571	0.01064%	$ 43,849.05	334	0.01102%	$ 80,742.19	$ 633,206.71
7	1	2017	3	2	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	465	0.00867%	$ 35,704.66	334	0.01102%	$ 80,742.19	$ 625,062.32
7	1	2017	4	3	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	397	0.00740%	$ 30,479.97	334	0.01102%	$ 80,742.19	$ 619,837.63
7	1	2017	5	4	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	394	0.00734%	$ 30,249.46	334	0.01102%	$ 80,742.19	$ 619,607.12
7	1	2017	6	5	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	368	0.00686%	$ 28,251.79	334	0.01102%	$ 80,742.19	$ 617,609.45
7	1	2017	7	6	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	438	0.00818%	$ 33,682.40	334	0.01102%	$ 80,742.19	$ 623,294.70
7	1	2017	8	7	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	622	0.01160%	$ 47,790.62	334	0.01102%	$ 80,742.19	$ 653,659.63
7	1	2017	9	8	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	334	0.01102%	$ 80,742.19	$ 698,297.64
7	1	2017	10	9	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	384	0.01267%	$ 92,829.35	$ 724,137.86
7	1	2017	11	10	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	424	0.01399%	$ 102,499.07	$ 765,587.75
7	1	2017	12	11	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	434	0.01432%	$ 104,916.50	$ 793,988.22
7	1	2017	13	12	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 837,274.60
7	1	2017	14	13	36	$ 39,838.68	86	$ 20,758.69	176	$ 288,269.17	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 935,402.42
7	1	2017	15	14	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 1,008,713.52
7	1	2017	16	15	36	$ 39,838.68	85	$ 20,568.00	173	$ 282,825.80	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 1,073,967.05
7	1	2017	17	16	36	$ 39,838.68	86	$ 20,758.69	162	$ 264,790.53	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 1,081,925.62
7	1	2017	18	17	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 1,061,906.75
7	1	2017	19	18	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 1,012,300.55
7	1	2017	20	19	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 984,196.63
7	1	2017	21	20	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	474	0.01564%	$ 114,586.22	$ 946,116.01
7	1	2017	22	21	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	424	0.01399%	$ 102,499.07	$ 947,595.77
7	1	2017	23	22	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	384	0.01267%	$ 92,829.35	$ 920,610.88
7	1	2017	24	23	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	334	0.01102%	$ 80,742.19	$ 806,732.72
7	2	2017	1	0	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	334	0.01102%	$ 80,742.19	$ 784,455.79
7	2	2017	2	1	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	622	0.01160%	$ 47,790.62	334	0.01102%	$ 80,742.19	$ 763,081.03
7	2	2017	3	2	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	622	0.01160%	$ 47,790.62	334	0.01102%	$ 80,742.19	$ 755,150.26
7	2	2017	4	3	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	473	0.00882%	$ 36,324.71	334	0.01102%	$ 80,742.19	$ 731,567.22
7	2	2017	5	4	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	622	0.01160%	$ 47,790.62	337	0.01111%	$ 81,377.98	$ 753,553.72
7	2	2017	6	5	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 722,696.03
7	2	2017	7	6	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 723,976.01
7	2	2017	8	7	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 802,687.37
7	2	2017	9	8	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 862,778.33
7	2	2017	10	9	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 945,231.75
7	2	2017	11	10	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 1,041,027.54
7	2	2017	12	11	36	$ 39,838.68	86	$ 20,758.69	188	$ 307,763.65	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 1,159,838.45
7	2	2017	13	12	46	$ 50,528.72	86	$ 20,758.69	204	$ 334,472.25	0	$ -	662	0.01235%	$ 50,863.97	0	0.00000%	$ -	$ 1,712,581.88
7	2	2017	14	13	42	$ 46,102.20	86	$ 20,758.69	211	$ 345,949.23	0	$ -	662	0.01235%	$ 50,863.97	42	0.00139%	$ 10,153.21	$ 1,729,785.55
7	2	2017	15	14	54	$ 59,724.82	87	$ 21,113.51	205	$ 335,341.22	0	$ -	662	0.01235%	$ 50,863.97	84	0.00277%	$ 20,306.42	$ 1,743,061.51
7	2	2017	16	15	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	126	0.00416%	$ 30,459.63	$ 1,637,713.09
7	2	2017	17	16	36	$ 39,838.68	74	$ 17,980.40	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	168	0.00554%	$ 40,612.84	$ 1,308,066.25
7	2	2017	18	17	36	$ 39,838.68	86	$ 20,758.69	158	$ 259,035.64	0	$ -	662	0.01235%	$ 50,863.97	210	0.00693%	$ 50,766.05	$ 1,145,643.23
7	2	2017	19	18	36	$ 39,838.68	86	$ 20,758.69	180	$ 295,794.79	0	$ -	662	0.01235%	$ 50,863.97	252	0.00832%	$ 60,919.26	$ 1,082,491.55
7	2	2017	20	19	48	$ 52,786.25	86	$ 20,758.69	206	$ 337,751.39	0	$ -	662	0.01235%	$ 50,863.97	294	0.00970%	$ 71,072.47	$ 1,058,337.92
7	2	2017	21	20	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	336	0.01109%	$ 81,225.68	$ 959,319.06
7	2	2017	22	21	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	378	0.01248%	$ 91,378.89	$ 951,082.40
7	2	2017	23	22	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	380	0.01254%	$ 91,862.37	$ 896,927.43
7	2	2017	24	23	36	$ 39,838.68	64	$ 15,448.32	155	$ 254,133.32	0	$ -	662	0.01235%	$ 50,863.97	332	0.01096%	$ 80,258.71	$ 805,682.23

Note: Due to the number of generating units, all units are not provided in this Schedule. Please see Excel file for all generating units.

KENTUCKY UTILITIES COMPANY
Assignment of Hourly Generation Investment Costs to Rate Classes

					KU Demand % of Total System Demand														
KU Rate Schedule ----->					1	100	140	200	210	300	320	600	620	700	710	720	60	61	62
Month	Day	Year	Hour	Total Investment by Hour															
7	1	2017	1	$734,146	$211,447	$51,626	$5,122	$64,773	$168,372	$74,581	$6,801	$51,220	$19,001	$22,417	$47,137	$0	$11,536	$67	$46
7	1	2017	2	$633,207	$171,688	$45,451	$4,585	$58,178	$153,112	$67,292	$6,276	$40,022	$15,913	$19,461	$40,663	$0	$10,462	$61	$42
7	1	2017	3	$625,062	$163,850	$40,683	$4,787	$59,490	$155,369	$68,877	$6,443	$38,614	$16,166	$19,311	$40,680	$0	$10,691	$62	$43
7	1	2017	4	$619,838	$159,882	$44,028	$5,250	$59,997	$153,108	$68,790	$7,349	$38,038	$12,806	$19,294	$40,315	$0	$10,874	$63	$43
7	1	2017	5	$619,607	$151,371	$47,542	$5,244	$60,633	$150,963	$70,924	$7,174	$38,667	$17,563	$18,867	$39,797	$0	$10,758	$62	$43
7	1	2017	6	$617,609	$137,752	$62,807	$5,485	$58,767	$147,811	$73,813	$6,640	$39,186	$17,236	$17,861	$39,318	$0	$10,826	$63	$43
7	1	2017	7	$623,295	$139,894	$76,680	$5,053	$58,853	$145,640	$77,776	$6,479	$40,112	$15,034	$17,717	$39,994	$0	$0	$61	$0
7	1	2017	8	$653,660	$150,941	$86,609	$5,197	$59,351	$143,320	$80,535	$6,564	$45,202	$15,223	$18,665	$41,993	$0	$0	$59	$0
7	1	2017	9	$698,298	$167,426	$98,509	$5,614	$61,613	$146,711	$83,838	$6,855	$48,348	$14,793	$19,842	$44,692	$0	$0	$58	$0
7	1	2017	10	$724,138	$190,915	$100,659	$5,731	$62,182	$144,121	$85,112	$6,923	$49,066	$10,865	$21,244	$47,266	$0	$0	$54	$0
7	1	2017	11	$765,588	$221,345	$100,446	$6,077	$63,461	$146,236	$86,000	$7,180	$50,405	$11,770	$22,631	$49,982	$0	$0	$53	$0
7	1	2017	12	$793,988	$242,586	$101,264	$5,991	$64,517	$145,722	$87,590	$6,644	$50,525	$13,267	$23,882	$51,949	$0	$0	$51	$0
7	1	2017	13	$837,275	$277,439	$98,574	$6,407	$66,941	$149,269	$90,291	$6,880	$53,541	$7,238	$25,528	$55,117	$0	$0	$52	$0
7	1	2017	14	$935,402	$306,702	$115,514	$6,802	$73,022	$163,185	$99,203	$7,540	$58,183	$13,450	$29,266	$62,481	$0	$0	$56	$0
7	1	2017	15	$1,008,714	$343,792	$115,627	$7,529	$77,800	$174,006	$102,492	$8,087	$59,936	$17,953	$32,613	$68,818	$0	$0	$60	$0
7	1	2017	16	$1,073,967	$383,107	$115,071	$8,380	$84,062	$188,813	$106,586	$8,800	$64,104	$7,715	$35,575	$71,692	$0	$0	$62	$0
7	1	2017	17	$1,081,926	$404,949	$95,604	$8,519	$84,535	$197,432	$108,191	$8,734	$67,937	$788	$35,177	$69,998	$0	$0	$62	$0
7	1	2017	18	$1,061,907	$408,280	$84,147	$8,142	$83,616	$196,676	$104,576	$8,588	$66,098	$523	$32,543	$68,657	$0	$0	$61	$0
7	1	2017	19	$1,012,301	$393,109	$79,977	$7,603	$79,534	$189,579	$98,561	$8,185	$58,534	$506	$30,699	$65,954	$0	$0	$60	$0
7	1	2017	20	$984,197	$387,046	$74,297	$7,130	$75,924	$183,949	$94,462	$7,955	$58,308	$507	$30,234	$64,325	$0	$0	$60	$0
7	1	2017	21	$946,116	$358,301	$69,754	$5,851	$73,457	$180,409	$89,839	$7,697	$59,104	$499	$28,961	$61,946	$0	$10,197	$59	$41
7	1	2017	22	$947,596	$335,557	$67,623	$5,739	$74,884	$185,518	$90,889	$7,976	$66,047	$12,471	$29,109	$60,948	$0	$10,729	$62	$43
7	1	2017	23	$920,611	$294,586	$64,526	$5,676	$76,867	$194,845	$90,863	$8,056	$69,782	$16,761	$28,514	$58,610	$0	$11,413	$66	$46
7	1	2017	24	$806,733	$237,199	$57,289	$5,400	$69,342	$178,010	$83,520	$7,297	$62,118	$19,594	$24,831	$51,164	$0	$10,862	$63	$43
7	2	2017	1	$784,456	$259,442	$51,947	$5,537	$67,040	$172,651	$84,097	$7,680	$43,050	$4,834	$22,809	$53,807	$0	$11,450	$66	$46
7	2	2017	2	$763,081	$232,100	$50,009	$5,414	$66,672	$174,017	$80,767	$7,613	$43,565	$18,130	$21,747	$51,228	$0	$11,706	$68	$47
7	2	2017	3	$755,150	$223,064	$52,396	$5,807	$69,626	$180,434	$84,249	$7,771	$44,943	$1,777	$21,836	$51,538	$0	$11,595	$67	$46
7	2	2017	4	$731,567	$200,487	$51,079	$6,091	$67,660	$172,847	$79,875	$7,419	$42,962	$21,936	$20,544	$48,339	$0	$12,209	$71	$49
7	2	2017	5	$753,554	$186,474	$58,738	$6,184	$71,724	$180,300	$85,924	$7,364	$45,488	$27,283	$21,271	$49,719	$0	$12,958	$75	$52
7	2	2017	6	$722,696	$166,639	$80,466	$6,321	$68,727	$169,327	$85,260	$6,769	$43,524	$16,058	$19,953	$47,354	$0	$12,179	$70	$49
7	2	2017	7	$723,976	$171,956	$104,143	$5,656	$67,124	$161,869	$87,429	$6,341	$43,496	$7,756	$20,400	$47,739	$0	$0	$69	$0
7	2	2017	8	$802,687	$186,224	$114,159	$6,275	$72,542	$171,103	$96,916	$7,016	$53,488	$18,795	$22,926	$53,173	$0	$0	$70	$0
7	2	2017	9	$862,778	$204,410	$123,256	$7,192	$78,690	$185,789	$106,346	$7,638	$62,048	$3,879	$25,374	$58,088	$0	$0	$69	$0
7	2	2017	10	$945,232	$251,786	$127,213	$7,740	$83,824	$195,508	$112,635	$8,125	$65,292	$510	$27,887	$64,643	$0	$0	$69	$0
7	2	2017	11	$1,041,028	$293,670	$138,930	$8,108	$86,505	$202,769	$113,984	$8,564	$66,695	$21,707	$29,653	$70,373	$0	$0	$70	$0
7	2	2017	12	$1,159,838	$343,254	$147,308	$8,558	$92,972	$215,570	$123,821	$9,293	$72,907	$38,170	$33,128	$74,786	$0	$0	$73	$0
7	2	2017	13	$1,712,582	$521,675	$218,588	$13,259	$140,004	$322,478	$185,704	$14,269	$112,878	$19,013	$51,714	$112,897	$0	$0	$104	$0
7	2	2017	14	$1,729,786	$548,661	$231,368	$12,790	$138,430	$317,125	$183,580	$14,114	$109,804	$812	$54,537	$118,462	$0	$0	$103	$0
7	2	2017	15	$1,743,062	$574,727	$211,072	$12,558	$136,490	$314,266	$181,885	$12,265	$111,954	$16,724	$54,319	$116,699	$0	$0	$101	$0
7	2	2017	16	$1,637,713	$576,479	$180,048	$11,324	$124,986	$286,264	$159,702	$10,949	$102,448	$26,045	$50,762	$108,614	$0	$0	$94	$0
7	2	2017	17	$1,308,066	$494,392	$121,687	$8,599	$94,650	$221,437	$120,552	$8,110	$79,134	$34,525	$39,723	$85,183	$0	$0	$74	$0
7	2	2017	18	$1,145,643	$451,022	$94,805	$7,667	$84,836	$201,293	$105,485	$7,320	$72,728	$9,882	$35,419	$75,119	$0	$0	$66	$0
7	2	2017	19	$1,082,492	$429,482	$84,279	$7,322	$80,105	$189,948	$97,672	$6,811	$70,374	$13,204	$32,965	$70,266	$0	$0	$64	$0
7	2	2017	20	$1,058,338	$423,440	$76,267	$7,027	$79,484	$193,718	$96,600	$6,815	$72,617	$512	$32,655	$69,137	$0	$0	$64	$0
7	2	2017	21	$959,319	$377,520	$68,905	$5,424	$70,306	$174,984	$83,506	$6,121	$63,420	$8,762	$28,282	$61,781	$0	$10,207	$59	$41
7	2	2017	22	$951,082	$348,354	$63,669	$5,477	$73,419	$185,669	$86,852	$6,435	$67,870	$13,523	$28,080	$61,025	$0	$10,606	$61	$42
7	2	2017	23	$896,927	$300,077	$61,112	$5,452	$71,772	$183,307	$82,666	$6,376	$68,369	$23,394	$26,542	$56,760	$0	$10,995	$64	$44
7	2	2017	24	$805,682	$249,163	$56,078	$5,265	$67,413	$175,408	$77,659	$7,047	$63,256	$18,064	$24,119	$51,295	$0	$10,811	$63	$43

KENTUCKY UTILITIES COMPANY
Probability of Dispatch with Time, Fuel, and Customer-Demand Split
Rate of Retun Summary

	Allocation Factor		Total	Residential (RS)	General Service	All Elect. Schools	Pwr Svc Secondary	PWR Svc Primary	Time of Day Secondary
	Name	No	Kentucky	(RS	(GS)	(AES)	(PS-Sec)	(PS-Pri)	(TOU-sec)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$554,543,189	$198,233,994	$12,037,991	$174,459,441	$13,950,651	$116,879,945
Intercompany Sales		2	$8,422,903	$2,827,720	$843,635	$70,490	$996,388	$76,891	$775,692
Curtailable Service Rider		W/S Peak	-$17,395,776	-$7,040,463	-$1,992,695	-$149,403	-$1,983,575	-$137,636	-$1,397,730
LATE PAYMENT CHARGES	LPAY		$3,857,505	$3,012,898	$568,302	$3,750	$98,651	$5,535	$41,764
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$1,967,237	$136,875	$853	$1,335	$51	$982
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$1,354,391	$355,528	$24,363	$299,161	$22,701	$227,139
OTHER MISC REVENUES	MISCSERV		$22,338,060	$20,843,640	$1,450,249	$9,036	$14,148	$542	$10,403
Total Unadjusted Revenues			$1,486,962,672	$577,508,613	$199,595,889	$11,997,081	$173,885,550	$13,918,735	$116,538,195
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$609,965	-$368,766	-$23,373	-$168,730	-$13,653	-$105,682
Total Adjusted Revenues At Current Rates			$1,485,327,440	$576,898,648	$199,227,123	$11,973,708	$173,716,820	$13,905,082	$116,432,513
Total O&M Expense			$933,774,239	$366,099,100	$108,134,858	$7,743,952	$98,247,554	$7,612,311	$75,106,135
Depreciation Expense			$228,062,837	$94,205,967	$25,278,489	$1,778,735	$22,781,652	$1,729,165	$17,334,955
Taxes Other Than Income Taxes			$37,820,875	$16,179,673	$4,263,051	$292,871	$3,636,796	$275,482	$2,758,922
Eliminate Advertising Expense		33	-$838,116	-$539,971	-$208,951	-$7,435	-$28,229	-$1,085	-$19,371
Total Expenses Before Interest and Taxes			$1,198,819,834	$475,944,770	$137,467,448	$9,808,123	$124,637,772	$9,615,873	$95,180,642
Earnings Before Interest and Taxes			$286,507,606	$100,953,878	$61,759,675	$2,165,585	$49,079,048	$4,289,208	$21,251,871
Interest			$86,095,200	$36,831,305	$9,704,383	$666,691	$8,278,778	$627,106	$6,280,393
Taxable Income			$200,412,405	$64,122,573	$52,055,292	$1,498,894	$40,800,270	$3,662,103	$14,971,479
Income Taxes		TAXINC	$83,997,066	$26,875,123	$21,817,471	$628,218	$17,100,254	$1,534,864	$6,274,863
Net Operating Income			$202,510,540	$74,078,755	$39,942,204	$1,537,367	$31,978,795	$2,754,344	$14,977,009
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$2,977,680,821	$785,212,588	$53,967,436	$671,429,128	$50,861,450	$509,409,701
CWIP			$118,703,941	$55,170,713	$13,888,975	$930,807	$10,281,861	$777,181	$7,745,424
Accumulated Depreciation			$2,699,542,764	$1,141,941,802	$303,505,556	$20,905,536	$263,430,537	$19,924,711	$199,639,030
Net Plant			$4,389,914,415	$1,890,909,732	$495,596,007	$33,992,707	$418,280,451	$31,713,919	$317,516,096
Working Capital									
Cash Working Capital			$106,348,560	$41,952,710	$12,396,500	$880,402	$11,117,576	$862,956	$8,499,383
Materials & Supplies			$119,808,344	$51,178,258	$13,495,675	$927,554	$11,540,046	$874,170	$8,755,371
Prepayments			$16,171,254	$6,907,838	$1,821,593	$125,198	$1,557,629	$117,992	$1,181,765
Total Working Capital			$242,328,157	$100,038,806	$27,713,768	$1,933,154	$24,215,251	$1,855,118	$18,436,519
Less:									
ADIT			$910,427,698	$394,209,282	$103,212,401	$7,038,340	$86,341,660	$6,535,982	$65,429,106
Accumulated ITCs			$81,185,411	$27,277,811	$8,181,216	$667,994	$9,688,342	$742,765	$7,471,737
Customer Advances			$1,549,704	$1,121,389	$225,909	$7,430	$46,805	$3,440	$32,378
Net Rate Base			$3,639,079,759	$1,568,340,056	$411,690,249	$28,212,097	$346,418,895	$26,286,850	$263,019,395
Rate of Return At Current Rates			5.56%	4.72%	9.70%	5.45%	9.23%	10.48%	5.69%
Indexed Rate of Return At Current Rates			100%	85%	174%	98%	166%	188%	102%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$576,898,648	$199,227,123	$11,973,708	$173,716,820	$13,905,082	$116,432,513
Proposed Increase			$94,389,820	$37,000,063	$10,285,675	$777,151	$9,478,306	$643,891	$6,865,948
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$3,516,381	$995,258	$74,620	$990,703	$68,743	$698,101
Increase in Miscellaneous Charges	MISCSERV		$19,720	$18,401	$1,280	$8	$12	$0	$9
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$617,433,493	$210,509,336	$12,825,487	$184,185,842	$14,617,716	$123,996,571
Total Operating Expenses			$1,282,816,900	$502,819,892	$159,284,919	$10,436,342	$141,738,026	$11,150,738	$101,455,504
Increase in Uncollectible Expense	Cust01		$362,905	$233,808	$90,476	$3,219	$12,223	$470	$8,388
Increase in PSC Fees	Billed rev		$200,113	$75,775	$27,087	$1,645	$23,839	$1,906	$15,971
Incremental Taxable Income			$102,515,177	$40,206,862	$11,163,370	$846,906	$10,432,947	$710,258	$7,539,690
Incremental Income Taxes			$39,751,942	$15,590,870	$4,328,780	$328,402	$4,045,546	$275,414	$2,923,639
Total Pro-Forma Operating Expenses			$1,323,131,860	$518,720,345	$163,731,262	$10,769,608	$145,819,634	$11,428,528	$104,403,501
Net Operating Income			$265,293,495	$98,713,147	$46,778,074	$2,055,879	$38,366,208	$3,189,188	$19,593,070
Net Cost Rate Base			$3,639,079,759	$1,568,340,056	$411,690,249	$28,212,097	$346,418,895	$26,286,850	$263,019,395
Rate of Return At Proposed Rates			7.29%	6.29%	11.36%	7.29%	11.08%	12.13%	7.45%
Indexed ROR @ Proposed Rates				86%	156%	100%	152%	166%	102%

KENTUCKY UTILITIES COMPANY

Probability of Dispatch with Time, Fuel, and Customer-Demand Split

Rate of Retun Summary

	Allocation Factor Name	No	Total Kentucky	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$251,561,897	$86,711,460	$29,892,107	$26,032,396	$29,470	$156,512
Intercompany Sales		2	$8,422,903	$1,864,604	$664,048	$245,150	$57,388	$207	$691
Curtailable Service Rider		W/S Peak	-$17,395,776	-$3,139,126	-$1,128,649	-$425,628	$0	$0	-$873
LATE PAYMENT CHARGES	LPAY		$3,857,505	$107,885	$18,686	$0	$33	$0	$0
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$439	$48	$0	$461	$0	$0
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$527,875	$173,201	$72,131	$85,795	$69	$290
OTHER MISC REVENUES	MISCSERV		$22,338,060	$4,653	$505	$0	$4,883	$0	$0
Total Unadjusted Revenues			$1,486,962,672	$250,928,228	$86,439,299	$29,783,760	$26,180,956	$29,746	$156,620
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$210,279	-$68,614	-$23,719	-$42,194	-$66	-$192
Total Adjusted Revenues At Current Rates			$1,485,327,440	$250,717,949	$86,370,685	$29,760,041	$26,138,762	$29,680	$156,428
Total O&M Expense			$933,774,239	$176,971,680	$61,535,978	$23,428,622	$8,773,634	$19,899	$100,517
Depreciation Expense			$228,062,837	$40,608,708	$13,524,138	$5,412,511	$5,383,220	$4,935	$20,360
Taxes Other Than Income Taxes			$37,820,875	$6,420,980	$2,110,426	$868,033	$1,010,394	$812	$3,435
Eliminate Advertising Expense		33	-$838,116	-$8,682	-$752	-$63	-$23,471	$0	-$108
Total Expenses Before Interest and Taxes			$1,198,819,834	$223,992,686	$77,169,790	$29,709,103	$15,143,777	$25,646	$124,204
Earnings Before Interest and Taxes			$286,507,606	$26,725,263	$9,200,895	$50,938	$10,994,986	$4,034	$32,225
Interest			$86,095,200	$14,616,678	$4,804,160	$1,975,985	$2,300,054	$1,849	$7,819
Taxable Income			$200,412,405	$12,108,585	$4,396,735	-$1,925,047	$8,694,931	$2,185	$24,406
Income Taxes		TAXINC	$83,997,066	$5,074,963	$1,842,764	-$806,828	$3,644,229	$916	$10,229
Net Operating Income			$202,510,540	$21,650,300	$7,358,131	$857,766	$7,350,757	$3,118	$21,996
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$1,185,930,707	$389,952,707	$160,027,134	$185,498,904	$149,631	$633,032
CWIP			$118,703,941	$17,670,807	$5,642,942	$2,684,161	$3,897,688	$2,600	$10,783
Accumulated Depreciation			$2,699,542,764	$465,533,124	$153,570,561	$61,935,817	$68,857,184	$56,368	$242,537
Net Plant			$4,389,914,415	$738,068,389	$242,025,087	$100,775,478	$120,539,408	$95,863	$401,278
Working Capital									
Cash Working Capital			$106,348,560	$20,006,851	$6,947,281	$2,650,039	$1,020,964	$2,268	$11,630
Materials & Supplies			$119,808,344	$20,382,933	$6,702,229	$2,750,432	$3,188,223	$2,572	$10,880
Prepayments			$16,171,254	$2,751,207	$904,640	$371,242	$430,334	$347	$1,469
Total Working Capital			$242,328,157	$43,140,991	$14,554,151	$5,771,714	$4,639,521	$5,187	$23,978
Less:									
ADIT			$910,427,698	$151,902,151	$49,691,935	$20,686,701	$25,277,549	$19,518	$83,073
Accumulated ITCs			$81,185,411	$17,971,527	$6,325,805	$2,334,892	$515,040	$1,867	$6,414
Customer Advances			$1,549,704	$73,483	$0	$0	$38,665	$19	$186
Net Rate Base			$3,639,079,759	$611,262,219	$200,561,498	$83,525,598	$99,347,675	$79,646	$335,583
Rate of Return At Current Rates			5.56%	3.54%	3.67%	1.03%	7.40%	3.91%	6.55%
Indexed Rate of Return At Current Rates			100%	64%	66%	18%	133%	70%	118%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$250,717,949	$86,370,685	$29,760,041	$26,138,762	$29,680	$156,428
Proposed Increase			$94,389,820	$18,614,379	$6,363,804	$2,483,771	$1,866,484	$2,173	$8,175
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$1,567,846	$563,707	$212,581	$0	$0	$436
Increase in Miscellaneous Charges	MISCSERV		$19,720	$4	$0	$0	$4	$0	$0
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$270,900,178	$93,298,197	$32,456,393	$28,005,251	$31,853	$165,039
Total Operating Expenses			$1,282,816,900	$229,067,649	$79,012,554	$28,902,275	$18,788,006	$26,562	$134,433
Increase in Uncollectible Expense	Cust01		$362,905	$3,759	$326	$27	$10,163	$0	$47
Increase in PSC Fees	Billed rev		$200,113	$34,374	$11,849	$4,085	$3,557	$4	$21
Incremental Taxable Income			$102,515,177	$20,144,091	$6,915,337	$2,692,240	$1,852,764	$2,169	$8,543
Incremental Income Taxes			$39,751,942	$7,811,202	$2,681,535	$1,043,960	$718,440	$841	$3,313
Total Pro-Forma Operating Expenses			$1,323,131,860	$236,916,985	$81,706,264	$29,950,347	$19,520,165	$27,407	$137,813
Net Operating Income			$265,293,495	$33,983,193	$11,591,933	$2,506,046	$8,485,085	$4,446	$27,226
Net Cost Rate Base			$3,639,079,759	$611,262,219	$200,561,498	$83,525,598	$99,347,675	$79,646	$335,583
Rate of Return At Proposed Rates			7.29%	5.56%	5.78%	3.00%	8.54%	5.58%	8.11%
Indexed ROR @ Proposed Rates				76%	79%	41%	117%	77%	111%

Kentucky Utilities & LG&E
Forecasted Test Year Generation Statistics

(1) Generating Unit	(2) Fuel	(3) KU + LG&E Ownership Capacity 1/		(3A) Forecasted Average Fuel Cost 2/	(4) Forecasted Net MWH Produced 3/	(5) Generation Order 4/	(6) Total Gross Investment 1/	(7) Total Net Investment 1/	(8) Capacity Factor	Designation	(9) Net Investment Energy	(10) Net Investment Demand
Brown Solar	Solar	10		$0.0000	19,522	1	$25,475,574	$24,869,280	22.29%	Solar	$24,869,280	$0
Dix Dam 1	Hydro	11		$0.0000	25,269	2	$14,123,640	$3,949,856	26.22%	Hydro	$3,949,856	$0
Dix Dam 2	Hydro	11		$0.0000	25,269	2	$14,123,640	$3,949,855	26.22%	Hydro	$3,949,855	$0
Dix Dam 3	Hydro	11		$0.0000	25,268	2	$14,123,639	$3,949,855	26.22%	Hydro	$3,949,855	$0
Ohio Falls 1	Hydro	13		$0.0000	35,468	2	$15,936,615	$2,069,225	31.15%	Hydro	$2,069,225	$0
Ohio Falls 2	Hydro	13		$0.0000	35,468	2	$15,936,615	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 3	Hydro	13		$0.0000	35,468	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 4	Hydro	10		$0.0000	35,468	2	$15,936,614	$2,069,226	40.49%	Hydro	$2,069,226	$0
Ohio Falls 5	Hydro	13		$0.0000	35,468	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 6	Hydro	13		$0.0000	35,469	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 7	Hydro	13		$0.0000	35,469	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 8	Hydro	10		$0.0000	35,469	2	$15,936,614	$2,069,226	40.49%	Hydro	$2,069,226	$0
Trimble County 2	Coal	628.5	(a)	$0.0193	3,367,360	3	$1,111,229,983	$880,695,676	61.16%	Base	$880,695,676	$0
Mill Creek 4	Coal	544		$0.0211	3,205,409	4	$837,207,205	$602,354,116	67.26%	Base	$602,354,116	$0
Mill Creek 3	Coal	463		$0.0216	2,296,304	5	$534,353,330	$412,814,072	56.62%	Base	$412,814,072	$0
Ghent 2	Coal	556		$0.0211	2,926,599	6	$426,925,817	$230,306,975	60.09%	Base	$230,306,975	$0
Mill Creek 2	Coal	356		$0.0215	1,578,371	7	$376,161,674	$324,010,100	50.61%	Base	$324,010,100	$0
Ghent 1	Coal	557		$0.0214	2,984,003	8	$732,470,922	$472,757,776	61.16%	Base	$472,757,776	$0
Mill Creek 1	Coal	356		$0.0210	1,892,628	9	$328,252,201	$224,580,500	60.69%	Base	$224,580,500	$0
Trimble County 1	Coal	425	(a)	$0.0217	2,063,666	10	$641,927,268	$368,792,796	55.43%	Base	$368,792,796	$0
Ghent 4	Coal	556		$0.0224	2,928,773	11	$1,197,830,397	$869,222,907	60.13%	Base	$869,222,907	$0
Cane Run 7	Gas	808		$0.0218	4,881,876	12	$530,421,264	$503,531,414	68.97%	Base	$503,531,414	$0
Ghent 3	Coal	557		$0.0227	2,892,762	13	$694,725,329	$389,380,015	59.29%	Base	$389,380,015	$0
Brown 2	Coal	180		$0.0316	337,136	15	$65,243,804	$32,365,017	21.38%	Intermediate	$6,919,972	$25,445,045
Brown 1	Coal	114		$0.0353	133,696	16	$84,714,615	$34,940,306	13.39%	Intermediate	$4,677,741	$30,262,565
Brown 3	Coal	464		$0.0352	836,934	17	$959,593,511	$717,432,540	20.59%	Intermediate	$147,723,706	$569,708,834
Trimble County 5	Gas	199		$0.0353	412,064	18	$67,773,389	$37,167,908	23.64%	Peak	$0	$37,167,908
Trimble County 6	Gas	199		$0.0352	340,822	19	$68,123,095	$39,147,099	19.55%	Peak	$0	$39,147,099
Trimble County 7	Gas	199		$0.0355	216,530	20	$58,859,184	$36,397,367	12.42%	Peak	$0	$36,397,367
Trimble County 8	Gas	199		$0.0350	73,170	21	$56,427,769	$34,926,680	4.20%	Peak	$0	$34,926,680
Trimble County 9	Gas	199		$0.0351	206,922	22	$57,017,600	$35,401,129	11.87%	Peak	$0	$35,401,129
Trimble County 10	Gas	199		$0.0345	47,408	23	$63,011,288	$38,702,047	2.72%	Peak	$0	$38,702,047
Paddy's Run 13	Gas	178		$0.0352	192,857	24	$84,247,706	$56,428,259	12.37%	Peak	$0	$56,428,259
Brown 9	Gas/Oil	126		$0.0488	11,645	26	$56,321,311	$26,219,865	1.06%	Peak	$0	$26,219,865
Brown 10	Gas/Oil	126		$0.0480	9,683	27	$36,511,347	$19,321,109	0.88%	Peak	$0	$19,321,109
Brown 5	Gas	123		$0.0449	38,599	28	$50,149,164	$25,142,199	3.58%	Peak	$0	$25,142,199
Brown 8	Gas/Oil	126		$0.0485	17,630	29	$37,676,408	$14,114,510	1.60%	Peak	$0	$14,114,510
Brown 11	Gas/Oil	126		$0.0482	13,080	30	$45,748,645	$16,936,492	1.19%	Peak	$0	$16,936,492
Brown 6	Gas/Oil	177		$0.0361	71,392	31	$66,107,337	$36,727,111	4.60%	Peak	$0	$36,727,111
Brown 7	Gas/Oil	177		$0.0360	92,767	32	$61,613,444	$31,606,825	5.98%	Peak	$0	$31,606,825

Kentucky Utilities & LG&E
Forecasted Test Year Generation Statistics

(1) Generating Unit	(2) Fuel	(3) KU + LG&E Ownership Capacity 1/	(3A) Forecasted Average Fuel Cost 2/	(4) Forecasted Net MWH Produced 3/	(5) Generation Order 4/	(6) Total Gross Investment 1/	(7) Total Net Investment 1/	(8) Capacity Factor	Designation	(9) Net Investment Energy	(10) Net Investment Demand
Cane Run 11	Gas/Oil	16	$0.0502	56	33	$3,698,729	$448,806	0.04%	Peak	$0	$448,806
Paddy's Run 11	Gas	16	$0.0496	209	34	$2,151,053	$391,303	0.15%	Peak	$0	$391,303
Paddy's Run 12	Gas	33	$0.0574	182	35	$4,318,568	$204,485	0.06%	Peak	$0	$204,485
Zorn 1	Gas	18	$0.0688	126	36	$1,974,690	-$111,858	0.08%	Peak	$0	-$111,858
Haefling 1	Gas/Oil	21	$0.1959	72	37	$2,183,480	$714,218	0.04%	Peak	$0	$714,218
Haefling 2	Gas/Oil	21	$0.1959	72	37	$2,183,479	$714,217	0.04%	Peak	$0	$714,217

	Energy	Demand
TOTAL BASE	$5,278,446,347	$0
TOTAL INTERMEDIATE	$159,321,419	$625,416,444
TOTAL PEAK	$0	$450,599,771
TOTAL HYDRO	$28,403,373	$0
TOTAL SOLAR	$24,869,280	$0
TOTAL ALL UNITS	$5,491,040,419	$1,076,016,215
PERCENT OF TOTAL	83.61%	16.39%

1/ Per KU response to AG 1-284.
2/ Per KU response to AG 1-288.
3/ Per KU response to AG 1-285(a). Kwh reflects only KU + LG&E ownership share of output.
4/ Per KU response to AG 1-286.

(a) Reflects KU and LG&E combined 75% ownership

KENTUCKY UTILITIES COMPANY

Base Intermediate Peak Cost of Service Studyp with Customer-Demand Split

Rate of Return Summary

	Allocation Factor Name	No	Total Kentucky	Residential (RS) (RS	General Service (GS)	All Elect. Schools (AES)	Pwr Svc Secondary (PS-Sec)	PWR Svc Primary (PS-Pri)	Time of Day Secondary (TOU-sec)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$554,543,189	$198,233,994	$12,037,991	$174,459,441	$13,950,651	$116,879,945
Intercompany Sales		2	$8,422,903	$2,827,720	$843,635	$70,490	$996,388	$76,891	$775,692
Curtailable Service Rider		W/S Peak	-$17,395,776	-$7,040,463	-$1,992,695	-$149,403	-$1,983,575	-$137,636	-$1,397,730
LATE PAYMENT CHARGES	LPAY		$3,857,505	$3,012,898	$568,302	$3,750	$98,651	$5,535	$41,764
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$1,967,237	$136,875	$853	$1,335	$51	$982
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$1,366,827	$358,887	$24,355	$297,525	$22,573	$225,639
OTHER MISC REVENUES	MISCSERV		$22,338,060	$20,843,640	$1,450,249	$9,036	$14,148	$542	$10,403
Total Unadjusted Revenues			$1,486,962,672	$577,521,049	$199,599,248	$11,997,072	$173,883,914	$13,918,608	$116,536,695
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$609,965	-$368,766	-$23,373	-$168,730	-$13,653	-$105,682
Total Adjusted Revenues At Current Rates			$1,485,327,440	$576,911,084	$199,230,482	$11,973,700	$173,715,185	$13,904,954	$116,431,013
Total O&M Expense			$933,774,239	$364,512,984	$107,901,850	$7,707,076	$98,442,964	$7,652,076	$75,412,147
Depreciation Expense			$228,062,837	$95,168,459	$25,494,732	$1,779,782	$22,629,806	$1,720,236	$17,226,911
Taxes Other Than Income Taxes			$37,820,875	$16,323,085	$4,295,272	$293,027	$3,614,170	$274,152	$2,742,823
Eliminate Advertising Expense		33	-$838,116	-$539,971	-$208,951	-$7,435	-$28,229	-$1,085	-$19,371
Total Expenses Before Interest and Taxes			$1,198,819,834	$475,464,557	$137,482,903	$9,772,450	$124,658,712	$9,645,378	$95,362,510
Earnings Before Interest and Taxes			$286,507,606	$101,446,527	$61,747,580	$2,201,250	$49,056,472	$4,259,576	$21,068,503
Interest			$86,095,200	$37,157,767	$9,777,729	$667,046	$8,227,275	$624,077	$6,243,746
Taxable Income			$200,412,405	$64,288,759	$51,969,850	$1,534,204	$40,829,197	$3,635,499	$14,824,757
Income Taxes		TAXINC	$83,997,066	$26,944,775	$21,781,660	$643,017	$17,112,378	$1,523,714	$6,213,368
Net Operating Income			$202,510,540	$74,501,752	$39,965,919	$1,558,232	$31,944,094	$2,735,862	$14,855,134
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$3,004,281,951	$791,189,054	$53,996,361	$667,232,461	$50,614,653	$506,423,592
CWIP			$118,703,941	$55,451,909	$13,952,151	$931,113	$10,237,498	$774,572	$7,713,859
Accumulated Depreciation			$2,699,542,764	$1,150,937,772	$304,887,445	$20,936,892	$261,627,227	$19,858,173	$198,764,998
Net Plant			$4,389,914,415	$1,908,796,088	$500,253,761	$33,990,581	$415,842,732	$31,531,051	$315,372,452
Working Capital									
Cash Working Capital			$106,348,560	$41,761,712	$12,368,442	$875,962	$11,141,107	$867,744	$8,536,233
Materials & Supplies			$119,808,344	$51,635,459	$13,598,394	$928,051	$11,467,916	$869,929	$8,704,048
Prepayments			$16,171,254	$6,969,549	$1,835,457	$125,265	$1,547,894	$117,420	$1,174,838
Total Working Capital			$242,328,157	$100,366,720	$27,802,293	$1,929,277	$24,156,917	$1,855,092	$18,415,118
Less:									
ADIT			$910,427,698	$397,514,838	$103,955,059	$7,041,934	$85,820,166	$6,505,314	$65,058,041
Accumulated ITCs			$81,185,411	$27,786,173	$8,295,430	$668,546	$9,608,142	$738,049	$7,414,671
Customer Advances			$1,549,704	$1,121,389	$225,909	$7,430	$46,805	$3,440	$32,378
Net Rate Base			$3,639,079,759	$1,582,740,409	$415,579,657	$28,201,948	$344,524,536	$26,139,340	$261,282,481
Rate of Return At Current Rates			5.56%	4.71%	9.62%	5.53%	9.27%	10.47%	5.69%
Indexed Rate of Return At Current Rates			100%	85%	173%	99%	167%	188%	102%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$576,911,084	$199,230,482	$11,973,700	$173,715,185	$13,904,954	$116,431,013
Proposed Increase			$94,389,820	$37,000,063	$10,285,675	$777,151	$9,478,306	$643,891	$6,865,948
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$3,516,381	$995,258	$74,620	$990,703	$68,743	$698,101
Increase in Miscellaneous Charges	MISCSERV		$19,720	$18,401	$1,280	$8	$12	$0	$9
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$617,445,928	$210,512,695	$12,825,478	$184,184,206	$14,617,589	$123,995,071
Total Operating Expenses			$1,282,816,900	$502,409,332	$159,264,563	$10,415,467	$141,771,090	$11,169,093	$101,575,879
Increase in Uncollectible Expense	Cust01		$362,905	$233,808	$90,476	$3,219	$12,223	$470	$8,388
Increase in PSC Fees	Billed rev		$200,113	$75,775	$27,087	$1,645	$23,839	$1,906	$15,971
Incremental Taxable Income			$102,515,177	$40,206,862	$11,163,370	$846,906	$10,432,947	$710,258	$7,539,690
Incremental Income Taxes			$39,751,942	$15,590,870	$4,328,780	$328,402	$4,045,546	$275,414	$2,923,639
Total Pro-Forma Operating Expenses			$1,323,131,860	$518,309,785	$163,710,906	$10,748,733	$145,852,698	$11,446,883	$104,523,876
Net Operating Income			$265,293,495	$99,136,144	$46,801,789	$2,076,745	$38,331,508	$3,170,706	$19,471,195
Net Cost Rate Base			$3,639,079,759	$1,582,740,409	$415,579,657	$28,201,948	$344,524,536	$26,139,340	$261,282,481
Rate of Return At Proposed Rates			7.29%	6.26%	11.26%	7.36%	11.13%	12.13%	7.45%
Indexed ROR @ Proposed Rates				86%	154%	101%	153%	166%	102%

KENTUCKY UTILITIES COMPANY
Base Intermediate Peak Cost of Service Studyp with Customer-Demand Split
Rate of Return Summary

	Allocation Factor Name	Allocation Factor No	Total Kentucky	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$251,561,897	$86,711,460	$29,892,107	$26,032,396	$29,470	$156,512
Intercompany Sales		2	$8,422,903	$1,864,604	$664,048	$245,150	$57,388	$207	$691
Curtailable Service Rider		W/S Peak	-$17,395,776	-$3,139,126	-$1,128,649	-$425,628	$0	$0	-$873
LATE PAYMENT CHARGES	LPAY		$3,857,505	$107,885	$18,686	$0	$33	$0	$0
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$439	$48	$0	$461	$0	$0
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$518,336	$172,233	$71,625	$84,297	$63	$284
OTHER MISC REVENUES	MISCSERV		$22,338,060	$4,653	$505	$0	$4,883	$0	$0
Total Unadjusted Revenues			$1,486,962,672	$250,918,689	$86,438,331	$29,783,254	$26,179,458	$29,740	$156,614
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$210,279	-$68,614	-$23,719	-$42,194	-$66	-$192
Total Adjusted Revenues At Current Rates			$1,485,327,440	$250,708,410	$86,369,716	$29,759,535	$26,137,265	$29,675	$156,422
Total O&M Expense			$933,774,239	$177,646,684	$61,953,831	$23,547,452	$8,875,979	$20,274	$100,924
Depreciation Expense			$228,062,837	$39,853,498	$13,471,422	$5,409,761	$5,283,707	$4,564	$19,960
Taxes Other Than Income Taxes			$37,820,875	$6,308,453	$2,102,571	$867,623	$995,566	$757	$3,375
Eliminate Advertising Expense		33	-$838,116	-$8,682	-$752	-$63	-$23,471	$0	-$108
Total Expenses Before Interest and Taxes			$1,198,819,834	$223,799,952	$77,527,071	$29,824,774	$15,131,782	$25,594	$124,152
Earnings Before Interest and Taxes			$286,507,606	$26,908,458	$8,842,646	-$65,239	$11,005,483	$4,081	$32,270
Interest			$86,095,200	$14,360,522	$4,786,279	$1,975,052	$2,266,301	$1,723	$7,683
Taxable Income			$200,412,405	$12,547,936	$4,056,366	-$2,040,291	$8,739,182	$2,358	$24,587
Income Taxes		TAXINC	$83,997,066	$5,259,105	$1,700,109	-$855,129	$3,662,775	$988	$10,305
Net Operating Income			$202,510,540	$21,649,354	$7,142,537	$789,890	$7,342,708	$3,092	$21,965
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$1,165,058,360	$388,495,729	$159,951,137	$182,748,591	$139,364	$621,986
CWIP			$118,703,941	$17,450,169	$5,627,540	$2,683,357	$3,868,615	$2,491	$10,666
Accumulated Depreciation			$2,699,542,764	$458,152,697	$153,450,265	$62,468,536	$68,165,152	$53,876	$239,732
Net Plant			$4,389,914,415	$724,355,832	$240,673,005	$100,165,958	$118,452,054	$87,980	$392,921
Working Capital									
Cash Working Capital			$106,348,560	$20,088,134	$6,997,598	$2,664,349	$1,033,289	$2,313	$11,679
Materials & Supplies			$119,808,344	$20,024,194	$6,677,188	$2,749,126	$3,140,953	$2,395	$10,690
Prepayments			$16,171,254	$2,702,786	$901,260	$371,066	$423,953	$323	$1,443
Total Working Capital			$242,328,157	$42,815,114	$14,576,046	$5,784,541	$4,598,195	$5,031	$23,812
Less:									
ADIT			$910,427,698	$149,308,476	$49,510,886	$20,677,258	$24,935,785	$18,242	$81,700
Accumulated ITCs			$81,185,411	$17,572,646	$6,297,961	$2,333,440	$462,480	$1,671	$6,203
Customer Advances			$1,549,704	$73,483	$0	$0	$38,665	$19	$186
Net Rate Base			$3,639,079,759	$600,216,341	$199,440,204	$82,939,802	$97,613,319	$73,079	$328,644
Rate of Return At Current Rates			5.56%	3.61%	3.58%	0.95%	7.52%	4.23%	6.68%
Indexed Rate of Return At Current Rates			100%	65%	64%	17%	135%	76%	120%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$250,708,410	$86,369,716	$29,759,535	$26,137,265	$29,675	$156,422
Proposed Increase			$94,389,820	$18,614,379	$6,363,804	$2,483,771	$1,866,484	$2,173	$8,175
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$1,567,846	$563,707	$212,581	$0	$0	$436
Increase in Miscellaneous Charges	MISCSERV		$19,720	$4	$0	$0	$4	$0	$0
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$270,890,639	$93,297,228	$32,455,887	$28,003,753	$31,847	$165,033
Total Operating Expenses			$1,282,816,900	$229,059,056	$79,227,180	$28,969,645	$18,794,557	$26,582	$134,457
Increase in Uncollectible Expense	Cust01		$362,905	$3,759	$326	$27	$10,163	$0	$47
Increase in PSC Fees	Billed rev		$200,113	$34,374	$11,849	$4,085	$3,557	$4	$21
Incremental Taxable Income			$102,515,177	$20,144,091	$6,915,337	$2,692,240	$1,852,764	$2,169	$8,543
Incremental Income Taxes			$39,751,942	$7,811,202	$2,681,535	$1,043,960	$718,440	$841	$3,313
Total Pro-Forma Operating Expenses			$1,323,131,860	$236,908,392	$81,920,889	$30,017,717	$19,526,717	$27,427	$137,838
Net Operating Income			$265,293,495	$33,982,247	$11,376,339	$2,438,170	$8,477,036	$4,420	$27,196
Net Cost Rate Base			$3,639,079,759	$600,216,341	$199,440,204	$82,939,802	$97,613,319	$73,079	$328,644
Rate of Return At Proposed Rates			7.29%	5.66%	5.70%	2.94%	8.68%	6.05%	8.28%
Indexed ROR @ Proposed Rates				78%	78%	40%	119%	83%	114%

CHARGING FOR DISTRIBUTION UTILITY SERVICES: ISSUES IN RATE DESIGN

December 2000

Frederick Weston

with assistance from:
Cheryl Harrington
David Moskovitz
Wayne Shirley
Richard Cowart

The Regulatory Assistance Project
16 State Street, Montpelier, VT 05602
Phone: 802-223-8199
Fax: 802-223-8172
rapvermont@aol.com

IV. THE COSTS OF DISTRIBUTION SERVICES

A first question to be answered when designing rates is what does it cost to provide the service? What are the causes and magnitudes of the relevant costs? It s helpful to observe that the costs recovered by distribution-level rates have historically extended far beyond the distribution system. Are there other costs, not directly related to distribution services, that distribution rates are expected to recover? What follow here are an overview of utility costing methodologies and a discussion of some practical considerations to keep in mind when determining rate structures.

A. Utility Plant Costing Methods

Utilities and regulatory commissions use a variety of methods for determining and allocating cost responsibility among customers and customer classes. There are two general types of cost study, embedded and marginal. Embedded, or fully distributed, seeks to identify and assign the historical, or accounting, costs that make up a utility s revenue requirement. Marginal, as the name connotes, aims at determining the change in total costs imposed on the system by a change in output (whether measured by kilowatt-hour, kilowatt, customer, customer group, or other relevant cost driver). Each commission around the country uses these studies in its own way to inform the rate design process; in the end, most commissions rely on embedded cost studies for ultimate allocations and price levels, constrained as they are by a legal requirement to set rates that offer the prudent utility a reasonable opportunity to earn a fair rate of return on its assets used in service to public.[33] The allocations, however, are often structured to reflect at least relative differences in the marginal costs of providing a company s various services.

1. Cost Causation

There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature marginal, embedded, fixed, variable, joint, common,[34] etc. and thus on how they should be recovered in rates.

33. NARUC, p. 32.

34. The costs of multiple products or services supplied by the same plant or process are either common or joint. Common are those that generally do not vary with changes in output. The classic example is the president s desk, which is needed to run the firm as a whole but is incremental to the provision of no particular good or service. Another example is that of an airline flight, the majority of whose costs are incurred in a single lump and do not vary with the number of passengers carried. Put another way, common costs are those for which the unit of production (the single flight), which is the basis of cost incurrence, is larger than the unit of sale (a

(continued...)

Numbers of customers, usage, and demand, however, are only part of the story. Other factors also play an important role: geography (particularly population density), system design (*e.g.*, aerial versus underground lines), and the utility s business practices (for example, the extent of expenditures on billing, answering customers questions/complaints, etc.). The implications of such factors on rate design is unclear, however: one can charge for services on the basis of numbers of customers, usage, and demand, but not on the basis of other such factors.[35]

2. Embedded Costs

a. Cost Classification: Customers, Demand, and Energy

Traditionally, customer costs are those that are seen to vary with the number of customers on the system service drops (the line from the distribution radial to the home or business), meters, and billing and collection. Some utilities and jurisdictions also include some portion of the primary and secondary distribution plant (poles, wires, and transformers) in these costs, on the ground that they also are driven more by numbers of customers than by demand or energy. Similar reasoning leads to the designation of the costs of customer service and customer premises equipment as customer-related. But, since the system and its components are sized to serve a maximum level of anticipated demand, the notion that there are any customer costs (aside from perhaps metering and billing) that are not more properly categorized as demand can be challenged (see Subsections 3 and 4, below).

Utilities classify significant portions of their embedded distribution investment as demand-related, reasoning that it is designed and installed to serve a customer or group of customers according to their contribution to some peak load (system, substation, etc.). Substations are a typical example of such costs, but so too may be a significant portion of the wires and related facilities, since they are sized, at least in part, to serve a peak demand.

There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A

---

34. (...continued)
single ticket to a single passenger). Kahn, Vol. I, p. 77. If services produced in common can be produced in varying proportions, it may then be possible to identify separate marginal production costs for each.

Products that are produced in fixed proportions (*e.g.*, cotton fiber and cottonseed oil, beef and hides, mutton and wool) are characterized by joint costs. For that aspect of their production process that is joint, the products have no separately identifiable marginal costs. *Id.*, p. 79. See also Bonbright, pp. 355-360.

35. These other cost factors can have huge effects on prices. Three distribution utilities in the American south, owned by the same holding company and using the same costing methodology, recently proposed new metering, customer service rates, and delivery rates. The rates, designed as a combination of monthly per-customer and per-kW of peak demand charges, vary from company to company by ratios ranging from 1.25 to 1.9.

variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.

Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related.[36] However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).

Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, can not price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access.

Other assumptions are of a more technical nature. What constitutes the minimum system? What are the proper types of equipment to be modeled? What cost data are applicable (historical, current installations, etc.)? Doesn t the minimum system in fact include demand costs, since such a system can serve some amount of demand? The zero-intercept method attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related. Does use of an abstract minimum system place a disproportionate share of the cost burden on

36. It is called zero-intercept because it relates installed cost to current carrying capacity or demand rating, creat[ing] a curve for various sizes of the equipment involved, using regression techniques, and extend[ing] the curve to a no-load intercept. NARUC, p. 92.

certain customers or classes, in certain cases even resulting in double-counting? The answers chosen to these and other questions will have impacts upon the respective assignments (by type and customer class) of costs.[37]

Historically, the investment decisions of system planners in vertically-integrated utilities were constrained by the least total cost objective: simply, that they would make that combination of investments that were expected, given their assessments of risk, to meet expected demand for service over some reasonable planning horizon. Given the inability to store electricity and the typical obligation to serve all customers *on demand*, a utility was required to have sufficient capacity available to meet peak demand. And, if its only obligation were to meet peak demand, then it would install only the most inexpensive capacity. However, it had also to serve energy needs at other times, and it is a general characteristic of electric generation technology that as capacity costs decrease variable operating costs increase. There is, therefore, a trade-off between capacity and energy costs that system planners considered when building (or purchasing) new capacity, if they hoped to minimize total costs. Put another way, significant portions of generating capacity were purchased not to meet demand, but to serve energy, when the fuel cost savings that the more expensive generation would produce were greater than the additional costs of that capacity. These incremental capacity costs were therefore correctly viewed as energy costs.

A similar kind of analysis can inform the design of distribution systems, as it also does transmission. The question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity larger substations, conductors, transformers will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made.[38] For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.[39]

b. Cost Allocation

As a general matter, distribution facilities are designed and operated to serve localized area loads. Substations are designed to meet the maximum expected load of the distribution feeders radiating from them. The feeders are designed to meet at least the maximum expected loads at the primary

37. Sterzinger, George, The Customer Charge and Problems of Double Allocation of Costs, *Public Utilities Fortnightly*, July 2, 1981, p. 31; see also Bonbright, p. 347-348.

38. Losses vary with the square of the load. We note also that there is some minimum amount of losses that cannot be avoided, and that conductors must be sized such that the losses can be absorbed while still meeting peak load. To this degree, losses impose a capacity, rather than energy, cost.

39. An unhappy consequence of separating distribution and transmission planning from that of generation in restructured markets is the potential loss of this capacity-versus-energy consideration when making new investment. Certainly, without some sort of regulatory or legislative requirement, wires-only companies have no generation cost-savings motive to guide their planning decisions.

and secondary service levels. (As noted above, some investment in distribution capacity may be seen as reducing energy losses rather than serving peak demand.) For costing purposes it is the relevant subsystem s (substation, feeder, etc.?) peak that matters, but these peaks may or may not be coincident with each other or with the overall system s peak. There can be significant variation among them. Consequently, one practice is to allocate the costs of substations and primary feeders (which usually enjoy relatively high load factors) to customer class non-coincident peaks and to allocate secondary feeders and line transformers (with lower load factors) to the individual customer s maximum demand.[40] In addition, costs are allocated according to voltage level; customers taking service at higher levels are typically not assigned any of the costs of the lower-voltage systems that do not serve them. Costs are then allocated among customer rate groups (or classes) which requires, among other things, information and judgments about coincidence of demand when customers of different classes share facilities, as is often the case.

3. Marginal Costs

For the reasons stated earlier, it is the long-run marginal cost that is most relevant to designing rates. It can be described as the cost of that lumpy, geographically dispersed set of investments that a utility must make if demand continues to grow after the distribution system has initially been built out.

a. Demand and Energy

As already noted, the drivers of distribution costs are typically seen to be peak demand (itself driven by both customer demand and numbers of customers) and energy needs.[41] For the purposes of marginal cost analysis, it is also necessary to identify investments that are not made to serve incremental demands, but are made for some other purpose reliability, replacement of existing systems, etc. The costs of these investments are generally not included in marginal cost calculations, although, in certain cases, there may be legitimate arguments to the contrary.[42]

---

40. Class non-coincident peak may not be the best measure of cost causation, since much of the system serves a variety of customer classes. Chernick, Paul, *From Here to Efficiency: Securing Demand-Management Resources*, Vol. 5, 1993, p. 81. Ideally, the object is to design rates that reflect the costs of customers contributions to the relevant peak.

41. It is worth noting that, in the short run, distribution costs vary more closely with numbers of customers than with load (except in capacity-constrained areas). For rate design, with its focus on the long run, this fact need not be a distraction. It does, however, have implications for setting revenue requirements. We address this question in Chapter V, below.

42. For instance, at the time that an investment to replace existing facilities (whose loads, let us say, are not expected to change over some extended period) is being contemplated, there are costs that can potentially be avoided. In the extreme, replacement would be unnecessary if all customers served by the facility were to decide to go off grid. Other, more likely alternatives involve combinations of end-use efficiency, distributed generation, and smaller, more efficient distribution technologies. On these bases, the marginal or, more reasonably, the larger

(continued...)

Many of the same cost classification and assignment questions that pervade embedded cost analyses also recur in marginal cost studies, although their answers have different analytical effects. Whereas an embedded cost study strives to identify and assign total historical costs to classes of service (on the basis of any of a number of principles, including cost causation and fairness), a marginal cost analysis aims to determine the cost consequences of changes in output and thus the value of resources that must be used to serve incremental demand. Therefore, costs that are unaffected by changes in output (which describes all common and many joint costs) are excluded from the costs under examination.[43]

The study period for a marginal cost analysis is forward-looking and should be of sufficient duration to assure that all incremental demand is related to the investments forecast to serve that demand: a mismatch of timing and investment could result in significantly over- or understated costs. Those incremental costs are then discounted to their present value and annualized over the planning horizon. This has the effect of smoothing out the lumpiness of investment in relation to changes in demand.[44] This analysis relates changes in total costs to changes in demand (aggregating demand increases caused by the addition of customers with those caused by increases in demand per customer).[45] Since new customers create additional demand, this approach is not unreasonable.

Even so, some jurisdictions consider certain costs customer-related and treat them separately for the purpose of marginal cost analysis. Customer premises equipment that which is dedicated specifically to individual customers and unrelated to variations in demand (meters and perhaps service drops) are probably the only distribution costs that can be directly assigned to customers (except in the cases of customers who have additional facilities transformers, wires, even

42. (...continued)
incremental costs of distribution can be calculated. If replacement of the particular component of the system is forecast for some time in the future, then its expected future costs would need to be discounted appropriately to yield a present-value incremental cost.

43. Because marginal cost is defined as the change in total cost arising from a change in output, all costs are, strictly speaking, included in the analysis. It just happens that most are netted out, to reveal those that are caused by the change in output. As a practical matter, however, an analyst may simply identify the costs that vary with output and exclude the rest. It is this second approach, however, that raises debates about the nature of costs and whether they should be included in the analysis. Are they joint or common? Do they vary with demand, energy, customers, or not at all? Resolving the issues usually requires large doses of judgment.

44. An alternative approach is to calculate the cost (savings) of advancing (deferring) by one year the planned stream of investments to meet the increment (decrement) in demand. This approach yields a cost that is equal to the value of the marginal investments for one year (which is the same as the economic carrying charge on those investments). This method is often used, for example, to determine an annual cost per kW of generating capacity.

45. For sizing much of the distribution system, demand is the critical factor. One customer contributing six kilowatts to peak demand has the same impact as two each contributing three kilowatts.

substations, dedicated solely to their needs).[46] Some jurisdictions also consider other facilities (line transformers, secondary level conductors) in some measure customer-related, but, to the extent that they are jointly-used to serve more than one customer, it may be difficult to establish that the addition or loss of any one customer will affect the costs of those facilities.[47] In any event, if some costs are deemed marginal customer costs (which means that they are avoidable only at the time of hook-up), it by no means follows that they should be recovered in recurring monthly fixed fees (see Section V.A.5., below).

Other approaches sometimes used to resolve the cost-causation question are the minimum system and zero intercept methods. Here, instead of using embedded cost data, the distribution system is modeled to determine the cost (in current dollars) of a hypothetical system that could serve all customers minimum demand or (in the case of zero-intercept) that could provide voltage but not power.[48] This cost would be deemed customer-related and separated from the total incremental cost previously determined, to identify the demand (or, more properly, the demand- and energy-related) portion. For the reasons stated earlier, we challenge the wisdom of these approaches.[49]

Other methodological difficulties may also arise. By definition, joint and common costs are not marginal, but occasionally they creep into the analysis, when, for example, they make use of what are in effect *average*, not *marginal*, investments and expenditures.[50] And, as with embedded costs, marginal costs are typically broken out by customer class. Here, again, the analysis requires

46. After the meter, the customer service drop is typically seen as the least demand-related component of the system: it is sized to exceed any realistic maximum demand that the consumer might impose and it will last a very long time. However, although it is true that no investment would be made unless a customer were present, it is also true that the amount of the initial investment increases as the customer s forecasted load increases. Thus, customer investments can be seen as demand-related, as can investments farther up the system transformers, wires, and substations whose sizing depends on expected peak demand. Bouford, James D., Standardized Component Method for the Determination of Marginal and Avoided Demand Cost at the Distribution Level, Central Maine Power Company, (unpublished and undated), pp. 3-4.

47. NARUC, p. 136.

48. A handbook published by the National Economic Research Associates (NERA), which is often cited in support of the minimum system distribution cost classification, states that only the labor costs necessary to put together a minimum system and no conductor and transformer costs are customer-related. NERA, How To Quantify Marginal Costs: Topic 4, (prepared for the Electric Utility Rate Design Study, March 10, 1977), pp. 76.

49. California, for instance, has rejected the minimum system approach to marginal costs, favoring instead a method which uses the weighted average of the costs of continuing to serve existing customers and the costs of initiating service to new customers.

50. See, *e.g.*, NARUC, p. 127, which notes that, because calculating marginal distribution and customer costs can be difficult, it is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. This tack is justified by the sweeping assumption that projected embedded distribution costs are a reasonable approximation of marginal costs. The assumption is, however, contestable. FERC accounting requirements, which form the basis of most embedded cost analyses, include in distribution certain, and often substantial, administrative and general (A&G) costs (Accounts 920 to 935). A&G is not caused by the provision of distribution service.

reasonable assessments of the coincidence of demand, when customers of different classes share facilities.

Another dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile). These influences combine in assorted ways, with themselves but also with changes in load and rates of investment, to produce variations in costs from one area of the distribution system to another. It is not unusual to see marginal distribution costs varying greatly from one place to another, even when the distances between the different areas is comparatively short. Table 1 describes the significant variations in costs for incremental distribution investments in a large mid-western utility.

	Average System Marginal Costs per kW	Area Specific High-Low Marginal Costs per kW	Annual Cost @ 15% Capital Cost Recovery Factor	Average Marginal Costs per kWh @ 20% Load Factor[51]	High Marginal Costs per kWh @ 20% Load Factor
Transmission	$230	NA	$34	$0.02	$0.04
Distribution Lines	$960	$1,575 - 0	$140	$0.08	$0.135
Distribution Transformers	$60	$300 - 0	$9	$0.0015	$0.025
Total	$1,250	$1,875 - 0	$183	$.1015	$0.20

Table 1

Differentiating marginal costs along these lines will tell a utility where investment (whether in new facilities, end-use efficiency, or distributed generation) is needed and what the minimum value of that investment is. Whether for rate-making purposes this information is useful should distribution rates be geographically deaveraged ? is a tougher question. We take it up in Chapter V, below.

51. This is estimated load factor for the incremental distribution investment alone, not for the entire distribution system altogether. Incremental investment to meet peak needs typically manifests low load factors; 20% is a conservatively high estimate.

4. Key Concern in Determining Costs: Follow the Money

The occasionally technical and arcane matters taken up in embedded and marginal cost studies are, of course, important, but it is perhaps more important to bear in mind that, in rate design cases, what is fundamentally at issue is who should bear what revenue responsibilities. In the interplay between cost allocation and rate structures, the debate over money is played out. First is the question of what costs will be categorized as *distribution*, as opposed to transmission or generation in the case of vertically integrated utilities, or perhaps competitive services in other instances. This is no small matter, since significant portions of a firm s joint and common costs (typically, administrative and general) are often attributed to the distribution business, even though there is no causal relationship between them. Then there is the designation of a cost as either *customer* or *demand*, which will affect both how costs are divvied up among classes and who within each class will pay them (*i.e.*, both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system s costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough. Seemingly small changes in a rate design can have very significant consequences for different customers.[52]

---

52. Consider the following example (the hypothetical rates cover distribution services only). A residential customer using 500 kWh per month and paying $0.05 per delivered kWh and a monthly customer charge of $5.00 sees a monthly bill of $30. If rates were revised so that residential customers paid a fixed charge of $20 per month plus $0.02 cents per kWh, a customer using 500 kWh would receive the same total bill of $30. For this customer, the rate redesign is revenue neutral. However, for a customer using 300 kWh/month, the monthly bill under the original rate structure is $20 and, under the new rates, is $26 a 30% increase, even though there is no change in usage. For a customer using 700 kWh/month, the original bill is $40 and the revised bill is $34, a 15% reduction.

Consider again the customer using 500 kWh/month. If, under the original rate structure, she reduced her electricity use to 300 kWh per month (whether by load reduction, demand-side management, the installation of a rooftop solar electric system, or some combination of these options), she would reduce her bill by $10. However, under the revised rate structure, she would only reduce her bill by $4.

Whether the impacts of a rate design change are immediate and substantial depends, of course, on a variety of factors. The extent to which class cost allocations are altered will determine whether particular customers total bills (all else being equal) will go up or down. Even those changes that are meant to be class revenue-neutral will affect individual customer bills: as already noted, shifts from usage-based to fixed charges recover disproportionately higher revenues from low-volume users and then, more subtly, there are the effects (both positive and negative) on bills and revenues that flow from demand responses to the changes in rate structure.

5. Usage Sensitivity: What s Avoidable?

a. Peak Demand and Sizing the Wires

Distribution investment is made to serve an expected level of demand over a period of time, often determined by the useful life of the equipment. To the extent that, once a network (or component of it) is built, there is excess capacity in it, the marginal cost of using that excess capacity will be quite low (possibly very close to zero, insofar as there is little in the way of variable cost). It is this phenomenon that the short-run marginal cost of delivering a kilowatt-hour is zero that underlies the argument that there should be no per-kilowatt-hour charge for doing so.

As peak load grows, it will press up against the capacity limits of the system. At the time of constraint, the marginal cost of delivering a kilowatt-hour is, in fact, significantly greater than zero: at a minimum it is the cost of the additional investment needed to carry that marginal kilowatt-hour to end-users.[53] At that point, presumably, the new investment is made, and it is sized to minimize the total costs of delivery over the long term and thus, as before, there is suddenly excess capacity causing once again the marginal cost to fall to almost zero.

This non-linearity of investment with demand is a characteristic of much of the distribution system, the closer one gets to the end-user. To the extent that there are not an infinite number of equipment sizes to enable precise matching of investment and demand, excess capacity is almost necessarily built into the system, from substation facilities to feeders, transformers, customer service drops. But this has less to do with the finitude of equipment options than it does with the least total cost planning objective (optimizing total construction and operations costs over the investment horizon). The analytical key is to view the system over a time period long enough to smooth out the lumpiness of investment in relation to changes in demand.[54]

What emerges from such analysis is the recognition that there are costs associated with load growth, savings generated by reductions in load growth, and savings flowing from reductions in existing load. These values, not necessarily equal to each other, reflect in part the fungibility of significant portions of the system (*e.g.*, substations and feeders). Capacity unused, or freed up, by one customer can be used by others.[55]

Sometimes cited as an interesting and somewhat anomalous characteristic of some distribution investment, specifically that closest to customers (such as the service drop) is its manifestation of positive marginal costs with load growth but seemingly zero marginal (or avoided) costs with load reductions. This is because, so the argument goes, load reduction makes no capacity available for

53. And it may indeed be greater, if the value to consumers of that marginal delivery is greater than the cost of the additional investment. See Appendix A.

54. The justification for analyzing costs over the long run, and for setting prices on that basis, is discussed in Appendix A.

55. Chernick, Vol. 5, p. 68.

alternative uses, that did not already exist. This not so, however, because the inability to re-use capacity does not mean that there is no value to not using it. At the very least, future replacement costs can be deferred and the equipment installed on replacement can be down-sized, thereby reducing costs for all users.[56]

The differences in costs and savings associated with load growth, reduced growth rates, and reductions in existing load may leave some room for debate about their implications for rate design; but, given the declining-cost nature of the distribution system, these differences will probably have less of an impact than will the need to recover an embedded revenue requirement. The critical point here is that distribution costs vary primarily with load over the longer term.

b. Energy: The Costs of Throughput

As discussed earlier, to the extent that distribution investments are made to offset energy needs, there are necessarily costs associated with avoiding those investments. Losses, heat build-up, frequency of overloads, etc., are aspects of energy use that affect distribution investment and operations; thus there are marginal energy costs in distribution. Whether avoiding those costs make alternatives to distribution cost-effective is an empirical question. But, for purposes of rate design, it is sufficient to say that these marginal costs should be understood and appropriately reflected in rates. They are unquestionably volumetric in nature.

B. Conclusion: The Costs of Distribution Services

Cost studies are intended to provide useful information about the causes and magnitudes of costs, to inform a rate design process that is guided by the general principle that those who cause a cost should pay that cost. However, the usual drivers ascribed to distribution costs (both embedded and marginal) describe only part of the story, and the force-fitting of square costs into round drivers can lead to rate designs that will not best promote long-run dynamic efficiency. This is especially true of embedded cost studies, in which a central objective is to assign or allocate costs to particular services or classes of customers, even though many of those costs cannot be assigned unequivocally according to the principle of causation. By their very nature, many utility costs are joint or common to two or more services; consequently there can be no unshakeable assertion that any one service in fact caused a cost and, therefore, that a particular rate element should recover it. And marginal cost studies often suffer from this deficiency as well. This means that regulators should be very careful before relying upon what are essentially (though not necessarily

56. *Id.*, pp. 68-71. Also affected is the magnitude and cost of over-sizing equipment in order to serve forecast demand. See also NERA, pp. 17-18.

unreasonable) arbitrary cost assignments for the purposes of designing rates.[57] Too great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design.

Marginal cost analysis demonstrates that distribution costs vary with load in the long run. This has important implications for rate design. Embedded cost analysis, though it relies on *a priori* assumptions about causes (and allocations therefore) of historical costs, is useful in rate design at least insofar as it informs the process of reconciling marginal cost-based rates with revenue requirements.[58] We recognize that there are honest disagreements over approaches to both kinds of analysis.[59] But what is important here is for regulators to be aware of the fundamental relationships between costs and demand for electric service, in order to devise rates that best serve the objectives they seek.

57. To ensure that [embedded distribution plant] costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst s evaluation of how the costs in these accounts were incurred. NARUC, p. 89. Interestingly, the manual, in a table on page 34, acknowledges that there is an energy-related component to embedded distribution costs, but is otherwise silent on the question.

58. Bonbright, pp. 366-367. Bonbright expresses some skepticism as to the usefulness of most embedded cost studies for rate design, on the ground that they often ignore the relationship between cost causation and apportionment. One may suspect that the choice of [allocation] formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons. *Id.*, p. 368.

59. See, *e.g.*, Chernick, Vol. 5, pp. 58-83, and NARUC, pp. 86-104 and 137-146.

KENTUCKY UTILITIES COMPANY
BIP 100% Demand Cost of Service Study
Rate of Return Summary

	Allocation Factor Name	No	Total Kentucky	Residential (RS	General Service (GS)	All Elect. Schools (AES)	Pwr Svc Secondary (PS-Sec)	PWR Svc Primary (PS-Pri)	Time of Day Secondary (TOU-sec)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$554,543,189	$198,233,994	$12,037,991	$174,459,441	$13,950,651	$116,879,945
Intercompany Sales		2	$8,422,903	$2,827,720	$843,635	$70,490	$996,388	$76,891	$775,692
Curtailable Service Rider		W/S Peak	-$17,395,776	-$7,040,463	-$1,992,695	-$149,403	-$1,983,575	-$137,636	-$1,397,730
LATE PAYMENT CHARGES	LPAY		$3,857,505	$3,012,898	$568,302	$3,750	$98,651	$5,535	$41,764
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$1,967,237	$136,875	$853	$1,335	$51	$982
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$1,300,151	$351,801	$26,510	$317,551	$24,217	$242,207
OTHER MISC REVENUES	MISCSERV		$22,338,060	$20,843,640	$1,450,249	$9,036	$14,148	$542	$10,403
Total Unadjusted Revenues			$1,486,962,672	$577,454,374	$199,592,161	$11,999,227	$173,903,940	$13,920,251	$116,553,263
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$609,965	-$368,766	-$23,373	-$168,730	-$13,653	-$105,682
Total Adjusted Revenues At Current Rates			$1,485,327,440	$576,844,408	$199,223,396	$11,975,854	$173,735,210	$13,906,598	$116,447,581
Total O&M Expense			$933,774,239	$357,581,583	$107,165,155	$7,931,089	$100,524,776	$7,822,965	$77,134,549
Depreciation Expense			$228,062,837	$91,173,068	$25,070,087	$1,908,907	$23,829,802	$1,818,740	$18,219,736
Taxes Other Than Income Taxes			$37,820,875	$15,541,469	$4,212,199	$318,288	$3,848,925	$293,422	$2,937,049
Eliminate Advertising Expense		33	-$838,116	-$539,971	-$208,951	-$7,435	-$28,229	-$1,085	-$19,371
Total Expenses Before Interest and Taxes			$1,198,819,834	$463,756,149	$136,238,490	$10,150,849	$128,175,274	$9,934,043	$98,271,963
Earnings Before Interest and Taxes			$286,507,606	$113,088,259	$62,984,906	$1,825,005	$45,559,936	$3,972,556	$18,175,619
Interest			$86,095,200	$35,378,502	$9,588,623	$724,549	$8,761,668	$667,944	$6,685,880
Taxable Income			$200,412,405	$77,709,757	$53,396,283	$1,100,456	$36,798,268	$3,304,612	$11,489,739
Income Taxes		TAXINC	$83,997,066	$32,569,798	$22,379,508	$461,224	$15,422,930	$1,385,033	$4,815,592
Net Operating Income			$202,510,540	$80,518,461	$40,605,397	$1,363,781	$30,137,006	$2,587,523	$13,360,027
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$2,860,945,780	$775,954,761	$58,628,786	$710,282,759	$54,148,526	$542,041,564
CWIP			$118,703,941	$52,275,557	$13,614,557	$1,033,768	$11,191,500	$852,883	$8,503,159
Accumulated Depreciation			$2,699,542,764	$1,098,013,447	$299,262,454	$22,647,332	$277,522,782	$21,162,993	$211,916,300
Net Plant			$4,389,914,415	$1,815,207,889	$490,306,864	$37,015,221	$443,951,477	$33,838,416	$338,628,423
Working Capital									
Cash Working Capital			$106,348,560	$40,927,040	$12,279,730	$902,937	$11,391,796	$888,322	$8,743,642
Materials & Supplies			$119,808,344	$49,171,899	$13,336,558	$1,007,670	$12,207,834	$930,666	$9,316,224
Prepayments			$16,171,254	$6,637,027	$1,800,116	$136,011	$1,647,765	$125,618	$1,257,467
Total Working Capital			$242,328,157	$96,735,967	$27,416,403	$2,046,618	$25,247,395	$1,944,606	$19,317,334
Less:									
ADIT			$910,427,698	$377,735,899	$101,852,881	$7,681,162	$91,760,671	$6,992,953	$69,972,960
Accumulated ITCs			$81,185,411	$27,786,173	$8,295,430	$668,546	$9,608,142	$738,049	$7,414,671
Customer Advances			$1,549,704	$889,185	$201,229	$14,935	$116,546	$9,165	$90,078
Net Rate Base			$3,639,079,759	$1,505,532,599	$407,373,728	$30,697,196	$367,713,514	$28,042,855	$280,468,048
Rate of Return At Current Rates			5.56%	5.35%	9.97%	4.44%	8.20%	9.23%	4.76%
Indexed Rate of Return At Current Rates			100%	96%	179%	80%	147%	166%	86%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$576,844,408	$199,223,396	$11,975,854	$173,735,210	$13,906,598	$116,447,581
Proposed Increase			$94,389,820	$37,000,063	$10,285,675	$777,151	$9,478,306	$643,891	$6,865,948
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$3,516,381	$995,258	$74,620	$990,703	$68,743	$698,101
Increase in Miscellaneous Charges	MISCSERV		$19,720	$18,401	$1,280	$8	$12	$0	$9
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$617,379,253	$210,505,609	$12,827,633	$184,204,232	$14,619,232	$124,011,639
Total Operating Expenses			$1,282,816,900	$496,325,947	$158,617,998	$10,612,074	$143,598,204	$11,319,075	$103,087,555
Increase in Uncollectible Expense	Cust01		$362,905	$233,808	$90,476	$3,219	$12,223	$470	$8,388
Increase in PSC Fees	Billed rev		$200,113	$75,775	$27,087	$1,645	$23,839	$1,906	$15,971
Incremental Taxable Income			$102,515,177	$40,206,862	$11,163,370	$846,906	$10,432,947	$710,258	$7,539,690
Incremental Income Taxes			$39,751,942	$15,590,870	$4,328,780	$328,402	$4,045,546	$275,414	$2,923,639
Total Pro-Forma Operating Expenses			$1,323,131,860	$512,226,400	$163,064,341	$10,945,340	$147,679,812	$11,596,865	$106,035,552
Net Operating Income			$265,293,495	$105,152,853	$47,441,267	$1,882,293	$36,524,419	$3,022,367	$17,976,088
Net Cost Rate Base			$3,639,079,759	$1,505,532,599	$407,373,728	$30,697,196	$367,713,514	$28,042,855	$280,468,048
Rate of Return At Proposed Rates			7.29%	6.98%	11.65%	6.13%	9.93%	10.78%	6.41%
Indexed ROR @ Proposed Rates			100%	96%	160%	84%	136%	148%	88%

KENTUCKY UTILITIES COMPANY
BIP 100% Demand Cost of Service Study
Rate of Return Summary

	Allocation Factor Name	Allocation Factor No	Total Kentucky	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$251,561,897	$86,711,460	$29,892,107	$26,032,396	$29,470	$156,512
Intercompany Sales		2	$8,422,903	$1,864,604	$664,048	$245,150	$57,388	$207	$691
Curtailable Service Rider		W/S Peak	-$17,395,776	-$3,139,126	-$1,128,649	-$425,628	$0	$0	-$873
LATE PAYMENT CHARGES	LPAY		$3,857,505	$107,885	$18,686	$0	$33	$0	$0
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$439	$48	$0	$461	$0	$0
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$557,163	$172,233	$71,625	$78,854	$70	$262
OTHER MISC REVENUES	MISCSERV		$22,338,060	$4,653	$505	$0	$4,883	$0	$0
Total Unadjusted Revenues			$1,486,962,672	$250,957,516	$86,438,331	$29,783,254	$26,174,016	$29,747	$156,592
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$210,279	-$68,614	-$23,719	-$42,194	-$66	-$192
Total Adjusted Revenues At Current Rates			$1,485,327,440	$250,747,237	$86,369,716	$29,759,535	$26,131,822	$29,681	$156,400
Total O&M Expense			$933,774,239	$181,683,028	$61,953,831	$23,547,452	$8,310,172	$20,992	$98,649
Depreciation Expense			$228,062,837	$42,180,123	$13,471,422	$5,409,761	$4,957,565	$4,978	$18,649
Taxes Other Than Income Taxes			$37,820,875	$6,763,609	$2,102,571	$867,623	$931,764	$838	$3,118
Eliminate Advertising Expense		33	-$838,116	-$8,682	-$752	-$63	-$23,471	$0	-$108
Total Expenses Before Interest and Taxes			$1,198,819,834	$230,618,077	$77,527,071	$29,824,774	$14,176,030	$26,807	$120,308
Earnings Before Interest and Taxes			$286,507,606	$20,129,160	$8,842,646	-$65,239	$11,955,792	$2,874	$36,092
Interest			$86,095,200	$15,396,637	$4,786,279	$1,975,052	$2,121,061	$1,907	$7,099
Taxable Income			$200,412,405	$4,732,523	$4,056,366	-$2,040,291	$9,834,731	$967	$28,993
Income Taxes		TAXINC	$83,997,066	$1,983,500	$1,700,109	-$855,129	$4,121,943	$405	$12,152
Net Operating Income			$202,510,540	$18,145,660	$7,142,537	$789,890	$7,833,849	$2,469	$23,941
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$1,248,526,922	$388,495,729	$159,951,137	$171,048,129	$154,215	$574,930
CWIP			$118,703,941	$19,299,846	$5,627,540	$2,683,357	$3,609,331	$2,820	$9,624
Accumulated Depreciation			$2,699,542,764	$488,971,975	$153,450,265	$62,468,536	$63,844,965	$59,359	$222,357
Net Plant			$4,389,914,415	$778,854,793	$240,673,005	$100,165,958	$110,812,495	$97,676	$362,197
Working Capital									
Cash Working Capital			$106,348,560	$20,574,186	$6,997,598	$2,664,349	$965,155	$2,399	$11,405
Materials & Supplies			$119,808,344	$21,458,792	$6,677,188	$2,749,126	$2,939,853	$2,651	$9,881
Prepayments			$16,171,254	$2,896,422	$901,260	$371,066	$396,810	$358	$1,334
Total Working Capital			$242,328,157	$44,929,401	$14,576,046	$5,784,541	$4,301,818	$5,408	$22,620
Less:									
ADIT			$910,427,698	$160,826,291	$49,510,886	$20,677,258	$23,321,239	$20,291	$75,207
Accumulated ITCs			$81,185,411	$17,572,646	$6,297,961	$2,333,440	$462,480	$1,671	$6,203
Customer Advances			$1,549,704	$208,701	$0	$0	$19,710	$43	$110
Net Rate Base			$3,639,079,759	$645,176,555	$199,440,204	$82,939,802	$91,310,883	$81,078	$303,297
Rate of Return At Current Rates			5.56%	2.81%	3.58%	0.95%	8.58%	3.05%	7.89%
Indexed Rate of Return At Current Rates			100%	51%	64%	17%	154%	55%	142%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$250,747,237	$86,369,716	$29,759,535	$26,131,822	$29,681	$156,400
Proposed Increase			$94,389,820	$18,614,379	$6,363,804	$2,483,771	$1,866,484	$2,173	$8,175
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$1,567,846	$563,707	$212,581	$0	$0	$436
Increase in Miscellaneous Charges	MISCSERV		$19,720	$4	$0	$0	$4	$0	$0
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$270,929,466	$93,297,228	$32,455,887	$27,998,310	$31,854	$165,011
Total Operating Expenses			$1,282,816,900	$232,601,577	$79,227,180	$28,969,645	$18,297,973	$27,212	$132,460
Increase in Uncollectible Expense	Cust01		$362,905	$3,759	$326	$27	$10,163	$0	$47
Increase in PSC Fees	Billed rev		$200,113	$34,374	$11,849	$4,085	$3,557	$4	$21
Incremental Taxable Income			$102,515,177	$20,144,091	$6,915,337	$2,692,240	$1,852,764	$2,169	$8,543
Incremental Income Taxes			$39,751,942	$7,811,202	$2,681,535	$1,043,960	$718,440	$841	$3,313
Total Pro-Forma Operating Expenses			$1,323,131,860	$240,450,913	$81,920,889	$30,017,717	$19,030,133	$28,057	$135,840
Net Operating Income			$265,293,495	$30,478,553	$11,376,339	$2,438,170	$8,968,177	$3,797	$29,171
Net Cost Rate Base			$3,639,079,759	$645,176,555	$199,440,204	$82,939,802	$91,310,883	$81,078	$303,297
Rate of Return At Proposed Rates			7.29%	4.72%	5.70%	2.94%	9.82%	4.68%	9.62%
Indexed ROR @ Proposed Rates				65%	78%	40%	135%	64%	132%

KENTUCKY UTILITIES COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Rate of Return Summary

	Allocation Factor Name	No.	Total Kentucky	Residential (RS)	General Service (GS)	All Elect. Schools (AES)	Pwr Svc Secondary (PS-Sec)	PWR Svc Primary (PS-Pri)	Time of Day Secondary (TOU-sec)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$554,543,189	$198,233,994	$12,037,991	$174,459,441	$13,950,651	$116,879,945
Intercompany Sales		2	$8,422,903	$2,827,720	$843,635	$70,490	$996,388	$76,891	$775,692
Curtailable Service Rider		W/S Peak	-$17,395,776	-$7,040,463	-$1,992,695	-$149,403	-$1,983,575	-$137,636	-$1,397,730
LATE PAYMENT CHARGES	LPAY		$3,857,505	$3,012,898	$568,302	$3,750	$98,651	$5,535	$41,764
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$1,967,237	$136,875	$853	$1,335	$51	$982
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$1,287,715	$348,442	$26,518	$319,187	$24,345	$243,707
OTHER MISC REVENUES	MISCSERV		$22,338,060	$20,843,640	$1,450,249	$9,036	$14,148	$542	$10,403
Total Unadjusted Revenues			$1,486,962,672	$577,441,938	$199,588,802	$11,999,236	$173,905,576	$13,920,379	$116,554,763
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$609,965	-$368,766	-$23,373	-$168,730	-$13,653	-$105,682
Total Adjusted Revenues At Current Rates			$1,485,327,440	$576,831,972	$199,220,037	$11,975,863	$173,736,846	$13,906,725	$116,449,081
Total O&M Expense			$933,774,239	$359,167,699	$107,398,164	$7,967,965	$100,329,365	$7,783,200	$76,828,537
Depreciation Expense			$228,062,837	$90,210,576	$24,853,845	$1,907,861	$23,981,647	$1,827,670	$18,327,780
Taxes Other Than Income Taxes			$37,820,875	$15,398,057	$4,179,978	$318,132	$3,871,550	$294,752	$2,953,148
Eliminate Advertising Expense		33	-$838,116	-$539,971	-$208,951	-$7,435	-$28,229	-$1,085	-$19,371
Total Expenses Before Interest and Taxes			$1,198,819,834	$464,236,362	$136,223,036	$10,186,523	$128,154,334	$9,904,538	$98,090,094
Earnings Before Interest and Taxes			$286,507,606	$112,595,611	$62,997,001	$1,789,340	$45,582,512	$4,002,188	$18,358,987
Interest			$86,095,200	$35,052,040	$9,515,276	$724,194	$8,813,172	$670,972	$6,722,527
Taxable Income			$200,412,405	$77,543,571	$53,481,725	$1,065,146	$36,769,341	$3,331,215	$11,636,461
Income Taxes		TAXINC	$83,997,066	$32,500,146	$22,415,319	$446,425	$15,410,806	$1,396,183	$4,877,086
Net Operating Income			$202,510,540	$80,095,465	$40,581,682	$1,342,915	$30,171,706	$2,606,005	$13,481,901
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$2,834,344,650	$769,978,294	$58,599,861	$714,479,427	$54,395,323	$545,027,674
CWIP			$118,703,941	$51,994,361	$13,551,381	$1,033,462	$11,235,862	$855,492	$8,534,724
Accumulated Depreciation			$2,699,542,764	$1,089,017,477	$297,880,565	$22,615,976	$279,326,092	$21,229,531	$212,790,331
Net Plant			$4,389,914,415	$1,797,321,533	$485,649,110	$37,017,347	$446,389,196	$34,021,284	$340,772,067
Working Capital									
Cash Working Capital			$106,348,560	$41,118,038	$12,307,788	$907,378	$11,368,265	$883,534	$8,706,793
Materials & Supplies			$119,808,344	$48,714,698	$13,233,839	$1,007,173	$12,279,964	$934,908	$9,367,548
Prepayments			$16,171,254	$6,575,316	$1,786,251	$135,944	$1,657,501	$126,190	$1,264,394
Total Working Capital			$242,328,157	$96,408,052	$27,327,878	$2,050,495	$25,305,729	$1,944,632	$19,338,735
Less:									
ADIT			$910,427,698	$374,430,343	$101,110,222	$7,677,568	$92,282,164	$7,023,621	$70,344,025
Accumulated ITCs			$81,185,411	$27,277,811	$8,181,216	$667,994	$9,688,342	$742,765	$7,471,737
Customer Advances			$1,549,704	$889,185	$201,229	$14,935	$116,546	$9,165	$90,078
Net Rate Base			$3,639,079,759	$1,491,132,246	$403,484,320	$30,707,345	$369,607,873	$28,190,365	$282,204,961
Rate of Return At Current Rates			5.56%	5.37%	10.06%	4.37%	8.16%	9.24%	4.78%
Indexed Rate of Return At Current Rates			100%	97%	181%	79%	147%	166%	86%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$576,831,972	$199,220,037	$11,975,863	$173,736,846	$13,906,725	$116,449,081
Proposed Increase			$94,389,820	$37,000,063	$10,285,675	$777,151	$9,478,306	$643,891	$6,865,948
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$3,516,381	$995,258	$74,620	$990,703	$68,743	$698,101
Increase in Miscellaneous Charges	MISCSERV		$19,720	$18,401	$1,280	$8	$12	$0	$9
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$617,366,817	$210,502,250	$12,827,642	$184,205,867	$14,619,360	$124,013,139
Total Operating Expenses			$1,282,816,900	$496,736,508	$158,638,355	$10,632,948	$143,565,140	$11,300,720	$102,967,180
Increase in Uncollectible Expense	Cust01		$362,905	$233,808	$90,476	$3,219	$12,223	$470	$8,388
Increase in PSC Fees	Billed rev		$200,113	$75,775	$27,087	$1,645	$23,839	$1,906	$15,971
Incremental Taxable Income			$102,515,177	$40,206,862	$11,163,370	$846,906	$10,432,947	$710,258	$7,539,690
Incremental Income Taxes			$39,751,942	$15,590,870	$4,328,780	$328,402	$4,045,546	$275,414	$2,923,639
Total Pro-Forma Operating Expenses			$1,323,131,860	$512,636,961	$163,084,698	$10,966,214	$147,646,748	$11,578,510	$105,915,177
Net Operating Income			$265,293,495	$104,729,857	$47,417,552	$1,861,428	$36,559,119	$3,040,849	$18,097,962
Net Cost Rate Base			$3,639,079,759	$1,491,132,246	$403,484,320	$30,707,345	$369,607,873	$28,190,365	$282,204,961
Rate of Return At Proposed Rates			7.29%	7.02%	11.75%	6.06%	9.89%	10.79%	6.41%
Indexed ROR @ Proposed Rates				96%	161%	83%	136%	148%	88%

KENTUCKY UTILITIES COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Rate of Return Summary

	Allocation Factor Name	No.	Total Kentucky	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
Revenues At Current Rates									
Operating Revenues									
Sales	DIR		$1,464,489,053	$251,561,897	$86,711,460	$29,892,107	$26,032,396	$29,470	$156,512
Intercompany Sales		2	$8,422,903	$1,864,604	$664,048	$245,150	$57,388	$207	$691
Curtailable Service Rider		W/S Peak	-$17,395,776	-$3,139,126	-$1,128,649	-$425,628	$0	$0	-$873
LATE PAYMENT CHARGES	LPAY		$3,857,505	$107,885	$18,686	$0	$33	$0	$0
OTHER SERVICE CHARGES	MISCSERV		$2,108,282	$439	$48	$0	$461	$0	$0
RENT FROM ELEC PROPERTY	RBT	Rate Base	$3,142,645	$566,702	$173,201	$72,131	$80,352	$76	$268
OTHER MISC REVENUES	MISCSERV		$22,338,060	$4,653	$505	$0	$4,883	$0	$0
Total Unadjusted Revenues			$1,486,962,672	$250,967,055	$86,439,299	$29,783,760	$26,175,513	$29,753	$156,598
Adj to eliminate Off System ECR revenues	ECRREV		-$1,635,232	-$210,279	-$68,614	-$23,719	-$42,194	-$66	-$192
Total Adjusted Revenues At Current Rates			$1,485,327,440	$250,756,776	$86,370,685	$29,760,041	$26,133,320	$29,687	$156,406
Total O&M Expense			$933,774,239	$181,008,024	$61,535,978	$23,428,622	$8,207,827	$20,617	$98,241
Depreciation Expense			$228,062,837	$42,935,333	$13,524,138	$5,412,511	$5,057,078	$5,349	$19,048
Taxes Other Than Income Taxes			$37,820,875	$6,876,136	$2,110,426	$868,033	$946,591	$893	$3,178
Eliminate Advertising Expense		33	-$838,116	-$8,682	-$752	-$63	-$23,471	$0	-$108
Total Expenses Before Interest and Taxes			$1,198,819,834	$230,810,811	$77,169,790	$29,709,103	$14,188,025	$26,860	$120,360
Earnings Before Interest and Taxes			$286,507,606	$19,945,965	$9,200,895	$50,938	$11,945,295	$2,828	$36,047
Interest			$86,095,200	$15,652,793	$4,804,160	$1,975,985	$2,154,814	$2,033	$7,234
Taxable Income			$200,412,405	$4,293,172	$4,396,735	-$1,925,047	$9,790,481	$794	$28,812
Income Taxes		TAXINC	$83,997,066	$1,799,359	$1,842,764	-$806,828	$4,103,397	$333	$12,076
Net Operating Income			$202,510,540	$18,146,606	$7,358,131	$857,766	$7,841,898	$2,495	$23,971
Rate Base									
Total Gross Plant (including Plant Held for Future Use)			$6,970,753,239	$1,269,399,269	$389,952,707	$160,027,134	$173,798,441	$164,482	$585,976
CWIP			$118,703,941	$19,520,483	$5,642,942	$2,684,161	$3,638,404	$2,929	$9,740
Accumulated Depreciation			$2,699,542,764	$496,352,402	$153,570,561	$61,935,817	$64,536,997	$61,851	$225,163
Net Plant			$4,389,914,415	$792,567,350	$242,025,087	$100,775,478	$112,899,848	$105,560	$370,554
Working Capital									
Cash Working Capital			$106,348,560	$20,492,903	$6,947,281	$2,650,039	$952,830	$2,354	$11,356
Materials & Supplies			$119,808,344	$21,817,531	$6,702,229	$2,750,432	$2,987,124	$2,827	$10,071
Prepayments			$16,171,254	$2,944,844	$904,640	$371,242	$403,190	$382	$1,359
Total Working Capital			$242,328,157	$45,255,278	$14,554,151	$5,771,714	$4,343,144	$5,563	$22,786
Less:									
ADIT			$910,427,698	$163,419,967	$49,691,935	$20,686,701	$23,663,004	$21,567	$76,580
Accumulated ITCs			$81,185,411	$17,971,527	$6,325,805	$2,334,892	$515,040	$1,867	$6,414
Customer Advances			$1,549,704	$208,701	$0	$0	$19,710	$43	$110
Net Rate Base			$3,639,079,759	$656,222,432	$200,561,498	$83,525,598	$93,045,239	$87,645	$310,236
Rate of Return At Current Rates			5.56%	2.77%	3.67%	1.03%	8.43%	2.85%	7.73%
Indexed Rate of Return At Current Rates			100%	50%	66%	18%	151%	51%	139%
Rate of Return at Proposed Rates:									
Total Operating Revenue at Current Rates			$1,485,327,440	$250,756,776	$86,370,685	$29,760,041	$26,133,320	$29,687	$156,406
Proposed Increase			$94,389,820	$18,614,379	$6,363,804	$2,483,771	$1,866,484	$2,173	$8,175
Proposed reduction to CSR Credit	INTCRE	Intermed + Peak	$8,688,375	$1,567,846	$563,707	$212,581	$0	$0	$436
Increase in Miscellaneous Charges	MISCSERV		$19,720	$4	$0	$0	$4	$0	$0
Total Pro-Forma Operating Revenue at Proposed Rates			$1,588,425,355	$270,939,005	$93,298,197	$32,456,393	$27,999,808	$31,860	$165,017
Total Operating Expenses			$1,282,816,900	$232,610,170	$79,012,554	$28,902,275	$18,291,422	$27,193	$132,436
Increase in Uncollectible Expense	Cust01		$362,905	$3,759	$326	$27	$10,163	$0	$47
Increase in PSC Fees	Billed rev		$200,113	$34,374	$11,849	$4,085	$3,557	$4	$21
Incremental Taxable Income			$102,515,177	$20,144,091	$6,915,337	$2,692,240	$1,852,764	$2,169	$8,543
Incremental Income Taxes			$39,751,942	$7,811,202	$2,681,535	$1,043,960	$718,440	$841	$3,313
Total Pro-Forma Operating Expenses			$1,323,131,860	$240,459,506	$81,706,264	$29,950,347	$19,023,582	$28,038	$135,816
Net Operating Income			$265,293,495	$30,479,499	$11,591,933	$2,506,046	$8,976,226	$3,822	$29,201
Net Cost Rate Base			$3,639,079,759	$656,222,432	$200,561,498	$83,525,598	$93,045,239	$87,645	$310,236
Rate of Return At Proposed Rates			7.29%	4.64%	5.78%	3.00%	9.65%	4.36%	9.41%
Indexed ROR @ Proposed Rates				64%	79%	41%	132%	60%	129%

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base									
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	PT&D	23	$39,493	$35,942	$0	$3,550	$13,899	$0	$2,159
302.00 FRANCHISE AND CONSENTS	PT&D	23	$55,919	$50,892	$0	$5,027	$19,679	$0	$3,058
303.00 SOFTWARE	PT&D	23	$102,982,045	$93,723,881	$0	$9,258,164	$36,242,235	$0	$5,630,821
Total Intangible Plant			$103,077,457	$93,810,715	$0	$9,266,742	$36,275,813	$0	$5,636,038
Production Plant									
Total Production Plant									
Demand	PODPLT	52	$4,076,920,355	$4,076,920,355	$0	$0	$1,369,820,778	$0	$0
Energy	Energy	2	$0	$0	$0	$0	$0	$0	$0
Total Production Plant			**$4,076,920,355**	**$4,076,920,355**	**$0**	**$0**	**$1,369,820,778**	**$0**	**$0**
Transmission									
KENTUCKY SYSTEM PROPERTY	NCPT	13	$873,007,848	$873,007,848	$0	$0	$371,324,838	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	NCPT	13	$8,230,400	$8,230,400	$0	$0	$3,500,716	$0	$0
Total Transmission Plant			$881,238,248	$881,238,248	$0	$0	$374,825,553	$0	$0
Distribution									
TOTAL ACCTS 360-362	NCPP	14	$209,650,161	$209,650,161	$0	$0	$99,451,124	$0	$0
364 & 365-OVERHEAD LINES									
Primary:									
Demand	NCPP	14	$467,632,560	$467,632,560	$0	$0	$221,829,468	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0
Secondary:									
Demand	SICD	16	$101,814,953	$101,814,953	$0	$0	$84,813,873	$0	$0
Customer	CUST07	10	$147,670,352	$0	$0	$147,670,352	$0	$0	$119,230,454
366 & 367-UNDERGROUND LINES									
Primary:									
Demand	NCPP	14	$184,469,078	$184,469,078	$0	$0	$87,506,049	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0
Secondary:									
Demand	SICD	16	$3,355,326	$3,355,326	$0	$0	$2,795,053	$0	$0
Customer	CUST07	10	$13,100,417	$0	$0	$13,100,417	$0	$0	$10,577,402
368-TRANSFORMERS - POWER POOL									
Demand	SICDT	15	$2,865,065	$2,865,065	$0	$0	$1,987,749	$0	$0
Customer	CUST09	12	$2,549,563	$0	$0	$2,549,563	$0	$0	$2,038,966
368-TRANSFORMERS - ALL OTHER									
Demand	SICDT	15	$160,395,756	$160,395,756	$0	$0	$111,280,726	$0	$0
Customer	CUST09	12	$142,732,883	$0	$0	$142,732,883	$0	$0	$114,148,010
369-SERVICES	C02	20	$97,262,577	$0	$0	$97,262,577	$0	$0	$68,211,820
370-METERS	C03	21	$82,987,729	$0	$0	$82,987,729	$0	$0	$51,573,767
371-CUSTOMER INSTALLATION	C04	22	$282,792	$0	$0	$282,792	$0	$0	$0
373-STREET LIGHTING	C04	22	$114,827,799	$0	$0	$114,827,799	$0	$0	$0
Total Distribution Plant			$1,731,597,011	$1,130,182,900	$0	$601,414,112	$609,664,042	$0	$365,780,419
Total Prod, Trans, and Dist Plant			**$6,689,755,615**	**$6,088,341,503**	**$0**	**$601,414,112**	**$2,354,310,373**	**$0**	**$365,780,419**
General Plant									
Total General Plant	PT&D	23	$177,535,196	$161,574,647	$0	$15,960,549	$62,479,555	$0	$9,707,215
TOTAL COMMON PLANT			$0	$0	$0	$0			
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0	$0	$0	$0			
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	Prod	24	$271,089	$271,089	$0	$0	$91,084	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	Dist	26	$113,882	$74,329	$0	$39,553	$40,096	$0	$24,056
OTHER			$0	$0	$0	$0			
Total Plant in Service			$6,970,753,239	$6,344,072,283	$0	$626,680,956	$2,453,196,921	$0	$381,147,728
Construction Work in Progress (CWIP)									
CWIP Production	Prod	24	$28,153,069	$28,153,069	$0	$0	$9,459,262	$0	$0
CWIP Transmission	Trans	25	$30,190,923	$30,190,923	$0	$0	$12,841,396	$0	$0
CWIP Distribution Plant	Dist	26	$32,868,652	$21,452,791	$0	$11,415,861	$11,572,459	$0	$6,943,134
CWIP General Plant	PT&D	23	$27,491,296	$25,019,807	$0	$2,471,488	$9,674,949	$0	$1,503,161
RWIP			$0	$0	$0	$0			
Total Construction Work in Progress			$118,703,941	$104,816,591	$0	$13,887,350	$43,548,066	$0	$8,446,294
Total Gross Utility Plant			$7,089,457,179	$6,448,888,874	$0	$640,568,305	$2,496,744,988	$0	$389,594,023

	General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base									
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	$3,810	$0	$552	$326	$0	$6	$3,999	$0	$49
302.00 FRANCHISE AND CONSENTS	$5,395	$0	$782	$462	$0	$8	$5,663	$0	$69
303.00 SOFTWARE	$9,935,338	$0	$1,439,892	$850,338	$0	$15,386	$10,428,468	$0	$126,847
Total Intangible Plant	$9,944,543	$0	$1,441,226	$851,126	$0	$15,400	$10,438,130	$0	$126,965
Production Plant									
Total Production Plant									
Demand	$410,839,418	$0	$0	$33,544,901	$0	$0	$486,523,368	$0	$0
Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Plant	**$410,839,418**	**$0**	**$0**	**$33,544,901**	**$0**	**$0**	**$486,523,368**	**$0**	**$0**
Transmission									
KENTUCKY SYSTEM PROPERTY	$94,008,351	$0	$0	$9,075,533	$0	$0	$82,877,417	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	$886,277	$0	$0	$85,561	$0	$0	$781,338	$0	$0
Total Transmission Plant	$94,894,628	$0	$0	$9,161,093	$0	$0	$83,658,755	$0	$0
Distribution									
TOTAL ACCTS 360-362	$25,178,052	$0	$0	$2,430,680	$0	$0	$22,196,878	$0	$0
364 & 365-OVERHEAD LINES									
Primary:									
Demand	$56,160,592	$0	$0	$5,421,723	$0	$0	$49,510,971	$0	$0
Customer	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:									
Demand	$15,274,553	$0	$0	$1,072,922	$0	$0	$0	$0	$0
Customer	$0	$0	$23,069,101	$0	$0	$164,168	$0	$0	$0
366 & 367-UNDERGROUND LINES									
Primary:									
Demand	$22,153,916	$0	$0	$2,138,731	$0	$0	$19,530,811	$0	$0
Customer	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:									
Demand	$503,375	$0	$0	$35,358	$0	$0	$0	$0	$0
Customer	$0	$0	$2,046,551	$0	$0	$14,564	$0	$0	$0
368-TRANSFORMERS - POWER POOL									
Demand	$357,984	$0	$0	$25,146	$0	$0	$281,078	$0	$0
Customer	$0	$0	$394,506	$0	$0	$2,807	$0	$0	$21,319
368-TRANSFORMERS - ALL OTHER									
Demand	$20,041,100	$0	$0	$1,407,736	$0	$0	$15,735,696	$0	$0
Customer	$0	$0	$22,085,734	$0	$0	$157,170	$0	$0	$1,193,487
369-SERVICES	$0	$0	$26,718,683	$0	$0	$253,038	$0	$0	$1,815,298
370-METERS	$0	$0	$19,221,425	$0	$0	$407,717	$0	$0	$5,209,960
371-CUSTOMER INSTALLATION	$0	$0	$0	$0	$0	$0	$0	$0	$0
373-STREET LIGHTING	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Distribution Plant	$139,669,572	$0	$93,536,000	$12,532,297	$0	$999,465	$107,255,435	$0	$8,240,063
Total Prod, Trans, and Dist Plant	**$645,403,618**	**$0**	**$93,536,000**	**$55,238,291**	**$0**	**$999,465**	**$677,437,557**	**$0**	**$8,240,063**
General Plant									
Total General Plant	$17,127,959	$0	$2,482,293	$1,465,934	$0	$26,524	$17,978,087	$0	$218,678
TOTAL COMMON PLANT									
106.00 COMPLETED CONSTR NOT CLASSIFIED									
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	$27,318	$0	$0	$2,231	$0	$0	$32,351	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	$9,186	$0	$6,152	$824	$0	$66	$7,054	$0	$542
OTHER									
Total Plant in Service	$672,512,624	$0	$97,465,671	$57,558,406	$0	$1,041,455	$705,893,179	$0	$8,586,247
Construction Work in Progress (CWIP)									
CWIP Production	$2,837,041	$0	$0	$231,643	$0	$0	$3,359,675	$0	$0
CWIP Transmission	$3,251,058	$0	$0	$313,856	$0	$0	$2,866,121	$0	$0
CWIP Distribution Plant	$2,651,166	$0	$1,775,472	$237,884	$0	$18,972	$2,035,890	$0	$156,410
CWIP General Plant	$2,652,262	$0	$384,383	$227,000	$0	$4,107	$2,783,904	$0	$33,862
RWIP									
Total Construction Work in Progress	$11,391,526	$0	$2,159,855	$1,010,383	$0	$23,079	$11,045,589	$0	$190,273
Total Gross Utility Plant	$683,904,150	$0	$99,625,526	$58,568,789	$0	$1,064,534	$716,938,769	$0	$8,776,520

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base																		
Plant in Service																		
Intangible Plant																		
301.00 ORGANIZATION	PT&D	23	$39,493	$35,942	$0	$3,550	$301	$0	$7	$3,080	$0	$8	$7,177	$0	$15	$2,199	$0	$10
302.00 FRANCHISE AND CONSENTS	PT&D	23	$55,919	$50,892	$0	$5,027	$427	$0	$10	$4,360	$0	$12	$10,162	$0	$21	$3,114	$0	$15
303.00 SOFTWARE	PT&D	23	$102,982,045	$93,723,881	$0	$9,258,164	$785,923	$0	$17,683	$8,030,432	$0	$21,500	$18,714,100	$0	$39,289	$5,734,154	$0	$26,796
Total Intangible Plant			$103,077,457	$93,810,715	$0	$9,266,742	$786,651	$0	$17,699	$8,037,872	$0	$21,520	$18,731,438	$0	$39,326	$5,739,467	$0	$26,820
Production Plant																		
Total Production Plant																		
Demand	PODPLT	52	$4,076,920,355	$4,076,920,355	$0	$0	$37,299,744	$0	$0	$375,211,211	$0	$0	$902,483,397	$0	$0	$317,665,480	$0	$0
Energy	Energy	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Plant			**$4,076,920,355**	**$4,076,920,355**	**$0**	**$0**	**$37,299,744**	**$0**	**$0**	**$375,211,211**	**$0**	**$0**	**$902,483,397**	**$0**	**$0**	**$317,665,480**	**$0**	**$0**
Transmission																		
KENTUCKY SYSTEM PROPERTY	NCPT	13	$873,007,848	$873,007,848	$0	$0	$6,517,580	$0	$0	$64,055,947	$0	$0	$148,410,186	$0	$0	$54,315,430	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	NCPT	13	$8,230,400	$8,230,400	$0	$0	$61,445	$0	$0	$603,896	$0	$0	$1,399,157	$0	$0	$512,066	$0	$0
Total Transmission Plant			$881,238,248	$881,238,248	$0	$0	$6,579,025	$0	$0	$64,659,843	$0	$0	$149,809,343	$0	$0	$54,827,497	$0	$0
Distribution																		
TOTAL ACCTS 360-362	NCPP	14	$209,650,161	$209,650,161	$0	$0	$1,745,589	$0	$0	$17,155,965	$0	$0	$39,748,378	$0	$0	$0	$0	$0
364 & 365-OVERHEAD LINES																		
Primary:																		
Demand	NCPP	14	$467,632,560	$467,632,560	$0	$0	$3,893,602	$0	$0	$38,267,025	$0	$0	$88,660,249	$0	$0	$0	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$101,814,953	$101,814,953	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST07	10	$147,670,352	$0	$0	$147,670,352	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366 & 367-UNDERGROUND LINES																		
Primary:																		
Demand	NCPP	14	$184,469,078	$184,469,078	$0	$0	$1,535,927	$0	$0	$15,095,362	$0	$0	$34,974,200	$0	$0	$0	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$3,355,326	$3,355,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST07	10	$13,100,417	$0	$0	$13,100,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - POWER POOL																		
Demand	SICDT	15	$2,865,065	$2,865,065	$0	$0	$0	$0	$0	$197,790	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST09	12	$2,549,563	$0	$0	$2,549,563	$0	$0	$0	$0	$0	$2,926	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - ALL OTHER																		
Demand	SICDT	15	$160,395,756	$160,395,756	$0	$0	$0	$0	$0	$11,072,931	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST09	12	$142,732,883	$0	$0	$142,732,883	$0	$0	$0	$0	$0	$163,796	$0	$0	$0	$0	$0	$0
369-SERVICES	C02	20	$97,262,577	$0	$0	$97,262,577	$0	$0	$0	$0	$0	$263,738	$0	$0	$0	$0	$0	$0
370-METERS	C03	21	$82,987,729	$0	$0	$82,987,729	$0	$0	$1,148,686	$0	$0	$966,202	$0	$0	$2,552,238	$0	$0	$1,740,656
371-CUSTOMER INSTALLATION	C04	22	$282,792	$0	$0	$282,792	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373-STREET LIGHTING	C04	22	$114,827,799	$0	$0	$114,827,799	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Distribution Plant			$1,731,597,011	$1,130,182,900	$0	$601,414,112	$7,175,118	$0	$1,148,686	$81,789,072	$0	$1,396,662	$163,382,826	$0	$2,552,238	$0	$0	$1,740,656
Total Prod, Trans, and Dist Plant			**$6,689,755,615**	**$6,088,341,503**	**$0**	**$601,414,112**	**$51,053,888**	**$0**	**$1,148,686**	**$521,660,126**	**$0**	**$1,396,662**	**$1,215,675,567**	**$0**	**$2,552,238**	**$372,492,977**	**$0**	**$1,740,656**
General Plant																		
Total General Plant	PT&D	23	$177,535,196	$161,574,647	$0	$15,960,549	$1,354,887	$0	$30,484	$13,844,008	$0	$37,065	$32,262,045	$0	$67,732	$9,885,356	$0	$46,194
TOTAL COMMON PLANT			$0	$0	$0	$0												
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0	$0	$0	$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	Prod	24	$271,089	$271,089	$0	$0	$2,480	$0	$0	$24,949	$0	$0	$60,009	$0	$0	$21,123	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	Dist	26	$113,882	$74,329	$0	$39,553	$472	$0	$76	$5,379	$0	$92	$10,745	$0	$168	$0	$0	$114
OTHER			$0	$0	$0	$0												
Total Plant in Service			$6,970,753,239	$6,344,072,283	$0	$626,680,956	$53,198,378	$0	$1,196,946	$543,572,335	$0	$1,455,339	$1,266,739,805	$0	$2,659,464	$388,138,922	$0	$1,813,785
Construction Work in Progress (CWIP)																		
CWIP Production	Prod	24	$28,153,069	$28,153,069	$0	$0	$257,572	$0	$0	$2,591,011	$0	$0	$6,232,076	$0	$0	$2,193,631	$0	$0
CWIP Transmission	Trans	25	$30,190,923	$30,190,923	$0	$0	$225,395	$0	$0	$2,215,224	$0	$0	$5,132,417	$0	$0	$1,878,371	$0	$0
CWIP Distribution Plant	Dist	26	$32,868,652	$21,452,791	$0	$11,415,861	$136,196	$0	$21,804	$1,552,496	$0	$26,511	$3,101,284	$0	$48,446	$0	$0	$33,041
CWIP General Plant	PT&D	23	$27,491,296	$25,019,807	$0	$2,471,488	$209,804	$0	$4,720	$2,143,742	$0	$5,740	$4,995,772	$0	$10,488	$1,530,746	$0	$7,153
RWIP			$0	$0	$0	$0												
Total Construction Work in Progress			$118,703,941	$104,816,591	$0	$13,887,350	$828,968	$0	$26,525	$8,502,474	$0	$32,251	$19,461,549	$0	$58,934	$5,602,748	$0	$40,194
Total Gross Utility Plant			$7,089,457,179	$6,448,888,874	$0	$640,568,305	$54,027,345	$0	$1,223,470	$552,074,809	$0	$1,487,590	$1,286,201,354	$0	$2,718,398	$393,741,670	$0	$1,853,979

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base																		
Plant in Service																		
Intangible Plant																		
301.00 ORGANIZATION	PT&D	23	$39,493	$35,942	$0	$3,550	$906	$0	$0	$242	$0	$743	$1	$0	$0	$2	$0	$1
302.00 FRANCHISE AND CONSENTS	PT&D	23	$55,919	$50,892	$0	$5,027	$1,283	$0	$1	$343	$0	$1,052	$1	$0	$0	$4	$0	$1
303.00 SOFTWARE	PT&D	23	$102,982,045	$93,723,881	$0	$9,258,164	$2,363,033	$0	$1,134	$630,972	$0	$1,936,616	$2,419	$0	$11	$6,468	$0	$2,189
Total Intangible Plant			$103,077,457	$93,810,715	$0	$9,266,742	$2,365,223	$0	$1,135	$631,557	$0	$1,938,410	$2,421	$0	$11	$6,474	$0	$2,191
Production Plant																		
Total Production Plant																		
Demand	PODPLT	52	$4,076,920,355	$4,076,920,355	$0	$0	$117,252,229	$0	$0	$25,863,983	$0	$0	$93,769	$0	$0	$322,077	$0	$0
Energy	Energy	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Plant			**$4,076,920,355**	**$4,076,920,355**	**$0**	**$0**	**$117,252,229**	**$0**	**$0**	**$25,863,983**	**$0**	**$0**	**$93,769**	**$0**	**$0**	**$322,077**	**$0**	**$0**
Transmission																		
KENTUCKY SYSTEM PROPERTY	NCPT	13	$873,007,848	$873,007,848	$0	$0	$35,912,809	$0	$0	$6,440,994	$0	$0	$26,979	$0	$0	$41,784	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	NCPT	13	$8,230,400	$8,230,400	$0	$0	$338,573	$0	$0	$60,723	$0	$0	$254	$0	$0	$394	$0	$0
Total Transmission Plant			$881,238,248	$881,238,248	$0	$0	$36,251,382	$0	$0	$6,501,718	$0	$0	$27,233	$0	$0	$42,177	$0	$0
Distribution																		
TOTAL ACCTS 360-362	NCPP	14	$209,650,161	$209,650,161	$0	$0	$0	$0	$0	$1,725,078	$0	$0	$7,226	$0	$0	$11,191	$0	$0
364 & 365-OVERHEAD LINES																		
Primary:																		
Demand	NCPP	14	$467,632,560	$467,632,560	$0	$0	$0	$0	$0	$3,847,850	$0	$0	$16,117	$0	$0	$24,961	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$101,814,953	$101,814,953	$0	$0	$0	$0	$0	$646,706	$0	$0	$2,709	$0	$0	$4,191	$0	$0
Customer	CUST07	10	$147,670,352	$0	$0	$147,670,352	$0	$0	$0	$0	$0	$5,182,635	$0	$0	$123	$0	$0	$23,870
366 & 367-UNDERGROUND LINES																		
Primary:																		
Demand	NCPP	14	$184,469,078	$184,469,078	$0	$0	$0	$0	$0	$1,517,878	$0	$0	$6,358	$0	$0	$9,847	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$3,355,326	$3,355,326	$0	$0	$0	$0	$0	$21,312	$0	$0	$89	$0	$0	$138	$0	$0
Customer	CUST07	10	$13,100,417	$0	$0	$13,100,417	$0	$0	$0	$0	$0	$459,772	$0	$0	$11	$0	$0	$2,118
368-TRANSFORMERS - POWER POOL																		
Demand	SICDT	15	$2,865,065	$2,865,065	$0	$0	$0	$0	$0	$15,157	$0	$0	$63	$0	$0	$98	$0	$0
Customer	CUST09	12	$2,549,563	$0	$0	$2,549,563	$0	$0	$0	$0	$0	$88,629	$0	$0	$2	$0	$0	$408
368-TRANSFORMERS - ALL OTHER																		
Demand	SICDT	15	$160,395,756	$160,395,756	$0	$0	$0	$0	$0	$848,515	$0	$0	$3,554	$0	$0	$5,498	$0	$0
Customer	CUST09	12	$142,732,883	$0	$0	$142,732,883	$0	$0	$0	$0	$0	$4,961,715	$0	$0	$118	$0	$0	$22,853
369-SERVICES	C02	20	$97,262,577	$0	$0	$97,262,577	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
370-METERS	C03	21	$82,987,729	$0	$0	$82,987,729	$0	$0	$73,672	$0	$0	$0	$0	$0	$479	$0	$0	$92,926
371-CUSTOMER INSTALLATION	C04	22	$282,792	$0	$0	$282,792	$0	$0	$0	$0	$0	$282,792	$0	$0	$0	$0	$0	$0
373-STREET LIGHTING	C04	22	$114,827,799	$0	$0	$114,827,799	$0	$0	$0	$0	$0	$114,827,799	$0	$0	$0	$0	$0	$0
Total Distribution Plant			$1,731,597,011	$1,130,182,900	$0	$601,414,112	$0	$0	$73,672	$8,622,496	$0	$125,803,342	$36,117	$0	$733	$55,924	$0	$142,175
Total Prod, Trans, and Dist Plant			**$6,689,755,615**	**$6,088,341,503**	**$0**	**$601,414,112**	**$153,503,612**	**$0**	**$73,672**	**$40,988,197**	**$0**	**$125,803,342**	**$157,119**	**$0**	**$733**	**$420,178**	**$0**	**$142,175**
General Plant																		
Total General Plant	PT&D	23	$177,535,196	$161,574,647	$0	$15,960,549	$4,073,735	$0	$1,955	$1,087,760	$0	$3,338,615	$4,170	$0	$19	$11,151	$0	$3,773
TOTAL COMMON PLANT			$0	$0	$0	$0												
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0	$0	$0	$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	Prod	24	$271,089	$271,089	$0	$0	$7,797	$0	$0	$1,720	$0	$0	$6	$0	$0	$21	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	Dist	26	$113,882	$74,329	$0	$39,553	$0	$0	$5	$567	$0	$8,274	$2	$0	$0	$4	$0	$9
OTHER			$0	$0	$0	$0												
Total Plant in Service			$6,970,753,239	$6,344,072,283	$0	$626,680,956	$159,950,366	$0	$76,767	$42,709,800	$0	$131,088,642	$163,718	$0	$764	$437,828	$0	$148,148
Construction Work in Progress (CWIP)																		
CWIP Production	Prod	24	$28,153,069	$28,153,069	$0	$0	$809,682	$0	$0	$178,603	$0	$0	$648	$0	$0	$2,224	$0	$0
CWIP Transmission	Trans	25	$30,190,923	$30,190,923	$0	$0	$1,241,960	$0	$0	$222,747	$0	$0	$933	$0	$0	$1,445	$0	$0
CWIP Distribution Plant	Dist	26	$32,868,652	$21,452,791	$0	$11,415,861	$0	$0	$1,398	$163,670	$0	$2,387,961	$686	$0	$14	$1,062	$0	$2,699
CWIP General Plant	PT&D	23	$27,491,296	$25,019,807	$0	$2,471,488	$630,817	$0	$303	$168,439	$0	$516,984	$646	$0	$3	$1,727	$0	$584
RWIP			$0	$0	$0	$0												
Total Construction Work in Progress			$118,703,941	$104,816,591	$0	$13,887,350	$2,682,460	$0	$1,701	$733,459	$0	$2,904,945	$2,912	$0	$17	$6,457	$0	$3,283
Total Gross Utility Plant			$7,089,457,179	$6,448,888,874	$0	$640,568,305	$162,632,826	$0	$78,469	$43,443,259	$0	$133,993,587	$166,630	$0	$781	$444,286	$0	$151,431

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Accumulated Provision for Depreciation																		
Steam Production	PODRES	53	$1,351,527,013	$1,351,527,013	$0	$0	$455,517,313	$0	$0	$137,039,433	$0	$0	$11,104,146	$0	$0	$161,379,083	$0	$0
Hydraulic Production	PODRES	53	$11,357,150	$11,357,150	$0	$0	$3,827,802	$0	$0	$1,151,570	$0	$0	$93,310	$0	$0	$1,356,100	$0	$0
Other Production	PODRES	53	$279,457,486	$279,457,486	$0	$0	$94,188,072	$0	$0	$28,335,871	$0	$0	$2,296,023	$0	$0	$33,368,621	$0	$0
Transmission - Kentucky System Property	Trans	25	$303,777,627	$303,777,627	$0	$0	$129,208,664	$0	$0	$32,711,772	$0	$0	$3,157,983	$0	$0	$28,838,578	$0	$0
Transmission - Virginia Property	Trans	25	$4,014,978	$4,014,978	$0	$0	$1,707,729	$0	$0	$432,346	$0	$0	$41,739	$0	$0	$381,155	$0	$0
Distribution	Dist	26	$637,170,341	$415,869,870	$0	$221,300,471	$224,336,172	$0	$134,595,078	$51,393,776	$0	$34,418,150	$4,611,470	$0	$367,770	$39,466,447	$0	$3,032,070
General Plant	PT&D	23	$60,263,984	$54,846,206	$0	$5,417,778	$21,208,566	$0	$3,295,096	$5,814,053	$0	$842,610	$497,609	$0	$9,004	$6,102,627	$0	$74,230
Intangible Plant	PT&D	23	$51,974,185	$47,301,667	$0	$4,672,519	$18,291,156	$0	$2,841,829	$5,014,283	$0	$726,702	$429,158	$0	$7,765	$5,263,162	$0	$64,019
Total Accumulated Depreciation			$2,699,542,764	$2,468,151,996	$0	$231,390,768	$948,285,475	$0	$140,732,002	$261,893,104	$0	$35,987,461	$22,231,438	$0	$384,539	$276,155,774	$0	$3,170,319
Net Utility Plant			$4,389,914,415	$3,980,736,877	$0	$409,177,537	$1,548,459,513	$0	$248,862,021	$422,011,046	$0	$63,638,065	$36,337,352	$0	$679,995	$440,782,995	$0	$5,606,201
Working Capital																		
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurch	49	$106,348,560	$24,782,374	$70,863,851	$10,702,334	$10,262,788	$23,823,120	$7,032,130	$2,722,532	$7,102,999	$2,482,257	$238,504	$594,682	$74,192	$2,626,077	$8,369,119	$373,070
Materials and Supplies	TPIS	27	$119,808,344	$109,037,398	$0	$10,770,946	$42,163,802	$0	$6,550,896	$11,558,668	$0	$1,675,171	$989,273	$0	$17,900	$12,132,389	$0	$147,574
Prepayments	TPIS	27	$16,171,254	$14,717,434	$0	$1,453,819	$5,691,102	$0	$884,214	$1,560,143	$0	$226,108	$133,528	$0	$2,416	$1,637,582	$0	$19,919
Total Working Capital			$242,328,157	$148,537,206	$70,863,851	$22,927,100	$58,117,693	$23,823,120	$14,467,239	$15,841,343	$7,102,999	$4,383,536	$1,361,305	$594,682	$94,507	$16,396,048	$8,369,119	$540,563
Emission Allowance			$0	$0	$0	$0												
Deferred Debits																		
Service Pension Cost			$0	$0	$0	$0												
Accumulated Deferred Income Tax																		
Total Production Plant	Prod	24	$511,060,465	$511,060,465	$0	$0	$171,713,250	$0	$0	$51,500,585	$0	$0	$4,205,006	$0	$0	$60,987,912	$0	$0
Total Transmission Plant	Trans	25	$129,909,095	$129,909,095	$0	$0	$55,255,487	$0	$0	$13,989,038	$0	$0	$1,350,497	$0	$0	$12,332,684	$0	$0
Total Distribution Plant	Dist	26	$241,830,055	$157,838,222	$0	$83,991,833	$85,143,996	$0	$51,083,883	$19,505,867	$0	$13,062,979	$1,750,226	$0	$139,583	$14,978,998	$0	$1,150,784
Total General Plant	PT&D	23	$27,628,083	$25,144,297	$0	$2,483,786	$9,723,088	$0	$1,510,640	$2,665,458	$0	$386,295	$228,129	$0	$4,128	$2,797,756	$0	$34,031
Total Accumulated Deferred Income Tax			$910,427,698	$823,952,079	$0	$86,475,619	$321,835,821	$0	$52,594,523	$87,660,948	$0	$13,449,275	$7,533,857	$0	$143,710	$91,097,349	$0	$1,184,815
Accumulated Deferred Investment Tax Credits																		
Production	Prod	24	$81,185,411	$81,185,411	$0	$0	$27,277,811	$0	$0	$8,181,216	$0	$0	$667,994	$0	$0	$9,688,342	$0	$0
Transmission			$0	$0	$0	$0												
Transmission VA			$0	$0	$0	$0												
Distribution VA			$0	$0	$0	$0												
Distribution Plant KY,FERC & TN			$0	$0	$0	$0												
General			$0	$0	$0	$0												
Total Accum. Deferred Investment Tax Credits			$81,185,411	$81,185,411	$0	$0	$27,277,811	$0	$0	$8,181,216	$0	$0	$667,994	$0	$0	$9,688,342	$0	$0
Total Deferred Debits			$991,613,109	$905,137,490	$0	$86,475,619	$349,113,632	$0	$52,594,523	$95,842,164	$0	$13,449,275	$8,201,851	$0	$143,710	$100,785,692	$0	$1,184,815
Less: Customer Advances	DLINES	28	$1,549,704	$1,278,314	$0	$271,389	$670,063	$0	$219,122	$158,833	$0	$42,397	$14,633	$0	$302	$116,546	$0	$0
Less: Asset Retirement Obligations																		
Net Rate Base			$3,639,079,759	$3,222,858,279	$70,863,851	$345,357,629	$1,256,793,511	$23,823,120	$210,515,615	$341,851,392	$7,102,999	$54,529,929	$29,482,173	$594,682	$630,491	$356,276,805	$8,369,119	$4,961,949
Operation and Maintenance Expenses																		
Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	36	$9,442,701	$8,148,507	$1,294,194	$0	$2,737,849	$435,179	$0	$821,141	$129,738	$0	$67,046	$10,865	$0	$972,410	$152,807	$0
501 FUEL	TDFUEL	51	$372,621,659	$0	$372,621,659	$0	$0	$125,295,774	$0	$0	$37,353,925	$0	$0	$3,128,358	$0	$0	$43,995,748	$0
502 STEAM EXPENSES	OM502	47	$15,516,429	$15,516,429	$0	$0	$6,731,627	$0	$0	$1,809,550	$0	$0	$149,355	$0	$0	$1,698,023	$0	$0
505 ELECTRIC EXPENSES	OM505	48	$7,214,388	$7,214,388	$0	$0	$3,129,880	$0	$0	$841,353	$0	$0	$69,443	$0	$0	$789,498	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$14,444,590	$14,444,590	$0	$0	$4,853,296	$0	$0	$1,455,610	$0	$0	$118,850	$0	$0	$1,723,760	$0	$0
507 RENTS				$0	$0	$0												
509 ALLOWANCES				$0	$0	$0												
Total Steam Power Operation Expenses			$419,239,766	$45,323,913	$373,915,853	$0	$17,452,652	$125,730,953	$0	$4,927,655	$37,483,663	$0	$404,693	$3,139,223	$0	$5,183,691	$44,148,554	$0
Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	37	$10,261,750	$989,925	$9,271,825	$0	$332,609	$3,112,719	$0	$99,757	$928,662	$0	$8,145	$77,594	$0	$118,134	$1,096,811	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$5,959,887	$5,959,887	$0	$0	$2,002,486	$0	$0	$600,590	$0	$0	$49,038	$0	$0	$711,229	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$40,186,142	$0	$40,186,142	$0	$0	$13,491,213	$0	$0	$4,025,028	$0	$0	$336,310	$0	$0	$4,753,824	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$8,270,033	$0	$8,270,033	$0	$0	$2,776,399	$0	$0	$828,323	$0	$0	$69,210	$0	$0	$978,304	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$2,439,522	$0	$2,439,522	$0	$0	$818,992	$0	$0	$244,342	$0	$0	$20,416	$0	$0	$288,584	$0
Total Steam Power Generation Maintenance Expense			$67,117,335	$6,949,813	$60,167,522	$0	$2,335,095	$20,199,322	$0	$700,347	$6,026,355	$0	$57,183	$503,530	$0	$829,363	$7,117,523	$0
Total Steam Power Generation Expense			$486,357,101	$52,273,725	$434,083,376	$0	$19,787,747	$145,930,275	$0	$5,628,001	$43,510,018	$0	$461,876	$3,642,753	$0	$6,013,054	$51,266,078	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Accumulated Provision for Depreciation																		
Steam Production	PODRES	53	$1,351,527,013	$1,351,527,013	$0	$0	$12,338,090	$0	$0	$124,114,780	$0	$0	$298,336,073	$0	$0	$104,924,448	$0	$0
Hydraulic Production	PODRES	53	$11,357,150	$11,357,150	$0	$0	$103,679	$0	$0	$1,042,961	$0	$0	$2,506,977	$0	$0	$881,701	$0	$0
Other Production	PODRES	53	$279,457,486	$279,457,486	$0	$0	$2,551,167	$0	$0	$25,663,419	$0	$0	$61,687,445	$0	$0	$21,695,402	$0	$0
Transmission - Kentucky System Property	Trans	25	$303,777,627	$303,777,627	$0	$0	$2,267,901	$0	$0	$22,289,334	$0	$0	$51,641,797	$0	$0	$18,899,959	$0	$0
Transmission - Virginia Property	Trans	25	$4,014,978	$4,014,978	$0	$0	$29,974	$0	$0	$294,594	$0	$0	$682,541	$0	$0	$249,798	$0	$0
Distribution	Dist	26	$637,170,341	$415,869,870	$0	$221,300,471	$2,640,206	$0	$422,679	$30,095,669	$0	$513,925	$60,119,468	$0	$939,139	$0	$0	$640,504
General Plant	PT&D	23	$60,263,984	$54,846,206	$0	$5,417,778	$459,914	$0	$10,348	$4,699,322	$0	$12,582	$10,951,290	$0	$22,992	$3,355,565	$0	$15,681
Intangible Plant	PT&D	23	$51,974,185	$47,301,667	$0	$4,672,519	$396,649	$0	$8,924	$4,052,892	$0	$10,851	$9,444,851	$0	$19,829	$2,893,980	$0	$13,524
Total Accumulated Depreciation			$2,699,542,764	$2,468,151,996	$0	$231,390,768	$20,787,580	$0	$441,951	$212,252,973	$0	$537,358	$495,370,443	$0	$981,960	$152,900,853	$0	$669,708
Net Utility Plant			$4,389,914,415	$3,980,736,877	$0	$409,177,537	$33,239,765	$0	$781,519	$339,821,835	$0	$950,232	$790,830,912	$0	$1,736,438	$240,840,816	$0	$1,184,271
Working Capital																		
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurch	49	$106,348,560	$24,782,374	$70,863,851	$10,702,334	$198,114	$646,537	$38,883	$1,995,416	$6,524,872	$186,505	$4,681,868	$15,672,523	$138,512	$1,316,679	$5,579,084	$51,517
Materials and Supplies	TPIS	27	$119,808,344	$109,037,398	$0	$10,770,946	$914,336	$0	$20,572	$9,342,534	$0	$25,013	$21,771,822	$0	$45,709	$6,671,055	$0	$31,174
Prepayments	TPIS	27	$16,171,254	$14,717,434	$0	$1,453,819	$123,413	$0	$2,777	$1,261,018	$0	$3,376	$2,938,674	$0	$6,170	$900,433	$0	$4,208
Total Working Capital			$242,328,157	$148,537,206	$70,863,851	$22,927,100	$1,235,863	$646,537	$62,232	$12,598,968	$6,524,872	$214,895	$29,392,364	$15,672,523	$190,391	$8,888,167	$5,579,084	$86,899
Emission Allowance			$0	$0	$0	$0												
Deferred Debits																		
Service Pension Cost			$0	$0	$0	$0												
Accumulated Deferred Income Tax																		
Total Production Plant	Prod	24	$511,060,465	$511,060,465	$0	$0	$4,675,692	$0	$0	$47,034,428	$0	$0	$113,130,389	$0	$0	$39,820,809	$0	$0
Total Transmission Plant	Trans	25	$129,909,095	$129,909,095	$0	$0	$969,857	$0	$0	$9,531,930	$0	$0	$22,084,375	$0	$0	$8,082,480	$0	$0
Total Distribution Plant	Dist	26	$241,830,055	$157,838,222	$0	$83,991,833	$1,002,057	$0	$160,422	$11,422,436	$0	$195,054	$22,817,594	$0	$356,439	$0	$0	$243,095
Total General Plant	PT&D	23	$27,628,083	$25,144,297	$0	$2,483,786	$210,848	$0	$4,744	$2,154,409	$0	$5,768	$5,020,630	$0	$10,541	$1,538,362	$0	$7,189
Total Accumulated Deferred Income Tax			$910,427,698	$823,952,079	$0	$86,475,619	$6,858,454	$0	$165,166	$70,143,203	$0	$200,822	$163,052,988	$0	$366,979	$49,441,651	$0	$250,284
Accumulated Deferred Investment Tax Credits																		
Production	Prod	24	$81,185,411	$81,185,411	$0	$0	$742,765	$0	$0	$7,471,737	$0	$0	$17,971,527	$0	$0	$6,325,805	$0	$0
Transmission			$0	$0	$0	$0												
Transmission VA			$0	$0	$0	$0												
Distribution VA			$0	$0	$0	$0												
Distribution Plant KY,FERC & TN			$0	$0	$0	$0												
General			$0	$0	$0	$0												
Total Accum. Deferred Investment Tax Credits			$81,185,411	$81,185,411	$0	$0	$742,765	$0	$0	$7,471,737	$0	$0	$17,971,527	$0	$0	$6,325,805	$0	$0
Total Deferred Debits			$991,613,109	$905,137,490	$0	$86,475,619	$7,601,220	$0	$165,166	$77,614,940	$0	$200,822	$181,024,515	$0	$366,979	$55,767,456	$0	$250,284
Less: Customer Advances	DLINES	28	$1,549,704	$1,278,314	$0	$271,389	$9,165	$0	$0	$90,078	$0	$0	$208,701	$0	$0	$0	$0	$0
Less: Asset Retirement Obligations																		
Net Rate Base			$3,639,079,759	$3,222,858,279	$70,863,851	$345,357,629	$26,865,243	$646,537	$678,585	$274,715,785	$6,524,872	$964,304	$638,990,059	$15,672,523	$1,559,850	$193,961,527	$5,579,084	$1,020,886
Operation and Maintenance Expenses																		
Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	36	$9,442,701	$8,148,507	$1,294,194	$0	$74,551	$11,807	$0	$749,932	$119,161	$0	$1,803,786	$286,186	$0	$634,915	$101,869	$0
501 FUEL	TDFUEL	51	$372,621,659	$0	$372,621,659	$0	$0	$3,399,366	$0	$0	$34,308,577	$0	$0	$82,398,154	$0	$0	$29,329,971	$0
502 STEAM EXPENSES	OM502	47	$15,516,429	$15,516,429	$0	$0	$107,473	$0	$0	$1,136,735	$0	$0	$2,631,054	$0	$0	$909,744	$0	$0
505 ELECTRIC EXPENSES	OM505	48	$7,214,388	$7,214,388	$0	$0	$49,970	$0	$0	$528,527	$0	$0	$1,223,313	$0	$0	$422,987	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$14,444,590	$14,444,590	$0	$0	$132,154	$0	$0	$1,329,379	$0	$0	$3,197,512	$0	$0	$1,125,494	$0	$0
507 RENTS				$0	$0	$0												
509 ALLOWANCES				$0	$0	$0												
Total Steam Power Operation Expenses			$419,239,766	$45,323,913	$373,915,853	$0	$364,146	$3,411,173	$0	$3,744,572	$34,427,738	$0	$8,855,665	$82,684,340	$0	$3,093,140	$29,431,840	$0
Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	37	$10,261,750	$989,925	$9,271,825	$0	$9,057	$84,640	$0	$91,106	$853,871	$0	$219,134	$2,052,532	$0	$77,133	$730,976	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$5,959,887	$5,959,887	$0	$0	$54,527	$0	$0	$548,506	$0	$0	$1,319,304	$0	$0	$464,382	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$40,186,142	$0	$40,186,142	$0	$0	$366,851	$0	$0	$3,700,868	$0	$0	$8,896,129	$0	$0	$3,168,211	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$8,270,033	$0	$8,270,033	$0	$0	$75,495	$0	$0	$761,613	$0	$0	$1,830,762	$0	$0	$651,996	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$2,439,522	$0	$2,439,522	$0	$0	$22,270	$0	$0	$224,663	$0	$0	$540,044	$0	$0	$192,328	$0
Total Steam Power Generation Maintenance Expense			$67,117,335	$6,949,813	$60,167,522	$0	$63,584	$549,256	$0	$639,612	$5,541,016	$0	$1,538,438	$13,319,468	$0	$541,515	$4,743,511	$0
Total Steam Power Generation Expense			$486,357,101	$52,273,725	$434,083,376	$0	$427,730	$3,960,429	$0	$4,384,184	$39,968,755	$0	$10,394,104	$96,003,808	$0	$3,634,655	$34,175,351	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Accumulated Provision for Depreciation																		
Steam Production	PODRES	53	$1,351,527,013	$1,351,527,013	$0	$0	$38,406,343	$0	$0	$8,232,151	$0	$0	$29,734	$0	$0	$105,419	$0	$0
Hydraulic Production	PODRES	53	$11,357,150	$11,357,150	$0	$0	$322,736	$0	$0	$69,176	$0	$0	$250	$0	$0	$886	$0	$0
Other Production	PODRES	53	$279,457,486	$279,457,486	$0	$0	$7,941,343	$0	$0	$1,702,176	$0	$0	$6,148	$0	$0	$21,798	$0	$0
Transmission - Kentucky System Property	Trans	25	$303,777,627	$303,777,627	$0	$0	$12,496,460	$0	$0	$2,241,251	$0	$0	$9,388	$0	$0	$14,539	$0	$0
Transmission - Virginia Property	Trans	25	$4,014,978	$4,014,978	$0	$0	$165,164	$0	$0	$29,622	$0	$0	$124	$0	$0	$192	$0	$0
Distribution	Dist	26	$637,170,341	$415,869,870	$0	$221,300,471	$0	$0	$27,109	$3,172,793	$0	$46,291,463	$13,290	$0	$270	$20,578	$0	$52,316
General Plant	PT&D	23	$60,263,984	$54,846,206	$0	$5,417,778	$1,382,822	$0	$664	$369,238	$0	$1,133,287	$1,415	$0	$7	$3,785	$0	$1,281
Intangible Plant	PT&D	23	$51,974,185	$47,301,667	$0	$4,672,519	$1,192,603	$0	$572	$318,446	$0	$977,394	$1,221	$0	$6	$3,264	$0	$1,105
Total Accumulated Depreciation			$2,699,542,764	$2,468,151,996	$0	$231,390,768	$61,907,472	$0	$28,345	$16,134,854	$0	$48,402,143	$61,569	$0	$282	$170,462	$0	$54,701
Net Utility Plant			$4,389,914,415	$3,980,736,877	$0	$409,177,537	$100,725,354	$0	$50,124	$27,308,405	$0	$85,591,443	$105,061	$0	$499	$273,824	$0	$96,730
Working Capital																		
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurch	49	$106,348,560	$24,782,374	$70,863,851	$10,702,334	$583,442	$2,064,160	$2,437	$154,793	$479,219	$318,818	$610	$1,730	$14	$1,550	$5,806	$4,000
Materials and Supplies	TPIS	27	$119,808,344	$109,037,398	$0	$10,770,946	$2,749,113	$0	$1,319	$734,066	$0	$2,253,058	$2,814	$0	$13	$7,525	$0	$2,546
Prepayments	TPIS	27	$16,171,254	$14,717,434	$0	$1,453,819	$371,064	$0	$178	$99,081	$0	$304,109	$380	$0	$2	$1,016	$0	$344
Total Working Capital			$242,328,157	$148,537,206	$70,863,851	$22,927,100	$3,703,620	$2,064,160	$3,934	$987,940	$479,219	$2,875,985	$3,804	$1,730	$29	$10,091	$5,806	$6,890
Emission Allowance			$0	$0	$0	$0												
Deferred Debits																		
Service Pension Cost			$0	$0	$0	$0												
Accumulated Deferred Income Tax																		
Total Production Plant	Prod	24	$511,060,465	$511,060,465	$0	$0	$14,698,099	$0	$0	$3,242,168	$0	$0	$11,754	$0	$0	$40,374	$0	$0
Total Transmission Plant	Trans	25	$129,909,095	$129,909,095	$0	$0	$5,344,053	$0	$0	$958,461	$0	$0	$4,015	$0	$0	$6,218	$0	$0
Total Distribution Plant	Dist	26	$241,830,055	$157,838,222	$0	$83,991,833	$0	$0	$10,289	$1,204,194	$0	$17,569,347	$5,044	$0	$102	$7,810	$0	$19,856
Total General Plant	PT&D	23	$27,628,083	$25,144,297	$0	$2,483,786	$633,956	$0	$304	$169,278	$0	$519,556	$649	$0	$3	$1,735	$0	$587
Total Accumulated Deferred Income Tax			$910,427,698	$823,952,079	$0	$86,475,619	$20,676,108	$0	$10,593	$5,574,100	$0	$18,088,904	$21,462	$0	$105	$56,137	$0	$20,443
Accumulated Deferred Investment Tax Credits																		
Production	Prod	24	$81,185,411	$81,185,411	$0	$0	$2,334,892	$0	$0	$515,040	$0	$0	$1,867	$0	$0	$6,414	$0	$0
Transmission			$0	$0	$0	$0												
Transmission VA			$0	$0	$0	$0												
Distribution VA			$0	$0	$0	$0												
Distribution Plant KY,FERC & TN			$0	$0	$0	$0												
General			$0	$0	$0	$0												
Total Accum. Deferred Investment Tax Credits			$81,185,411	$81,185,411	$0	$0	$2,334,892	$0	$0	$515,040	$0	$0	$1,867	$0	$0	$6,414	$0	$0
Total Deferred Debits			$991,613,109	$905,137,490	$0	$86,475,619	$23,011,001	$0	$10,593	$6,089,140	$0	$18,088,904	$23,329	$0	$105	$62,551	$0	$20,443
Less: Customer Advances	DLINES	28	$1,549,704	$1,278,314	$0	$271,389	$0	$0	$0	$10,185	$0	$9,525	$43	$0	$0	$66	$0	$44
Less: Asset Retirement Obligations																		
Net Rate Base			$3,639,079,759	$3,222,858,279	$70,863,851	$345,357,629	$81,417,973	$2,064,160	$43,465	$22,197,020	$479,219	$70,369,000	$85,493	$1,730	$422	$221,298	$5,806	$83,133
Operation and Maintenance Expenses																		
Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	36	$9,442,701	$8,148,507	$1,294,194	$0	$234,351	$37,703	$0	$51,694	$8,742	$0	$187	$32	$0	$644	$106	$0
501 FUEL	TDFUEL	51	$372,621,659	$0	$372,621,659	$0	$0	$10,855,301	$0	$0	$2,516,881	$0	$0	$9,086	$0	$0	$30,519	$0
502 STEAM EXPENSES	OM502	47	$15,516,429	$15,516,429	$0	$0	$342,049	$0	$0	$0	$0	$0	$0	$0	$0	$820	$0	$0
505 ELECTRIC EXPENSES	OM505	48	$7,214,388	$7,214,388	$0	$0	$159,036	$0	$0	$0	$0	$0	$0	$0	$0	$381	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$14,444,590	$14,444,590	$0	$0	$415,426	$0	$0	$91,636	$0	$0	$332	$0	$0	$1,141	$0	$0
507 RENTS				$0	$0	$0												
509 ALLOWANCES				$0	$0	$0												
Total Steam Power Operation Expenses			$419,239,766	$45,323,913	$373,915,853	$0	$1,150,862	$10,893,003	$0	$143,331	$2,525,623	$0	$520	$9,117	$0	$2,986	$30,625	$0
Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	37	$10,261,750	$989,925	$9,271,825	$0	$28,470	$269,857	$0	$6,280	$63,172	$0	$23	$228	$0	$78	$761	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$5,959,887	$5,959,887	$0	$0	$171,406	$0	$0	$37,810	$0	$0	$137	$0	$0	$471	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$40,186,142	$0	$40,186,142	$0	$0	$1,169,622	$0	$0	$273,800	$0	$0	$989	$0	$0	$3,298	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$8,270,033	$0	$8,270,033	$0	$0	$240,700	$0	$0	$56,346	$0	$0	$204	$0	$0	$679	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$2,439,522	$0	$2,439,522	$0	$0	$71,003	$0	$0	$16,621	$0	$0	$60	$0	$0	$200	$0
Total Steam Power Generation Maintenance Expense			$67,117,335	$6,949,813	$60,167,522	$0	$199,877	$1,751,182	$0	$44,090	$409,939	$0	$160	$1,481	$0	$549	$4,938	$0
Total Steam Power Generation Expense			$486,357,101	$52,273,725	$434,083,376	$0	$1,350,739	$12,644,186	$0	$187,420	$2,935,562	$0	$679	$10,599	$0	$3,535	$35,563	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING			$0	$0	$0	$0												
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES			$0	$0	$0	$0												
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$8,523	$8,523	$0	$0	$2,864	$0	$0	$859	$0	$0	$70	$0	$0	$1,017	$0	$0
540 RENTS				$0	$0	$0												
Total Hydraulic Power Operation Expenses			$8,523	$8,523	$0	$0	$2,864	$0	$0 $0	$859	$0	$0 $0	$70	$0	$0	$1,017	$0	$0
Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	38	$186,494	$186,494	$0	$0	$62,661	$0	$0	$18,793	$0	$0	$1,534	$0	$0	$22,255	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$116,901	$116,901	$0	$0	$39,278	$0	$0	$11,780	$0	$0	$962	$0	$0	$13,950	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$22,497	$22,497	$0	$0	$7,559	$0	$0	$2,267	$0	$0	$185	$0	$0	$2,685	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$33,030	$0	$33,030	$0	$0	$11,089	$0	$0	$3,308	$0	$0	$276	$0	$0	$3,907	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Energy	2	$9,592	$0	$9,592	$0	$0	$3,220	$0	$0	$961	$0	$0	$80	$0	$0	$1,135	$0
Total Hydraulic Power Generation Maint. Expense			$368,513	$325,892	$42,622	$0	$109,498	$14,309	$0 $0	$32,841	$4,269	$0 $0	$2,681	$357	$0	$38,891	$5,042	$0
Total Hydraulic Power Generation Expense			$377,036	$334,414	$42,622	$0	$112,361	$14,309	$0 $0	$33,700	$4,269	$0 $0	$2,752	$357	$0	$39,908	$5,042	$0
Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	39	$1,071,395	$1,071,395	$0	$0	$359,982	$0	$0	$107,967	$0	$0	$8,815	$0	$0	$127,856	$0	$0
547 FUEL	TDFUEL	51	$130,769,641	$0	$130,769,641	$0	$0	$43,971,903	$0	$0	$13,109,166	$0	$0	$1,097,881	$0	$0	$15,440,080	$0
548 GENERATION EXPENSE	Prod	24	$611,306	$611,306	$0	$0	$205,395	$0	$0	$61,603	$0	$0	$5,030	$0	$0	$72,951	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$3,639,052	$3,639,052	$0	$0	$1,222,700	$0	$0	$366,715	$0	$0	$29,942	$0	$0	$434,270	$0	$0
550 RENTS	Prod	24	$4,421	$4,421	$0	$0	$1,485	$0	$0	$445	$0	$0	$36	$0	$0	$528	$0	$0
Total Other Power Generation Expenses			$136,095,816	$5,326,175	$130,769,641	$0	$1,789,563	$43,971,903	$0 $0	$536,729	$13,109,166	$0 $0	$43,824	$1,097,881	$0	$635,604	$15,440,080	$0
Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$257,199	$257,199	$0	$0	$86,417	$0	$0	$25,918	$0	$0	$2,116	$0	$0	$30,693	$0	$0
552 MAINTENANCE OF STRUCTURES	Prod	24	$1,680,721	$1,680,721	$0	$0	$564,712	$0	$0	$169,370	$0	$0	$13,829	$0	$0	$200,571	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$4,895,395	$4,895,395	$0	$0	$1,644,823	$0	$0	$493,319	$0	$0	$40,279	$0	$0	$584,197	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$5,139,215	$5,139,215	$0	$0	$1,726,745	$0	$0	$517,889	$0	$0	$42,285	$0	$0	$613,293	$0	$0
Total Other Power Generation Maintenance Expense			$11,972,530	$11,972,530	$0	$0	$4,022,698	$0	$0 $0	$1,206,496	$0	$0 $0	$98,510	$0	$0	$1,428,754	$0	$0
Total Other Power Generation Expense			$148,068,346	$17,298,705	$130,769,641	$0	$5,812,261	$43,971,903	$0 $0	$1,743,225	$13,109,166	$0 $0	$142,334	$1,097,881	$0	$2,064,358	$15,440,080	$0
Total Station Expense			$634,802,484	$69,906,845	$564,895,639	$0	$25,712,370	$189,916,487	$0 $0	$7,404,926	$56,623,453	$0 $0	$606,962	$4,740,991	$0	$8,117,320	$66,711,200	$0
Other Power Supply Expenses																		
555 PURCHASED POWER	PURCPWR	46	$50,619,307	$7,292,915	$43,326,391	$0	$3,163,949	$14,545,451	$0	$850,511	$4,339,554	$0	$70,199	$362,590	$0	$798,092	$5,125,300	$0
555 PURCHASED POWER OPTIONS			$0	$0	$0	$0												
555 BROKERAGE FEES			$0	$0	$0	$0												
555 MISO TRANSMISSION EXPENSES			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,864,717	$1,864,717	$0	$0	$626,534	$0	$0	$187,911	$0	$0	$15,343	$0	$0	$222,528	$0	$0
557 OTHER EXPENSES	Prod	24	$10,369	$10,369	$0	$0	$3,484	$0	$0	$1,045	$0	$0	$85	$0	$0	$1,237	$0	$0
Total Other Power Supply Expenses			$52,494,393	$9,168,002	$43,326,391	$0	$3,793,966	$14,545,451	$0 $0	$1,039,467	$4,339,554	$0 $0	$85,627	$362,590	$0	$1,021,857	$5,125,300	$0
Total Electric Power Generation Expenses			$687,296,876	$79,074,846	$608,222,030	$0	$29,506,336	$204,461,938	$0 $0	$8,444,393	$60,963,007	$0 $0	$692,588	$5,103,581	$0	$9,139,177	$71,836,500	$0
Transmission Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,804,305	$1,804,305	$0	$0	$767,442	$0	$0	$194,293	$0	$0	$18,757	$0	$0	$171,288	$0	$0
561 LOAD DISPATCHING	Trans	25	$3,644,052	$3,644,052	$0	$0	$1,549,960	$0	$0	$392,403	$0	$0	$37,882	$0	$0	$345,941	$0	$0
562 STATION EXPENSES	Trans	25	$1,303,298	$1,303,298	$0	$0	$554,344	$0	$0	$140,343	$0	$0	$13,549	$0	$0	$123,726	$0	$0
563 OVERHEAD LINE EXPENSES	Trans	25	$1,058,993	$1,058,993	$0	$0	$450,432	$0	$0	$114,036	$0	$0	$11,009	$0	$0	$100,534	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Trans	25	$2,940,449	$2,940,449	$0	$0	$1,250,690	$0	$0	$316,637	$0	$0	$30,568	$0	$0	$279,146	$0	$0
566 MISC. TRANSMISSION EXPENSES	Trans	25	$11,948,572	$11,948,572	$0	$0	$5,082,201	$0	$0	$1,286,661	$0	$0	$124,214	$0	$0	$1,134,316	$0	$0
567 RENTS	Trans	25	$112,005	$112,005	$0	$0	$47,640	$0	$0	$12,061	$0	$0	$1,164	$0	$0	$10,633	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
569 STRUCTURES			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$1,986,407	$1,986,407	$0	$0	$844,898	$0	$0	$213,903	$0	$0	$20,650	$0	$0	$188,576	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$10,570,832	$10,570,832	$0	$0	$4,496,194	$0	$0	$1,138,302	$0	$0	$109,891	$0	$0	$1,003,523	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT	Trans	25	$337,099	$337,099	$0	$0	$143,382	$0	$0	$36,300	$0	$0	$3,504	$0	$0	$32,002	$0	$0
575 MISO DAY 1&2 EXPENSE			$0	$0	$0	$0												
Total Transmission Expenses			$35,706,011	$35,706,011	$0	$0	$15,187,182	$0	$0 $0	$3,844,941	$0	$0 $0	$371,189	$0	$0	$3,389,685	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING			$0	$0	$0	$0												
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES			$0	$0	$0	$0												
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$8,523	$8,523	$0	$0	$78	$0	$0	$784	$0	$0	$1,887	$0	$0	$664	$0	$0
540 RENTS				$0	$0	$0												
Total Hydraulic Power Operation Expenses			$8,523	$8,523	$0	$0	$78	$0	$0	$784	$0	$0	$1,887	$0	$0	$664	$0	$0
Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	38	$186,494	$186,494	$0	$0	$1,706	$0	$0	$17,164	$0	$0	$41,283	$0	$0	$14,531	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$116,901	$116,901	$0	$0	$1,070	$0	$0	$10,759	$0	$0	$25,878	$0	$0	$9,109	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$22,497	$22,497	$0	$0	$206	$0	$0	$2,070	$0	$0	$4,980	$0	$0	$1,753	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$33,030	$0	$33,030	$0	$0	$302	$0	$0	$3,042	$0	$0	$7,312	$0	$0	$2,604	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Energy	2	$9,592	$0	$9,592	$0	$0	$88	$0	$0	$883	$0	$0	$2,123	$0	$0	$756	$0
Total Hydraulic Power Generation Maint. Expense			$368,513	$325,892	$42,622	$0	$2,982	$389	$0	$29,993	$3,925	$0	$72,141	$9,435	$0	$25,393	$3,360	$0
Total Hydraulic Power Generation Expense			$377,036	$334,414	$42,622	$0	$3,060	$389	$0	$30,777	$3,925	$0	$74,027	$9,435	$0	$26,057	$3,360	$0
Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	39	$1,071,395	$1,071,395	$0	$0	$9,802	$0	$0	$98,604	$0	$0	$237,168	$0	$0	$83,481	$0	$0
547 FUEL	TDFUEL	51	$130,769,641	$0	$130,769,641	$0	$0	$1,192,990	$0	$0	$12,040,417	$0	$0	$28,917,205	$0	$0	$10,293,201	$0
548 GENERATION EXPENSE	Prod	24	$611,306	$611,306	$0	$0	$5,593	$0	$0	$56,260	$0	$0	$135,321	$0	$0	$47,632	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$3,639,052	$3,639,052	$0	$0	$33,294	$0	$0	$334,913	$0	$0	$805,555	$0	$0	$283,548	$0	$0
550 RENTS	Prod	24	$4,421	$4,421	$0	$0	$40	$0	$0	$407	$0	$0	$979	$0	$0	$344	$0	$0
Total Other Power Generation Expenses			$136,095,816	$5,326,175	$130,769,641	$0	$48,729	$1,192,990	$0	$490,184	$12,040,417	$0	$1,179,023	$28,917,205	$0	$415,005	$10,293,201	$0
Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$257,199	$257,199	$0	$0	$2,353	$0	$0	$23,671	$0	$0	$56,935	$0	$0	$20,040	$0	$0
552 MAINTENANCE OF STRUCTURES	Prod	24	$1,680,721	$1,680,721	$0	$0	$15,377	$0	$0	$154,682	$0	$0	$372,051	$0	$0	$130,958	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$4,895,395	$4,895,395	$0	$0	$44,788	$0	$0	$450,538	$0	$0	$1,083,664	$0	$0	$381,439	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$5,139,215	$5,139,215	$0	$0	$47,019	$0	$0	$472,977	$0	$0	$1,137,637	$0	$0	$400,437	$0	$0
Total Other Power Generation Maintenance Expense			$11,972,530	$11,972,530	$0	$0	$109,537	$0	$0	$1,101,868	$0	$0	$2,650,287	$0	$0	$932,876	$0	$0
Total Other Power Generation Expense			$148,068,346	$17,298,705	$130,769,641	$0	$158,266	$1,192,990	$0	$1,592,052	$12,040,417	$0	$3,829,311	$28,917,205	$0	$1,347,880	$10,293,201	$0
Total Station Expense			$634,802,484	$69,906,845	$564,895,639	$0	$589,056	$5,153,809	$0	$6,007,013	$52,013,097	$0	$14,297,442	$124,930,449	$0	$5,008,592	$44,471,912	$0
Other Power Supply Expenses																		
555 PURCHASED POWER	PURCPWR	46	$50,619,307	$7,292,915	$43,326,391	$0	$50,513	$395,517	$0	$534,280	$3,990,064	$0	$1,236,628	$9,591,295	$0	$427,591	$3,415,783	$0
555 PURCHASED POWER OPTIONS			$0	$0	$0	$0												
555 BROKERAGE FEES			$0	$0	$0	$0												
555 MISO TRANSMISSION EXPENSES			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,864,717	$1,864,717	$0	$0	$17,060	$0	$0	$171,616	$0	$0	$412,781	$0	$0	$145,295	$0	$0
557 OTHER EXPENSES	Prod	24	$10,369	$10,369	$0	$0	$95	$0	$0	$954	$0	$0	$2,295	$0	$0	$808	$0	$0
Total Other Power Supply Expenses			$52,494,393	$9,168,002	$43,326,391	$0	$67,669	$395,517	$0	$706,850	$3,990,064	$0	$1,651,705	$9,591,295	$0	$573,694	$3,415,783	$0
Total Electric Power Generation Expenses			$687,296,876	$79,074,846	$608,222,030	$0	$656,724	$5,549,326	$0	$6,713,863	$56,003,161	$0	$15,949,146	$134,521,744	$0	$5,582,286	$47,887,696	$0
Transmission Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,804,305	$1,804,305	$0	$0	$13,470	$0	$0	$132,389	$0	$0	$306,729	$0	$0	$112,257	$0	$0
561 LOAD DISPATCHING	Trans	25	$3,644,052	$3,644,052	$0	$0	$27,205	$0	$0	$267,378	$0	$0	$619,484	$0	$0	$226,720	$0	$0
562 STATION EXPENSES	Trans	25	$1,303,298	$1,303,298	$0	$0	$9,730	$0	$0	$95,628	$0	$0	$221,559	$0	$0	$81,087	$0	$0
563 OVERHEAD LINE EXPENSES	Trans	25	$1,058,993	$1,058,993	$0	$0	$7,906	$0	$0	$77,702	$0	$0	$180,027	$0	$0	$65,887	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Trans	25	$2,940,449	$2,940,449	$0	$0	$21,952	$0	$0	$215,752	$0	$0	$499,873	$0	$0	$182,944	$0	$0
566 MISC. TRANSMISSION EXPENSES	Trans	25	$11,948,572	$11,948,572	$0	$0	$89,204	$0	$0	$876,713	$0	$0	$2,031,241	$0	$0	$743,397	$0	$0
567 RENTS	Trans	25	$112,005	$112,005	$0	$0	$836	$0	$0	$8,218	$0	$0	$19,041	$0	$0	$6,969	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
569 STRUCTURES			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$1,986,407	$1,986,407	$0	$0	$14,830	$0	$0	$145,750	$0	$0	$337,687	$0	$0	$123,587	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$10,570,832	$10,570,832	$0	$0	$78,918	$0	$0	$775,623	$0	$0	$1,797,027	$0	$0	$657,679	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT	Trans	25	$337,099	$337,099	$0	$0	$2,517	$0	$0	$24,734	$0	$0	$57,306	$0	$0	$20,973	$0	$0
575 MISO DAY 1&2 EXPENSE			$0	$0	$0	$0												
Total Transmission Expenses			$35,706,011	$35,706,011	$0	$0	$266,569	$0	$0	$2,619,888	$0	$0	$6,069,975	$0	$0	$2,221,500	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING			$0	$0	$0	$0												
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES			$0	$0	$0	$0												
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$8,523	$8,523	$0	$0	$245	$0	$0	$54	$0	$0	$0	$0	$0	$1	$0	$0
540 RENTS				$0	$0	$0												
Total Hydraulic Power Operation Expenses			$8,523	$8,523	$0	$0	$245	$0	$0	$54	$0	$0	$0	$0	$0	$1	$0	$0
Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	38	$186,494	$186,494	$0	$0	$5,364	$0	$0	$1,183	$0	$0	$4	$0	$0	$15	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$116,901	$116,901	$0	$0	$3,362	$0	$0	$742	$0	$0	$3	$0	$0	$9	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$22,497	$22,497	$0	$0	$647	$0	$0	$143	$0	$0	$1	$0	$0	$2	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$33,030	$0	$33,030	$0	$0	$961	$0	$0	$225	$0	$0	$1	$0	$0	$3	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Energy	2	$9,592	$0	$9,592	$0	$0	$279	$0	$0	$65	$0	$0	$0	$0	$0	$1	$0
Total Hydraulic Power Generation Maint. Expense			$368,513	$325,892	$42,622	$0	$9,373	$1,241	$0	$2,067	$290	$0	$7	$1	$0	$26	$3	$0
Total Hydraulic Power Generation Expense			$377,036	$334,414	$42,622	$0	$9,618	$1,241	$0	$2,122	$290	$0	$8	$1	$0	$26	$3	$0
Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	39	$1,071,395	$1,071,395	$0	$0	$30,813	$0	$0	$6,797	$0	$0	$25	$0	$0	$85	$0	$0
547 FUEL	TDFUEL	51	$130,769,641	$0	$130,769,641	$0	$0	$3,809,612	$0	$0	$883,286	$0	$0	$3,189	$0	$0	$10,711	$0
548 GENERATION EXPENSE	Prod	24	$611,306	$611,306	$0	$0	$17,581	$0	$0	$3,878	$0	$0	$14	$0	$0	$48	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$3,639,052	$3,639,052	$0	$0	$104,659	$0	$0	$23,086	$0	$0	$84	$0	$0	$287	$0	$0
550 RENTS	Prod	24	$4,421	$4,421	$0	$0	$127	$0	$0	$28	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Generation Expenses			$136,095,816	$5,326,175	$130,769,641	$0	$153,181	$3,809,612	$0	$33,789	$883,286	$0	$123	$3,189	$0	$421	$10,711	$0
Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$257,199	$257,199	$0	$0	$7,397	$0	$0	$1,632	$0	$0	$6	$0	$0	$20	$0	$0
552 MAINTENANCE OF STRUCTURES	Prod	24	$1,680,721	$1,680,721	$0	$0	$48,338	$0	$0	$10,662	$0	$0	$39	$0	$0	$133	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$4,895,395	$4,895,395	$0	$0	$140,792	$0	$0	$31,056	$0	$0	$113	$0	$0	$387	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$5,139,215	$5,139,215	$0	$0	$147,804	$0	$0	$32,603	$0	$0	$118	$0	$0	$406	$0	$0
Total Other Power Generation Maintenance Expense			$11,972,530	$11,972,530	$0	$0	$344,330	$0	$0	$75,954	$0	$0	$275	$0	$0	$946	$0	$0
Total Other Power Generation Expense			$148,068,346	$17,298,705	$130,769,641	$0	$497,511	$3,809,612	$0	$109,743	$883,286	$0	$398	$3,189	$0	$1,367	$10,711	$0
Total Station Expense			$634,802,484	$69,906,845	$564,895,639	$0	$1,857,867	$16,455,038	$0	$299,285	$3,819,139	$0	$1,085	$13,788	$0	$4,928	$46,277	$0
Other Power Supply Expenses																		
555 PURCHASED POWER	PURCPWR	46	$50,619,307	$7,292,915	$43,326,391	$0	$160,767	$1,261,019	$0	$0	$295,195	$0	$0	$1,067	$0	$385	$3,556	$0
555 PURCHASED POWER OPTIONS			$0	$0	$0	$0												
555 BROKERAGE FEES			$0	$0	$0	$0												
555 MISO TRANSMISSION EXPENSES			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,864,717	$1,864,717	$0	$0	$53,629	$0	$0	$11,830	$0	$0	$43	$0	$0	$147	$0	$0
557 OTHER EXPENSES	Prod	24	$10,369	$10,369	$0	$0	$298	$0	$0	$66	$0	$0	$0	$0	$0	$1	$0	$0
Total Other Power Supply Expenses			$52,494,393	$9,168,002	$43,326,391	$0	$214,695	$1,261,019	$0	$11,896	$295,195	$0	$43	$1,067	$0	$533	$3,556	$0
Total Electric Power Generation Expenses			$687,296,876	$79,074,846	$608,222,030	$0	$2,072,562	$17,716,057	$0	$311,180	$4,114,334	$0	$1,128	$14,855	$0	$5,461	$49,833	$0
Transmission Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,804,305	$1,804,305	$0	$0	$74,223	$0	$0	$13,312	$0	$0	$56	$0	$0	$86	$0	$0
561 LOAD DISPATCHING	Trans	25	$3,644,052	$3,644,052	$0	$0	$149,905	$0	$0	$26,886	$0	$0	$113	$0	$0	$174	$0	$0
562 STATION EXPENSES	Trans	25	$1,303,298	$1,303,298	$0	$0	$53,614	$0	$0	$9,616	$0	$0	$40	$0	$0	$62	$0	$0
563 OVERHEAD LINE EXPENSES	Trans	25	$1,058,993	$1,058,993	$0	$0	$43,564	$0	$0	$7,813	$0	$0	$33	$0	$0	$51	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Trans	25	$2,940,449	$2,940,449	$0	$0	$120,961	$0	$0	$21,694	$0	$0	$91	$0	$0	$141	$0	$0
566 MISC. TRANSMISSION EXPENSES	Trans	25	$11,948,572	$11,948,572	$0	$0	$491,527	$0	$0	$88,156	$0	$0	$369	$0	$0	$572	$0	$0
567 RENTS	Trans	25	$112,005	$112,005	$0	$0	$4,608	$0	$0	$826	$0	$0	$3	$0	$0	$5	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
569 STRUCTURES			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$1,986,407	$1,986,407	$0	$0	$81,715	$0	$0	$14,656	$0	$0	$61	$0	$0	$95	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$10,570,832	$10,570,832	$0	$0	$434,851	$0	$0	$77,991	$0	$0	$327	$0	$0	$506	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT	Trans	25	$337,099	$337,099	$0	$0	$13,867	$0	$0	$2,487	$0	$0	$10	$0	$0	$16	$0	$0
575 MISO DAY 1&2 EXPENSE			$0	$0	$0	$0												
Total Transmission Expenses			$35,706,011	$35,706,011	$0	$0	$1,468,834	$0	$0	$263,437	$0	$0	$1,103	$0	$0	$1,709	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense																		
580 OPERATION SUPERVISION AND ENGI	LBDO	40	$1,510,424	$621,285	$0	$889,139	$325,363	$0	$560,784	$76,656	$0	$191,127	$7,030	$0	$3,704	$58,913	$0	$45,498
581 LOAD DISPATCHING	Acct362	29	$341,053	$341,053	$0	$0	$161,784	$0	$0	$40,959	$0	$0	$3,954	$0	$0	$36,109	$0	$0
582 STATION EXPENSES	Acct362	29	$1,798,545	$1,798,545	$0	$0	$853,171	$0	$0	$215,997	$0	$0	$20,852	$0	$0	$190,422	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$4,706,317	$3,737,182	$0	$969,134	$2,012,446	$0	$782,488	$468,816	$0	$151,398	$42,623	$0	$1,077	$324,932	$0	$0
584 UNDERGROUND LINE EXPENSES			$0	$0	$0	$0												
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$8,749,183	$0	$0	$8,749,183	$0	$0	$5,437,289	$0	$0	$2,026,465	$0	$0	$42,985	$0	$0	$549,273
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE	C04	22	-$142,800	$0	$0	-$142,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$6,743,173	$4,401,150	$0	$2,342,023	$2,374,149	$0	$1,424,420	$543,900	$0	$364,247	$48,803	$0	$3,892	$417,673	$0	$32,088
588 MISC DISTR EXP -- MAPPIN			$0	$0	$0	$0												
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Expense			$23,705,895	$10,899,216	$0	$12,806,679	$5,726,913	$0	$8,204,981	$1,346,329	$0	$2,733,238	$123,263	$0	$51,658	$1,028,050	$0	$626,859
Distribution Maintenance Expense																		
590 MAINTENANCE SUPERVISION AND ENG	LBDM	41	$57,449	$46,964	$0	$10,485	$24,838	$0	$8,464	$5,851	$0	$1,638	$536	$0	$12	$4,229	$0	$2
591 STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$1,286,692	$1,286,692	$0	$0	$610,364	$0	$0	$154,526	$0	$0	$14,918	$0	$0	$136,230	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$30,239,215	$24,012,295	$0	$6,226,920	$12,930,446	$0	$5,027,675	$3,012,256	$0	$972,771	$273,864	$0	$6,923	$2,087,764	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$790,500	$738,959	$0	$51,541	$355,272	$0	$41,615	$89,141	$0	$8,052	$8,554	$0	$57	$76,840	$0	$0
595 MAINTENANCE OF LINE TRANSFORMERS	Acct368	32	$96,331	$50,972	$0	$45,359	$35,364	$0	$36,275	$6,369	$0	$7,019	$447	$0	$50	$5,001	$0	$379
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0	$0	$0	$0												
597 MAINTENANCE OF METERS	C03	21	$1,371,953	$0	$0	$1,371,953	$0	$0	$852,618	$0	$0	$317,769	$0	$0	$6,740	$0	$0	$86,131
598 MISCELLANEOUS DISTRIBUTION EXPENSES	Dist	26	$550,314	$359,180	$0	$191,134	$193,756	$0	$116,248	$44,388	$0	$29,726	$3,983	$0	$318	$34,087	$0	$2,619
Total Distribution Maintenance Expense			$34,392,454	$26,495,062	$0	$7,897,392	$14,150,040	$0	$6,082,894	$3,312,531	$0	$1,336,974	$302,302	$0	$14,100	$2,344,150	$0	$89,131
Total Distribution Expense			$58,098,349	$37,394,279	$0	$20,704,070	$19,876,953	$0	$14,287,875	$4,658,859	$0	$4,070,213	$425,565	$0	$65,758	$3,372,200	$0	$715,990
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$3,631,554	$0	$0	$3,631,554	$0	$0	$2,339,692	$0	$0	$905,383	$0	$0	$32,215	$0	$0	$122,315
902 METER READING EXPENSES	MREAD	50	$5,301,482	$0	$0	$5,301,482	$0	$0	$3,511,773	$0	$0	$1,358,939	$0	$0	$48,354	$0	$0	$183,589
903 RECORDS AND COLLECTION	C05	33	$20,167,471	$0	$0	$20,167,471	$0	$0	$12,993,246	$0	$0	$5,027,952	$0	$0	$178,904	$0	$0	$679,261
904 UNCOLLECTIBLE ACCOUNTS	C05	33	$5,566,157	$0	$0	$5,566,157	$0	$0	$3,586,094	$0	$0	$1,387,699	$0	$0	$49,377	$0	$0	$187,474
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Expense			$34,666,664	$0	$0	$34,666,664	$0	$0	$22,430,805	$0	$0	$8,679,972	$0	$0	$308,849	$0	$0	$1,172,638
Customer Service Expense																		
907 SUPERVISION	C05	33	$651,425	$0	$0	$651,425	$0	$0	$419,692	$0	$0	$162,407	$0	$0	$5,779	$0	$0	$21,941
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$450,051	$0	$0	$450,051	$0	$0	$289,953	$0	$0	$112,202	$0	$0	$3,992	$0	$0	$15,158
908 CUSTOMER ASSISTANCE EXP-INCENTIVES			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA	C05	33	$389,845	$0	$0	$389,845	$0	$0	$251,164	$0	$0	$97,192	$0	$0	$3,458	$0	$0	$13,130
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE	C05	33	$1,861,027	$0	$0	$1,861,027	$0	$0	$1,198,999	$0	$0	$463,973	$0	$0	$16,509	$0	$0	$62,681
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 ADVERTISING EXPENSES	C05	33	$794,217	$0	$0	$794,217	$0	$0	$511,688	$0	$0	$198,006	$0	$0	$7,045	$0	$0	$26,750
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Expense			$4,146,565	$0	$0	$4,146,565	$0	$0	$2,671,497	$0	$0	$1,033,780	$0	$0	$36,784	$0	$0	$139,661
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$33,809,232	$16,862,756	$7,680,251	$9,266,225	$6,605,090	$2,579,032	$6,010,631	$1,804,838	$769,353	$2,178,329	$155,829	$64,306	$66,183	$1,852,563	$908,271	$344,371
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	35	$7,269,104	$3,625,552	$1,651,281	$1,992,271	$1,420,118	$554,501	$1,292,307	$388,046	$165,414	$468,348	$33,504	$13,826	$14,230	$398,307	$195,282	$74,041
922 ADMINISTRATIVE EXPENSES TRANSFERRED	LBSUB7	35	-$4,414,266	-$2,201,667	-$1,002,764	-$1,209,835	-$862,386	-$336,729	-$784,772	-$235,647	-$100,450	-$284,411	-$20,346	-$8,396	-$8,641	-$241,878	-$118,587	-$44,962
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	35	$19,133,213	$9,542,917	$4,346,383	$5,243,912	$3,737,931	$1,459,518	$3,401,517	$1,021,388	$435,390	$1,232,753	$88,186	$36,392	$37,454	$1,048,396	$514,006	$194,885
924 PROPERTY INSURANCE	TUP	34	$5,543,869	$5,042,952	$0	$500,917	$1,952,424	$0	$304,658	$534,805	$0	$77,906	$45,800	$0	$832	$560,637	$0	$6,863
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$3,904,092	$1,947,213	$886,870	$1,070,009	$762,717	$297,812	$694,073	$208,412	$88,840	$251,541	$17,994	$7,426	$7,642	$213,923	$104,882	$39,766
926 EMPLOYEE BENEFITS	LBSUB7	35	$38,912,106	$19,407,875	$8,839,442	$10,664,789	$7,602,005	$2,968,289	$6,917,824	$2,077,245	$885,473	$2,507,108	$179,348	$74,012	$76,173	$2,132,172	$1,045,358	$396,348
928 REGULATORY COMMISSION FEES	TUP	34	$1,800,307	$1,637,640	$0	$162,667	$634,027	$0	$98,934	$173,672	$0	$25,299	$14,873	$0	$270	$182,060	$0	$2,229
929 DUPLICATE CHARGES			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	35	$5,197,262	$2,592,196	$1,180,632	$1,424,433	$1,015,355	$396,457	$923,973	$277,445	$118,267	$334,860	$23,955	$9,885	$10,174	$284,782	$139,622	$52,938
931 RENTS AND LEASES	PT&D	23	$1,831,134	$1,666,513	$0	$164,620	$644,427	$0	$100,122	$176,661	$0	$25,603	$15,120	$0	$274	$185,430	$0	$2,255
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$873,720	$795,172	$0	$78,548	$307,486	$0	$47,773	$84,293	$0	$12,216	$7,214	$0	$131	$88,477	$0	$1,076
Total Administrative and General Expense			$113,859,773	$60,919,119	$23,582,096	$29,358,557	$23,819,194	$7,918,880	$19,007,040	$6,511,159	$2,362,287	$6,829,552	$561,478	$197,451	$204,722	$6,704,871	$2,788,834	$1,069,810
Total Operation and Maintenance Expenses			$933,774,239	$213,094,256	$631,804,126	$88,875,857	$88,389,665	$212,380,817	$58,397,217	$23,459,352	$63,325,295	$20,613,517	$2,050,821	$5,301,031	$616,113	$22,605,933	$74,625,333	$3,098,099
Total Operation and Maintenance Exp. Less Purchased Power			$883,154,932	$205,801,340	$588,477,735	$88,875,857	$85,225,716	$197,835,367	$58,397,217	$22,608,840	$58,985,741	$20,613,517	$1,980,622	$4,938,441	$616,113	$21,807,841	$69,500,033	$3,098,099

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense																		
580 OPERATION SUPERVISION AND ENGI	LBDO	40	$1,510,424	$621,285	$0	$889,139	$4,338	$0	$9,875	$45,274	$0	$8,407	$98,776	$0	$21,941	$0	$0	$14,964
581 LOAD DISPATCHING	Acct362	29	$341,053	$341,053	$0	$0	$2,840	$0	$0	$27,909	$0	$0	$64,662	$0	$0	$0	$0	$0
582 STATION EXPENSES	Acct362	29	$1,798,545	$1,798,545	$0	$0	$14,975	$0	$0	$147,177	$0	$0	$340,993	$0	$0	$0	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$4,706,317	$3,737,182	$0	$969,134	$25,553	$0	$0	$251,140	$0	$0	$581,861	$0	$0	$0	$0	$0
584 UNDERGROUND LINE EXPENSES			$0	$0	$0	$0												
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$8,749,183	$0	$0	$8,749,183	$0	$0	$121,103	$0	$0	$101,864	$0	$0	$269,076	$0	$0	$183,513
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE	C04	22	-$142,800	$0	$0	-$142,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$6,743,173	$4,401,150	$0	$2,342,023	$27,941	$0	$4,473	$318,502	$0	$5,439	$636,244	$0	$9,939	$0	$0	$6,778
588 MISC DISTR EXP -- MAPPIN			$0	$0	$0	$0												
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Expense			$23,705,895	$10,899,216	$0	$12,806,679	$75,647	$0	$135,451	$790,002	$0	$115,710	$1,722,536	$0	$300,956	$0	$0	$205,255
Distribution Maintenance Expense																		
590 MAINTENANCE SUPERVISION AND ENG	LBDM	41	$57,449	$46,964	$0	$10,485	$331	$0	$0	$3,267	$0	$0	$7,535	$0	$0	$0	$0	$0
591 STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$1,286,692	$1,286,692	$0	$0	$10,713	$0	$0	$105,292	$0	$0	$243,949	$0	$0	$0	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$30,239,215	$24,012,295	$0	$6,226,920	$164,184	$0	$0	$1,613,633	$0	$0	$3,738,599	$0	$0	$0	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$790,500	$738,959	$0	$51,541	$6,043	$0	$0	$59,390	$0	$0	$137,599	$0	$0	$0	$0	$0
595 MAINTENANCE OF LINE TRANSFORMERS	Acct368	32	$96,331	$50,972	$0	$45,359	$0	$0	$0	$3,519	$0	$52	$0	$0	$0	$0	$0	$0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0	$0	$0	$0												
597 MAINTENANCE OF METERS	C03	21	$1,371,953	$0	$0	$1,371,953	$0	$0	$18,990	$0	$0	$15,973	$0	$0	$42,194	$0	$0	$28,777
598 MISCELLANEOUS DISTRIBUTION EXPENSES	Dist	26	$550,314	$359,180	$0	$191,134	$2,280	$0	$365	$25,993	$0	$444	$51,924	$0	$811	$0	$0	$553
Total Distribution Maintenance Expense			$34,392,454	$26,495,062	$0	$7,897,392	$183,552	$0	$19,355	$1,811,093	$0	$16,469	$4,179,607	$0	$43,005	$0	$0	$29,330
Total Distribution Expense			$58,098,349	$37,394,279	$0	$20,704,070	$259,198	$0	$154,806	$2,601,096	$0	$132,179	$5,902,143	$0	$343,960	$0	$0	$234,585
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$3,631,554	$0	$0	$3,631,554	$0	$0	$4,699	$0	$0	$83,933	$0	$0	$37,621	$0	$0	$3,260
902 METER READING EXPENSES	MREAD	50	$5,301,482	$0	$0	$5,301,482	$0	$0	$7,053	$0	$0	$125,980	$0	$0	$56,467	$0	$0	$4,892
903 RECORDS AND COLLECTION	C05	33	$20,167,471	$0	$0	$20,167,471	$0	$0	$26,096	$0	$0	$466,115	$0	$0	$208,922	$0	$0	$18,102
904 UNCOLLECTIBLE ACCOUNTS	C05	33	$5,566,157	$0	$0	$5,566,157	$0	$0	$7,203	$0	$0	$128,646	$0	$0	$57,662	$0	$0	$4,996
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Expense			$34,666,664	$0	$0	$34,666,664	$0	$0	$45,051	$0	$0	$804,675	$0	$0	$360,672	$0	$0	$31,250
Customer Service Expense																		
907 SUPERVISION	C05	33	$651,425	$0	$0	$651,425	$0	$0	$843	$0	$0	$15,056	$0	$0	$6,748	$0	$0	$585
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$450,051	$0	$0	$450,051	$0	$0	$582	$0	$0	$10,402	$0	$0	$4,662	$0	$0	$404
908 CUSTOMER ASSISTANCE EXP-INCENTIVES			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA	C05	33	$389,845	$0	$0	$389,845	$0	$0	$504	$0	$0	$9,010	$0	$0	$4,039	$0	$0	$350
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE	C05	33	$1,861,027	$0	$0	$1,861,027	$0	$0	$2,408	$0	$0	$43,012	$0	$0	$19,279	$0	$0	$1,670
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 ADVERTISING EXPENSES	C05	33	$794,217	$0	$0	$794,217	$0	$0	$1,028	$0	$0	$18,356	$0	$0	$8,228	$0	$0	$713
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Expense			$4,146,565	$0	$0	$4,146,565	$0	$0	$5,366	$0	$0	$95,836	$0	$0	$42,956	$0	$0	$3,722
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$33,809,232	$16,862,756	$7,680,251	$9,266,225	$142,198	$70,104	$37,761	$1,428,835	$707,275	$167,402	$3,377,725	$1,699,915	$129,887	$976,870	$605,350	$50,687
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	35	$7,269,104	$3,625,552	$1,651,281	$1,992,271	$30,573	$15,073	$8,119	$307,205	$152,067	$35,992	$726,223	$365,488	$27,926	$210,030	$130,152	$10,898
922 ADMINISTRATIVE EXPENSES TRANSFERRED	LBSUB7	35	-$4,414,266	-$2,201,667	-$1,002,764	-$1,209,835	-$18,566	-$9,153	-$4,930	-$186,554	-$92,345	-$21,857	-$441,009	-$221,948	-$16,959	-$127,544	-$79,037	-$6,618
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	35	$19,133,213	$9,542,917	$4,346,383	$5,243,912	$80,472	$39,673	$21,370	$808,602	$400,259	$94,736	$1,911,511	$962,010	$73,505	$552,827	$342,578	$28,685
924 PROPERTY INSURANCE	TUP	34	$5,543,869	$5,042,952	$0	$500,917	$42,249	$0	$957	$431,716	$0	$1,163	$1,005,794	$0	$2,126	$307,901	$0	$1,450
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$3,904,092	$1,947,213	$886,870	$1,070,009	$16,420	$8,095	$4,360	$164,994	$81,672	$19,331	$390,040	$196,296	$14,999	$112,803	$69,902	$5,853
926 EMPLOYEE BENEFITS	LBSUB7	35	$38,912,106	$19,407,875	$8,839,442	$10,664,789	$163,661	$80,685	$43,460	$1,644,491	$814,025	$192,668	$3,887,530	$1,956,485	$149,491	$1,124,310	$696,716	$58,338
928 REGULATORY COMMISSION FEES	TUP	34	$1,800,307	$1,637,640	$0	$162,667	$13,720	$0	$311	$140,195	$0	$378	$326,620	$0	$690	$99,987	$0	$471
929 DUPLICATE CHARGES			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	35	$5,197,262	$2,592,196	$1,180,632	$1,424,433	$21,859	$10,777	$5,805	$219,645	$108,725	$25,734	$519,235	$261,316	$19,967	$150,167	$93,056	$7,792
931 RENTS AND LEASES	PT&D	23	$1,831,134	$1,666,513	$0	$164,620	$13,975	$0	$314	$142,790	$0	$382	$332,757	$0	$699	$101,960	$0	$476
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$873,720	$795,172	$0	$78,548	$6,668	$0	$150	$68,132	$0	$182	$158,774	$0	$333	$48,650	$0	$227
Total Administrative and General Expense			$113,859,773	$60,919,119	$23,582,096	$29,358,557	$513,229	$215,254	$117,676	$5,170,050	$2,171,678	$516,111	$12,195,200	$5,219,563	$402,665	$3,557,962	$1,858,718	$158,259
Total Operation and Maintenance Expenses			$933,774,239	$213,094,256	$631,804,126	$88,875,857	$1,695,721	$5,764,580	$322,899	$17,104,896	$58,174,839	$1,548,802	$40,116,464	$139,741,307	$1,150,253	$11,361,748	$49,746,414	$427,816
Total Operation and Maintenance Exp. Less Purchased Power			$883,154,932	$205,801,340	$588,477,735	$88,875,857	$1,645,207	$5,369,063	$322,899	$16,570,616	$54,184,775	$1,548,802	$38,879,836	$130,150,011	$1,150,253	$10,934,157	$46,330,631	$427,816

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense																		
580 OPERATION SUPERVISION AND ENGI	LBDO	40	$1,510,424	$621,285	$0	$889,139	$0	$0	$633	$4,883	$0	$31,383	$20	$0	$4	$32	$0	$819
581 LOAD DISPATCHING	Acct362	29	$341,053	$341,053	$0	$0	$0	$0	$0	$2,806	$0	$0	$12	$0	$0	$18	$0	$0
582 STATION EXPENSES	Acct362	29	$1,798,545	$1,798,545	$0	$0	$0	$0	$0	$14,799	$0	$0	$62	$0	$0	$96	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$4,706,317	$3,737,182	$0	$969,134	$0	$0	$0	$29,497	$0	$34,013	$124	$0	$1	$191	$0	$157
584 UNDERGROUND LINE EXPENSES			$0	$0	$0	$0												
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$8,749,183	$0	$0	$8,749,183	$0	$0	$7,767	$0	$0	$0	$0	$0	$50	$0	$0	$9,797
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE	C04	22	-$142,800	$0	$0	-$142,800	$0	$0	$0	$0	$0	-$142,800	$0	$0	$0	$0	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$6,743,173	$4,401,150	$0	$2,342,023	$0	$0	$287	$33,578	$0	$489,902	$141	$0	$3	$218	$0	$554
588 MISC DISTR EXP -- MAPPIN			$0	$0	$0	$0												
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Expense			$23,705,895	$10,899,216	$0	$12,806,679	$0	$0	$8,687	$85,563	$0	$412,498	$358	$0	$58	$555	$0	$11,326
Distribution Maintenance Expense																		
590 MAINTENANCE SUPERVISION AND ENG	LBDM	41	$57,449	$46,964	$0	$10,485	$0	$0	$0	$373	$0	$368	$2	$0	$0	$2	$0	$2
591 STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$1,286,692	$1,286,692	$0	$0	$0	$0	$0	$10,587	$0	$0	$44	$0	$0	$69	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$30,239,215	$24,012,295	$0	$6,226,920	$0	$0	$0	$189,525	$0	$218,540	$794	$0	$5	$1,229	$0	$1,007
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$790,500	$738,959	$0	$51,541	$0	$0	$0	$6,056	$0	$1,809	$25	$0	$0	$39	$0	$8
595 MAINTENANCE OF LINE TRANSFORMERS	Acct368	32	$96,331	$50,972	$0	$45,359	$0	$0	$0	$270	$0	$1,577	$1	$0	$0	$2	$0	$7
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0	$0	$0	$0												
597 MAINTENANCE OF METERS	C03	21	$1,371,953	$0	$0	$1,371,953	$0	$0	$1,218	$0	$0	$0	$0	$0	$8	$0	$0	$1,536
598 MISCELLANEOUS DISTRIBUTION EXPENSES	Dist	26	$550,314	$359,180	$0	$191,134	$0	$0	$23	$2,740	$0	$39,981	$11	$0	$0	$18	$0	$45
Total Distribution Maintenance Expense			$34,392,454	$26,495,062	$0	$7,897,392	$0	$0	$1,241	$209,551	$0	$262,275	$878	$0	$13	$1,359	$0	$2,605
Total Distribution Expense			$58,098,349	$37,394,279	$0	$20,704,070	$0	$0	$9,929	$295,114	$0	$674,773	$1,236	$0	$72	$1,914	$0	$13,932
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$3,631,554	$0	$0	$3,631,554	$0	$0	$272	$0	$0	$101,698	$0	$0	$0	$0	$0	$467
902 METER READING EXPENSES	MREAD	50	$5,301,482	$0	$0	$5,301,482	$0	$0	$408	$0	$0	$0	$0	$0	$0	$0	$0	$4,028
903 RECORDS AND COLLECTION	C05	33	$20,167,471	$0	$0	$20,167,471	$0	$0	$1,508	$0	$0	$564,769	$0	$0	$0	$0	$0	$2,595
904 UNCOLLECTIBLE ACCOUNTS	C05	33	$5,566,157	$0	$0	$5,566,157	$0	$0	$416	$0	$0	$155,874	$0	$0	$0	$0	$0	$716
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Expense			$34,666,664	$0	$0	$34,666,664	$0	$0	$2,604	$0	$0	$822,341	$0	$0	$0	$0	$0	$7,806
Customer Service Expense																		
907 SUPERVISION	C05	33	$651,425	$0	$0	$651,425	$0	$0	$49	$0	$0	$18,242	$0	$0	$0	$0	$0	$84
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$450,051	$0	$0	$450,051	$0	$0	$34	$0	$0	$12,603	$0	$0	$0	$0	$0	$58
908 CUSTOMER ASSISTANCE EXP-INCENTIVES			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA	C05	33	$389,845	$0	$0	$389,845	$0	$0	$29	$0	$0	$10,917	$0	$0	$0	$0	$0	$50
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE	C05	33	$1,861,027	$0	$0	$1,861,027	$0	$0	$139	$0	$0	$52,116	$0	$0	$0	$0	$0	$239
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 ADVERTISING EXPENSES	C05	33	$794,217	$0	$0	$794,217	$0	$0	$59	$0	$0	$22,241	$0	$0	$0	$0	$0	$102
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Expense			$4,146,565	$0	$0	$4,146,565	$0	$0	$310	$0	$0	$116,120	$0	$0	$0	$0	$0	$533
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$33,809,232	$16,862,756	$7,680,251	$9,266,225	$401,869	$223,567	$2,371	$115,340	$52,258	$275,093	$445	$189	$13	$1,154	$630	$3,495
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	35	$7,269,104	$3,625,552	$1,651,281	$1,992,271	$86,403	$48,068	$510	$24,798	$11,236	$59,146	$96	$41	$3	$248	$135	$751
922 ADMINISTRATIVE EXPENSES TRANSFERREL	LBSUB7	35	-$4,414,266	-$2,201,667	-$1,002,764	-$1,209,835	-$52,470	-$29,190	-$310	-$15,059	-$6,823	-$35,917	-$58	-$25	-$2	-$151	-$82	-$456
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	35	$19,133,213	$9,542,917	$4,346,383	$5,243,912	$227,425	$126,520	$1,342	$65,273	$29,574	$155,680	$252	$107	$7	$653	$357	$1,978
924 PROPERTY INSURANCE	TUP	34	$5,543,869	$5,042,952	$0	$500,917	$127,177	$0	$61	$33,972	$0	$104,781	$130	$0	$1	$347	$0	$118
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$3,904,092	$1,947,213	$886,870	$1,070,009	$46,406	$25,816	$274	$13,319	$6,034	$31,766	$51	$22	$2	$133	$73	$404
926 EMPLOYEE BENEFITS	LBSUB7	35	$38,912,106	$19,407,875	$8,839,442	$10,664,789	$462,524	$257,310	$2,729	$132,748	$60,146	$316,613	$512	$217	$15	$1,328	$725	$4,022
928 REGULATORY COMMISSION FEES	TUP	34	$1,800,307	$1,637,640	$0	$162,667	$41,299	$0	$20	$11,032	$0	$34,027	$42	$0	$0	$113	$0	$38
929 DUPLICATE CHARGES			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	35	$5,197,262	$2,592,196	$1,180,632	$1,424,433	$61,777	$34,367	$365	$17,730	$8,033	$42,288	$68	$29	$2	$177	$97	$537
931 RENTS AND LEASES	PT&D	23	$1,831,134	$1,666,513	$0	$164,620	$42,017	$0	$20	$11,219	$0	$34,435	$43	$0	$0	$115	$0	$39
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$873,720	$795,172	$0	$78,548	$20,048	$0	$10	$5,353	$0	$16,431	$21	$0	$0	$55	$0	$19
Total Administrative and General Expense			$113,859,773	$60,919,119	$23,582,096	$29,358,557	$1,464,476	$686,458	$7,393	$415,726	$160,459	$1,034,342	$1,602	$580	$41	$4,173	$1,935	$10,945
Total Operation and Maintenance Expenses			$933,774,239	$213,094,256	$631,804,126	$88,875,857	$5,005,871	$18,402,515	$20,236	$1,285,457	$4,274,793	$2,647,577	$5,070	$15,434	$113	$13,258	$51,767	$33,216
Total Operation and Maintenance Exp. Less Purchased Power			$883,154,932	$205,801,340	$588,477,735	$88,875,857	$4,845,104	$17,141,495	$20,236	$1,285,457	$3,979,597	$2,647,577	$5,070	$14,368	$113	$12,872	$48,212	$33,216

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses																		
Labor-Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	FO19	42	$7,176,311	$6,192,742	$983,568	$0	$2,080,724	$330,729	$0	$624,055	$98,599	$0	$50,954	$8,258	$0	$739,017	$116,131	$0
501 FUEL	TDFUEL	51	$2,518,295	$0	$2,518,295	$0	$0	$846,789	$0	$0	$252,450	$0	$0	$21,142	$0	$0	$297,337	$0
502 STEAM EXPENSES	Prod	24	$8,257,131	$8,257,131	$0	$0	$2,774,347	$0	$0	$832,088	$0	$0	$67,940	$0	$0	$985,373	$0	$0
505 ELECTRIC EXPENSES	Prod	24	$5,890,264	$5,890,264	$0	$0	$1,979,093	$0	$0	$593,574	$0	$0	$48,465	$0	$0	$702,921	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$1,708,296	$1,708,296	$0	$0	$573,977	$0	$0	$172,148	$0	$0	$14,056	$0	$0	$203,861	$0	$0
507 RENTS			$0	$0	$0	$0												
Total Steam Power Operation Expenses			$25,550,297	$22,048,433	$3,501,864	$0	$7,408,141	$1,177,518	$0	$2,221,865	$351,049	$0	$181,415	$29,400	$0	$2,631,172	$413,468	$0
Labor-Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	43	$8,497,622	$819,744	$7,677,878	$0	$275,429	$2,577,602	$0	$82,607	$769,013	$0	$6,745	$64,255	$0	$97,825	$908,255	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$1,238,874	$1,238,874	$0	$0	$416,254	$0	$0	$124,844	$0	$0	$10,193	$0	$0	$147,842	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$9,213,874	$0	$9,213,874	$0	$0	$3,093,264	$0	$0	$922,858	$0	$0	$77,109	$0	$0	$1,089,956	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$1,992,105	$0	$1,992,105	$0	$0	$668,786	$0	$0	$199,528	$0	$0	$16,672	$0	$0	$235,656	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$397,544	$0	$397,544	$0	$0	$133,463	$0	$0	$39,818	$0	$0	$3,327	$0	$0	$47,027	$0
Total Steam Power Generation Maintenance Expense			$21,340,020	$2,058,618	$19,281,401	$0	$691,683	$6,473,114	$0	$207,451	$1,931,217	$0	$16,938	$161,362	$0	$245,667	$2,280,895	$0
Total Steam Power Generation Expense			$46,890,316	$24,107,052	$22,783,265	$0	$8,099,825	$7,650,632	$0	$2,429,316	$2,282,266	$0	$198,353	$190,762	$0	$2,876,839	$2,694,363	$0
Labor-Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING			$0	$0	$0	$0												
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES			$0	$0	$0	$0												
539 MISC. HYDRAULIC POWER EXPENSES			$0	$0	$0	$0												
540 RENTS			$0	$0	$0	$0												
Total Hydraulic Power Operation Expenses			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$166,692	$166,692	$0	$0	$56,007	$0	$0	$16,798	$0	$0	$1,372	$0	$0	$19,892	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$47,185	$47,185	$0	$0	$15,854	$0	$0	$4,755	$0	$0	$388	$0	$0	$5,631	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS			$0	$0	$0	$0												
544 MAINTENANCE OF ELECTRIC PLANT			$0	$0	$0	$0												
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0	$0	$0	$0												
Total Hydraulic Power Generation Maint. Expense			$213,877	$213,877	$0	$0	$71,861	$0	$0	$21,553	$0	$0	$1,760	$0	$0	$25,523	$0	$0
Total Hydraulic Power Generation Expense			$213,877	$213,877	$0	$0	$71,861	$0	$0	$21,553	$0	$0	$1,760	$0	$0	$25,523	$0	$0
Labor-Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	Prod	24	$848,268	$848,268	$0	$0	$285,013	$0	$0	$85,482	$0	$0	$6,980	$0	$0	$101,229	$0	$0
547 FUEL			$0	$0	$0	$0												
548 GENERATION EXPENSE	Prod	24	$327,051	$327,051	$0	$0	$109,887	$0	$0	$32,958	$0	$0	$2,691	$0	$0	$39,029	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$1,662,761	$1,662,761	$0	$0	$558,678	$0	$0	$167,560	$0	$0	$13,681	$0	$0	$198,427	$0	$0
550 RENTS			$0	$0	$0	$0												
Total Other Power Generation Expenses			$2,838,080	$2,838,080	$0	$0	$953,578	$0	$0	$285,999	$0	$0	$23,352	$0	$0	$338,685	$0	$0
Labor-Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$201,322	$201,322	$0	$0	$67,643	$0	$0	$20,288	$0	$0	$1,656	$0	$0	$24,025	$0	$0
552 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$1,017,670	$1,017,670	$0	$0	$341,931	$0	$0	$102,553	$0	$0	$8,373	$0	$0	$121,445	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$1,600,551	$1,600,551	$0	$0	$537,776	$0	$0	$161,291	$0	$0	$13,169	$0	$0	$191,003	$0	$0
Total Other Power Generation Maintenance Expense			$2,819,543	$2,819,543	$0	$0	$947,350	$0	$0	$284,131	$0	$0	$23,199	$0	$0	$336,473	$0	$0
Total Other Power Generation Expense			$5,657,623	$5,657,623	$0	$0	$1,900,927	$0	$0	$570,130	$0	$0	$46,551	$0	$0	$675,158	$0	$0
Total Production Expense			$52,761,816	$29,978,551	$22,783,265	$0	$10,072,613	$7,650,632	$0	$3,020,999	$2,282,266	$0	$246,664	$190,762	$0	$3,577,520	$2,694,363	$0
Labor-Purchased Power																		
555 PURCHASED POWER			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,829,189	$1,829,189	$0	$0	$614,596	$0	$0	$184,331	$0	$0	$15,051	$0	$0	$218,288	$0	$0
557 OTHER EXPENSES			$0	$0	$0	$0												
Total Purchased Power Labor			$1,829,189	$1,829,189	$0	$0	$614,596	$0	$0	$184,331	$0	$0	$15,051	$0	$0	$218,288	$0	$0
Transmission Labor Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,648,654	$1,648,654	$0	$0	$701,238	$0	$0	$177,533	$0	$0	$17,139	$0	$0	$156,512	$0	$0
561 LOAD DISPATCHING	Trans	25	$3,065,460	$3,065,460	$0	$0	$1,303,862	$0	$0	$330,099	$0	$0	$31,868	$0	$0	$291,014	$0	$0
562 STATION EXPENSES	Trans	25	$505,135	$505,135	$0	$0	$214,854	$0	$0	$54,395	$0	$0	$5,251	$0	$0	$47,954	$0	$0
563 OVERHEAD LINE EXPENSES			$0	$0	$0	$0												
566 MISC. TRANSMISSION EXPENSES	Trans	25	$118,042	$118,042	$0	$0	$50,208	$0	$0	$12,711	$0	$0	$1,227	$0	$0	$11,206	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$937,915	$937,915	$0	$0	$398,932	$0	$0	$100,998	$0	$0	$9,750	$0	$0	$89,039	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$466,793	$466,793	$0	$0	$198,546	$0	$0	$50,266	$0	$0	$4,853	$0	$0	$44,314	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT			$0	$0	$0	$0												
Total Transmission Labor Expenses			$6,741,999	$6,741,999	$0	$0	$2,867,640	$0	$0	$726,001	$0	$0	$70,088	$0	$0	$640,039	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses																		
Labor-Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	FO19	42	$7,176,311	$6,192,742	$983,568	$0	$56,657	$8,973	$0	$569,937	$90,561	$0	$1,370,850	$217,497	$0	$482,526	$77,419	$0
501 FUEL	TDFUEL	51	$2,518,295	$0	$2,518,295	$0	$0	$22,974	$0	$0	$231,868	$0	$0	$556,873	$0	$0	$198,221	$0
502 STEAM EXPENSES	Prod	24	$8,257,131	$8,257,131	$0	$0	$75,544	$0	$0	$759,929	$0	$0	$1,827,832	$0	$0	$643,379	$0	$0
505 ELECTRIC EXPENSES	Prod	24	$5,890,264	$5,890,264	$0	$0	$53,890	$0	$0	$542,099	$0	$0	$1,303,892	$0	$0	$458,958	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$1,708,296	$1,708,296	$0	$0	$15,629	$0	$0	$157,220	$0	$0	$378,155	$0	$0	$133,107	$0	$0
507 RENTS			$0	$0	$0	$0												
Total Steam Power Operation Expenses			$25,550,297	$22,048,433	$3,501,864	$0	$201,721	$31,947	$0	$2,029,183	$322,429	$0	$4,880,729	$774,370	$0	$1,717,970	$275,640	$0
Labor-Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	43	$8,497,622	$819,744	$7,677,878	$0	$7,500	$70,090	$0	$75,444	$707,080	$0	$181,462	$1,699,675	$0	$63,873	$605,312	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$1,238,874	$1,238,874	$0	$0	$11,334	$0	$0	$114,017	$0	$0	$274,242	$0	$0	$96,531	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$9,213,874	$0	$9,213,874	$0	$0	$84,111	$0	$0	$848,535	$0	$0	$2,039,703	$0	$0	$726,407	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$1,992,105	$0	$1,992,105	$0	$0	$18,186	$0	$0	$183,459	$0	$0	$440,998	$0	$0	$157,054	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$397,544	$0	$397,544	$0	$0	$3,629	$0	$0	$36,611	$0	$0	$88,005	$0	$0	$31,342	$0
Total Steam Power Generation Maintenance Expense			$21,340,020	$2,058,618	$19,281,401	$0	$18,834	$176,016	$0	$189,461	$1,775,685	$0	$455,704	$4,268,383	$0	$160,403	$1,520,115	$0
Total Steam Power Generation Expense			$46,890,316	$24,107,052	$22,783,265	$0	$220,555	$207,963	$0	$2,218,644	$2,098,114	$0	$5,336,433	$5,042,753	$0	$1,878,373	$1,795,755	$0
Labor-Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING			$0	$0	$0	$0												
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES			$0	$0	$0	$0												
539 MISC. HYDRAULIC POWER EXPENSES			$0	$0	$0	$0												
540 RENTS			$0	$0	$0	$0												
Total Hydraulic Power Operation Expenses			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$166,692	$166,692	$0	$0	$1,525	$0	$0	$15,341	$0	$0	$36,900	$0	$0	$12,988	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$47,185	$47,185	$0	$0	$432	$0	$0	$4,343	$0	$0	$10,445	$0	$0	$3,677	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS			$0	$0	$0	$0												
544 MAINTENANCE OF ELECTRIC PLANT			$0	$0	$0	$0												
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0	$0	$0	$0												
Total Hydraulic Power Generation Maint. Expense			$213,877	$213,877	$0	$0	$1,957	$0	$0	$19,684	$0	$0	$47,345	$0	$0	$16,665	$0	$0
Total Hydraulic Power Generation Expense			$213,877	$213,877	$0	$0	$1,957	$0	$0	$19,684	$0	$0	$47,345	$0	$0	$16,665	$0	$0
Labor-Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	Prod	24	$848,268	$848,268	$0	$0	$7,761	$0	$0	$78,069	$0	$0	$187,776	$0	$0	$66,095	$0	$0
547 FUEL			$0	$0	$0	$0												
548 GENERATION EXPENSE	Prod	24	$327,051	$327,051	$0	$0	$2,992	$0	$0	$30,099	$0	$0	$72,397	$0	$0	$25,483	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$1,662,761	$1,662,761	$0	$0	$15,213	$0	$0	$153,029	$0	$0	$368,076	$0	$0	$129,559	$0	$0
550 RENTS			$0	$0	$0	$0												
Total Other Power Generation Expenses			$2,838,080	$2,838,080	$0	$0	$25,966	$0	$0	$261,197	$0	$0	$628,249	$0	$0	$221,138	$0	$0
Labor-Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$201,322	$201,322	$0	$0	$1,842	$0	$0	$18,528	$0	$0	$44,565	$0	$0	$15,687	$0	$0
552 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$1,017,670	$1,017,670	$0	$0	$9,311	$0	$0	$93,659	$0	$0	$225,276	$0	$0	$79,295	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$1,600,551	$1,600,551	$0	$0	$14,643	$0	$0	$147,304	$0	$0	$354,304	$0	$0	$124,712	$0	$0
Total Other Power Generation Maintenance Expense			$2,819,543	$2,819,543	$0	$0	$25,796	$0	$0	$259,491	$0	$0	$624,145	$0	$0	$219,693	$0	$0
Total Other Power Generation Expense			$5,657,623	$5,657,623	$0	$0	$51,762	$0	$0	$520,688	$0	$0	$1,252,394	$0	$0	$440,831	$0	$0
Total Production Expense			$52,761,816	$29,978,551	$22,783,265	$0	$274,274	$207,963	$0	$2,759,016	$2,098,114	$0	$6,636,172	$5,042,753	$0	$2,335,869	$1,795,755	$0
Labor-Purchased Power																		
555 PURCHASED POWER			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,829,189	$1,829,189	$0	$0	$16,735	$0	$0	$168,346	$0	$0	$404,916	$0	$0	$142,527	$0	$0
557 OTHER EXPENSES			$0	$0	$0	$0												
Total Purchased Power Labor			$1,829,189	$1,829,189	$0	$0	$16,735	$0	$0	$168,346	$0	$0	$404,916	$0	$0	$142,527	$0	$0
Transmission Labor Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,648,654	$1,648,654	$0	$0	$12,308	$0	$0	$120,968	$0	$0	$280,269	$0	$0	$102,573	$0	$0
561 LOAD DISPATCHING	Trans	25	$3,065,460	$3,065,460	$0	$0	$22,886	$0	$0	$224,925	$0	$0	$521,124	$0	$0	$190,722	$0	$0
562 STATION EXPENSES	Trans	25	$505,135	$505,135	$0	$0	$3,771	$0	$0	$37,064	$0	$0	$85,872	$0	$0	$31,428	$0	$0
563 OVERHEAD LINE EXPENSES			$0	$0	$0	$0												
566 MISC. TRANSMISSION EXPENSES	Trans	25	$118,042	$118,042	$0	$0	$881	$0	$0	$8,661	$0	$0	$20,067	$0	$0	$7,344	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$937,915	$937,915	$0	$0	$7,002	$0	$0	$68,818	$0	$0	$159,444	$0	$0	$58,354	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$466,793	$466,793	$0	$0	$3,485	$0	$0	$34,250	$0	$0	$79,354	$0	$0	$29,042	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT			$0	$0	$0	$0												
Total Transmission Labor Expenses			$6,741,999	$6,741,999	$0	$0	$50,333	$0	$0	$494,686	$0	$0	$1,146,131	$0	$0	$419,463	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses																		
Labor-Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	FO19	42	$7,176,311	$6,192,742	$983,568	$0	$178,103	$28,654	$0	$39,287	$6,644	$0	$142	$24	$0	$489	$81	$0
501 FUEL	TDFUEL	51	$2,518,295	$0	$2,518,295	$0	$0	$73,364	$0	$0	$17,010	$0	$0	$61	$0	$0	$206	$0
502 STEAM EXPENSES	Prod	24	$8,257,131	$8,257,131	$0	$0	$237,475	$0	$0	$52,383	$0	$0	$190	$0	$0	$652	$0	$0
505 ELECTRIC EXPENSES	Prod	24	$5,890,264	$5,890,264	$0	$0	$169,404	$0	$0	$37,368	$0	$0	$135	$0	$0	$465	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$1,708,296	$1,708,296	$0	$0	$49,131	$0	$0	$10,837	$0	$0	$39	$0	$0	$135	$0	$0
507 RENTS			$0	$0	$0	$0												
Total Steam Power Operation Expenses			$25,550,297	$22,048,433	$3,501,864	$0	$634,113	$102,017	$0	$139,875	$23,653	$0	$507	$85	$0	$1,742	$287	$0
Labor-Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	43	$8,497,622	$819,744	$7,677,878	$0	$23,576	$223,465	$0	$5,200	$52,312	$0	$19	$189	$0	$65	$630	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$1,238,874	$1,238,874	$0	$0	$35,630	$0	$0	$7,859	$0	$0	$28	$0	$0	$98	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$9,213,874	$0	$9,213,874	$0	$0	$268,171	$0	$0	$62,777	$0	$0	$227	$0	$0	$756	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$1,992,105	$0	$1,992,105	$0	$0	$57,980	$0	$0	$13,573	$0	$0	$49	$0	$0	$163	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$397,544	$0	$397,544	$0	$0	$11,571	$0	$0	$2,709	$0	$0	$10	$0	$0	$33	$0
Total Steam Power Generation Maintenance Expense			$21,340,020	$2,058,618	$19,281,401	$0	$59,206	$561,187	$0	$13,060	$131,370	$0	$47	$475	$0	$163	$1,582	$0
Total Steam Power Generation Expense			$46,890,316	$24,107,052	$22,783,265	$0	$693,319	$663,204	$0	$152,935	$155,023	$0	$554	$560	$0	$1,904	$1,869	$0
Labor-Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING			$0	$0	$0	$0												
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES			$0	$0	$0	$0												
539 MISC. HYDRAULIC POWER EXPENSES			$0	$0	$0	$0												
540 RENTS			$0	$0	$0	$0												
Total Hydraulic Power Operation Expenses			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$166,692	$166,692	$0	$0	$4,794	$0	$0	$1,057	$0	$0	$4	$0	$0	$13	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$47,185	$47,185	$0	$0	$1,357	$0	$0	$299	$0	$0	$1	$0	$0	$4	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS			$0	$0	$0	$0												
544 MAINTENANCE OF ELECTRIC PLANT			$0	$0	$0	$0												
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0	$0	$0	$0												
Total Hydraulic Power Generation Maint. Expense			$213,877	$213,877	$0	$0	$6,151	$0	$0	$1,357	$0	$0	$5	$0	$0	$17	$0	$0
Total Hydraulic Power Generation Expense			$213,877	$213,877	$0	$0	$6,151	$0	$0	$1,357	$0	$0	$5	$0	$0	$17	$0	$0
Labor-Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	Prod	24	$848,268	$848,268	$0	$0	$24,396	$0	$0	$5,381	$0	$0	$20	$0	$0	$67	$0	$0
547 FUEL			$0	$0	$0	$0												
548 GENERATION EXPENSE	Prod	24	$327,051	$327,051	$0	$0	$9,406	$0	$0	$2,075	$0	$0	$8	$0	$0	$26	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$1,662,761	$1,662,761	$0	$0	$47,821	$0	$0	$10,549	$0	$0	$38	$0	$0	$131	$0	$0
550 RENTS			$0	$0	$0	$0												
Total Other Power Generation Expenses			$2,838,080	$2,838,080	$0	$0	$81,623	$0	$0	$18,005	$0	$0	$65	$0	$0	$224	$0	$0
Labor-Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$201,322	$201,322	$0	$0	$5,790	$0	$0	$1,277	$0	$0	$5	$0	$0	$16	$0	$0
552 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$1,017,670	$1,017,670	$0	$0	$29,268	$0	$0	$6,456	$0	$0	$23	$0	$0	$80	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$1,600,551	$1,600,551	$0	$0	$46,032	$0	$0	$10,154	$0	$0	$37	$0	$0	$126	$0	$0
Total Other Power Generation Maintenance Expense			$2,819,543	$2,819,543	$0	$0	$81,090	$0	$0	$17,887	$0	$0	$65	$0	$0	$223	$0	$0
Total Other Power Generation Expense			$5,657,623	$5,657,623	$0	$0	$162,713	$0	$0	$35,892	$0	$0	$130	$0	$0	$447	$0	$0
Total Production Expense			$52,761,816	$29,978,551	$22,783,265	$0	$862,183	$663,204	$0	$190,184	$155,023	$0	$690	$560	$0	$2,368	$1,869	$0
Labor-Purchased Power																		
555 PURCHASED POWER			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,829,189	$1,829,189	$0	$0	$52,607	$0	$0	$11,604	$0	$0	$42	$0	$0	$145	$0	$0
557 OTHER EXPENSES			$0	$0	$0	$0												
Total Purchased Power Labor			$1,829,189	$1,829,189	$0	$0	$52,607	$0	$0	$11,604	$0	$0	$42	$0	$0	$145	$0	$0
Transmission Labor Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,648,654	$1,648,654	$0	$0	$67,820	$0	$0	$12,164	$0	$0	$51	$0	$0	$79	$0	$0
561 LOAD DISPATCHING	Trans	25	$3,065,460	$3,065,460	$0	$0	$126,103	$0	$0	$22,617	$0	$0	$95	$0	$0	$147	$0	$0
562 STATION EXPENSES	Trans	25	$505,135	$505,135	$0	$0	$20,780	$0	$0	$3,727	$0	$0	$16	$0	$0	$24	$0	$0
563 OVERHEAD LINE EXPENSES			$0	$0	$0	$0												
566 MISC. TRANSMISSION EXPENSES	Trans	25	$118,042	$118,042	$0	$0	$4,856	$0	$0	$871	$0	$0	$4	$0	$0	$6	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$937,915	$937,915	$0	$0	$38,583	$0	$0	$6,920	$0	$0	$29	$0	$0	$45	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$466,793	$466,793	$0	$0	$19,202	$0	$0	$3,444	$0	$0	$14	$0	$0	$22	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT			$0	$0	$0	$0												
Total Transmission Labor Expenses			$6,741,999	$6,741,999	$0	$0	$277,345	$0	$0	$49,742	$0	$0	$208	$0	$0	$323	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																		
580 OPERATION SUPERVISION AND ENGI	FO23	45	$1,081,711	$444,942	$0	$636,769	$233,013	$0	$401,613	$54,898	$0	$136,878	$5,035	$0	$2,653	$42,191	$0	$32,584
581 LOAD DISPATCHING	Acct362	29	$342,506	$342,506	$0	$0	$162,474	$0	$0	$41,133	$0	$0	$3,971	$0	$0	$36,263	$0	$0
582 STATION EXPENSES	Acct362	29	$870,967	$870,967	$0	$0	$413,158	$0	$0	$104,599	$0	$0	$10,098	$0	$0	$92,214	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$2,170,209	$1,723,315	$0	$446,894	$927,993	$0	$360,826	$216,184	$0	$69,814	$19,655	$0	$497	$149,835	$0	$0
584 UNDERGROUND LINE EXPENSES			$0	$0	$0	$0												
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$5,717,580	$0	$0	$5,717,580	$0	$0	$3,553,262	$0	$0	$1,324,293	$0	$0	$28,090	$0	$0	$358,949
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE			$0	$0	$0	$0												
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$3,343,041	$2,181,944	$0	$1,161,097	$1,177,024	$0	$706,180	$269,648	$0	$180,582	$24,195	$0	$1,930	$207,069	$0	$15,908
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Labor Expense			$13,526,014	$5,563,674	$0	$7,962,340	$2,913,662	$0	$5,021,881	$686,462	$0	$1,711,567	$62,953	$0	$33,169	$527,572	$0	$407,441
Distribution Maintenance Labor Expense																		
590 MAINTENANCE SUPERVISION AND EN			$0	$0	$0	$0												
591 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$605,269	$605,269	$0	$0	$287,120	$0	$0	$72,690	$0	$0	$7,017	$0	$0	$64,083	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$6,158,359	$4,890,217	$0	$1,268,142	$2,633,346	$0	$1,023,910	$613,460	$0	$198,109	$55,774	$0	$1,410	$425,183	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$413,802	$386,822	$0	$26,980	$185,974	$0	$21,784	$46,662	$0	$4,215	$4,478	$0	$30	$40,223	$0	$0
595 MAINTENANCE OF LINE TRANSFORME	Acct368	32	$51,420	$27,208	$0	$24,212	$18,877	$0	$19,363	$3,400	$0	$3,746	$239	$0	$27	$2,669	$0	$202
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0	$0	$0	$0												
597 MAINTENANCE OF METERS			$0	$0	$0	$0												
598 MAINTENANCE OF MISC DISTR PLANT			$0	$0	$0	$0												
Total Distribution Maintenance Labor Expense			$7,228,850	$5,909,516	$0	$1,319,334	$3,125,317	$0	$1,065,057	$736,212	$0	$206,071	$67,508	$0	$1,466	$532,159	$0	$202
Total Distribution Labor Expense			$20,754,864	$11,473,190	$0	$9,281,674	$6,038,978	$0	$6,086,938	$1,422,675	$0	$1,917,637	$130,461	$0	$34,636	$1,059,731	$0	$407,644
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$3,259,518	$0	$0	$3,259,518	$0	$0	$2,100,001	$0	$0	$812,630	$0	$0	$28,915	$0	$0	$109,784
902 METER READING EXPENSES	MREAD	50	$754,379	$0	$0	$754,379	$0	$0	$499,711	$0	$0	$193,371	$0	$0	$6,881	$0	$0	$26,124
903 RECORDS AND COLLECTION	C05	33	$11,992,171	$0	$0	$11,992,171	$0	$0	$7,726,166	$0	$0	$2,989,768	$0	$0	$106,381	$0	$0	$403,909
904 UNCOLLECTIBLE ACCOUNTS			$0	$0	$0	$0												
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Labor Expense			$16,006,068	$0	$0	$16,006,068	$0	$0	$10,325,878	$0	$0	$3,995,770	$0	$0	$142,177	$0	$0	$539,817
Customer Service Expense																		
907 SUPERVISION	C05	33	$614,307	$0	$0	$614,307	$0	$0	$395,778	$0	$0	$153,153	$0	$0	$5,449	$0	$0	$20,690
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$1,585,968	$0	$0	$1,585,968	$0	$0	$1,021,788	$0	$0	$395,398	$0	$0	$14,069	$0	$0	$53,417
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA			$0	$0	$0	$0												
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE			$0	$0	$0	$0												
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 WATER HEATER - HEAT PUMP PROGRAM			$0	$0	$0	$0												
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Labor Expense			$2,200,275	$0	$0	$2,200,275	$0	$0	$1,417,565	$0	$0	$548,550	$0	$0	$19,518	$0	$0	$74,108
Total Labor Excluding A&G			$100,294,210	$50,022,929	$22,783,265	$27,488,016	$19,593,828	$7,650,632	$17,830,381	$5,354,005	$2,282,266	$6,461,958	$462,263	$190,762	$196,331	$5,495,579	$2,694,363	$1,021,568

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																		
580 OPERATION SUPERVISION AND ENGI	FO23	45	$1,081,711	$444,942	$0	$636,769	$3,107	$0	$7,072	$32,424	$0	$6,021	$70,740	$0	$15,713	$0	$0	$10,717
581 LOAD DISPATCHING	Acct362	29	$342,506	$342,506	$0	$0	$2,852	$0	$0	$28,028	$0	$0	$64,937	$0	$0	$0	$0	$0
582 STATION EXPENSES	Acct362	29	$870,967	$870,967	$0	$0	$7,252	$0	$0	$71,272	$0	$0	$165,130	$0	$0	$0	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$2,170,209	$1,723,315	$0	$446,894	$11,783	$0	$0	$115,807	$0	$0	$268,312	$0	$0	$0	$0	$0
584 UNDERGROUND LINE EXPENSES			$0	$0	$0	$0												
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$5,717,580	$0	$0	$5,717,580	$0	$0	$79,141	$0	$0	$66,568	$0	$0	$175,841	$0	$0	$119,925
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE			$0	$0	$0	$0												
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$3,343,041	$2,181,944	$0	$1,161,097	$13,852	$0	$2,218	$157,903	$0	$2,696	$315,429	$0	$4,927	$0	$0	$3,361
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Labor Expense			$13,526,014	$5,563,674	$0	$7,962,340	$38,846	$0	$88,430	$405,434	$0	$75,285	$884,547	$0	$196,481	$0	$0	$134,002
Distribution Maintenance Labor Expense																		
590 MAINTENANCE SUPERVISION AND EN			$0	$0	$0	$0												
591 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$605,269	$605,269	$0	$0	$5,040	$0	$0	$49,530	$0	$0	$114,755	$0	$0	$0	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$6,158,359	$4,890,217	$0	$1,268,142	$33,437	$0	$0	$328,624	$0	$0	$761,383	$0	$0	$0	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$413,802	$386,822	$0	$26,980	$3,163	$0	$0	$31,089	$0	$0	$72,029	$0	$0	$0	$0	$0
595 MAINTENANCE OF LINE TRANSFORME	Acct368	32	$51,420	$27,208	$0	$24,212	$0	$0	$0	$1,878	$0	$28	$0	$0	$0	$0	$0	$0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0	$0	$0	$0												
597 MAINTENANCE OF METERS			$0	$0	$0	$0												
598 MAINTENANCE OF MISC DISTR PLANT			$0	$0	$0	$0												
Total Distribution Maintenance Labor Expense			$7,228,850	$5,909,516	$0	$1,319,334	$41,640	$0	$0	$411,121	$0	$28	$948,167	$0	$0	$0	$0	$0
Total Distribution Labor Expense			$20,754,864	$11,473,190	$0	$9,281,674	$80,485	$0	$88,430	$816,555	$0	$75,313	$1,832,715	$0	$196,481	$0	$0	$134,002
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$3,259,518	$0	$0	$3,259,518	$0	$0	$4,218	$0	$0	$75,335	$0	$0	$33,767	$0	$0	$2,926
902 METER READING EXPENSES	MREAD	50	$754,379	$0	$0	$754,379	$0	$0	$1,004	$0	$0	$17,926	$0	$0	$8,035	$0	$0	$696
903 RECORDS AND COLLECTION	C05	33	$11,992,171	$0	$0	$11,992,171	$0	$0	$15,518	$0	$0	$277,166	$0	$0	$124,231	$0	$0	$10,764
904 UNCOLLECTIBLE ACCOUNTS			$0	$0	$0	$0												
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Labor Expense			$16,006,068	$0	$0	$16,006,068	$0	$0	$20,739	$0	$0	$370,427	$0	$0	$166,033	$0	$0	$14,386
Customer Service Expense																		
907 SUPERVISION	C05	33	$614,307	$0	$0	$614,307	$0	$0	$795	$0	$0	$14,198	$0	$0	$6,364	$0	$0	$551
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$1,585,968	$0	$0	$1,585,968	$0	$0	$2,052	$0	$0	$36,655	$0	$0	$16,430	$0	$0	$1,424
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA			$0	$0	$0	$0												
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE			$0	$0	$0	$0												
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 WATER HEATER - HEAT PUMP PROGRAM			$0	$0	$0	$0												
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Labor Expense			$2,200,275	$0	$0	$2,200,275	$0	$0	$2,847	$0	$0	$50,853	$0	$0	$22,793	$0	$0	$1,975
Total Labor Excluding A&G			$100,294,210	$50,022,929	$22,783,265	$27,488,016	$421,828	$207,963	$112,017	$4,238,603	$2,098,114	$496,593	$10,019,934	$5,042,753	$385,308	$2,897,859	$1,795,755	$150,363

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																		
580 OPERATION SUPERVISION AND ENGI	FO23	45	$1,081,711	$444,942	$0	$636,769	$0	$0	$454	$3,497	$0	$22,475	$15	$0	$3	$23	$0	$587
581 LOAD DISPATCHING	Acct362	29	$342,506	$342,506	$0	$0	$0	$0	$0	$2,818	$0	$0	$12	$0	$0	$18	$0	$0
582 STATION EXPENSES	Acct362	29	$870,967	$870,967	$0	$0	$0	$0	$0	$7,167	$0	$0	$30	$0	$0	$46	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$2,170,209	$1,723,315	$0	$446,894	$0	$0	$0	$13,602	$0	$15,684	$57	$0	$0	$88	$0	$72
584 UNDERGROUND LINE EXPENSES			$0	$0	$0	$0												
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$5,717,580	$0	$0	$5,717,580	$0	$0	$5,076	$0	$0	$0	$0	$0	$33	$0	$0	$6,402
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE			$0	$0	$0	$0												
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$3,343,041	$2,181,944	$0	$1,161,097	$0	$0	$142	$16,647	$0	$242,877	$70	$0	$1	$108	$0	$274
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Labor Expense			$13,526,014	$5,563,674	$0	$7,962,340	$0	$0	$5,672	$43,731	$0	$281,037	$183	$0	$38	$284	$0	$7,336
Distribution Maintenance Labor Expense																		
590 MAINTENANCE SUPERVISION AND EN			$0	$0	$0	$0												
591 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$605,269	$605,269	$0	$0	$0	$0	$0	$4,980	$0	$0	$21	$0	$0	$32	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$6,158,359	$4,890,217	$0	$1,268,142	$0	$0	$0	$38,598	$0	$44,507	$162	$0	$1	$250	$0	$205
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$413,802	$386,822	$0	$26,980	$0	$0	$0	$3,170	$0	$947	$13	$0	$0	$21	$0	$4
595 MAINTENANCE OF LINE TRANSFORME	Acct368	32	$51,420	$27,208	$0	$24,212	$0	$0	$0	$144	$0	$842	$1	$0	$0	$1	$0	$4
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0	$0	$0	$0												
597 MAINTENANCE OF METERS			$0	$0	$0	$0												
598 MAINTENANCE OF MISC DISTR PLANT			$0	$0	$0	$0												
Total Distribution Maintenance Labor Expense			$7,228,850	$5,909,516	$0	$1,319,334	$0	$0	$0	$46,892	$0	$46,295	$196	$0	$1	$304	$0	$213
Total Distribution Labor Expense			$20,754,864	$11,473,190	$0	$9,281,674	$0	$0	$5,672	$90,623	$0	$327,332	$380	$0	$39	$588	$0	$7,549
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$3,259,518	$0	$0	$3,259,518	$0	$0	$244	$0	$0	$91,279	$0	$0	$0	$0	$0	$419
902 METER READING EXPENSES	MREAD	50	$754,379	$0	$0	$754,379	$0	$0	$58	$0	$0	$0	$0	$0	$0	$0	$0	$573
903 RECORDS AND COLLECTION	C05	33	$11,992,171	$0	$0	$11,992,171	$0	$0	$897	$0	$0	$335,828	$0	$0	$0	$0	$0	$1,543
904 UNCOLLECTIBLE ACCOUNTS			$0	$0	$0	$0												
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Labor Expense			$16,006,068	$0	$0	$16,006,068	$0	$0	$1,199	$0	$0	$427,108	$0	$0	$0	$0	$0	$2,535
Customer Service Expense																		
907 SUPERVISION	C05	33	$614,307	$0	$0	$614,307	$0	$0	$46	$0	$0	$17,203	$0	$0	$0	$0	$0	$79
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$1,585,968	$0	$0	$1,585,968	$0	$0	$119	$0	$0	$44,413	$0	$0	$0	$0	$0	$204
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA			$0	$0	$0	$0												
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE			$0	$0	$0	$0												
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 WATER HEATER - HEAT PUMP PROGRAM			$0	$0	$0	$0												
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Labor Expense			$2,200,275	$0	$0	$2,200,275	$0	$0	$165	$0	$0	$61,616	$0	$0	$0	$0	$0	$283
Total Labor Excluding A&G			$100,294,210	$50,022,929	$22,783,265	$27,488,016	$1,192,135	$663,204	$7,035	$342,153	$155,023	$816,056	$1,320	$560	$39	$3,423	$1,869	$10,367

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$33,809,236	$16,862,758	$7,680,252	$9,266,226	$6,605,091	$2,579,032	$6,010,632	$1,804,838	$769,353	$2,178,330	$155,829	$64,306	$66,183	$1,852,563	$908,271	$344,371
921 OFFICE SUPPLIES AND EXPENSES			$0	$0	$0	$0												
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	35	-$3,161,163	-$1,576,668	-$718,104	-$866,392	-$617,576	-$241,140	-$561,994	-$168,752	-$71,935	-$203,674	-$14,570	-$6,013	-$6,188	-$173,215	-$84,923	-$32,199
923 OUTSIDE SERVICES EMPLOYED			$0	$0	$0	$0												
924 PROPERTY INSURANCE			$0	$0	$0	$0												
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$560,277	$279,445	$127,275	$153,557	$109,458	$42,739	$99,606	$29,909	$12,750	$36,099	$2,582	$1,066	$1,097	$30,700	$15,052	$5,707
926 EMPLOYEE BENEFITS	LBSUB7	35	$39,380,962	$19,641,723	$8,945,949	$10,793,290	$7,693,603	$3,004,054	$7,001,178	$2,102,273	$896,142	$2,537,316	$181,509	$74,904	$77,090	$2,157,863	$1,057,954	$401,123
928 REGULATORY COMMISSION FEES			$0	$0	$0	$0												
929 DUPLICATE CHARGES-CR			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES			$0	$0	$0	$0												
931 RENTS AND LEASES			$0	$0	$0	$0												
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$593,047	$539,732	$0	$53,315	$208,710	$0	$32,426	$57,215	$0	$8,292	$4,897	$0	$89	$60,055	$0	$730
Total Labor Administrative and General Expense			$71,182,359	$35,746,990	$16,035,372	$19,399,997	$13,999,285	$5,384,686	$12,581,848	$3,825,484	$1,606,310	$4,556,363	$330,248	$134,263	$138,271	$3,927,967	$1,896,353	$719,733
Total Labor Operation and Maintenance Expenses			$171,476,569	$85,769,919	$38,818,637	$46,888,013	$33,593,112	$13,035,318	$30,412,230	$9,179,488	$3,888,576	$11,018,320	$792,510	$325,025	$334,602	$9,423,545	$4,590,717	$1,741,301
Depreciation Expenses																		
Steam Production	Prod	24	$99,900,146	$99,900,146	$0	$0	$33,565,850	$0	$0	$10,067,138	$0	$0	$821,978	$0	$0	$11,921,684	$0	$0
Hydraulic Production	Prod	24	$1,118,831	$1,118,831	$0	$0	$375,920	$0	$0	$112,747	$0	$0	$9,206	$0	$0	$133,517	$0	$0
Other Production	Prod	24	$35,620,454	$35,620,454	$0	$0	$11,968,259	$0	$0	$3,589,544	$0	$0	$293,085	$0	$0	$4,250,803	$0	$0
Transmission - Kentucky System Property	Trans	25	$20,185,930	$20,185,930	$0	$0	$8,585,876	$0	$0	$2,173,687	$0	$0	$209,847	$0	$0	$1,916,315	$0	$0
Transmission - Virginia Property	Trans	25	$182,214	$182,214	$0	$0	$77,503	$0	$0	$19,621	$0	$0	$1,894	$0	$0	$17,298	$0	$0
Distribution	Dist	26	$43,044,393	$28,094,318	$0	$14,950,075	$15,155,153	$0	$9,092,644	$3,471,935	$0	$2,325,137	$311,530	$0	$24,845	$2,666,178	$0	$204,833
General Plant	PT&D	23	$11,631,105	$10,585,460	$0	$1,045,645	$4,093,308	$0	$635,962	$1,122,127	$0	$162,626	$96,040	$0	$1,738	$1,177,823	$0	$14,327
Intangible Plant	PT&D	23	$16,379,764	$14,907,211	$0	$1,472,553	$5,764,493	$0	$895,608	$1,580,261	$0	$229,021	$135,250	$0	$2,447	$1,658,695	$0	$20,176
Total Depreciation Expense			$228,062,837	$210,594,563	$0	$17,468,273	$79,586,362	$0	$10,624,214	$22,137,060	$0	$2,716,784	$1,878,831	$0	$29,030	$23,742,312	$0	$239,335
Regulatory Credits and Accretion Expenses																		
Production Plant			$0	$0	$0	$0												
Transmission Plant			$0	$0	$0	$0												
Distribution Plant			$0	$0	$0	$0												
Total Regulatory Credits and Accretion Expenses			$0	$0	$0	$0												
Property Taxes	TUP	34	$24,894,101	$22,644,793	$0	$2,249,308	$8,767,134	$0	$1,368,030	$2,401,478	$0	$349,828	$205,660	$0	$3,738	$2,517,477	$0	$30,818
Other Taxes	TUP	34	$12,926,774	$11,758,775	$0	$1,167,999	$4,552,515	$0	$710,378	$1,247,017	$0	$181,655	$106,793	$0	$1,941	$1,307,252	$0	$16,003
Gain Disposition of Allowances			$0	$0	$0	$0												
Interest	TUP	34	$86,095,200	$78,316,064	$0	$7,779,137	$30,320,764	$0	$4,731,276	$8,305,412	$0	$1,209,864	$711,266	$0	$12,928	$8,706,589	$0	$106,583
Other Expenses			$0	$0	$0	$0												
Total Other Expenses			$1,285,753,151	$536,408,451	$631,804,126	$117,540,575	$211,616,440	$212,380,817	$75,831,115	$57,550,320	$63,325,295	$25,071,648	$4,953,371	$5,301,031	$663,749	$58,879,562	$74,625,333	$3,490,838

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$33,809,236	$16,862,758	$7,680,252	$9,266,226	$142,198	$70,104	$37,761	$1,428,836	$707,275	$167,402	$3,377,726	$1,699,915	$129,887	$976,870	$605,350	$50,687
921 OFFICE SUPPLIES AND EXPENSES			$0	$0	$0	$0												
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	35	-$3,161,163	-$1,576,668	-$718,104	-$866,392	-$13,296	-$6,555	-$3,531	-$133,596	-$66,130	-$15,652	-$315,817	-$158,942	-$12,144	-$91,337	-$56,600	-$4,739
923 OUTSIDE SERVICES EMPLOYED			$0	$0	$0	$0												
924 PROPERTY INSURANCE			$0	$0	$0	$0												
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$560,277	$279,445	$127,275	$153,557	$2,356	$1,162	$626	$23,678	$11,721	$2,774	$55,975	$28,171	$2,152	$16,188	$10,032	$840
926 EMPLOYEE BENEFITS	LBSUB7	35	$39,380,962	$19,641,723	$8,945,949	$10,793,290	$165,633	$81,657	$43,984	$1,664,306	$823,834	$194,990	$3,934,371	$1,980,059	$151,293	$1,137,857	$705,111	$59,041
928 REGULATORY COMMISSION FEES			$0	$0	$0	$0												
929 DUPLICATE CHARGES-CR			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES			$0	$0	$0	$0												
931 RENTS AND LEASES			$0	$0	$0	$0												
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$593,047	$539,732	$0	$53,315	$4,526	$0	$102	$46,245	$0	$124	$107,770	$0	$226	$33,022	$0	$154
Total Labor Administrative and General Expense			$71,182,359	$35,746,990	$16,035,372	$19,399,997	$301,418	$146,369	$78,942	$3,029,469	$1,476,699	$349,637	$7,160,024	$3,549,202	$271,414	$2,072,599	$1,263,893	$105,983
Total Labor Operation and Maintenance Expenses			$171,476,569	$85,769,919	$38,818,637	$46,888,013	$723,246	$354,332	$190,958	$7,268,072	$3,574,813	$846,231	$17,179,958	$8,591,955	$656,722	$4,970,458	$3,059,648	$256,346
Depreciation Expenses																		
Steam Production	Prod	24	$99,900,146	$99,900,146	$0	$0	$913,986	$0	$0	$9,194,110	$0	$0	$22,114,296	$0	$0	$7,784,020	$0	$0
Hydraulic Production	Prod	24	$1,118,831	$1,118,831	$0	$0	$10,236	$0	$0	$102,969	$0	$0	$247,669	$0	$0	$87,177	$0	$0
Other Production	Prod	24	$35,620,454	$35,620,454	$0	$0	$325,892	$0	$0	$3,278,257	$0	$0	$7,885,086	$0	$0	$2,775,475	$0	$0
Transmission - Kentucky System Property	Trans	25	$20,185,930	$20,185,930	$0	$0	$150,701	$0	$0	$1,481,119	$0	$0	$3,431,582	$0	$0	$1,255,896	$0	$0
Transmission - Virginia Property	Trans	25	$182,214	$182,214	$0	$0	$1,360	$0	$0	$13,370	$0	$0	$30,976	$0	$0	$11,337	$0	$0
Distribution	Dist	26	$43,044,393	$28,094,318	$0	$14,950,075	$178,361	$0	$28,554	$2,033,129	$0	$34,719	$4,061,404	$0	$63,444	$0	$0	$43,270
General Plant	PT&D	23	$11,631,105	$10,585,460	$0	$1,045,645	$88,765	$0	$1,997	$906,981	$0	$2,428	$2,113,627	$0	$4,437	$647,633	$0	$3,026
Intangible Plant	PT&D	23	$16,379,764	$14,907,211	$0	$1,472,553	$125,005	$0	$2,813	$1,277,277	$0	$3,420	$2,976,563	$0	$6,249	$912,043	$0	$4,262
Total Depreciation Expense			$228,062,837	$210,594,563	$0	$17,468,273	$1,794,306	$0	$33,364	$18,287,214	$0	$40,567	$42,861,203	$0	$74,131	$13,473,580	$0	$50,558
Regulatory Credits and Accretion Expenses																		
Production Plant			$0	$0	$0	$0												
Transmission Plant			$0	$0	$0	$0												
Distribution Plant			$0	$0	$0	$0												
Total Regulatory Credits and Accretion Expenses			$0	$0	$0	$0												
Property Taxes	TUP	34	$24,894,101	$22,644,793	$0	$2,249,308	$189,713	$0	$4,296	$1,938,570	$0	$5,224	$4,516,400	$0	$9,545	$1,382,595	$0	$6,510
Other Taxes	TUP	34	$12,926,774	$11,758,775	$0	$1,167,999	$98,512	$0	$2,231	$1,006,642	$0	$2,712	$2,345,234	$0	$4,957	$717,941	$0	$3,381
Gain Disposition of Allowances			$0	$0	$0	$0												
Interest	TUP	34	$86,095,200	$78,316,064	$0	$7,779,137	$656,114	$0	$14,858	$6,704,461	$0	$18,065	$15,619,780	$0	$33,013	$4,781,645	$0	$22,515
Other Expenses			$0	$0	$0	$0												
Total Other Expenses			$1,285,753,151	$536,408,451	$631,804,126	$117,540,575	$4,434,366	$5,764,580	$377,648	$45,041,783	$58,174,839	$1,615,370	$105,459,081	$139,741,307	$1,271,898	$31,717,509	$49,746,414	$510,779

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$33,809,236	$16,862,758	$7,680,252	$9,266,226	$401,870	$223,567	$2,371	$115,340	$52,258	$275,093	$445	$189	$13	$1,154	$630	$3,495
921 OFFICE SUPPLIES AND EXPENSES			$0	$0	$0	$0												
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	35	-$3,161,163	-$1,576,668	-$718,104	-$866,392	-$37,575	-$20,903	-$222	-$10,784	-$4,886	-$25,721	-$42	-$18	-$1	-$108	-$59	-$327
923 OUTSIDE SERVICES EMPLOYED			$0	$0	$0	$0												
924 PROPERTY INSURANCE			$0	$0	$0	$0												
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$560,277	$279,445	$127,275	$153,557	$6,660	$3,705	$39	$1,911	$866	$4,559	$7	$3	$0	$19	$10	$58
926 EMPLOYEE BENEFITS	LBSUB7	35	$39,380,962	$19,641,723	$8,945,949	$10,793,290	$468,097	$260,410	$2,762	$134,348	$60,871	$320,428	$518	$220	$15	$1,344	$734	$4,071
928 REGULATORY COMMISSION FEES			$0	$0	$0	$0												
929 DUPLICATE CHARGES-CR			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES			$0	$0	$0	$0												
931 RENTS AND LEASES			$0	$0	$0	$0												
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$593,047	$539,732	$0	$53,315	$13,608	$0	$7	$3,634	$0	$11,152	$14	$0	$0	$37	$0	$13
Total Labor Administrative and General Expense			$71,182,359	$35,746,990	$16,035,372	$19,399,997	$852,660	$466,778	$4,958	$244,449	$109,109	$585,511	$943	$394	$27	$2,447	$1,316	$7,309
Total Labor Operation and Maintenance Expenses			$171,476,569	$85,769,919	$38,818,637	$46,888,013	$2,044,795	$1,129,982	$11,993	$586,601	$264,132	$1,401,567	$2,262	$954	$66	$5,870	$3,185	$17,677
Depreciation Expenses																		
Steam Production	Prod	24	$99,900,146	$99,900,146	$0	$0	$2,873,128	$0	$0	$633,767	$0	$0	$2,298	$0	$0	$7,892	$0	$0
Hydraulic Production	Prod	24	$1,118,831	$1,118,831	$0	$0	$32,178	$0	$0	$7,098	$0	$0	$26	$0	$0	$88	$0	$0
Other Production	Prod	24	$35,620,454	$35,620,454	$0	$0	$1,024,444	$0	$0	$225,976	$0	$0	$819	$0	$0	$2,814	$0	$0
Transmission - Kentucky System Property	Trans	25	$20,185,930	$20,185,930	$0	$0	$830,386	$0	$0	$148,930	$0	$0	$624	$0	$0	$966	$0	$0
Transmission - Virginia Property	Trans	25	$182,214	$182,214	$0	$0	$7,496	$0	$0	$1,344	$0	$0	$6	$0	$0	$9	$0	$0
Distribution	Dist	26	$43,044,393	$28,094,318	$0	$14,950,075	$0	$0	$1,831	$214,340	$0	$3,127,245	$898	$0	$18	$1,390	$0	$3,534
General Plant	PT&D	23	$11,631,105	$10,585,460	$0	$1,045,645	$266,888	$0	$128	$71,264	$0	$218,727	$273	$0	$1	$731	$0	$247
Intangible Plant	PT&D	23	$16,379,764	$14,907,211	$0	$1,472,553	$375,851	$0	$180	$100,359	$0	$308,028	$385	$0	$2	$1,029	$0	$348
Total Depreciation Expense			$228,062,837	$210,594,563	$0	$17,468,273	$5,410,371	$0	$2,140	$1,403,078	$0	$3,654,000	$5,328	$0	$21	$14,919	$0	$4,130
Regulatory Credits and Accretion Expenses																		
Production Plant			$0	$0	$0	$0												
Transmission Plant			$0	$0	$0	$0												
Distribution Plant			$0	$0	$0	$0												
Total Regulatory Credits and Accretion Expenses			$0	$0	$0	$0												
Property Taxes	TUP	34	$24,894,101	$22,644,793	$0	$2,249,308	$571,073	$0	$276	$152,548	$0	$470,509	$585	$0	$3	$1,560	$0	$532
Other Taxes	TUP	34	$12,926,774	$11,758,775	$0	$1,167,999	$296,541	$0	$143	$79,214	$0	$244,321	$304	$0	$1	$810	$0	$276
Gain Disposition of Allowances			$0	$0	$0	$0												
Interest	TUP	34	$86,095,200	$78,316,064	$0	$7,779,137	$1,975,032	$0	$953	$527,580	$0	$1,627,234	$2,024	$0	$9	$5,395	$0	$1,839
Other Expenses			$0	$0	$0	$0												
Total Other Expenses			$1,285,753,151	$536,408,451	$631,804,126	$117,540,575	$13,258,889	$18,402,515	$23,747	$3,447,877	$4,274,793	$8,643,640	$13,310	$15,434	$148	$35,942	$51,767	$39,993

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Amount

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)		1	18,343,080,487	-	18,343,080,487	-		6,091,971,051			1,817,505,619			151,861,000			2,146,594,132	
Energy (Loss Adjusted)(at Source)	Energy	2	19,428,782,556	-	19,428,782,556	-		6,522,592,615			1,945,979,163			162,595,559			2,298,329,870	
Customers (Monthly Bills)	Bills	3	8,273,588	-	-	8,273,588			5,168,140			999,948			7,118			54,034
Average Customers (Bills/12)	Cust	4	689,466	-	-	689,466			430,678			83,329			593			4,503
Average Customers (Lighting = Lights)	Cust	5	689,466	-	-	689,466			430,678			83,329			593			4,503
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	668,477	-	-	668,477			430,678			166,658			5,930			22,515
Street Lighting	Lighting	7	114,827,799	-	-	114,827,799			-			-			-			-
Average Customers	Customers	8	689,466	-	-	689,466			430,678			83,329			593			4,503
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	539,008	-	-	539,008			430,678			83,329			593			4,503
Average Secondary Customers	CUST07	10	533,407	-	-	533,407			430,678			83,329			593			-
Average Primary Customers	CUST08	11	538,978	-	-	538,978			430,678			83,329			593			4,503
Average Transformer Customers	CUST09	12	538,528	-	-	538,528			430,678			83,329			593			4,503
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	5,021,135	5,021,135	-	-	2,135,688			540,692			52,198			476,672		
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	4,502,184	4,502,184	-	-	2,135,688			540,692			52,198			476,672		
Sum of the Individual Customer Demands (Transformer)	SICDT	15	6,459,671	6,459,671	-	-	4,481,645			807,122			56,694			633,729		
Sum of the Individual Customer Demands (Secondary)	SICD	16	5,379,998	5,379,998	-	-	4,481,645			807,122			56,694			-		
Summer Peak Period Demand Allocator	SCP	17	3,586,335	3,586,335	-	-	1,347,051			403,389			27,081			425,406		
Winter Peak Period Demand Allocator	WCP	18	3,808,066	3,808,066	-	-	1,652,086			444,103			36,655			416,731		
Base Demand Allocator	BDEM	19	2,211,838	2,211,838	-	-	742,554			221,537			18,510			261,650		
Weighted cost of Services	C02	20	1	-	-	1			70.13162%			27.47067%			0.26016%			1.86639%
Weighted Cost of Meters	C03	21	1	-	-	1			62.14626%			23.16177%			0.49130%			6.27799%
Lighting Systems -- Lighting Customers	C04	22	1	-	-	1												
PT&D Plant	PT&D	23	6,689,755,615	6,088,341,503	-	601,414,112	$2,354,310,373	$0	$365,780,419 $0	$645,403,618	$0	$93,536,000 $0	$55,238,291	$0	$999,465 $0	$677,437,557	$0	$8,240,063
Production Plant	Prod	24	4,076,920,355	4,076,920,355	-	-	$1,369,820,778	$0	$0 $0	$410,839,418	$0	$0 $0	$33,544,901	$0	$0 $0	$486,523,368	$0	$0
Transmission Plant	Trans	25	881,238,248	881,238,248	-	-	$374,825,553	$0	$0 $0	$94,894,628	$0	$0 $0	$9,161,093	$0	$0 $0	$83,658,755	$0	$0
Distribution Plant	Dist	26	1,731,597,011	1,130,182,900	-	601,414,112	$609,664,042	$0	$365,780,419 $0	$139,669,572	$0	$93,536,000 $0	$12,532,297	$0	$999,465 $0	$107,255,435	$0	$8,240,063
Total Plant in Service	TPIS	27	6,970,753,239	6,344,072,283	-	626,680,956	$2,453,196,921	$0	$381,147,728 $0	$672,512,624	$0	$97,465,671 $0	$57,558,406	$0	$1,041,455 $0	$705,893,179	$0	$8,586,247
Distrib Overhead + Underground Lines Plant	DLINES	28	918,042,686	757,271,917	-	160,770,769	$396,944,443	$0	$129,807,856 $0	$94,092,436	$0	$25,115,652 $0	$8,668,735	$0	$178,732 $0	$69,041,782	$0	$0
Account 362	Acct362	29	209,650,161	209,650,161	-	-	$99,451,124	$0	$0 $0	$25,178,052	$0	$0 $0	$2,430,680	$0	$0 $0	$22,196,878	$0	$0
Account 365	Acct365	30	717,117,865	569,447,513	-	147,670,352	$306,643,341	$0	$119,230,454 $0	$71,435,145	$0	$23,069,101 $0	$6,494,646	$0	$164,168 $0	$49,510,971	$0	$0
Account 367	Acct367	31	200,924,821	187,824,404	-	13,100,417	$90,301,102	$0	$10,577,402 $0	$22,657,291	$0	$2,046,551 $0	$2,174,089	$0	$14,564 $0	$19,530,811	$0	$0
Account 368	Acct368	32	308,543,267	163,260,822	-	145,282,445	$113,268,475	$0	$116,186,976 $0	$20,399,084	$0	$22,480,239 $0	$1,432,882	$0	$159,978 $0	$16,016,774	$0	$1,214,805
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	668,477	-	-	668,477			430678			166658			5930			22515
Total Utility Plant	TUP	34	7,089,457,179	6,448,888,874	-	640,568,305	$2,496,744,988	$0	$389,594,023 $0	$683,904,150	$0	$99,625,526 $0	$58,568,789	$0	$1,064,534 $0	$716,938,769	$0	$8,776,520
Total Labor Excluding A&G	LBSUB7	35	100,294,210	50,022,929	22,783,265	27,488,016	$19,593,828	$7,650,632	$17,830,381 $0	$5,354,005	$2,282,266	$6,461,958 $0	$462,263	$190,762	$196,331 $0	$5,495,579	$2,694,363	$1,021,568
Steam Power Operation Labor	LBSUB1	36	18,373,986	15,855,691	2,518,295	-	$5,327,417	$846,789	$0 $0	$1,597,810	$252,450	$0 $0	$130,461	$21,142	$0 $0	$1,892,155	$297,337	$0
Total Steam Power Maintenance Labor Expense	LBSUB2	37	21,340,020	2,058,618	19,281,401	-	$ 691,683	$ 6,473,114	$ - $-	$ 207,451	$ 1,931,217	$ - $-	$ 16,938	$ 161,362	$ - $-	$ 245,667	$ 2,280,895	$ -
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	213,877	213,877	-	-	$71,861	$0	$0 $0	$21,553	$0	$0 $0	$1,760	$0	$0 $0	$25,523	$0	$0
Total Other Power Operating Labor Expense	LBSUB5	39	2,838,080	2,838,080	-	-	$953,578	$0	$0 $0	$285,999	$0	$0 $0	$23,352	$0	$0 $0	$338,685	$0	$0
Total Distribution Operation Labor Expense	LBDO	40	13,526,014	5,563,674	-	7,962,340	$2,913,662	$0	$5,021,881 $0	$686,462	$0	$1,711,567 $0	$62,953	$0	$33,169 $0	$527,572	$0	$407,441
Total Distribution Maintenance Labor Expense	LBDM	41	7,228,850	5,909,516	-	1,319,334	$3,125,317	$0	$1,065,057 $0	$736,212	$0	$206,071 $0	$67,508	$0	$1,466 $0	$532,159	$0	$202
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	18,373,986	15,855,691	2,518,295	-	$5,327,417	$846,789	$0 $0	$1,597,810	$252,450	$0 $0	$130,461	$21,142	$0 $0	$1,892,155	$297,337	$0
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	12,842,398	1,238,874	11,603,523	-	$416,254	$3,895,512	$0 $0	$124,844	$1,162,204	$0 $0	$10,193	$97,108	$0 $0	$147,842	$1,372,640	$0
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	12,444,303	5,118,732	-	7,325,570	$2,680,649	$0	$4,620,268 $0	$631,564	$0	$1,574,688 $0	$57,919	$0	$30,517 $0	$485,381	$0	$374,857
Purchased Power	PURCPWR	46	50,619,307	7,292,915	43,326,391	-	$3,163,949	$14,545,451	$0 $0	$850,511	$4,339,554	$0 $0	$70,199	$362,590	$0 $0	$798,092	$5,125,300	$0
Acct 502: Steam Expense	OM502	47	15,516,429	15,516,429	-	-	$6,731,627	$0	$0 $0	$1,809,550	$0	$0 $0	$149,355	$0	$0 $0	$1,698,023	$0	$0
Acct 505: Electric Expense	OM505	48	7,214,388	7,214,388	-	-	$3,129,880	$0	$0 $0	$841,353	$0	$0 $0	$69,443	$0	$0 $0	$789,498	$0	$0
Total O&M Expense Less Purchased Power	O&MxPurch	49	883,154,932	205,801,340	588,477,735	88,875,857	$85,225,716	$197,835,367	$58,397,217 $0	$22,608,840	$58,985,741	$20,613,517 $0	$1,980,622	$4,938,441	$616,113 $0	$21,807,841	$69,500,033	$3,098,099
Meter Reading	MREAD	50	650,165	-	-	650,165			430678			166658			5930			22515
Time Differentiated Fuel Cost	TDFUEL	51	100.0000%		100.00%			33.63%			10.02%			0.84%			11.81%	
Probability of Dispatch Gross Plant	PODPLT	52	100.0000%	100.0000%			33.5994%			10.0772%			0.8228%			11.9336%		
Probability of Dispatch Depreciation Reserve	PODRES	53	100.0000%	100.0000%			33.7039%			10.1396%			0.8216%			11.9405%		
Memo: Purchased Pwer Expense																		
Demand	Production Plant		$7,292,915	$7,292,915			$3,163,949	$0	$0 $0	$850,511	$0	$0 $0	$70,199	$0	$0 $0	$798,092	$0	$0
Energy	Energy @ Source		$43,326,391		$43,326,391		$0	$14,545,451	$0 $0	$0	$4,339,554	$0 $0	$0	$362,590	$0 $0	$0	$5,125,300	$0
Total			$50,619,307				$3,163,949	$14,545,451	$0 $0	$850,511	$4,339,554	$0 $0	$70,199	$362,590	$0 $0	$798,092	$5,125,300	$0
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		$15,516,429	$15,516,429			$6,731,627	$0	$0 $0	$1,809,550	$0	$0 $0	$149,355	$0	$0 $0	$1,698,023	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0
Total			$15,516,429				$6,731,627	$0	$0 $0	$1,809,550	$0	$0 $0	$149,355	$0	$0 $0	$1,698,023	$0	$0
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		$7,214,388	$7,214,388			$3,129,880	$0	$0 $0	$841,353	$0	$0 $0	$69,443	$0	$0 $0	$789,498	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0
Total			$7,214,388				$3,129,880	$0	$0 $0	$841,353	$0	$0 $0	$69,443	$0	$0 $0	$789,498	$0	$0
Time Differentiated Fuel Cost																		
Fuel Cost Per KWH @ Meter								0.023217			0.0232			0.023254			0.023136	
KWH @ Meter								6,091,971,051			1,817,505,619			151,861,000			2,146,594,132	
Time Differentiated Fuel Cost					420,625,506			141,437,292			42,166,130			3,531,376			49,663,602	
Pct Allocation			100.00%		100.00%			33.63%			10.02%			0.84%			11.81%	

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Amount

	Allocation Factor		Total Kentucky				Power Service-Primary (PS-Pri)				Time of Day-Sec (TOU-Sec)				Time of Day-Pri (TOU-Pri)				Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer		Demand	Energy	Customer		Demand	Energy	Customer		Demand	Energy	Customer
Energy (at the Meter)		1	18,343,080,487	-	18,343,080,487	-		169,814,471				1,671,130,915				4,118,000,917				1,497,714,279	
Energy (Loss Adjusted)(at Source)	Energy	2	19,428,782,556	-	19,428,782,556	-		177,361,189				1,789,257,708				4,301,008,844				1,531,734,094	
Customers (Monthly Bills)	Bills	3	8,273,588	-	-	8,273,588			2,070				7,419				3,318				360
Average Customers (Bills/12)	Cust	4	689,466	-	-	689,466			173				618				277				30
Average Customers (Lighting = Lights)	Cust	5	689,466	-	-	689,466			173				618				277				30
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	668,477	-	-	668,477			865				15,450				6,925				600
Street Lighting	Lighting	7	114,827,799	-	-	114,827,799			-				-				-				-
Average Customers	Customers	8	689,466	-	-	689,466			173				618				277				30
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	539,008	-	-	539,008			173				618				277				30
Average Secondary Customers	CUST07	10	533,407	-	-	533,407			-				-				-				-
Average Primary Customers	CUST08	11	538,978	-	-	538,978			173				618				277				-
Average Transformer Customers	CUST09	12	538,528	-	-	538,528			-				618				-				-
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	5,021,135	5,021,135	-	-	37,486				368,420				853,586				312,397		
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	4,502,184	4,502,184	-	-	37,486				368,420				853,586				-		
Sum of the Individual Customer Demands (Transformer)	SICDT	15	6,459,671	6,459,671	-	-	-				445,944				-				-		
Sum of the Individual Customer Demands (Secondary)	SICD	16	5,379,998	5,379,998	-	-	-				-				-				-		
Summer Peak Period Demand Allocator	SCP	17	3,586,335	3,586,335	-	-	31,910				313,580				686,213				255,097		
Winter Peak Period Demand Allocator	WCP	18	3,808,066	3,808,066	-	-	26,376				278,979				645,717				223,271		
Base Demand Allocator	BDEM	19	2,211,838	2,211,838	-	-	20,191				203,695				489,641				174,378		
Weighted cost of Services	C02	20	1	-	-	1			0.00000%				0.27116%				0.00000%				0.00000%
Weighted Cost of Meters	C03	21	1	-	-	1			1.38416%				1.16427%				3.07544%				2.09749%
Lighting Systems -- Lighting Customers	C04	22	1	-	-	1															
PT&D Plant	PT&D	23	6,689,755,615	6,088,341,503	-	601,414,112	$51,053,888	$0	$1,148,686	$0	$521,660,126	$0	$1,396,662	$0	$1,215,675,567	$0	$2,552,238	$0	$372,492,977	$0	$1,740,656
Production Plant	Prod	24	4,076,920,355	4,076,920,355	-	-	$37,299,744	$0	$0	$0	$375,211,211	$0	$0	$0	$902,483,397	$0	$0	$0	$317,665,480	$0	$0
Transmission Plant	Trans	25	881,238,248	881,238,248	-	-	$6,579,025	$0	$0	$0	$64,659,843	$0	$0	$0	$149,809,343	$0	$0	$0	$54,827,497	$0	$0
Distribution Plant	Dist	26	1,731,597,011	1,130,182,900	-	601,414,112	$7,175,118	$0	$1,148,686	$0	$81,789,072	$0	$1,396,662	$0	$163,382,826	$0	$2,552,238	$0	$0	$0	$1,740,656
Total Plant in Service	TPIS	27	6,970,753,239	6,344,072,283	-	626,680,956	$53,198,378	$0	$1,196,946	$0	$543,572,335	$0	$1,455,339	$0	$1,266,739,805	$0	$2,659,464	$0	$388,138,922	$0	$1,813,785
Distrib Overhead + Underground Lines Plant	DLINES	28	918,042,686	757,271,917	-	160,770,769	$5,429,529	$0	$0	$0	$53,362,386	$0	$0	$0	$123,634,449	$0	$0	$0	$0	$0	$0
Account 362	Acct362	29	209,650,161	209,650,161	-	-	$1,745,589	$0	$0	$0	$17,155,965	$0	$0	$0	$39,748,378	$0	$0	$0	$0	$0	$0
Account 365	Acct365	30	717,117,865	569,447,513	-	147,670,352	$3,893,602	$0	$0	$0	$38,267,025	$0	$0	$0	$88,660,249	$0	$0	$0	$0	$0	$0
Account 367	Acct367	31	200,924,821	187,824,404	-	13,100,417	$1,535,927	$0	$0	$0	$15,095,362	$0	$0	$0	$34,974,200	$0	$0	$0	$0	$0	$0
Account 368	Acct368	32	308,543,267	163,260,822	-	145,282,445	$0	$0	$0	$0	$11,270,721	$0	$166,722	$0	$0	$0	$0	$0	$0	$0	$0
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	668,477	-	-	668,477			865				15450				6925				600
Total Utility Plant	TUP	34	7,089,457,179	6,448,888,874	-	640,568,305	$54,027,345	$0	$1,223,470	$0	$552,074,809	$0	$1,487,590	$0	$1,286,201,354	$0	$2,718,398	$0	$393,741,670	$0	$1,853,979
Total Labor Excluding A&G	LBSUB7	35	100,294,210	50,022,929	22,783,265	27,488,016	$421,828	$207,963	$112,017	$0	$4,238,603	$2,098,114	$496,593	$0	$10,019,934	$5,042,753	$385,308	$0	$2,897,859	$1,795,755	$150,363
Steam Power Operation Labor	LBSUB1	36	18,373,986	15,855,691	2,518,295	-	$145,064	$22,974	$0	$0	$1,459,247	$231,868	$0	$0	$3,509,879	$556,873	$0	$0	$1,235,444	$198,221	$0
Total Steam Power Maintenance Labor Expense	LBSUB2	37	21,340,020	2,058,618	19,281,401	-	$ 18,834	$ 176,016	$ -	$-	$ 189,461	$ 1,775,685	$ -	$-	$ 455,704	$ 4,268,383	$ -	$-	$ 160,403	$ 1,520,115	$ -
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	213,877	213,877	-	-	$1,957	$0	$0	$0	$19,684	$0	$0	$0	$47,345	$0	$0	$0	$16,665	$0	$0
Total Other Power Operating Labor Expense	LBSUB5	39	2,838,080	2,838,080	-	-	$25,966	$0	$0	$0	$261,197	$0	$0	$0	$628,249	$0	$0	$0	$221,138	$0	$0
Total Distribution Operation Labor Expense	LBDO	40	13,526,014	5,563,674	-	7,962,340	$38,846	$0	$88,430	$0	$405,434	$0	$75,285	$0	$884,547	$0	$196,481	$0	$0	$0	$134,002
Total Distribution Maintenance Labor Expense	LBDM	41	7,228,850	5,909,516	-	1,319,334	$41,640	$0	$0	$0	$411,121	$0	$28	$0	$948,167	$0	$0	$0	$0	$0	$0
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	18,373,986	15,855,691	2,518,295	-	$145,064	$22,974	$0	$0	$1,459,247	$231,868	$0	$0	$3,509,879	$556,873	$0	$0	$1,235,444	$198,221	$0
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	12,842,398	1,238,874	11,603,523	-	$11,334	$105,926	$0	$0	$114,017	$1,068,605	$0	$0	$274,242	$2,568,707	$0	$0	$96,531	$914,803	$0
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																			
Distribution Operation Labor Excl. Super. & Eng	FO23	45	12,444,303	5,118,732	-	7,325,570	$35,739	$0	$81,358	$0	$373,010	$0	$69,265	$0	$813,808	$0	$180,768	$0	$0	$0	$123,286
Purchased Power	PURCPWR	46	50,619,307	7,292,915	43,326,391	-	$50,513	$395,517	$0	$0	$534,280	$3,990,064	$0	$0	$1,236,628	$9,591,295	$0	$0	$427,591	$3,415,783	$0
Acct 502: Steam Expense	OM502	47	15,516,429	15,516,429	-	-	$107,473	$0	$0	$0	$1,136,735	$0	$0	$0	$2,631,054	$0	$0	$0	$909,744	$0	$0
Acct 505: Electric Expense	OM505	48	7,214,388	7,214,388	-	-	$49,970	$0	$0	$0	$528,527	$0	$0	$0	$1,223,313	$0	$0	$0	$422,987	$0	$0
Total O&M Expense Less Purchased Power	O&MxPurch	49	883,154,932	205,801,340	588,477,735	88,875,857	$1,645,207	$5,369,063	$322,899	$0	$16,570,616	$54,184,775	$1,548,802	$0	$38,879,836	$130,150,011	$1,150,253	$0	$10,934,157	$46,330,631	$427,816
Meter Reading	MREAD	50	650,165	-	-	650,165			865				15450				6925				600
Time Differentiated Fuel Cost	TDFUEL	51	100.0000%		100.00%			0.91%				9.21%				22.11%				7.87%	
Probability of Dispatch Gross Plant	PODPLT	52	100.0000%	100.0000%			0.9149%				9.2033%				22.1364%				7.7918%		
Probability of Dispatch Depreciation Reserve	PODRES	53	100.0000%	100.0000%			0.9129%				9.1833%				22.0740%				7.7634%		
Memo: Purchased Pwer Expense																					
Demand	Production Plant		$7,292,915	$7,292,915			$50,513	$0	$0	$0	$534,280	$0	$0	$0	$1,236,628	$0	$0	$0	$427,591	$0	$0
Energy	Energy @ Source		$43,326,391		$43,326,391		$0	$395,517	$0	$0	$0	$3,990,064	$0	$0	$0	$9,591,295	$0	$0	$0	$3,415,783	$0
Total			$50,619,307				$50,513	$395,517	$0	$0	$534,280	$3,990,064	$0	$0	$1,236,628	$9,591,295	$0	$0	$427,591	$3,415,783	$0
Memo: Acct 502: Steam Expense																					
Demand	Production Plant		$15,516,429	$15,516,429			$107,473	$0	$0	$0	$1,136,735	$0	$0	$0	$2,631,054	$0	$0	$0	$909,744	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$15,516,429				$107,473	$0	$0	$0	$1,136,735	$0	$0	$0	$2,631,054	$0	$0	$0	$909,744	$0	$0
Memo: Acct 505: Electric Expense																					
Demand	Production Plant		$7,214,388	$7,214,388			$49,970	$0	$0	$0	$528,527	$0	$0	$0	$1,223,313	$0	$0	$0	$422,987	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$7,214,388				$49,970	$0	$0	$0	$528,527	$0	$0	$0	$1,223,313	$0	$0	$0	$422,987	$0	$0
Time Differentiated Fuel Cost																					
Fuel Cost Per KWH @ Meter								0.022597				0.023175				0.022587				0.022106	
KWH @ Meter								169,814,471				1,671,130,915				4,118,000,917				1,497,714,279	
Time Differentiated Fuel Cost					420,625,506			3,837,298				38,728,459				93,013,287				33,108,472	
Pct Allocation			100.00%		100.00%			0.91%				9.21%				22.11%				7.87%	

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Amount

	Allocation Factor		Total Kentucky				Fluctuating Load Service (FLS)			Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)		1	18,343,080,487	-	18,343,080,487	-		552,917,598			123,634,653			446,721			1,489,131	
Energy (Loss Adjusted)(at Source)	Energy	2	19,428,782,556	-	19,428,782,556	-		565,476,838			132,373,983			478,298			1,594,393	
Customers (Monthly Bills)	Bills	3	8,273,588	-	-	8,273,588			12			2,021,809			48			9,312
Average Customers (Bills/12)	Cust	4	689,466	-	-	689,466			1			168,484			4			776
Average Customers (Lighting = Lights)	Cust	5	689,466	-	-	689,466			1			168,484			4			776
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	668,477	-	-	668,477			50			18,720			-			86
Street Lighting	Lighting	7	114,827,799	-	-	114,827,799			-			114,827,799			-			-
Average Customers	Customers	8	689,466	-	-	689,466			1			168,484			4			776
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	539,008	-	-	539,008			1			18,720			-			86
Average Secondary Customers	CUST07	10	533,407	-	-	533,407			-			18,720			0			86
Average Primary Customers	CUST08	11	538,978	-	-	538,978			-			18,720			0			86
Average Transformer Customers	CUST09	12	538,528	-	-	538,528			-			18,720			0			86
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	5,021,135	5,021,135	-	-	206,554			37,046			155			240		
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	4,502,184	4,502,184	-	-	-			37,046			155			240		
Sum of the Individual Customer Demands (Transformer)	SICDT	15	6,459,671	6,459,671	-	-	-			34,173			143			221		
Sum of the Individual Customer Demands (Secondary)	SICD	16	5,379,998	5,379,998	-	-	-			34,173			143			221		
Summer Peak Period Demand Allocator	SCP	17	3,586,335	3,586,335	-	-	96,438			-			-			170		
Winter Peak Period Demand Allocator	WCP	18	3,808,066	3,808,066	-	-	83,946			-			-			201		
Base Demand Allocator	BDEM	19	2,211,838	2,211,838	-	-	64,376			15,070			54			182		
Weighted cost of Services	C02	20	1	-	-	1			0.00000%			0.00000%			0.00000%			0.00000%
Weighted Cost of Meters	C03	21	1	-	-	1			0.08877%			0.00000%			0.00058%			0.11198%
Lighting Systems -- Lighting Customers	C04	22	1	-	-	1						100.00000%						
PT&D Plant	PT&D	23	6,689,755,615	6,088,341,503	-	601,414,112	$153,503,612	$0	$73,672 $0	$40,988,197	$0	$125,803,342 $0	$157,119	$0	$733 $0	$420,178	$0	$142,175
Production Plant	Prod	24	4,076,920,355	4,076,920,355	-	-	$117,252,229	$0	$0 $0	$25,863,983	$0	$0 $0	$93,769	$0	$0 $0	$322,077	$0	$0
Transmission Plant	Trans	25	881,238,248	881,238,248	-	-	$36,251,382	$0	$0 $0	$6,501,718	$0	$0 $0	$27,233	$0	$0 $0	$42,177	$0	$0
Distribution Plant	Dist	26	1,731,597,011	1,130,182,900	-	601,414,112	$0	$0	$73,672 $0	$8,622,496	$0	$125,803,342 $0	$36,117	$0	$733 $0	$55,924	$0	$142,175
Total Plant in Service	TPIS	27	6,970,753,239	6,344,072,283	-	626,680,956	$159,950,366	$0	$76,767 $0	$42,709,800	$0	$131,088,642 $0	$163,718	$0	$764 $0	$437,828	$0	$148,148
Distrib Overhead + Underground Lines Plant	DLINES	28	918,042,686	757,271,917	-	160,770,769	$0	$0	$0 $0	$6,033,747	$0	$5,642,407 $0	$25,273	$0	$134 $0	$39,137	$0	$25,988
Account 362	Acct362	29	209,650,161	209,650,161	-	-	$0	$0	$0 $0	$1,725,078	$0	$0 $0	$7,226	$0	$0 $0	$11,191	$0	$0
Account 365	Acct365	30	717,117,865	569,447,513	-	147,670,352	$0	$0	$0 $0	$4,494,556	$0	$5,182,635 $0	$18,826	$0	$123 $0	$29,152	$0	$23,870
Account 367	Acct367	31	200,924,821	187,824,404	-	13,100,417	$0	$0	$0 $0	$1,539,191	$0	$459,772 $0	$6,447	$0	$11 $0	$9,985	$0	$2,118
Account 368	Acct368	32	308,543,267	163,260,822	-	145,282,445	$0	$0	$0 $0	$863,672	$0	$5,050,343 $0	$3,618	$0	$120 $0	$5,596	$0	$23,261
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	668,477	-	-	668,477			50			18720			0			86
Total Utility Plant	TUP	34	7,089,457,179	6,448,888,874	-	640,568,305	$162,632,826	$0	$78,469 $0	$43,443,259	$0	$133,993,587 $0	$166,630	$0	$781 $0	$444,286	$0	$151,431
Total Labor Excluding A&G	LBSUB7	35	100,294,210	50,022,929	22,783,265	27,488,016	$1,192,135	$663,204	$7,035 $0	$342,153	$155,023	$816,056 $0	$1,320	$560	$39 $0	$3,423	$1,869	$10,367
Steam Power Operation Labor	LBSUB1	36	18,373,986	15,855,691	2,518,295	-	$456,010	$73,364	$0 $0	$100,589	$17,010	$0 $0	$365	$61	$0 $0	$1,253	$206	$0
Total Steam Power Maintenance Labor Expense	LBSUB2	37	21,340,020	2,058,618	19,281,401	-	$ 59,206	$ 561,187	$ - $-	$ 13,060	$ 131,370	$ - $-	$ 47	$ 475	$ - $-	$ 163	$ 1,582	$ -
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	213,877	213,877	-	-	$6,151	$0	$0 $0	$1,357	$0	$0 $0	$5	$0	$0 $0	$17	$0	$0
Total Other Power Operating Labor Expense	LBSUB5	39	2,838,080	2,838,080	-	-	$81,623	$0	$0 $0	$18,005	$0	$0 $0	$65	$0	$0 $0	$224	$0	$0
Total Distribution Operation Labor Expense	LBDO	40	13,526,014	5,563,674	-	7,962,340	$0	$0	$5,672 $0	$43,731	$0	$281,037 $0	$183	$0	$38 $0	$284	$0	$7,336
Total Distribution Maintenance Labor Expense	LBDM	41	7,228,850	5,909,516	-	1,319,334	$0	$0	$0 $0	$46,892	$0	$46,295 $0	$196	$0	$1 $0	$304	$0	$213
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	18,373,986	15,855,691	2,518,295	-	$456,010	$73,364	$0 $0	$100,589	$17,010	$0 $0	$365	$61	$0 $0	$1,253	$206	$0
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	12,842,398	1,238,874	11,603,523	-	$35,630	$337,722	$0 $0	$7,859	$79,058	$0 $0	$28	$286	$0 $0	$98	$952	$0
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	12,444,303	5,118,732	-	7,325,570	$0	$0	$5,218 $0	$40,233	$0	$258,562 $0	$169	$0	$35 $0	$261	$0	$6,749
Purchased Power	PURCPWR	46	50,619,307	7,292,915	43,326,391	-	$160,767	$1,261,019	$0 $0	$0	$295,195	$0 $0	$0	$1,067	$0 $0	$385	$3,556	$0
Acct 502: Steam Expense	OM502	47	15,516,429	15,516,429	-	-	$342,049	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$820	$0	$0
Acct 505: Electric Expense	OM505	48	7,214,388	7,214,388	-	-	$159,036	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$381	$0	$0
Total O&M Expense Less Purchased Power	O&MxPurch	49	883,154,932	205,801,340	588,477,735	88,875,857	$4,845,104	$17,141,495	$20,236 $0	$1,285,457	$3,979,597	$2,647,577 $0	$5,070	$14,368	$113 $0	$12,872	$48,212	$33,216
Meter Reading	MREAD	50	650,165	-	-	650,165			50			0			0			494
Time Differentiated Fuel Cost	TDFUEL	51	100.0000%		100.00%			2.91%			0.68%			0.00%			0.01%	
Probability of Dispatch Gross Plant	PODPLT	52	100.0000%	100.0000%			2.8760%			0.6344%			0.0023%			0.0079%		
Probability of Dispatch Depreciation Reserve	PODRES	53	100.0000%	100.0000%			2.8417%			0.6091%			0.0022%			0.0078%		
Memo: Purchased Pwer Expense																		
Demand	Production Plant		$7,292,915	$7,292,915			$160,767	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$385	$0	$0
Energy	Energy @ Source		$43,326,391		$43,326,391		$0	$1,261,019	$0 $0	$0	$295,195	$0 $0	$0	$1,067	$0 $0	$0	$3,556	$0
Total			$50,619,307				$160,767	$1,261,019	$0 $0	$0	$295,195	$0 $0	$0	$1,067	$0 $0	$385	$3,556	$0
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		$15,516,429	$15,516,429			$342,049	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$820	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0
Total			$15,516,429				$342,049	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$820	$0	$0
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		$7,214,388	$7,214,388			$159,036	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$381	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0
Total			$7,214,388				$159,036	$0	$0 $0	$0	$0	$0 $0	$0	$0	$0 $0	$381	$0	$0

Time Differentiated Fuel Cost																		
Fuel Cost Per KWH @ Meter								0.022162			0.02298			0.022959			0.023135	
KWH @ Meter								552,917,598			123,634,653			446,721			1,489,131	
Time Differentiated Fuel Cost					420,625,506			12,253,760			2,841,124			10,256			34,451	
Pct Allocation			100.00%		100.00%			2.91%			0.68%			0.00%			0.01%	

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Percentage

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			All Electric Schools (AES)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0	1	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	33.21128%	0.00000%	0.00000%	9.90840%	0.00000%	0.00000%	0.82789%	0.00000%	0.00000%	11.70247%	0.00000%
Energy (Loss Adjusted)(at Source)	Energy	2	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	33.57180%	0.00000%	0.00000%	10.01596%	0.00000%	0.00000%	0.83688%	0.00000%	0.00000%	11.82951%	0.00000%
Customers (Monthly Bills)	Bills	3	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	62.46552%	0.00000%	0.00000%	12.08603%	0.00000%	0.00000%	0.08603%	0.00000%	0.00000%	0.65309%
Average Customers (Bills/12)	Cust	4	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	62.46544%	0.00000%	0.00000%	12.08602%	0.00000%	0.00000%	0.08601%	0.00000%	0.00000%	0.65311%
Average Customers (Lighting = Lights)	Cust	5	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	62.46544%	0.00000%	0.00000%	12.08602%	0.00000%	0.00000%	0.08601%	0.00000%	0.00000%	0.65311%
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	64.42675%	0.00000%	0.00000%	24.93100%	0.00000%	0.00000%	0.88709%	0.00000%	0.00000%	3.36810%
Street Lighting	Lighting	7	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Customers	Customers	8	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	62.46544%	0.00000%	0.00000%	12.08602%	0.00000%	0.00000%	0.08601%	0.00000%	0.00000%	0.65311%
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	79.90197%	0.00000%	0.00000%	15.45970%	0.00000%	0.00000%	0.11002%	0.00000%	0.00000%	0.83542%
Average Secondary Customers	CUST07	10	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	80.74096%	0.00000%	0.00000%	15.62203%	0.00000%	0.00000%	0.11117%	0.00000%	0.00000%	0.00000%
Average Primary Customers	CUST08	11	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	79.90640%	0.00000%	0.00000%	15.46055%	0.00000%	0.00000%	0.11002%	0.00000%	0.00000%	0.83547%
Average Transformer Customers	CUST09	12	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	79.97317%	0.00000%	0.00000%	15.47347%	0.00000%	0.00000%	0.11011%	0.00000%	0.00000%	0.83617%
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	100.00000%	100.00000%	0.00000%	0.00000%	42.53396%	0.00000%	0.00000%	10.76833%	0.00000%	0.00000%	1.03957%	0.00000%	0.00000%	9.49332%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	100.00000%	100.00000%	0.00000%	0.00000%	47.43670%	0.00000%	0.00000%	12.00956%	0.00000%	0.00000%	1.15940%	0.00000%	0.00000%	10.58758%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	SICDT	15	100.00000%	100.00000%	0.00000%	0.00000%	69.37885%	0.00000%	0.00000%	12.49478%	0.00000%	0.00000%	0.87766%	0.00000%	0.00000%	9.81054%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	SICD	16	100.00000%	100.00000%	0.00000%	0.00000%	83.30198%	0.00000%	0.00000%	15.00227%	0.00000%	0.00000%	1.05380%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	SCP	17	100.00000%	100.00000%	0.00000%	0.00000%	37.56064%	0.00000%	0.00000%	11.24794%	0.00000%	0.00000%	0.75513%	0.00000%	0.00000%	11.86186%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	WCP	18	100.00000%	100.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
Base Demand Allocator	BDEM	19	100.00000%	100.00000%	0.00000%	0.00000%	33.57180%	0.00000%	0.00000%	10.01596%	0.00000%	0.00000%	0.83688%	0.00000%	0.00000%	11.82951%	0.00000%	0.00000%
Weighted cost of Services	C02	20	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	70.13162%	0.00000%	0.00000%	27.47067%	0.00000%	0.00000%	0.26016%	0.00000%	0.00000%	1.86639%
Weighted Cost of Meters	C03	21	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	62.14626%	0.00000%	0.00000%	23.16177%	0.00000%	0.00000%	0.49130%	0.00000%	0.00000%	6.27799%
Lighting Systems -- Lighting Customers	C04	22	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	PT&D	23	100.00000%	91.00992%	0.00000%	8.99008%	35.19277%	0.00000%	5.46777%	9.64764%	0.00000%	1.39820%	0.82571%	0.00000%	0.01494%	10.12649%	0.00000%	0.12317%
Production Plant	Prod	24	100.00000%	100.00000%	0.00000%	0.00000%	33.59940%	0.00000%	0.00000%	10.07720%	0.00000%	0.00000%	0.82280%	0.00000%	0.00000%	11.93360%	0.00000%	0.00000%
Transmission Plant	Trans	25	100.00000%	100.00000%	0.00000%	0.00000%	42.53396%	0.00000%	0.00000%	10.76833%	0.00000%	0.00000%	1.03957%	0.00000%	0.00000%	9.49332%	0.00000%	0.00000%
Distribution Plant	Dist	26	100.00000%	65.26824%	0.00000%	34.73176%	35.20819%	0.00000%	21.12388%	8.06594%	0.00000%	5.40172%	0.72374%	0.00000%	0.05772%	6.19402%	0.00000%	0.47586%
Total Plant in Service	TPIS	27	100.00000%	91.00985%	0.00000%	8.99015%	35.19271%	0.00000%	5.46781%	9.64763%	0.00000%	1.39821%	0.82571%	0.00000%	0.01494%	10.12650%	0.00000%	0.12318%
Distrib Overhead + Underground Lines Plant	DLINES	28	100.00000%	82.48766%	0.00000%	17.51234%	43.23812%	0.00000%	14.13963%	10.24924%	0.00000%	2.73578%	0.94426%	0.00000%	0.01947%	7.52054%	0.00000%	0.00000%
Account 362	Acct362	29	100.00000%	100.00000%	0.00000%	0.00000%	47.43670%	0.00000%	0.00000%	12.00956%	0.00000%	0.00000%	1.15940%	0.00000%	0.00000%	10.58758%	0.00000%	0.00000%
Account 365	Acct365	30	100.00000%	79.40780%	0.00000%	20.59220%	42.76052%	0.00000%	16.62634%	9.96142%	0.00000%	3.21692%	0.90566%	0.00000%	0.02289%	6.90416%	0.00000%	0.00000%
Account 367	Acct367	31	100.00000%	93.47994%	0.00000%	6.52006%	44.94273%	0.00000%	5.26436%	11.27650%	0.00000%	1.01857%	1.08204%	0.00000%	0.00725%	9.72046%	0.00000%	0.00000%
Account 368	Acct368	32	100.00000%	52.91343%	0.00000%	47.08657%	36.71073%	0.00000%	37.65662%	6.61142%	0.00000%	7.28593%	0.46440%	0.00000%	0.05185%	5.19110%	0.00000%	0.39372%
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	64.42675%	0.00000%	0.00000%	24.93100%	0.00000%	0.00000%	0.88709%	0.00000%	0.00000%	3.36810%
Total Utility Plant	TUP	34	100.00000%	90.96449%	0.00000%	9.03551%	35.21772%	0.00000%	5.49540%	9.64678%	0.00000%	1.40526%	0.82614%	0.00000%	0.01502%	10.11275%	0.00000%	0.12380%
Total Labor Excluding A&G	LBSUB7	35	100.00000%	49.87619%	22.71643%	27.40738%	19.53635%	7.62819%	17.77808%	5.33830%	2.27557%	6.44300%	0.46091%	0.19020%	0.19576%	5.47946%	2.68646%	1.01857%
Steam Power Operation Labor	LBSUB1	36	100.00000%	86.29424%	13.70576%	0.00000%	28.99435%	4.60863%	0.00000%	8.69604%	1.37395%	0.00000%	0.71003%	0.11507%	0.00000%	10.29801%	1.61825%	0.00000%
Total Steam Power Maintenance Labor Expense	LBSUB2	37	100.00000%	9.64675%	90.35325%	0.00000%	3.24125%	30.33321%	0.00000%	0.97212%	9.04975%	0.00000%	0.07937%	0.75615%	0.00000%	1.15120%	10.68835%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	100.00000%	100.00000%	0.00000%	0.00000%	33.59940%	0.00000%	0.00000%	10.07720%	0.00000%	0.00000%	0.82280%	0.00000%	0.00000%	11.93360%	0.00000%	0.00000%
Total Other Power Operating Labor Expense	LBSUB5	39	100.00000%	100.00000%	0.00000%	0.00000%	33.59940%	0.00000%	0.00000%	10.07720%	0.00000%	0.00000%	0.82280%	0.00000%	0.00000%	11.93360%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	LBDO	40	100.00000%	41.13314%	0.00000%	58.86686%	21.54117%	0.00000%	37.12758%	5.07513%	0.00000%	12.65389%	0.46542%	0.00000%	0.24523%	3.90043%	0.00000%	3.01228%
Total Distribution Maintenance Labor Expense	LBDM	41	100.00000%	81.74905%	0.00000%	18.25095%	43.23394%	0.00000%	14.73342%	10.18436%	0.00000%	2.85067%	0.93386%	0.00000%	0.02029%	7.36160%	0.00000%	0.00280%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	100.00000%	86.29424%	13.70576%	0.00000%	28.99435%	4.60863%	0.00000%	8.69604%	1.37395%	0.00000%	0.71003%	0.11507%	0.00000%	10.29801%	1.61825%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	100.00000%	9.64675%	90.35325%	0.00000%	3.24125%	30.33321%	0.00000%	0.97212%	9.04975%	0.00000%	0.07937%	0.75615%	0.00000%	1.15120%	10.68835%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	100.00000%	41.13314%	0.00000%	58.86686%	21.54117%	0.00000%	37.12758%	5.07513%	0.00000%	12.65389%	0.46542%	0.00000%	0.24523%	3.90043%	0.00000%	3.01228%
Purchased Power	PURCPWR	46	100.00000%	14.40738%	85.59262%	0.00000%	6.25048%	28.73499%	0.00000%	1.68021%	8.57292%	0.00000%	0.13868%	0.71631%	0.00000%	1.57666%	10.12519%	0.00000%
Acct 502: Steam Expense	OM502	47	100.00000%	100.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
Acct 505: Electric Expense	OM505	48	100.00000%	100.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	O&MxPurch	49	100.00000%	23.30297%	66.63358%	10.06345%	9.65014%	22.40098%	6.61234%	2.56001%	6.67898%	2.33408%	0.22427%	0.55918%	0.06976%	2.46931%	7.86952%	0.35080%
Meter Reading	MREAD	50	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	66.24134%	0.00000%	0.00000%	25.63319%	0.00000%	0.00000%	0.91208%	0.00000%	0.00000%	3.46297%
Time Differentiated Fuel Cost	TDFUEL	51	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	33.62547%	0.00000%	0.00000%	10.02463%	0.00000%	0.00000%	0.83955%	0.00000%	0.00000%	11.80708%	0.00000%
Probability of Dispatch Gross Plant	PODPLT	52	100.00000%	100.00000%	0.00000%	0.00000%	33.59940%	0.00000%	0.00000%	10.07720%	0.00000%	0.00000%	0.82280%	0.00000%	0.00000%	11.93360%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	PODRES	53	100.00000%	100.00000%	0.00000%	0.00000%	33.70390%	0.00000%	0.00000%	10.13960%	0.00000%	0.00000%	0.82160%	0.00000%	0.00000%	11.94050%	0.00000%	0.00000%
Memo: Purchased Pwer Expense	0	0																
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
Energy	Energy @ Source	0	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	33.57180%	0.00000%	0.00000%	10.01596%	0.00000%	0.00000%	0.83688%	0.00000%	0.00000%	11.82951%	0.00000%
Total	0	0	100.00000%	0.00000%	0.00000%	0.00000%	6.25048%	28.73499%	0.00000%	1.68021%	8.57292%	0.00000%	0.13868%	0.71631%	0.00000%	1.57666%	10.12519%	0.00000%
	0 0	0																
Memo: Acct 502: Steam Expense	0	0																
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
Energy	Energy @ Source	0																
Total	0	0	100.00000%	0.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
	0 0	0																
Memo: Acct 505: Electric Expense	0	0																
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	43.38387%	0.00000%	0.00000%	11.66216%	0.00000%	0.00000%	0.96256%	0.00000%	0.00000%	10.94339%	0.00000%	0.00000%
Energy	Energy @ Source	0																

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Percentage

	Allocation Factor			Total Kentucky			Power Service-Primary (PS-Pri)			Time of Day-Sec (TOU-Sec)			Time of Day-Pri (TOU-Pri)			Retail Transmission (RTS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0	1	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.92577%	0.00000%	0.00000%	9.11042%	0.00000%	0.00000%	22.44989%	0.00000%	0.00000%	8.16501%	0.00000%
Energy (Loss Adjusted)(at Source)	Energy	2	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.91288%	0.00000%	0.00000%	9.20931%	0.00000%	0.00000%	22.13730%	0.00000%	0.00000%	7.88384%	0.00000%
Customers (Monthly Bills)	Bills	3	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02502%	0.00000%	0.00000%	0.08967%	0.00000%	0.00000%	0.04010%	0.00000%	0.00000%	0.00435%
Average Customers (Bills/12)	Cust	4	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02509%	0.00000%	0.00000%	0.08963%	0.00000%	0.00000%	0.04018%	0.00000%	0.00000%	0.00435%
Average Customers (Lighting = Lights)	Cust	5	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02509%	0.00000%	0.00000%	0.08963%	0.00000%	0.00000%	0.04018%	0.00000%	0.00000%	0.00435%
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.12940%	0.00000%	0.00000%	2.31122%	0.00000%	0.00000%	1.03594%	0.00000%	0.00000%	0.08976%
Street Lighting	Lighting	7	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Customers	Customers	8	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02509%	0.00000%	0.00000%	0.08963%	0.00000%	0.00000%	0.04018%	0.00000%	0.00000%	0.00435%
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.03210%	0.00000%	0.00000%	0.11466%	0.00000%	0.00000%	0.05139%	0.00000%	0.00000%	0.00557%
Average Secondary Customers	CUST07	10	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Primary Customers	CUST08	11	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.03210%	0.00000%	0.00000%	0.11466%	0.00000%	0.00000%	0.05139%	0.00000%	0.00000%	0.00000%
Average Transformer Customers	CUST09	12	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.11476%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	100.00000%	100.00000%	0.00000%	0.00000%	0.74657%	0.00000%	0.00000%	7.33739%	0.00000%	0.00000%	16.99987%	0.00000%	0.00000%	6.22164%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	100.00000%	100.00000%	0.00000%	0.00000%	0.83262%	0.00000%	0.00000%	8.18314%	0.00000%	0.00000%	18.95938%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	SICDT	15	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	6.90351%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	SICD	16	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	SCP	17	100.00000%	100.00000%	0.00000%	0.00000%	0.88977%	0.00000%	0.00000%	8.74375%	0.00000%	0.00000%	19.13409%	0.00000%	0.00000%	7.11303%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	WCP	18	100.00000%	100.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%
Base Demand Allocator	BDEM	19	100.00000%	100.00000%	0.00000%	0.00000%	0.91288%	0.00000%	0.00000%	9.20931%	0.00000%	0.00000%	22.13731%	0.00000%	0.00000%	7.88384%	0.00000%	0.00000%
Weighted cost of Services	C02	20	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.27116%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Weighted Cost of Meters	C03	21	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	1.38416%	0.00000%	0.00000%	1.16427%	0.00000%	0.00000%	3.07544%	0.00000%	0.00000%	2.09749%
Lighting Systems -- Lighting Customers	C04	22	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	PT&D	23	100.00000%	91.00992%	0.00000%	8.99008%	0.76317%	0.00000%	0.01717%	7.79790%	0.00000%	0.02088%	18.17220%	0.00000%	0.03815%	5.56811%	0.00000%	0.02602%
Production Plant	Prod	24	100.00000%	100.00000%	0.00000%	0.00000%	0.91490%	0.00000%	0.00000%	9.20330%	0.00000%	0.00000%	22.13640%	0.00000%	0.00000%	7.79180%	0.00000%	0.00000%
Transmission Plant	Trans	25	100.00000%	100.00000%	0.00000%	0.00000%	0.74657%	0.00000%	0.00000%	7.33739%	0.00000%	0.00000%	16.99987%	0.00000%	0.00000%	6.22164%	0.00000%	0.00000%
Distribution Plant	Dist	26	100.00000%	65.26824%	0.00000%	34.73176%	0.41436%	0.00000%	0.06634%	4.72333%	0.00000%	0.08066%	9.43538%	0.00000%	0.14739%	0.00000%	0.00000%	0.10052%
Total Plant in Service	TPIS	27	100.00000%	91.00985%	0.00000%	8.99015%	0.76317%	0.00000%	0.01717%	7.79790%	0.00000%	0.02088%	18.17221%	0.00000%	0.03815%	5.56811%	0.00000%	0.02602%
Distrib Overhead + Underground Lines Plant	DLINES	28	100.00000%	82.48766%	0.00000%	17.51234%	0.59142%	0.00000%	0.00000%	5.81263%	0.00000%	0.00000%	13.46718%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Account 362	Acct362	29	100.00000%	100.00000%	0.00000%	0.00000%	0.83262%	0.00000%	0.00000%	8.18314%	0.00000%	0.00000%	18.95938%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Account 365	Acct365	30	100.00000%	79.40780%	0.00000%	20.59220%	0.54295%	0.00000%	0.00000%	5.33623%	0.00000%	0.00000%	12.36341%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Account 367	Acct367	31	100.00000%	93.47994%	0.00000%	6.52006%	0.76443%	0.00000%	0.00000%	7.51294%	0.00000%	0.00000%	17.40661%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Account 368	Acct368	32	100.00000%	52.91343%	0.00000%	47.08657%	0.00000%	0.00000%	0.00000%	3.65288%	0.00000%	0.05404%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.12940%	0.00000%	0.00000%	2.31122%	0.00000%	0.00000%	1.03594%	0.00000%	0.00000%	0.08976%
Total Utility Plant	TUP	34	100.00000%	90.96449%	0.00000%	9.03551%	0.76208%	0.00000%	0.01726%	7.78726%	0.00000%	0.02098%	18.14245%	0.00000%	0.03834%	5.55390%	0.00000%	0.02615%
Total Labor Excluding A&G	LBSUB7	35	100.00000%	49.87619%	22.71643%	27.40738%	0.42059%	0.20735%	0.11169%	4.22617%	2.09196%	0.49514%	9.99054%	5.02796%	0.38418%	2.88936%	1.79049%	0.14992%
Steam Power Operation Labor	LBSUB1	36	100.00000%	86.29424%	13.70576%	0.00000%	0.78951%	0.12504%	0.00000%	7.94192%	1.26194%	0.00000%	19.10244%	3.03077%	0.00000%	6.72387%	1.07881%	0.00000%
Total Steam Power Maintenance Labor Expense	LBSUB2	37	100.00000%	9.64675%	90.35325%	0.00000%	0.08826%	0.82482%	0.00000%	0.88782%	8.32092%	0.00000%	2.13544%	20.00177%	0.00000%	0.75166%	7.12331%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	100.00000%	100.00000%	0.00000%	0.00000%	0.91490%	0.00000%	0.00000%	9.20330%	0.00000%	0.00000%	22.13640%	0.00000%	0.00000%	7.79180%	0.00000%	0.00000%
Total Other Power Operating Labor Expense	LBSUB5	39	100.00000%	100.00000%	0.00000%	0.00000%	0.91490%	0.00000%	0.00000%	9.20330%	0.00000%	0.00000%	22.13640%	0.00000%	0.00000%	7.79180%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	LBDO	40	100.00000%	41.13314%	0.00000%	58.86686%	0.28719%	0.00000%	0.65378%	2.99744%	0.00000%	0.55660%	6.53960%	0.00000%	1.45262%	0.00000%	0.00000%	0.99070%
Total Distribution Maintenance Labor Expense	LBDM	41	100.00000%	81.74905%	0.00000%	18.25095%	0.57602%	0.00000%	0.00000%	5.68722%	0.00000%	0.00038%	13.11644%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	100.00000%	86.29424%	13.70576%	0.00000%	0.78951%	0.12504%	0.00000%	7.94192%	1.26194%	0.00000%	19.10244%	3.03077%	0.00000%	6.72387%	1.07881%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	100.00000%	9.64675%	90.35325%	0.00000%	0.08826%	0.82482%	0.00000%	0.88782%	8.32092%	0.00000%	2.13544%	20.00177%	0.00000%	0.75166%	7.12331%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	100.00000%	41.13314%	0.00000%	58.86686%	0.28719%	0.00000%	0.65378%	2.99744%	0.00000%	0.55660%	6.53960%	0.00000%	1.45262%	0.00000%	0.00000%	0.99070%
Purchased Power	PURCPWR	46	100.00000%	14.40738%	85.59262%	0.00000%	0.09979%	0.78136%	0.00000%	1.05549%	7.88249%	0.00000%	2.44300%	18.94790%	0.00000%	0.84472%	6.74799%	0.00000%
Acct 502: Steam Expense	OM502	47	100.00000%	100.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%
Acct 505: Electric Expense	OM505	48	100.00000%	100.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	O&MxPurch	49	100.00000%	23.30297%	66.63358%	10.06345%	0.18629%	0.60794%	0.03656%	1.87630%	6.13536%	0.17537%	4.40238%	14.73694%	0.13024%	1.23808%	5.24604%	0.04844%
Meter Reading	MREAD	50	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.13304%	0.00000%	0.00000%	2.37632%	0.00000%	0.00000%	1.06511%	0.00000%	0.00000%	0.09228%
Time Differentiated Fuel Cost	TDFUEL	51	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.91228%	0.00000%	0.00000%	9.20735%	0.00000%	0.00000%	22.11309%	0.00000%	0.00000%	7.87125%	0.00000%
Probability of Dispatch Gross Plant	PODPLT	52	100.00000%	100.00000%	0.00000%	0.00000%	0.91490%	0.00000%	0.00000%	9.20330%	0.00000%	0.00000%	22.13640%	0.00000%	0.00000%	7.79180%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	PODRES	53	100.00000%	100.00000%	0.00000%	0.00000%	0.91290%	0.00000%	0.00000%	9.18330%	0.00000%	0.00000%	22.07400%	0.00000%	0.00000%	7.76340%	0.00000%	0.00000%
Memo: Purchased Pwer Expense	0	0																
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%
Energy	Energy @ Source	0	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.91288%	0.00000%	0.00000%	9.20931%	0.00000%	0.00000%	22.13730%	0.00000%	0.00000%	7.88384%	0.00000%
Total	0	0	100.00000%	0.00000%	0.00000%	0.00000%	0.09979%	0.78136%	0.00000%	1.05549%	7.88249%	0.00000%	2.44300%	18.94790%	0.00000%	0.84472%	6.74799%	0.00000%
	0	0 0																
Memo: Acct 502: Steam Expense	0	0																
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%
Energy	Energy @ Source	0																
Total	0	0	100.00000%	0.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%
	0	0 0																
Memo: Acct 505: Electric Expense	0	0																
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	0.69264%	0.00000%	0.00000%	7.32601%	0.00000%	0.00000%	16.95657%	0.00000%	0.00000%	5.86310%	0.00000%	0.00000%

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Percentage

	Allocation Factor		Total Kentucky				Fluctuating Load Service (FLS)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0	1	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	3.01431%	0.00000%
Energy (Loss Adjusted)(at Source)	Energy	2	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	2.91051%	0.00000%
Customers (Monthly Bills)	Bills	3	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00015%
Average Customers (Bills/12)	Cust	4	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00015%
Average Customers (Lighting = Lights)	Cust	5	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00015%
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00748%
Street Lighting	Lighting	7	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%
Average Customers	Customers	8	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00015%
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00019%
Average Secondary Customers	CUST07	10	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%
Average Primary Customers	CUST08	11	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%
Average Transformer Customers	CUST09	12	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	100.00000%	100.00000%	0.00000%	0.00000%	4.11369%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	SICDT	15	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	SICD	16	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	SCP	17	100.00000%	100.00000%	0.00000%	0.00000%	2.68904%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	WCP	18	100.00000%	100.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%
Base Demand Allocator	BDEM	19	100.00000%	100.00000%	0.00000%	0.00000%	2.91051%	0.00000%	0.00000%
Weighted cost of Services	C02	20	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%
Weighted Cost of Meters	C03	21	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.08877%
Lighting Systems -- Lighting Customers	C04	22	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	PT&D	23	100.00000%	91.00992%	0.00000%	8.99008%	2.29461%	0.00000%	0.00110%
Production Plant	Prod	24	100.00000%	100.00000%	0.00000%	0.00000%	2.87600%	0.00000%	0.00000%
Transmission Plant	Trans	25	100.00000%	100.00000%	0.00000%	0.00000%	4.11369%	0.00000%	0.00000%
Distribution Plant	Dist	26	100.00000%	65.26824%	0.00000%	34.73176%	0.00000%	0.00000%	0.00425%
Total Plant in Service	TPIS	27	100.00000%	91.00985%	0.00000%	8.99015%	2.29459%	0.00000%	0.00110%
Distrib Overhead + Underground Lines Plant	DLINES	28	100.00000%	82.48766%	0.00000%	17.51234%	0.00000%	0.00000%	0.00000%
Account 362	Acct362	29	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Account 365	Acct365	30	100.00000%	79.40780%	0.00000%	20.59220%	0.00000%	0.00000%	0.00000%
Account 367	Acct367	31	100.00000%	93.47994%	0.00000%	6.52006%	0.00000%	0.00000%	0.00000%
Account 368	Acct368	32	100.00000%	52.91343%	0.00000%	47.08657%	0.00000%	0.00000%	0.00000%
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00748%
Total Utility Plant	TUP	34	100.00000%	90.96449%	0.00000%	9.03551%	2.29401%	0.00000%	0.00111%
Total Labor Excluding A&G	LBSUB7	35	100.00000%	49.87619%	22.71643%	27.40738%	1.18864%	0.66126%	0.00701%
Steam Power Operation Labor	LBSUB1	36	100.00000%	86.29424%	13.70576%	0.00000%	2.48182%	0.39928%	0.00000%
Total Steam Power Maintenance Labor Expense	LBSUB2	37	100.00000%	9.64675%	90.35325%	0.00000%	0.27744%	2.62974%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	100.00000%	100.00000%	0.00000%	0.00000%	2.87600%	0.00000%	0.00000%
Total Other Power Operating Labor Expense	LBSUB5	39	100.00000%	100.00000%	0.00000%	0.00000%	2.87600%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	LBDO	40	100.00000%	41.13314%	0.00000%	58.86686%	0.00000%	0.00000%	0.04193%
Total Distribution Maintenance Labor Expense	LBDM	41	100.00000%	81.74905%	0.00000%	18.25095%	0.00000%	0.00000%	0.00000%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	100.00000%	86.29424%	13.70576%	0.00000%	2.48182%	0.39928%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	100.00000%	9.64675%	90.35325%	0.00000%	0.27744%	2.62974%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44							
Distribution Operation Labor Excl. Super. & Eng	FO23	45	100.00000%	41.13314%	0.00000%	58.86686%	0.00000%	0.00000%	0.04193%
Purchased Power	PURCPWR	46	100.00000%	14.40738%	85.59262%	0.00000%	0.31760%	2.49118%	0.00000%
Acct 502: Steam Expense	OM502	47	100.00000%	100.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%
Acct 505: Electric Expense	OM505	48	100.00000%	100.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	O&MxPurch	49	100.00000%	23.30297%	66.63358%	10.06345%	0.54861%	1.94094%	0.00229%
Meter Reading	MREAD	50	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00769%
Time Differentiated Fuel Cost	TDFUEL	51	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	2.91322%	0.00000%
Probability of Dispatch Gross Plant	PODPLT	52	100.00000%	100.00000%	0.00000%	0.00000%	2.87600%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	PODRES	53	100.00000%	100.00000%	0.00000%	0.00000%	2.84170%	0.00000%	0.00000%
Memo: Purchased Pwer Expense	0	0							
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%
Energy	Energy @ Source	0	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	2.91051%	0.00000%
Total	0	0	100.00000%	0.00000%	0.00000%	0.00000%	0.31760%	2.49118%	0.00000%
0	0	0							
Memo: Acct 502: Steam Expense	0	0							
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%
Energy	Energy @ Source	0							
Total	0	0	100.00000%	0.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%
0	0	0							
Memo: Acct 505: Electric Expense	0	0							
Demand	Production Plant	0	100.00000%	100.00000%	0.00000%	0.00000%	2.20443%	0.00000%	0.00000%

	Outdoor Lighting (ST & POL)			Lighting Energy (LE)			Traffic Energy (TE)		
	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0.00000%	0.67401%	0.00000%	0.00000%	0.00244%	0.00000%	0.00000%	0.00812%	0.00000%
Energy (Loss Adjusted)(at Source)	0.00000%	0.68133%	0.00000%	0.00000%	0.00246%	0.00000%	0.00000%	0.00821%	0.00000%
Customers (Monthly Bills)	0.00000%	0.00000%	24.43691%	0.00000%	0.00000%	0.00058%	0.00000%	0.00000%	0.11255%
Average Customers (Bills/12)	0.00000%	0.00000%	24.43688%	0.00000%	0.00000%	0.00058%	0.00000%	0.00000%	0.11255%
Average Customers (Lighting = Lights)	0.00000%	0.00000%	24.43688%	0.00000%	0.00000%	0.00058%	0.00000%	0.00000%	0.11255%
Weighted Average Customers (Lighting =9 Lights per Cust)	0.00000%	0.00000%	2.80040%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01287%
Street Lighting	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Customers	0.00000%	0.00000%	24.43688%	0.00000%	0.00000%	0.00058%	0.00000%	0.00000%	0.11255%
Average Customers (Lighting = 9 Lights per Cust)	0.00000%	0.00000%	3.47305%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01596%
Average Secondary Customers	0.00000%	0.00000%	3.50960%	0.00000%	0.00000%	0.00008%	0.00000%	0.00000%	0.01616%
Average Primary Customers	0.00000%	0.00000%	3.47332%	0.00000%	0.00000%	0.00008%	0.00000%	0.00000%	0.01600%
Average Transformer Customers	0.00000%	0.00000%	3.47622%	0.00000%	0.00000%	0.00008%	0.00000%	0.00000%	0.01601%
Maximum Class Non-Coincident Peak Demands (Transmission)	0.73779%	0.00000%	0.00000%	0.00309%	0.00000%	0.00000%	0.00479%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	0.82284%	0.00000%	0.00000%	0.00345%	0.00000%	0.00000%	0.00534%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	0.52901%	0.00000%	0.00000%	0.00222%	0.00000%	0.00000%	0.00343%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	0.63518%	0.00000%	0.00000%	0.00266%	0.00000%	0.00000%	0.00412%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00475%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%
Base Demand Allocator	0.68133%	0.00000%	0.00000%	0.00246%	0.00000%	0.00000%	0.00821%	0.00000%	0.00000%
Weighted cost of Services	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Weighted Cost of Meters	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00058%	0.00000%	0.00000%	0.11198%
Lighting Systems -- Lighting Customers	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	0.61270%	0.00000%	1.88054%	0.00235%	0.00000%	0.00001%	0.00628%	0.00000%	0.00213%
Production Plant	0.63440%	0.00000%	0.00000%	0.00230%	0.00000%	0.00000%	0.00790%	0.00000%	0.00000%
Transmission Plant	0.73779%	0.00000%	0.00000%	0.00309%	0.00000%	0.00000%	0.00479%	0.00000%	0.00000%
Distribution Plant	0.49795%	0.00000%	7.26516%	0.00209%	0.00000%	0.00004%	0.00323%	0.00000%	0.00821%
Total Plant in Service	0.61270%	0.00000%	1.88055%	0.00235%	0.00000%	0.00001%	0.00628%	0.00000%	0.00213%
Distrib Overhead + Underground Lines Plant	0.65724%	0.00000%	0.61461%	0.00275%	0.00000%	0.00001%	0.00426%	0.00000%	0.00283%
Account 362	0.82284%	0.00000%	0.00000%	0.00345%	0.00000%	0.00000%	0.00534%	0.00000%	0.00000%
Account 365	0.62675%	0.00000%	0.72270%	0.00263%	0.00000%	0.00002%	0.00407%	0.00000%	0.00333%
Account 367	0.76605%	0.00000%	0.22883%	0.00321%	0.00000%	0.00001%	0.00497%	0.00000%	0.00105%
Account 368	0.27992%	0.00000%	1.63683%	0.00117%	0.00000%	0.00004%	0.00181%	0.00000%	0.00754%
Weighted Average Customers (Lighting =9 Lights per Cust)	0.00000%	0.00000%	2.80040%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01287%
Total Utility Plant	0.61279%	0.00000%	1.89004%	0.00235%	0.00000%	0.00001%	0.00627%	0.00000%	0.00214%
Total Labor Excluding A&G	0.34115%	0.15457%	0.81366%	0.00132%	0.00056%	0.00004%	0.00341%	0.00186%	0.01034%
Steam Power Operation Labor	0.54745%	0.09258%	0.00000%	0.00198%	0.00033%	0.00000%	0.00682%	0.00112%	0.00000%
Total Steam Power Maintenance Labor Expense	0.06120%	0.61560%	0.00000%	0.00022%	0.00222%	0.00000%	0.00076%	0.00741%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	0.63440%	0.00000%	0.00000%	0.00230%	0.00000%	0.00000%	0.00790%	0.00000%	0.00000%
Total Other Power Operating Labor Expense	0.63440%	0.00000%	0.00000%	0.00230%	0.00000%	0.00000%	0.00790%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	0.32331%	0.00000%	2.07775%	0.00135%	0.00000%	0.00028%	0.00210%	0.00000%	0.05423%
Total Distribution Maintenance Labor Expense	0.64868%	0.00000%	0.64042%	0.00272%	0.00000%	0.00002%	0.00421%	0.00000%	0.00295%
Total Steam Power Operation Labor Excl Superv. & Eng.	0.54745%	0.09258%	0.00000%	0.00198%	0.00033%	0.00000%	0.00682%	0.00112%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	0.06120%	0.61560%	0.00000%	0.00022%	0.00222%	0.00000%	0.00076%	0.00741%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.									
Distribution Operation Labor Excl. Super. & Eng	0.32331%	0.00000%	2.07775%	0.00135%	0.00000%	0.00028%	0.00210%	0.00000%	0.05423%
Purchased Power	0.00000%	0.58317%	0.00000%	0.00000%	0.00211%	0.00000%	0.00076%	0.00702%	0.00000%
Acct 502: Steam Expense	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%
Acct 505: Electric Expense	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	0.14555%	0.45061%	0.29979%	0.00057%	0.00163%	0.00001%	0.00146%	0.00546%	0.00376%
Meter Reading	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.07598%
Time Differentiated Fuel Cost	0.00000%	0.67545%	0.00000%	0.00000%	0.00244%	0.00000%	0.00000%	0.00819%	0.00000%
Probability of Dispatch Gross Plant	0.63440%	0.00000%	0.00000%	0.00230%	0.00000%	0.00000%	0.00790%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	0.60910%	0.00000%	0.00000%	0.00220%	0.00000%	0.00000%	0.00780%	0.00000%	0.00000%
Memo: Purchased Pwer Expense									
Demand	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%
Energy	0.00000%	0.68133%	0.00000%	0.00000%	0.00246%	0.00000%	0.00000%	0.00821%	0.00000%
Total	0.00000%	0.58317%	0.00000%	0.00000%	0.00211%	0.00000%	0.00076%	0.00702%	0.00000%
Memo: Acct 502: Steam Expense									
Demand	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%
Energy									
Total	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%
Memo: Acct 505: Electric Expense									
Demand	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00528%	0.00000%	0.00000%

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base															
Plant in Service															
Intangible Plant															
301.00 ORGANIZATION	PT&D	1	$39,493	$24,068	$0	$0	$5,202	$0	$0	$6,672	$0	$3,550	$35,942	$0	$3,550
302.00 FRANCHISE AND CONSENTS	PT&D	1	$55,919	$34,078	$0	$0	$7,366	$0	$0	$9,447	$0	$5,027	$50,892	$0	$5,027
303.00 SOFTWARE	PT&D	1	$102,982,045	$62,760,080	$0	$0	$13,565,775	$0	$0	$17,398,027	$0	$9,258,164	$93,723,881	$0	$9,258,164
Total Intangible Plant			$103,077,457	$62,818,226	$0	$0	$13,578,343	$0	$0	$17,414,146	$0	$9,266,742	$93,810,715	$0	$9,266,742
Production Plant															
Total Production Plant		$4,076,920,355													
Demand	100.0000%		$4,076,920,355	$4,076,920,355									$4,076,920,355	$0	$0
Energy	0.0000%		$0		$0								$0	$0	$0
													$0	$0	$0
Total Production Plant			**$4,076,920,355**	**$4,076,920,355**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$4,076,920,355**	**$0**	**$0**
Transmission															
KENTUCKY SYSTEM PROPERTY	Dir		$873,007,848				$873,007,848						$873,007,848	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	Dir		$8,230,400				$8,230,400						$8,230,400	$0	$0
Total Transmission Plant			$881,238,248	$0	$0	$0	$881,238,248	$0	$0	$0	$0	$0	$881,238,248	$0	$0
Distribution															
TOTAL ACCTS 360-362	Dir		$209,650,161							$209,650,161			$209,650,161	$0	$0
364 & 365-OVERHEAD LINES		$717,117,865													
Primary:			$467,632,560												
Demand	100.0000% Demand									$467,632,560			$467,632,560	$0	$0
Customer	0.0000% Cust											$0	$0	$0	$0
Secondary:			$249,485,305												
Demand	40.8100% Demand									$101,814,953			$101,814,953	$0	$0
Customer	59.1900% Cust											$147,670,352	$0	$0	$147,670,352
366 & 367-UNDERGROUND LINES		$200,924,821													
Primary:			$184,469,078												
Demand	100.0000% Demand									$184,469,078			$184,469,078	$0	$0
Customer	0.0000% Cust											$0	$0	$0	$0
Secondary:			$16,455,743												
Demand	20.3900% Demand									$3,355,326			$3,355,326	$0	$0
Customer	79.6100% Cust											$13,100,417	$0	$0	$13,100,417
368-TRANSFORMERS - POWER POOL:			$5,414,628												
Demand	52.9134% Demand									$2,865,065.40			$2,865,065	$0	$0
Customer	47.0866% Customer											$2,549,563	$0	$0	$2,549,563
368-TRANSFORMERS - ALL OTHER:	Demand		$303,128,639												
Demand	52.9134% Demand									$160,395,756			$160,395,756	$0	$0
Customer	47.0866% Customer											$142,732,883	$0	$0	$142,732,883
369-SERVICES	Dir		$97,262,577									$97,262,577	$0	$0	$97,262,577
370-METERS	370-METERS		$82,987,729									$82,987,729	$0	$0	$82,987,729
371-CUSTOMER INSTALLATION	371-CUSTOMER INSTALLATION		$282,792									$282,792	$0	$0	$282,792
373-STREET LIGHTING	373-STREET LIGHTING		$114,827,799									$114,827,799	$0	$0	$114,827,799
Total Distribution Plant	Dist		$1,731,597,011	$0	$0	$0	$0	$0	$0	$1,130,182,900	$0	$601,414,112	$1,130,182,900	$0	$601,414,112
Total Prod, Trans, and Dist Plant			**$6,689,755,615**	**$4,076,920,355**	**$0**	**$0**	**$881,238,248**	**$0**	**$0**	**$1,130,182,900**	**$0**	**$601,414,112**	**$6,088,341,503**	**$0**	**$601,414,112**
General Plant															
Total General Plant	PT&D	1	$177,535,196	$108,194,812	$0	$0	$23,386,625	$0	$0	$29,993,210	$0	$15,960,549	$161,574,647	$0	$15,960,549
TOTAL COMMON PLANT			$0												
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	PROD	2	$271,089	$271,089	$0	$0	$0	$0	$0	$0	$0	$0	$271,089	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	DIST	4	$113,882	$0	$0	$0	$0	$0	$0	$74,329	$0	$39,553	$74,329	$0	$39,553
OTHER			$0												
Total Plant in Service			$6,970,753,239	$4,248,204,483	$0	$0	$918,203,216	$0	$0	$1,177,664,584	$0	$626,680,956	$6,344,072,283	$0	$626,680,956
Construction Work in Progress (CWIP)															
CWIP Production	PROD	2	$28,153,069	$28,153,069	$0	$0	$0	$0	$0	$0	$0	$0	$28,153,069	$0	$0
CWIP Transmission	TRANS	3	$30,190,923	$0	$0	$0	$30,190,923	$0	$0	$0	$0	$0	$30,190,923	$0	$0
CWIP Distribution Plant	DIST	4	$32,868,652	$0	$0	$0	$0	$0	$0	$21,452,791	$0	$11,415,861	$21,452,791	$0	$11,415,861
CWIP General Plant	PT&D	1	$27,491,296	$16,753,949	$0	$0	$3,621,415	$0	$0	$4,644,444	$0	$2,471,488	$25,019,807	$0	$2,471,488
RWIP			$0												
Total Construction Work in Progress			$118,703,941	$44,907,018	$0	$0	$33,812,338	$0	$0	$26,097,235	$0	$13,887,350	$104,816,591	$0	$13,887,350
Total Gross Utility Plant			$7,089,457,179	$4,293,111,501	$0	$0	$952,015,555	$0	$0	$1,203,761,819	$0	$640,568,305	$6,448,888,874	$0	$640,568,305

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Accumulated Provision for Depreciation															
Steam Production	PROD	2	$1,351,527,013	$1,351,527,013	$0	$0	$0	$0	$0	$0	$0	$0	$1,351,527,013	$0	$0
Hydraulic Production	PROD	2	$11,357,150	$11,357,150	$0	$0	$0	$0	$0	$0	$0	$0	$11,357,150	$0	$0
Other Production	PROD	2	$279,457,486	$279,457,486	$0	$0	$0	$0	$0	$0	$0	$0	$279,457,486	$0	$0
Transmission - Kentucky System Property	TRANS	3	$303,777,627	$0	$0	$0	$303,777,627	$0	$0	$0	$0	$0	$303,777,627	$0	$0
Transmission - Virginia Property	TRANS	3	$4,014,978	$0	$0	$0	$4,014,978	$0	$0	$0	$0	$0	$4,014,978	$0	$0
Distribution	DIST	4	$637,170,341	$0	$0	$0	$0	$0	$0	$415,869,870	$0	$221,300,471	$415,869,870	$0	$221,300,471
General Plant	PT&D	1	$60,263,984	$36,726,523	$0	$0	$7,938,545	$0	$0	$10,181,138	$0	$5,417,778	$54,846,206	$0	$5,417,778
Intangible Plant	PT&D	1	$51,974,185	$31,674,493	$0	$0	$6,846,534	$0	$0	$8,780,640	$0	$4,672,519	$47,301,667	$0	$4,672,519
Total Accumulated Depreciation			$2,699,542,764	$1,710,742,665	$0	$0	$322,577,684	$0	$0	$434,831,648	$0	$231,390,768	$2,468,151,996	$0	$231,390,768
Net Utility Plant			$4,389,914,415	$2,582,368,836	$0	$0	$629,437,870	$0	$0	$768,930,171	$0	$409,177,537	$3,980,736,877	$0	$409,177,537
Working Capital															
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurch	9	$106,348,560	$13,342,499	$70,863,851	$0	$5,301,675	$0	$0	$6,138,200	$0	$10,702,334	$24,782,374	$70,863,851	$10,702,334
Materials and Supplies	TPIS	5	$119,808,344	$73,015,114	$0	$0	$15,781,423	$0	$0	$20,240,860	$0	$10,770,946	$109,037,398	$0	$10,770,946
Prepayments	TPIS	5	$16,171,254	$9,855,290	$0	$0	$2,130,114	$0	$0	$2,732,031	$0	$1,453,819	$14,717,434	$0	$1,453,819
Total Working Capital			$242,328,157	$96,212,903	$70,863,851	$0	$23,213,212	$0	$0	$29,111,091	$0	$22,927,100	$148,537,206	$70,863,851	$22,927,100
Emission Allowance			$0										$0	$0	$0
Deferred Debits															
Service Pension Cost			$0										$0	$0	$0
Accumulated Deferred Income Tax													$0	$0	$0
Total Production Plant	PROD	2	$511,060,465	$511,060,465	$0	$0	$0	$0	$0	$0	$0	$0	$511,060,465	$0	$0
Total Transmission Plant	TRANS	3	$129,909,095	$0	$0	$0	$129,909,095	$0	$0	$0	$0	$0	$129,909,095	$0	$0
Total Distribution Plant	DIST	4	$241,830,055	$0	$0	$0	$0	$0	$0	$157,838,222	$0	$83,991,833	$157,838,222	$0	$83,991,833
Total General Plant	PT&D	1	$27,628,083	$16,837,310	$0	$0	$3,639,434	$0	$0	$4,667,553	$0	$2,483,786	$25,144,297	$0	$2,483,786
Total Accumulated Deferred Income Tax			$910,427,698	$527,897,775	$0	$0	$133,548,529	$0	$0	$162,505,774	$0	$86,475,619	$823,952,079	$0	$86,475,619
Accumulated Deferred Investment Tax Credits															
Production	PROD	2	$81,185,411	$81,185,411	$0	$0	$0	$0	$0	$0	$0	$0	$81,185,411	$0	$0
Transmission			$0										$0	$0	$0
Transmission VA			$0										$0	$0	$0
Distribution VA			$0										$0	$0	$0
Distribution Plant KY,FERC & TN			$0										$0	$0	$0
General			$0										$0	$0	$0
Total Accum. Deferred Investment Tax Credits			$81,185,411	$81,185,411	$0	$0	$0	$0	$0	$0	$0	$0	$81,185,411	$0	$0
Total Deferred Debits			$991,613,109	$609,083,187	$0	$0	$133,548,529	$0	$0	$162,505,774	$0	$86,475,619	$905,137,490	$0	$86,475,619
Less: Customer Advances	DLINES	6	$1,549,704	$0	$0	$0	$0	$0	$0	$1,278,314	$0	$271,389	$1,278,314	$0	$271,389
Less: Asset Retirement Obligations															
Net Rate Base			$3,639,079,759	$2,069,498,552	$70,863,851	$0	$519,102,553	$0	$0	$634,257,174	$0	$345,357,629	$3,222,858,279	$70,863,851	$345,357,629

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Operation and Maintenance Expenses															
Steam Power Generation Operation Expenses															
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	10	$9,442,701	$8,148,507	$1,294,194	$0	$0	$0	$0	$0	$0	$0	$8,148,507	$1,294,194	$0
501 FUEL	Dir		$372,621,659		$372,621,659								$0	$372,621,659	$0
502 STEAM EXPENSES	PROD	2	$15,516,429	$15,516,429	$0	$0	$0	$0	$0	$0	$0	$0	$15,516,429	$0	$0
505 ELECTRIC EXPENSES	PROD	2	$7,214,388	$7,214,388	$0	$0	$0	$0	$0	$0	$0	$0	$7,214,388	$0	$0
506 MISC. STEAM POWER EXPENSES	PROD	2	$14,444,590	$14,444,590	$0	$0	$0	$0	$0	$0	$0	$0	$14,444,590	$0	$0
507 RENTS			$0										$0	$0	$0
509 ALLOWANCES			$0										$0	$0	$0
Total Steam Power Operation Expenses			$419,239,766	$45,323,913	$373,915,853	$0	$0	$0	$0	$0	$0	$0	$45,323,913	$373,915,853	$0
Steam Power Generation Maintenance Expenses															
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	11	$10,261,750	$989,925	$9,271,825	$0	$0	$0	$0	$0	$0	$0	$989,925	$9,271,825	$0
511 MAINTENANCE OF STRUCTURES	PROD	2	$5,959,887	$5,959,887	$0	$0	$0	$0	$0	$0	$0	$0	$5,959,887	$0	$0
512 MAINTENANCE OF BOILER PLANT	Dir		$40,186,142		$40,186,142								$0	$40,186,142	$0
513 MAINTENANCE OF ELECTRIC PLANT	Dir		$8,270,033		$8,270,033								$0	$8,270,033	$0
514 MAINTENANCE OF MISC STEAM PLANT	Dir		$2,439,522		$2,439,522								$0	$2,439,522	$0
Total Steam Power Generation Maintenance Expense			$67,117,335	$6,949,813	$60,167,522	$0	$0	$0	$0	$0	$0	$0	$6,949,813	$60,167,522	$0
Total Steam Power Generation Expense			$486,357,101	$52,273,725	$434,083,376	$0	$0	$0	$0	$0	$0	$0	$52,273,725	$434,083,376	$0
Hydraulic Power Generation Operation Expenses															
535 OPERATION SUPERVISION & ENGINEERING			$0										$0	$0	$0
536 WATER FOR POWER			$0										$0	$0	$0
537 HYDRAULIC EXPENSES			$0										$0	$0	$0
538 ELECTRIC EXPENSES			$0										$0	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	PROD	2	$8,523	$8,523	$0	$0	$0	$0	$0	$0	$0	$0	$8,523	$0	$0
540 RENTS			$0										$0	$0	$0
Total Hydraulic Power Operation Expenses			$8,523	$8,523	$0	$0	$0	$0	$0	$0	$0	$0	$8,523	$0	$0
Hydraulic Power Generation Maintenance Expenses															
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	12	$186,494	$186,494	$0	$0	$0	$0	$0	$0	$0	$0	$186,494	$0	$0
542 MAINTENANCE OF STRUCTURES	PROD	2	$116,901	$116,901	$0	$0	$0	$0	$0	$0	$0	$0	$116,901	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	PROD	2	$22,497	$22,497	$0	$0	$0	$0	$0	$0	$0	$0	$22,497	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	DIR		$33,030		$33,030								$0	$33,030	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Dir		$9,592		$9,592								$0	$9,592	$0
Total Hydraulic Power Generation Maint. Expense			$368,513	$325,892	$42,622	$0	$0	$0	$0	$0	$0	$0	$325,892	$42,622	$0
Total Hydraulic Power Generation Expense			$377,036	$334,414	$42,622	$0	$0	$0	$0	$0	$0	$0	$334,414	$42,622	$0
Other Power Generation Operation Expense															
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	13	$1,071,395	$1,071,395	$0	$0	$0	$0	$0	$0	$0	$0	$1,071,395	$0	$0
547 FUEL	Dir		$130,769,641		$130,769,641								$0	$130,769,641	$0
548 GENERATION EXPENSE	PROD	2	$611,306	$611,306	$0	$0	$0	$0	$0	$0	$0	$0	$611,306	$0	$0
549 MISC OTHER POWER GENERATION	PROD	2	$3,639,052	$3,639,052	$0	$0	$0	$0	$0	$0	$0	$0	$3,639,052	$0	$0
550 RENTS	PROD	2	$4,421	$4,421	$0	$0	$0	$0	$0	$0	$0	$0	$4,421	$0	$0
Total Other Power Generation Expenses			$136,095,816	$5,326,175	$130,769,641	$0	$0	$0	$0	$0	$0	$0	$5,326,175	$130,769,641	$0
Other Power Generation Maintenance Expense															
551 MAINTENANCE SUPERVISION & ENGINEERING	PROD	2	$257,199	$257,199	$0	$0	$0	$0	$0	$0	$0	$0	$257,199	$0	$0
552 MAINTENANCE OF STRUCTURES	PROD	2	$1,680,721	$1,680,721	$0	$0	$0	$0	$0	$0	$0	$0	$1,680,721	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	PROD	2	$4,895,395	$4,895,395	$0	$0	$0	$0	$0	$0	$0	$0	$4,895,395	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	PROD	2	$5,139,215	$5,139,215	$0	$0	$0	$0	$0	$0	$0	$0	$5,139,215	$0	$0
Total Other Power Generation Maintenance Expense			$11,972,530	$11,972,530	$0	$0	$0	$0	$0	$0	$0	$0	$11,972,530	$0	$0
Total Other Power Generation Expense			$148,068,346	$17,298,705	$130,769,641	$0	$0	$0	$0	$0	$0	$0	$17,298,705	$130,769,641	$0
Total Station Expense			$634,802,484	$69,906,845	$564,895,639	$0	$0	$0	$0	$0	$0	$0	$69,906,845	$564,895,639	$0
Other Power Supply Expenses															
555 PURCHASED POWER	OMPP	20	$50,619,307	$7,292,915	$43,326,391	$0	$0	$0	$0	$0	$0	$0	$7,292,915	$43,326,391	$0
555 PURCHASED POWER OPTIONS													$0	$0	$0
555 BROKERAGE FEES													$0	$0	$0
555 MISO TRANSMISSION EXPENSES													$0	$0	$0
556 SYSTEM CONTROL AND LOAD DISPATCH	PROD	2	$1,864,717	$1,864,717	$0	$0	$0	$0	$0	$0	$0	$0	$1,864,717	$0	$0
557 OTHER EXPENSES	PROD	2	$10,369	$10,369	$0	$0	$0	$0	$0	$0	$0	$0	$10,369	$0	$0
Total Other Power Supply Expenses			$52,494,393	$9,168,002	$43,326,391	$0	$0	$0	$0	$0	$0	$0	$9,168,002	$43,326,391	$0
Total Electric Power Generation Expenses			$687,296,876	$79,074,846	$608,222,030	$0	$0	$0	$0	$0	$0	$0	$79,074,846	$608,222,030	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Transmission Expenses															
560 OPERATION SUPERVISION AND ENG	Dir		$1,804,305				$1,804,305						$1,804,305	$0	$0
561 LOAD DISPATCHING	Dir		$3,644,052				$3,644,052						$3,644,052	$0	$0
562 STATION EXPENSES	Dir		$1,303,298				$1,303,298						$1,303,298	$0	$0
563 OVERHEAD LINE EXPENSES	Dir		$1,058,993				$1,058,993						$1,058,993	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Dir		$2,940,449				$2,940,449						$2,940,449	$0	$0
566 MISC. TRANSMISSION EXPENSES	Dir		$11,948,572				$11,948,572						$11,948,572	$0	$0
567 RENTS	Dir		$112,005				$112,005						$112,005	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0										$0	$0	$0
569 STRUCTURES			$0										$0	$0	$0
570 MAINT OF STATION EQUIPMENT	Dir		$1,986,407				$1,986,407						$1,986,407	$0	$0
571 MAINT OF OVERHEAD LINES	Dir		$10,570,832				$10,570,832						$10,570,832	$0	$0
572 UNDERGROUND LINES			$0										$0	$0	$0
573 MISC PLANT	Dir		$337,099				$337,099						$337,099	$0	$0
575 MISO DAY 1&2 EXPENSE			$0										$0	$0	$0
Total Transmission Expenses			$35,706,011	$0	$0	$0	$35,706,011	$0	$0	$0	$0	$0	$35,706,011	$0	$0
Distribution Operation Expense															
580 OPERATION SUPERVISION AND ENGI	LBDO	14	$1,510,424	$0	$0	$0	$0	$0	$0	$621,285	$0	$889,139	$621,285	$0	$889,139
581 LOAD DISPATCHING	Acct 362		$341,053	$0	$0	$0	$0	$0	$0	$341,053	$0	$0	$341,053	$0	$0
582 STATION EXPENSES	Acct 362		$1,798,545	$0	$0	$0	$0	$0	$0	$1,798,545	$0	$0	$1,798,545	$0	$0
583 OVERHEAD LINE EXPENSES	Acct 365		$4,706,317	$0	$0	$0	$0	$0	$0	$3,737,182	$0	$969,134	$3,737,182	$0	$969,134
584 UNDERGROUND LINE EXPENSES			$0										$0	$0	$0
585 STREET LIGHTING EXPENSE			$0										$0	$0	$0
586 METER EXPENSES	Acct 370		$8,749,183	$0	$0	$0	$0	$0	$0	$0	$0	$8,749,183	$0	$0	$8,749,183
586 METER EXPENSES - LOAD MANAGEMENT			$0										$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE	Acct 371		-$142,800	$0	$0	$0	$0	$0	$0	$0	$0	-$142,800	$0	$0	-$142,800
588 MISCELLANEOUS DISTRIBUTION EXP	DIST	4	$6,743,173	$0	$0	$0	$0	$0	$0	$4,401,150	$0	$2,342,023	$4,401,150	$0	$2,342,023
588 MISC DISTR EXP -- MAPPIN			$0										$0	$0	$0
589 RENTS			$0										$0	$0	$0
Total Distribution Operation Expense			$23,705,895	$0	$0	$0	$0	$0	$0	$10,899,216	$0	$12,806,679	$10,899,216	$0	$12,806,679
Distribution Maintenance Expense															
590 MAINTENANCE SUPERVISION AND EN	LBDM	15	$57,449	$0	$0	$0	$0	$0	$0	$46,964	$0	$10,485	$46,964	$0	$10,485
591 STRUCTURES			$0										$0	$0	$0
592 MAINTENANCE OF STATION EQUIPME	Acct 362		$1,286,692	$0	$0	$0	$0	$0	$0	$1,286,692	$0	$0	$1,286,692	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct 365		$30,239,215	$0	$0	$0	$0	$0	$0	$24,012,295	$0	$6,226,920	$24,012,295	$0	$6,226,920
594 MAINTENANCE OF UNDERGROUND LIN	Acct 367		$790,500	$0	$0	$0 $0	$0	$0	$0 $0	$738,959	$0	$51,541	$738,959	$0	$51,541
595 MAINTENANCE OF LINE TRANSFORME	Acct 368		$96,331	$0	$0	$0 $0	$0	$0	$0 $0	$50,972	$0	$45,359	$50,972	$0	$45,359
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0										$0	$0	$0
597 MAINTENANCE OF METERS	Acct 370		$1,371,953	$0	$0	$0	$0	$0	$0	$0	$0	$1,371,953	$0	$0	$1,371,953
598 MISCELLANEOUS DISTRIBUTION EXPENSES	DIST	4	$550,314	$0	$0	$0	$0	$0	$0	$359,180	$0	$191,134	$359,180	$0	$191,134
Total Distribution Maintenance Expense			$34,392,454	$0	$0	$0	$0	$0	$0	$26,495,062	$0	$7,897,392	$26,495,062	$0	$7,897,392
Total Distribution Expense			$58,098,349	$0	$0	$0	$0	$0	$0	$37,394,279	$0	$20,704,070	$37,394,279	$0	$20,704,070
Customer Accounts Expense															
901 SUPERVISION/CUSTOMER ACCTS	Dir		$3,631,554									$3,631,554	$0	$0	$3,631,554
902 METER READING EXPENSES	Dir		$5,301,482									$5,301,482	$0	$0	$5,301,482
903 RECORDS AND COLLECTION	Dir		$20,167,471									$20,167,471	$0	$0	$20,167,471
904 UNCOLLECTIBLE ACCOUNTS	Dir		$5,566,157									$5,566,157	$0	$0	$5,566,157
905 MISC CUST ACCOUNTS	Dir		$0									$0	$0	$0	$0
Total Customer Accounts Expense			$34,666,664	$0	$0	$0	$0	$0	$0	$0	$0	$34,666,664	$0	$0	$34,666,664
Customer Service Expense															
907 SUPERVISION	Dir		$651,425									$651,425	$0	$0	$651,425
908 CUSTOMER ASSISTANCE EXPENSES	Dir		$450,051									$450,051	$0	$0	$450,051
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	Dir		$0										$0	$0	$0
909 INFORMATIONAL AND INSTRUCTIONA	Dir		$389,845									$389,845	$0	$0	$389,845
909 INFORM AND INSTRUC -LOAD MGMT	Dir		$0										$0	$0	$0
910 MISCELLANEOUS CUSTOMER SERVICE	Dir		$1,861,027									$1,861,027	$0	$0	$1,861,027
911 DEMONSTRATION AND SELLING EXP	Dir		$0										$0	$0	$0
912 DEMONSTRATION AND SELLING EXP	Dir		$0										$0	$0	$0
913 ADVERTISING EXPENSES	Dir		$794,217									$794,217	$0	$0	$794,217
916 MISC SALES EXPENSE	Dir		$0										$0	$0	$0
Total Customer Service Expense			$4,146,565	$0	$0	$0	$0	$0	$0	$0	$0	$4,146,565	$0	$0	$4,146,565
Administrative and General Expense															
920 ADMIN. & GEN. SALARIES-	LBSUB7	8	$33,809,232	$10,722,406	$7,680,251	$0	$2,272,732	$0	$0	$3,867,618	$0	$9,266,225	$16,862,756	$7,680,251	$9,266,225
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	8	$7,269,104	$2,305,355	$1,651,281	$0	$488,645	$0	$0	$831,552	$0	$1,992,271	$3,625,552	$1,651,281	$1,992,271
922 ADMINISTRATIVE EXPENSES TRANSFERRED	LBSUB7	8	-$4,414,266	-$1,399,959	-$1,002,764	$0	-$296,737	$0	$0	-$504,971	$0	-$1,209,835	-$2,201,667	-$1,002,764	-$1,209,835
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	8	$19,133,213	$6,067,990	$4,346,383	$0	$1,286,177	$0	$0	$2,188,750	$0	$5,243,912	$9,542,917	$4,346,383	$5,243,912
924 PROPERTY INSURANCE	TUP	7	$5,543,869	$3,357,161	$0	$0	$744,465	$0	$0	$941,327	$0	$500,917	$5,042,952	$0	$500,917
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	8	$3,904,092	$1,238,161	$886,870	$0	$262,442	$0	$0	$446,610	$0	$1,070,009	$1,947,213	$886,870	$1,070,009
926 EMPLOYEE BENEFITS	LBSUB7	8	$38,912,106	$12,340,754	$8,839,442	$0	$2,615,758	$0	$0	$4,451,363	$0	$10,664,789	$19,407,875	$8,839,442	$10,664,789
928 REGULATORY COMMISSION FEES	TUP	7	$1,800,307	$1,090,199	$0	$0	$241,756	$0	$0	$305,685	$0	$162,667	$1,637,640	$0	$162,667
929 DUPLICATE CHARGES			$0										$0	$0	$0
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	8	$5,197,262	$1,648,282	$1,180,632	$0	$349,371	$0	$0	$594,543	$0	$1,424,433	$2,592,196	$1,180,632	$1,424,433
931 RENTS AND LEASES	PT&D	1	$1,831,134	$1,115,943	$0	$0	$241,214	$0	$0	$309,356	$0	$164,620	$1,666,513	$0	$164,620
935 MAINTENANCE OF GENERAL PLANT	PT&D	1	$873,720	$532,469	$0	$0	$115,095	$0	$0	$147,608	$0	$78,548	$795,172	$0	$78,548
Total Administrative and General Expense			$113,859,773	$39,018,760	$23,582,096	$0	$8,320,918	$0	$0	$13,579,441	$0	$29,358,557	$60,919,119	$23,582,096	$29,358,557
Total Operation and Maintenance Expenses			$933,774,239	$118,093,606	$631,804,126	$0	$44,026,929	$0	$0	$50,973,720	$0	$88,875,857	$213,094,256	$631,804,126	$88,875,857
Total Operation and Maintenance Exp. Less Purchased Power			$883,154,932	$110,800,691	$588,477,735	$0	$44,026,929	$0	$0	$50,973,720	$0	$88,875,857	$205,801,340	$588,477,735	$88,875,857

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses															
Labor-Steam Power Generation Operation Expenses															
500 OPERATION SUPERVISION & ENGINEERING	FO19	16	$7,176,311	$6,192,742	$983,568	$0	$0	$0	$0	$0	$0	$0	$6,192,742	$983,568	$0
501 FUEL	Dir		$2,518,295		$2,518,295								$0	$2,518,295	$0
502 STEAM EXPENSES	PROD	2	$8,257,131	$8,257,131	$0	$0	$0	$0	$0	$0	$0	$0	$8,257,131	$0	$0
505 ELECTRIC EXPENSES	PROD	2	$5,890,264	$5,890,264	$0	$0	$0	$0	$0	$0	$0	$0	$5,890,264	$0	$0
506 MISC. STEAM POWER EXPENSES	PROD	2	$1,708,296	$1,708,296	$0	$0	$0	$0	$0	$0	$0	$0	$1,708,296	$0	$0
507 RENTS			$0										$0	$0	$0
Total Steam Power Operation Expenses			$25,550,297	$22,048,433	$3,501,864	$0	$0	$0	$0	$0	$0	$0	$22,048,433	$3,501,864	$0
Labor-Steam Power Generation Maintenance Expenses															
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	17	$8,497,622	$819,744	$7,677,878	$0	$0	$0	$0	$0	$0	$0	$819,744	$7,677,878	$0
511 MAINTENANCE OF STRUCTURES	PROD	2	$1,238,874	$1,238,874	$0	$0	$0	$0	$0	$0	$0	$0	$1,238,874	$0	$0
512 MAINTENANCE OF BOILER PLANT	Dir		$9,213,874		$9,213,874								$0	$9,213,874	$0
513 MAINTENANCE OF ELECTRIC PLANT	Dir		$1,992,105		$1,992,105								$0	$1,992,105	$0
514 MAINTENANCE OF MISC STEAM PLANT	Dir		$397,544		$397,544								$0	$397,544	$0
Total Steam Power Generation Maintenance Expense			$21,340,020	$2,058,618	$19,281,401	$0	$0	$0	$0	$0	$0	$0	$2,058,618	$19,281,401	$0
Total Steam Power Generation Expense			$46,890,316	$24,107,052	$22,783,265	$0	$0	$0	$0	$0	$0	$0	$24,107,052	$22,783,265	$0
Labor-Hydraulic Power Generation Operation Expenses															
535 OPERATION SUPERVISION & ENGINEERING			$0										$0	$0	$0
536 WATER FOR POWER			$0										$0	$0	$0
537 HYDRAULIC EXPENSES			$0										$0	$0	$0
538 ELECTRIC EXPENSES			$0										$0	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES			$0										$0	$0	$0
540 RENTS			$0										$0	$0	$0
Total Hydraulic Power Operation Expenses			$0	$0											
Labor-Hydraulic Power Generation Maintenance Expenses															
541 MAINTENANCE SUPERVISION & ENGINEERING	FO22	18	$166,692	$166,692	$0	$0	$0	$0	$0	$0	$0	$0	$166,692	$0	$0
542 MAINTENANCE OF STRUCTURES	PROD	2	$47,185	$47,185	$0	$0	$0	$0	$0	$0	$0	$0	$47,185	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS			$0										$0	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT			$0										$0	$0	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0										$0	$0	$0
Total Hydraulic Power Generation Maint. Expense			$213,877	$213,877	$0	$0	$0	$0	$0	$0	$0	$0	$213,877	$0	$0
Total Hydraulic Power Generation Expense			$213,877	$213,877	$0	$0	$0	$0	$0	$0	$0	$0	$213,877	$0	$0
Labor-Other Power Generation Operation Expense															
546 OPERATION SUPERVISION & ENGINEERING	PROD	2	$848,268	$848,268	$0	$0	$0	$0	$0	$0	$0	$0	$848,268	$0	$0
547 FUEL			$0										$0	$0	$0
548 GENERATION EXPENSE	PROD	2	$327,051	$327,051	$0	$0	$0	$0	$0	$0	$0	$0	$327,051	$0	$0
549 MISC OTHER POWER GENERATION	PROD	2	$1,662,761	$1,662,761	$0	$0	$0	$0	$0	$0	$0	$0	$1,662,761	$0	$0
550 RENTS			$0										$0	$0	$0
Total Other Power Generation Expenses			$2,838,080	$2,838,080	$0	$0	$0	$0	$0	$0	$0	$0	$2,838,080	$0	$0
Labor-Other Power Generation Maintenance Expense															
551 MAINTENANCE SUPERVISION & ENGINEERING	PROD	2	$201,322	$201,322	$0	$0	$0	$0	$0	$0	$0	$0	$201,322	$0	$0
552 MAINTENANCE OF STRUCTURES			$0										$0	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	PROD	2	$1,017,670	$1,017,670	$0	$0	$0	$0	$0	$0	$0	$0	$1,017,670	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	PROD	2	$1,600,551	$1,600,551	$0	$0	$0	$0	$0	$0	$0	$0	$1,600,551	$0	$0
Total Other Power Generation Maintenance Expense			$2,819,543	$2,819,543	$0	$0	$0	$0	$0	$0	$0	$0	$2,819,543	$0	$0
Total Other Power Generation Expense			$5,657,623	$5,657,623	$0	$0	$0	$0	$0	$0	$0	$0	$5,657,623	$0	$0
Total Production Expense			$52,761,816	$29,978,551	$22,783,265	$0	$0	$0	$0	$0	$0	$0	$29,978,551	$22,783,265	$0
Labor-Purchased Power															
555 PURCHASED POWER			$0										$0	$0	$0
556 SYSTEM CONTROL AND LOAD DISPATCH	PROD	2	$1,829,189	$1,829,189	$0	$0	$0	$0	$0	$0	$0	$0	$1,829,189	$0	$0
557 OTHER EXPENSES			$0										$0	$0	$0
Total Purchased Power Labor			$1,829,189	$1,829,189	$0	$0	$0	$0	$0	$0	$0	$0	$1,829,189	$0	$0
Transmission Labor Expenses															
560 OPERATION SUPERVISION AND ENG	Dir		$1,648,654				$1,648,654						$1,648,654	$0	$0
561 LOAD DISPATCHING	Dir		$3,065,460				$3,065,460						$3,065,460	$0	$0
562 STATION EXPENSES	Dir		$505,135				$505,135						$505,135	$0	$0
563 OVERHEAD LINE EXPENSES			$0										$0	$0	$0
566 MISC. TRANSMISSION EXPENSES	Dir		$118,042				$118,042						$118,042	$0	$0
568 MAINTENACE SUPERVISION AND ENG	Dir		$0										$0	$0	$0
570 MAINT OF STATION EQUIPMENT	Dir		$937,915				$937,915						$937,915	$0	$0
571 MAINT OF OVERHEAD LINES	Dir		$466,793				$466,793						$466,793	$0	$0
572 UNDERGROUND LINES			$0										$0	$0	$0
573 MISC PLANT			$0										$0	$0	$0
Total Transmission Labor Expenses			$6,741,999	$0	$0	$0	$6,741,999	$0	$0	$0	$0	$0	$6,741,999	$0	$0

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production				Transmission				Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer		Demand	Energy	Customer		Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																	
580 OPERATION SUPERVISION AND ENGI	FO23	19	$1,081,711	$0	$0	$0		$0	$0	$0		$444,942	$0	$636,769	$444,942	$0	$636,769
581 LOAD DISPATCHING	Acct 362		$342,506	$0	$0	$0		$0	$0	$0		$342,506	$0	$0	$342,506	$0	$0
582 STATION EXPENSES	Acct 362		$870,967	$0	$0	$0		$0	$0	$0		$870,967	$0	$0	$870,967	$0	$0
583 OVERHEAD LINE EXPENSES	Acct 365		$2,170,209	$0	$0	$0	$0	$0	$0	$0	$0	$1,723,315	$0	$446,894	$1,723,315	$0	$446,894
584 UNDERGROUND LINE EXPENSES			$0												$0	$0	$0
585 STREET LIGHTING EXPENSE			$0												$0	$0	$0
586 METER EXPENSES	Acct 370		$5,717,580	$0	$0	$0		$0	$0	$0		$0	$0	$5,717,580	$0	$0	$5,717,580
586 METER EXPENSES - LOAD MANAGEMENT			$0												$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE			$0												$0	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	DIST	4	$3,343,041	$0	$0	$0		$0	$0	$0		$2,181,944	$0	$1,161,097	$2,181,944	$0	$1,161,097
589 RENTS			$0												$0	$0	$0
Total Distribution Operation Labor Expense			$13,526,014	$0	$0	$0		$0	$0	$0		$5,563,674	$0	$7,962,340	$5,563,674	$0	$7,962,340
Distribution Maintenance Labor Expense																	
590 MAINTENANCE SUPERVISION AND EN			$0												$0	$0	$0
591 MAINTENANCE OF STRUCTURES			$0												$0	$0	$0
592 MAINTENANCE OF STATION EQUIPME	Acct 362		$605,269	$0	$0	$0		$0	$0	$0		$605,269	$0	$0	$605,269	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct 365		$6,158,359	$0	$0	$0	$0	$0	$0	$0	$0	$4,890,217	$0	$1,268,142	$4,890,217	$0	$1,268,142
594 MAINTENANCE OF UNDERGROUND LIN	Acct 367		$413,802	$0	$0	$0	$0	$0	$0	$0	$0	$386,822	$0	$26,980	$386,822	$0	$26,980
595 MAINTENANCE OF LINE TRANSFORME	Acct 368		$51,420	$0	$0	$0	$0	$0	$0	$0	$0	$27,208	$0	$24,212	$27,208	$0	$24,212
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS			$0												$0	$0	$0
597 MAINTENANCE OF METERS			$0												$0	$0	$0
598 MAINTENANCE OF MISC DISTR PLANT			$0												$0	$0	$0
Total Distribution Maintenance Labor Expense			$7,228,850	$0	$0	$0		$0	$0	$0		$5,909,516	$0	$1,319,334	$5,909,516	$0	$1,319,334
Total Distribution Labor Expense			$20,754,864	$0	$0	$0		$0	$0	$0		$11,473,190	$0	$9,281,674	$11,473,190	$0	$9,281,674
Customer Accounts Expense																	
901 SUPERVISION/CUSTOMER ACCTS	Dir		$3,259,518											$3,259,518	$0	$0	$3,259,518
902 METER READING EXPENSES	Dir		$754,379											$754,379	$0	$0	$754,379
903 RECORDS AND COLLECTION	Dir		$11,992,171											$11,992,171	$0	$0	$11,992,171
904 UNCOLLECTIBLE ACCOUNTS			$0												$0	$0	$0
905 MISC CUST ACCOUNTS			$0												$0	$0	$0
Total Customer Accounts Labor Expense			$16,006,068	$0	$0	$0		$0	$0	$0		$0	$0	$16,006,068	$0	$0	$16,006,068
Customer Service Expense																	
907 SUPERVISION	Dir		$614,307											$614,307	$0	$0	$614,307
908 CUSTOMER ASSISTANCE EXPENSES	Dir		$1,585,968											$1,585,968	$0	$0	$1,585,968
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0												$0	$0	$0
909 INFORMATIONAL AND INSTRUCTIONA			$0												$0	$0	$0
909 INFORM AND INSTRUC -LOAD MGMT			$0												$0	$0	$0
910 MISCELLANEOUS CUSTOMER SERVICE			$0												$0	$0	$0
911 DEMONSTRATION AND SELLING EXP			$0												$0	$0	$0
912 DEMONSTRATION AND SELLING EXP			$0												$0	$0	$0
913 WATER HEATER - HEAT PUMP PROGRAM			$0												$0	$0	$0
916 MISC SALES EXPENSE			$0												$0	$0	$0
Total Customer Service Labor Expense			$2,200,275	$0	$0	$0		$0	$0	$0		$0	$0	$2,200,275	$0	$0	$2,200,275
Total Labor Excluding A&G			$100,294,210	$31,807,740	$22,783,265	$0		$6,741,999	$0	$0		$11,473,190	$0	$27,488,016	$50,022,929	$22,783,265	$27,488,016
Administrative and General Expense																	
920 ADMIN. & GEN. SALARIES-	LBSUB7	8	$33,809,236	$10,722,407.55	$7,680,252	$0		$2,272,732	$0	$0		$3,867,619	$0	$9,266,226	$16,862,758	$7,680,252	$9,266,226
921 OFFICE SUPPLIES AND EXPENSES			$0												$0	$0	$0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	8	-$3,161,163	-$1,002,545.06	-$718,104	$0		-$212,500	$0	$0		-$361,622	$0	-$866,392	-$1,576,668	-$718,104	-$866,392
923 OUTSIDE SERVICES EMPLOYED			$0												$0	$0	$0
924 PROPERTY INSURANCE			$0												$0	$0	$0
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	8	$560,277	$177,688.70	$127,275	$0		$37,663	$0	$0		$64,093	$0	$153,557	$279,445	$127,275	$153,557
926 EMPLOYEE BENEFITS	LBSUB7	8	$39,380,962	$12,489,448.73	$8,945,949	$0		$2,647,276	$0	$0		$4,504,998	$0	$10,793,290	$19,641,723	$8,945,949	$10,793,290
928 REGULATORY COMMISSION FEES			$0												$0	$0	$0
929 DUPLICATE CHARGES-CR			$0												$0	$0	$0
930 MISCELLANEOUS GENERAL EXPENSES			$0												$0	$0	$0
931 RENTS AND LEASES			$0												$0	$0	$0
935 MAINTENANCE OF GENERAL PLANT	PT&D	1	$593,047	$361,419.35	$0	$0		$78,122	$0	$0		$100,191	$0	$53,315	$539,732	$0	$53,315
Total Labor Administrative and General Expense			$71,182,359	$22,748,419	$16,035,372	$0		$4,823,292	$0	$0		$8,175,279	$0	$19,399,997	$35,746,990	$16,035,372	$19,399,997
Total Labor Operation and Maintenance Expenses			$171,476,569	$54,556,159	$38,818,637	$0		$11,565,291	$0	$0		$19,648,469	$0	$46,888,013	$85,769,919	$38,818,637	$46,888,013

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Depreciation Expenses															
Steam Production	PROD	2	$99,900,146	$99,900,146.21	$0	$0	$0	$0	$0	$0	$0	$0	$99,900,146	$0	$0
Hydraulic Production	PROD	2	$1,118,831	$1,118,830.89	$0	$0	$0	$0	$0	$0	$0	$0	$1,118,831	$0	$0
Other Production	PROD	2	$35,620,454	$35,620,454.18	$0	$0	$0	$0	$0	$0	$0	$0	$35,620,454	$0	$0
Transmission - Kentucky System Property	TRANS	3	$20,185,930	$0.00	$0	$0	$20,185,930	$0	$0	$0	$0	$0	$20,185,930	$0	$0
Transmission - Virginia Property	TRANS	3	$182,214	$0.00	$0	$0	$182,214	$0	$0	$0	$0	$0	$182,214	$0	$0
Distribution	DIST	4	$43,044,393	$0.00	$0	$0	$0	$0	$0	$28,094,318	$0	$14,950,075	$28,094,318	$0	$14,950,075
General Plant	PT&D	1	$11,631,105	$7,088,314.01	$0	$0	$1,532,160	$0	$0	$1,964,986	$0	$1,045,645	$10,585,460	$0	$1,045,645
Intangible Plant	PT&D	1	$16,379,764	$9,982,276.82	$0	$0	$2,157,698	$0	$0	$2,767,235	$0	$1,472,553	$14,907,211	$0	$1,472,553
Total Depreciation Expense			$228,062,837	$153,710,022	$0	$0	$24,058,002	$0	$0	$32,826,539	$0	$17,468,273	$210,594,563	$0	$17,468,273
Regulatory Credits and Accretion Expenses															
Production Plant			$0										$0	$0	$0
Transmission Plant			$0										$0	$0	$0
Distribution Plant			$0										$0	$0	$0
Total Regulatory Credits and Accretion Expenses			$0	$0											
Property Taxes	TUP	7	$24,894,101	$15,074,941.30	$0	$0	$3,342,932	$0	$0	$4,226,920	$0	$2,249,308	$22,644,793	$0	$2,249,308
Other Taxes	TUP	7	$12,926,774	$7,827,973.60	$0	$0	$1,735,886	$0	$0	$2,194,915	$0	$1,167,999	$11,758,775	$0	$1,167,999
Gain Disposition of Allowances			$0												
Interest	TUP	7	$86,095,200	$52,136,050.20	$0	$0	$11,561,389	$0	$0	$14,618,625	$0	$7,779,137	$78,316,064	$0	$7,779,137
Other Expenses			$0										$0	$0	$0
Total Other Expenses			$1,285,753,151	$346,842,593	$631,804,126	$0	$84,725,138	$0	$0	$104,840,719	$0	$117,540,575	$536,408,451	$631,804,126	$117,540,575

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Classification Factors

Functionalization ---->	Functional Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->		No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
PT&D Plant	PT&D	1	100.0000%	60.9427%	0.0000%	0.0000%	13.1730%	0.0000%	0.0000%	16.8942%	0.0000%	8.9901%	91.0099%	0.0000%	8.9901%
Production Plant	PROD	2	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Transmission Plant	TRANS	3	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Distribution Plant	DIST	4	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	65.2682%	0.0000%	34.7318%	65.2682%	0.0000%	34.7318%
Total Plant in Service	TPIS	5	100.0000%	60.9433%	0.0000%	0.0000%	13.1722%	0.0000%	0.0000%	16.8944%	0.0000%	8.9901%	91.0099%	0.0000%	8.9901%
Distrib Overhead + Underground Lines Plant	DLINES	6	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	82.4877%	0.0000%	17.5123%	82.4877%	0.0000%	17.5123%
Total Utility Plant	TUP	7	100.0000%	60.5563%	0.0000%	0.0000%	13.4286%	0.0000%	0.0000%	16.9796%	0.0000%	9.0355%	90.9645%	0.0000%	9.0355%
Total Labor Excluding A&G	LBSUB7	8	100.0000%	31.7144%	22.7164%	0.0000%	6.7222%	0.0000%	0.0000%	11.4395%	0.0000%	27.4074%	49.8762%	22.7164%	27.4074%
Total O&M Expense Less Purchased Power	O&MxPurch	9	100.0000%	12.5460%	66.6336%	0.0000%	4.9852%	0.0000%	0.0000%	5.7718%	0.0000%	10.0635%	23.3030%	66.6336%	10.0635%
Steam Power Operation Labor	LBSUB1	10	100.0000%	86.2942%	13.7058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	86.2942%	13.7058%	0.0000%
Total Steam Power Maintenance Labor Expen	LBSUB2	11	100.0000%	9.6468%	90.3532%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	9.6468%	90.3532%	0.0000%
Total Hydraulic Power Maintenance Labor Exp	LBSUB4	12	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Total Other Power Operating Labor Expense	LBSUB5	13	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Total Distribution Operation Labor Expense	LBDO	14	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.1331%	0.0000%	58.8669%	41.1331%	0.0000%	58.8669%
Total Distribution Maintenance Labor Expense	LBDM	15	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	81.7490%	0.0000%	18.2510%	81.7490%	0.0000%	18.2510%
Total Steam Power Operation Labor Excl Supe	FO19	16	100.0000%	86.2942%	13.7058%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	86.2942%	13.7058%	0.0000%
Total Steam Power Maintenance Labor Excl Su	FO20	17	100.0000%	9.6468%	90.3532%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	9.6468%	90.3532%	0.0000%
Total Hydraulic Power Maintenance Labor Exc	FO22	18	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Distribution Operation Labor Excl. Super. & Er	FO23	19	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.1331%	0.0000%	58.8669%	41.1331%	0.0000%	58.8669%
Purchased Power Expense	OMPP	20	100.0000%	14.4074%	85.5926%								14.4074%	85.5926%	0.0000%

Memo: Purchased Power Expense				
Demand	Production Plant	$7,312,226	$7,312,226	
Energy	Production Energy	$43,441,113		$43,441,113
Total		$50,753,339	$7,312,226	$43,441,113
Pct			14.4074%	85.5926%

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Cost Summary

	Total Kentucky	Residential (RS) (RS	General Service (GS)	All Elect. Schools (AES)	Pwr Svc Secondary (PS-Sec)	PWR Svc Primary (PS-Pri)	Time of Day Secondary (TOU-sec)	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
CLASSIFIED DEMAND COSTS													
Rate Base													
Plant in Service													
Intangible	$93,810,715	$36,275,813	$9,944,543	$851,126	$10,438,130	$786,651	$8,037,872	$18,731,438	$5,739,467	$2,365,223	$631,557	$2,421	$6,474
Production	$4,076,920,355	$1,369,820,778	$410,839,418	$33,544,901	$486,523,368	$37,299,744	$375,211,211	$902,483,397	$317,665,480	$117,252,229	$25,863,983	$93,769	$322,077
Transmission	$881,238,248	$374,825,553	$94,894,628	$9,161,093	$83,658,755	$6,579,025	$64,659,843	$149,809,343	$54,827,497	$36,251,382	$6,501,718	$27,233	$42,177
Distribution	$1,130,182,900	$609,664,042	$139,669,572	$12,532,297	$107,255,435	$7,175,118	$81,789,072	$163,382,826	$0	$0	$8,622,496	$36,117	$55,924
General	$161,574,647	$62,479,555	$17,127,959	$1,465,934	$17,978,087	$1,354,887	$13,844,008	$32,262,045	$9,885,356	$4,073,735	$1,087,760	$4,170	$11,151
Plant Held for Future Use	$345,418	$131,180	$36,504	$3,055	$39,405	$2,952	$30,328	$70,755	$21,123	$7,797	$2,287	$9	$25
Total Gross Plant	$6,344,072,283	$2,453,196,921	$672,512,624	$57,558,406	$705,893,179	$53,198,378	$543,572,335	$1,266,739,805	$388,138,922	$159,950,366	$42,709,800	$163,718	$437,828
Construction Work In Progress													
Production	$28,153,069	$9,459,262	$2,837,041	$231,643	$3,359,675	$257,572	$2,591,011	$6,232,076	$2,193,631	$809,682	$178,603	$648	$2,224
Transmission	$30,190,923	$12,841,396	$3,251,058	$313,856	$2,866,121	$225,395	$2,215,224	$5,132,417	$1,878,371	$1,241,960	$222,747	$933	$1,445
Distribution	$21,452,791	$11,572,459	$2,651,166	$237,884	$2,035,890	$136,196	$1,552,496	$3,101,284	$0	$0	$163,670	$686	$1,062
General	$25,019,807	$9,674,949	$2,652,262	$227,000	$2,783,904	$209,804	$2,143,742	$4,995,772	$1,530,746	$630,817	$168,439	$646	$1,727
Total CWIP	$104,816,591	$43,548,066	$11,391,526	$1,010,383	$11,045,589	$828,968	$8,502,474	$19,461,549	$5,602,748	$2,682,460	$733,459	$2,912	$6,457
Accumulated Depreciation													
Intangible	$47,301,667	$18,291,156	$5,014,283	$429,158	$5,263,162	$396,649	$4,052,892	$9,444,851	$2,893,980	$1,192,603	$318,446	$1,221	$3,264
Production	$1,642,341,649	$553,533,187	$166,526,874	$13,493,479	$196,103,805	$14,992,937	$150,821,161	$362,530,496	$127,501,552	$46,670,423	$10,003,503	$36,132	$128,103
Transmission	$307,792,605	$130,916,394	$33,144,118	$3,199,721	$29,219,733	$2,297,875	$22,583,928	$52,324,338	$19,149,757	$12,661,624	$2,270,874	$9,512	$14,731
Distribution	$415,869,870	$224,336,172	$51,393,776	$4,611,470	$39,466,447	$2,640,206	$30,095,669	$60,119,468	$0	$0	$3,172,793	$13,290	$20,578
General	$54,846,206	$21,208,566	$5,814,053	$497,609	$6,102,627	$459,914	$4,699,322	$10,951,290	$3,355,565	$1,382,822	$369,238	$1,415	$3,785
Total Depreciation Reserve	$2,468,151,996	$948,285,475	$261,893,104	$22,231,438	$276,155,774	$20,787,580	$212,252,973	$495,370,443	$152,900,853	$61,907,472	$16,134,854	$61,569	$170,462
Net Utility Plant	$3,980,736,877	$1,548,459,513	$422,011,046	$36,337,352	$440,782,995	$33,239,765	$339,821,835	$790,830,912	$240,840,816	$100,725,354	$27,308,405	$105,061	$273,824
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	$24,782,374	$10,262,788	$2,722,532	$238,504	$2,626,077	$198,114	$1,995,416	$4,681,868	$1,316,679	$583,442	$154,793	$610	$1,550
Materials and Supplies	$109,037,398	$42,163,802	$11,558,668	$989,273	$12,132,389	$914,336	$9,342,534	$21,771,822	$6,671,055	$2,749,113	$734,066	$2,814	$7,525
Prepayments	$14,717,434	$5,691,102	$1,560,143	$133,528	$1,637,582	$123,413	$1,261,018	$2,938,674	$900,433	$371,064	$99,081	$380	$1,016
Total Working Capital	$148,537,206	$58,117,693	$15,841,343	$1,361,305	$16,396,048	$1,235,863	$12,598,968	$29,392,364	$8,888,167	$3,703,620	$987,940	$3,804	$10,091
Accumulated Deferred Income Taxes	$823,952,079	$321,835,821	$87,660,948	$7,533,857	$91,097,349	$6,858,454	$70,143,203	$163,052,988	$49,441,651	$20,676,108	$5,574,100	$21,462	$56,137
Accumulated ITCs	$81,185,411	$27,277,811	$8,181,216	$667,994	$9,688,342	$742,765	$7,471,737	$17,971,527	$6,325,805	$2,334,892	$515,040	$1,867	$6,414
Customer Advances	$1,278,314	$670,063	$158,833	$14,633	$116,546	$9,165	$90,078	$208,701	$0	$0	$10,185	$43	$66
Net Rate Base	$3,222,858,279	$1,256,793,511	$341,851,392	$29,482,173	$356,276,805	$26,865,243	$274,715,785	$638,990,059	$193,961,527	$81,417,973	$22,197,020	$85,493	$221,298
Operation and Maintenance Expenses													
Production & Purchased Power	$79,074,846	$29,506,336	$8,444,393	$692,588	$9,139,177	$656,724	$6,713,863	$15,949,146	$5,582,286	$2,072,562	$311,180	$1,128	$5,461
Transmission	$35,706,011	$15,187,182	$3,844,941	$371,189	$3,389,685	$266,569	$2,619,888	$6,069,975	$2,221,500	$1,468,834	$263,437	$1,103	$1,709
Distribution	$37,394,279	$19,876,953	$4,658,859	$425,565	$3,372,200	$259,198	$2,601,096	$5,902,143	$0	$0	$295,114	$1,236	$1,914
Customer Accounts Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Service Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Administrative and General Expense	$60,919,119	$23,819,194	$6,511,159	$561,478	$6,704,871	$513,229	$5,170,050	$12,195,200	$3,557,962	$1,464,476	$415,726	$1,602	$4,173
Total Operation and Maintenance Expenses	$213,094,256	$88,389,665	$23,459,352	$2,050,821	$22,605,933	$1,695,721	$17,104,896	$40,116,464	$11,361,748	$5,005,871	$1,285,457	$5,070	$13,258
Depreciation Expense													
Intangible	$14,907,211	$5,764,493	$1,580,261	$135,250	$1,658,695	$125,005	$1,277,277	$2,976,563	$912,043	$375,851	$100,359	$385	$1,029
Production	$136,639,431	$45,910,029	$13,769,429	$1,124,269	$16,306,003	$1,250,114	$12,575,337	$30,247,051	$10,646,671	$3,929,750	$866,841	$3,143	$10,795
Transmission	$20,368,144	$8,663,379	$2,193,309	$211,741	$1,933,613	$152,062	$1,494,489	$3,462,558	$1,267,233	$837,882	$150,275	$629	$975
Distribution	$28,094,318	$15,155,153	$3,471,935	$311,530	$2,666,178	$178,361	$2,033,129	$4,061,404	$0	$0	$214,340	$898	$1,390
General	$10,585,460	$4,093,308	$1,122,127	$96,040	$1,177,823	$88,765	$906,981	$2,113,627	$647,633	$266,888	$71,264	$273	$731
Total Depreciation Expense	$210,594,563	$79,586,362	$22,137,060	$1,878,831	$23,742,312	$1,794,306	$18,287,214	$42,861,203	$13,473,580	$5,410,371	$1,403,078	$5,328	$14,919
Taxes Other Than Income Taxes													
Property Taxes	$22,644,793	$8,767,134	$2,401,478	$205,660	$2,517,477	$189,713	$1,938,570	$4,516,400	$1,382,595	$571,073	$152,548	$585	$1,560
Other Taxes	$11,758,775	$4,552,515	$1,247,017	$106,793	$1,307,252	$98,512	$1,006,642	$2,345,234	$717,941	$296,541	$79,214	$304	$810
Total taxes Other Than Income Taxes	$34,403,568	$13,319,649	$3,648,496	$312,453	$3,824,729	$288,225	$2,945,212	$6,861,634	$2,100,535	$867,614	$231,761	$889	$2,370
Total Expenses Before Interest and Income Taxes	$458,092,387	$181,295,676	$49,244,908	$4,242,105	$50,172,974	$3,778,252	$38,337,321	$89,839,301	$26,935,864	$11,283,857	$2,920,297	$11,286	$30,547

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Cost Summary

	Total Kentucky	Residential (RS) (RS	General Service (GS)	All Elect. Schools (AES)	Pwr Svc Secondary (PS-Sec)	PWR Svc Primary (PS-Pri)	Time of Day Secondary (TOU-sec)	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
CLASSIFIED ENERGY COSTS													
Rate Base													
Plant in Service													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gross Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Construction Work In Progress													
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated Depreciation													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Reserve	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	$70,863,851	$23,823,120	$7,102,999	$594,682	$8,369,119	$646,537	$6,524,872	$15,672,523	$5,579,084	$2,064,160	$479,219	$1,730	$5,806
Materials and Supplies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Prepayments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Working Capital	$70,863,851	$23,823,120	$7,102,999	$594,682	$8,369,119	$646,537	$6,524,872	$15,672,523	$5,579,084	$2,064,160	$479,219	$1,730	$5,806
Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated ITCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Rate Base	$70,863,851	$23,823,120	$7,102,999	$594,682	$8,369,119	$646,537	$6,524,872	$15,672,523	$5,579,084	$2,064,160	$479,219	$1,730	$5,806
Operation and Maintenance Expenses													
Production & Purchased Power	$608,222,030	$204,461,938	$60,963,007	$5,103,581	$71,836,500	$5,549,326	$56,003,161	$134,521,744	$47,887,696	$17,716,057	$4,114,334	$14,855	$49,833
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Accounts Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Service Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Administrative and General Expense	$23,582,096	$7,918,880	$2,362,287	$197,451	$2,788,834	$215,254	$2,171,678	$5,219,563	$1,858,718	$686,458	$160,459	$580	$1,935
Total Operation and Maintenance Expenses	$631,804,126	$212,380,817	$63,325,295	$5,301,031	$74,625,333	$5,764,580	$58,174,839	$139,741,307	$49,746,414	$18,402,515	$4,274,793	$15,434	$51,767
Depreciation Expense													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes Other Than Income Taxes													
Property Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses Before Interest and Income Taxes	$631,804,126	$212,380,817	$63,325,295	$5,301,031	$74,625,333	$5,764,580	$58,174,839	$139,741,307	$49,746,414	$18,402,515	$4,274,793	$15,434	$51,767

KENTUCKY UTILITIES COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Cost Summary

	Total Kentucky	Residential (RS) (RS	General Service (GS)	All Elect. Schools (AES)	Pwr Svc Secondary (PS-Sec)	PWR Svc Primary (PS-Pri)	Time of Day Secondary (TOU-sec)	Time of Day Primary (TOU-Pri)	Retail Transmission (RTS)	Fluctuating Load (FLS)	Outdoor Lighting (ST & POL)	Lighting Energy (LE)	Traffic Energy (TE)
CLASSIFIED CUSTOMER COSTS													
Rate Base													
Plant in Service													
Intangible	$9,266,742	$5,636,038	$1,441,226	$15,400	$126,965	$17,699	$21,520	$39,326	$26,820	$1,135	$1,938,410	$11	$2,191
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$601,414,112	$365,780,419	$93,536,000	$999,465	$8,240,063	$1,148,686	$1,396,662	$2,552,238	$1,740,656	$73,672	$125,803,342	$733	$142,175
General	$15,960,549	$9,707,215	$2,482,293	$26,524	$218,678	$30,484	$37,065	$67,732	$46,194	$1,955	$3,338,615	$19	$3,773
Plant Held for Future Use	$39,553	$24,056	$6,152	$66	$542	$76	$92	$168	$114	$5	$8,274	$0	$9
Total Gross Plant	$626,680,956	$381,147,728	$97,465,671	$1,041,455	$8,586,247	$1,196,946	$1,455,339	$2,659,464	$1,813,785	$76,767	$131,088,642	$764	$148,148
Construction Work In Progress													
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$11,415,861	$6,943,134	$1,775,472	$18,972	$156,410	$21,804	$26,511	$48,446	$33,041	$1,398	$2,387,961	$14	$2,699
General	$2,471,488	$1,503,161	$384,383	$4,107	$33,862	$4,720	$5,740	$10,488	$7,153	$303	$516,984	$3	$584
Total CWIP	$13,887,350	$8,446,294	$2,159,855	$23,079	$190,273	$26,525	$32,251	$58,934	$40,194	$1,701	$2,904,945	$17	$3,283
Accumulated Depreciation													
Intangible	$4,672,519	$2,841,829	$726,702	$7,765	$64,019	$8,924	$10,851	$19,829	$13,524	$572	$977,394	$6	$1,105
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$221,300,471	$134,595,078	$34,418,150	$367,770	$3,032,070	$422,679	$513,925	$939,139	$640,504	$27,109	$46,291,463	$270	$52,316
General	$5,417,778	$3,295,096	$842,610	$9,004	$74,230	$10,348	$12,582	$22,992	$15,681	$664	$1,133,287	$7	$1,281
Total Depreciation Reserve	$231,390,768	$140,732,002	$35,987,461	$384,539	$3,170,319	$441,951	$537,358	$981,960	$669,708	$28,345	$48,402,143	$282	$54,701
Net Utility Plant	$409,177,537	$248,862,021	$63,638,065	$679,995	$5,606,201	$781,519	$950,232	$1,736,438	$1,184,271	$50,124	$85,591,443	$499	$96,730
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	$10,702,334	$7,032,130	$2,482,257	$74,192	$373,070	$38,883	$186,505	$138,512	$51,517	$2,437	$318,818	$14	$4,000
Materials and Supplies	$10,770,946	$6,550,896	$1,675,171	$17,900	$147,574	$20,572	$25,013	$45,709	$31,174	$1,319	$2,253,058	$13	$2,546
Prepayments	$1,453,819	$884,214	$226,108	$2,416	$19,919	$2,777	$3,376	$6,170	$4,208	$178	$304,109	$2	$344
Total Working Capital	$22,927,100	$14,467,239	$4,383,536	$94,507	$540,563	$62,232	$214,895	$190,391	$86,899	$3,934	$2,875,985	$29	$6,890
Accumulated Deferred Income Taxes	$86,475,619	$52,594,523	$13,449,275	$143,710	$1,184,815	$165,166	$200,822	$366,979	$250,284	$10,593	$18,088,904	$105	$20,443
Accumulated ITCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances	$271,389	$219,122	$42,397	$302	$0	$0	$0	$0	$0	$0	$9,525	$0	$44
Net Rate Base	$345,357,629	$210,515,615	$54,529,929	$630,491	$4,961,949	$678,585	$964,304	$1,559,850	$1,020,886	$43,465	$70,369,000	$422	$83,133
Operation and Maintenance Expenses													
Production & Purchased Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$20,704,070	$14,287,875	$4,070,213	$65,758	$715,990	$154,806	$132,179	$343,960	$234,585	$9,929	$674,773	$72	$13,932
Customer Accounts Expense	$34,666,664	$22,430,805	$8,679,972	$308,849	$1,172,638	$45,051	$804,675	$360,672	$31,250	$2,604	$822,341	$0	$7,806
Customer Service Expense	$4,146,565	$2,671,497	$1,033,780	$36,784	$139,661	$5,366	$95,836	$42,956	$3,722	$310	$116,120	$0	$533
Administrative and General Expense	$29,358,557	$19,007,040	$6,829,552	$204,722	$1,069,810	$117,676	$516,111	$402,665	$158,259	$7,393	$1,034,342	$41	$10,945
Total Operation and Maintenance Expenses	$88,875,857	$58,397,217	$20,613,517	$616,113	$3,098,099	$322,899	$1,548,802	$1,150,253	$427,816	$20,236	$2,647,577	$113	$33,216
Depreciation Expense													
Intangible	$1,472,553	$895,608	$229,021	$2,447	$20,176	$2,813	$3,420	$6,249	$4,262	$180	$308,028	$2	$348
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$14,950,075	$9,092,644	$2,325,137	$24,845	$204,833	$28,554	$34,719	$63,444	$43,270	$1,831	$3,127,245	$18	$3,534
General	$1,045,645	$635,962	$162,626	$1,738	$14,327	$1,997	$2,428	$4,437	$3,026	$128	$218,727	$1	$247
Total Depreciation Expense	$17,468,273	$10,624,214	$2,716,784	$29,030	$239,335	$33,364	$40,567	$74,131	$50,558	$2,140	$3,654,000	$21	$4,130
Taxes Other Than Income Taxes													
Property Taxes	$2,249,308	$1,368,030	$349,828	$3,738	$30,818	$4,296	$5,224	$9,545	$6,510	$276	$470,509	$3	$532
Other Taxes	$1,167,999	$710,378	$181,655	$1,941	$16,003	$2,231	$2,712	$4,957	$3,381	$143	$244,321	$1	$276
Total taxes Other Than Income Taxes	$3,417,307	$2,078,408	$531,483	$5,679	$46,821	$6,527	$7,936	$14,502	$9,891	$419	$714,830	$4	$808
Total Expenses Before Interest and Income Taxes	$109,761,438	$71,099,840	$23,861,784	$650,822	$3,384,255	$362,790	$1,597,304	$1,238,886	$488,264	$22,794	$7,016,406	$139	$38,154

KENTUCKY UTILITIES COMPANY
Summary of Class RORs at Current Rates

ROR At Current Rates

	Customer/Demand Distribution			Primary Distribution 100% Demand				
Class	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Average (All Methods)**	**Average Primary Distribution 100% Demand**
Residential (RS)	4.15%	4.71%	4.72%	4.73%	5.35%	5.37%	**4.84%**	**5.15%**
General Service (GS)	9.04%	9.62%	9.70%	9.36%	9.97%	10.06%	**9.62%**	**9.80%**
All Electric Schools (AES)	5.25%	5.53%	5.45%	4.21%	4.44%	4.37%	**4.88%**	**4.34%**
Pwr Serv-Sec (PS-Sec)	9.57%	9.27%	9.23%	8.45%	8.20%	8.16%	**8.81%**	**8.27%**
Pwr Serv-Prim (PS-Pri)	11.63%	10.47%	10.48%	10.22%	9.23%	9.24%	**10.21%**	**9.56%**
Time of Day-Sec (TOU-Sec)	6.43%	5.69%	5.69%	5.40%	4.76%	4.78%	**5.46%**	**4.98%**
Time of Day-Pri (TOU-Pri)	4.45%	3.61%	3.54%	3.53%	2.81%	2.77%	**3.45%**	**3.04%**
Retail Trans (RTS)	4.51%	3.58%	3.67%	4.51%	3.58%	3.67%	**3.92%**	**3.92%**
Fluctuating Load (FLS)	1.50%	0.95%	1.03%	1.50%	0.95%	1.03%	**1.16%**	**1.16%**
Outdoor Lighting (ST & POL)	8.60%	7.52%	7.40%	9.82%	8.58%	8.43%	**8.39%**	**8.94%**
Lighting Energy (LE)	9.83%	4.23%	3.91%	7.32%	3.05%	2.85%	**5.20%**	**4.41%**
Traffic Energy (TE)	8.07%	6.68%	6.55%	9.55%	7.89%	7.73%	**7.75%**	**8.39%**
TOTAL	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	**5.56%**	**5.56%**

Indexed ROR At Current Rates

	Customer/Demand Distribution			Primary Distribution 100% Demand				
Class	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Average (All Methods)**	**Average Primary Distribution 100% Demand**
Residential (RS)	75%	85%	85%	85%	96%	97%	**87%**	**93%**
General Service (GS)	163%	173%	174%	168%	179%	181%	**173%**	**176%**
All Electric Schools (AES)	94%	99%	98%	76%	80%	79%	**88%**	**78%**
Pwr Serv-Sec (PS-Sec)	172%	167%	166%	152%	147%	147%	**159%**	**149%**
Pwr Serv-Prim (PS-Pri)	209%	188%	188%	184%	166%	166%	**184%**	**172%**
Time of Day-Sec (TOU-Sec)	116%	102%	102%	97%	86%	86%	**98%**	**90%**
Time of Day-Pri (TOU-Pri)	80%	65%	64%	63%	51%	50%	**62%**	**55%**
Retail Trans (RTS)	81%	64%	66%	81%	64%	66%	**70%**	**70%**
Fluctuating Load (FLS)	27%	17%	18%	27%	17%	18%	**21%**	**21%**
Outdoor Lighting (ST & POL)	155%	135%	133%	177%	154%	152%	**151%**	**161%**
Lighting Energy (LE)	177%	76%	70%	132%	55%	51%	**93%**	**79%**
Traffic Energy (TE)	145%	120%	118%	172%	142%	139%	**139%**	**151%**
TOTAL	100%	100%	100%	100%	100%	100%	**100%**	**100%**

KENTUCKY UTILITIES COMPANY
Residential Customer Cost Analysis

		Total Company	Residential
Gross Plant			
369	Services		$68,211,820
370	Meters		$51,573,767
	Total Gross Plant		**$119,785,587**
Depreciation Reserve 1/			
	Services	$60,872,011	$42,690,527
	Meters	$35,613,859	$22,132,681
	Total Depreciation Reserve	**$96,485,870**	**$64,823,209**
Total Net Plant			**$54,962,378**
Operation & Maintenance Expenses			
586	Dist Oper - Meter		$5,437,289
597	Maintenance-Meters		$852,618
902	Meter Reading		$3,511,773
903	Records & Collections		$12,993,246
	Total O & M Expenses		**$22,794,926**
Depreciation Expense 1/			
	Services	$1,585,380	$1,111,853
	Meters	$3,025,031	$1,879,944
	Total Depreciation Expense	$4,610,411	$2,991,796
Revenue Requirement			
	Interest		$1,011,308
	Equity return		$2,995,749
	State Income Taxes @ 6.00%		$294,182
	Federal Income Tax @35.00%		$1,613,095
	Revenue For Return		$5,914,333
	O & M Expenses		$22,794,926
	Depreciation Expense		$2,991,796
	Subtotal Customer Revenue Requirement		$31,701,056
	Total Revenue Requirement		**$31,701,056**
	Number of Customers		430,678
	Number of Bills		5,168,136
	TOTAL MONTHLY CUSTOMER COST		$6.13

1/ Per Filing Schedule B-3.2. Total Company allocated to Residential

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

AFFIDAVIT OF Glenn Watkins

Commonwealth of Virginia)

Glenn Watkins, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony and the Schedules attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Glenn Watkins

SUBSCRIBED AND SWORN to before me this 17th day of February, 2017.

NOTARY PUBLIC

My Commission Expires: 10/31/2018

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2018
COMMONWEALTH OF VIRGINIA