COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS	)
ELECTRIC COMPANY FOR AN	)
ADJUSTMENT OF ITS ELECTRIC AND	)
GAS BASE RATES, A CERTIFICATE OF	) **CASE NO. 2012-00222**
PUBLIC CONVENIENCE AND NECESSITY,	)
APPROVAL OF OWNERSHIP OF GAS	)
SERVICE LINES AND RISERS, AND A	)
GAS LINE SURCHARGE	)

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

OCTOBER 3, 2012

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, VA 23235.

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

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

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

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

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, North Carolina, New Jersey, Ohio, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in my Schedule GAW-1 to my testimony.

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

A. Technical Associates has been retained by the OAG to evaluate the reasonableness of Louisville Gas & Electric Company's ("LG&E" or "Company") proposed electric and natural gas class cost of service studies (CCOSS), proposed distribution of revenues by class, and residential electric and natural gas rate designs. The purpose of my testimony, therefore, is to comment on LG&E'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. ELECTRIC CLASS COST OF SERVICE

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

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

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

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

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive certain costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records, as well as fundamental differences in opinions regarding the design or cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required. In this regard, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF LG&E's CCOSS.

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

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

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. Conroy's CCOSS to be mathematically accurate.

Q. DID YOUR EXAMINATION RESULT IN ANY DIFFERENCES OF OPINION OR DISAGREEMENTS WITH THE ASSUMPTIONS AND METHODOLOGIES USED BY MR. CONROY AS THEY RELATE TO LG&E's ELECTRIC COST ALLOCATION STUDY?

A. Yes. There are two material differences of opinion between my electric cost allocation study and that performed by Mr. Conroy. These differences relate to the classification and ultimate allocation of generation and distribution plant. However, it is important to note two significant points as they relate to Mr. Conroy's and my electric CCOSSs.

With regard to generation plant, my difference of opinion is by and large purely academic in nature. That is, while I do not agree with the naming convention Mr. Conroy claims to have used to classify and allocate generation plant, his ultimate allocation of this plant to various classes is not unreasonable, and fairly reflects cost causation across classes.

With regard to the classification of distribution plant, I do have numerous concerns with the data utilized by Mr. Conroy as well as with the mathematical methods he employed to classify this plant between customer-related and demand-related costs.

With the above exceptions outlined, my ultimate electric CCOSS findings (rates of return at current rates) are not significantly different than those calculated by Mr. Conroy. A comparison of Mr. Conroy's and my class rates of return at current rates are shown below:

Class	Class ROR At Current Rates	
	Conroy	Watkins
Residential	3.59%	5.19%
General Service	10.33%	11.49%
PS-Primary	12.41%	9.25%
PS-Secondary	10.60%	8.12%
TOD-Primary	5.56%	2.65%
TOD-Secondary	7.17%	4.64%
RTS-Transmission	4.65%	4.09%
Sp. Contract #1	0.59%	-0.48%
Sp. Contract #2	1.24%	-0.99%
Street Lighting	8.72%	8.31%
Lighting Energy	12.41%	1.58%
Traffic Signals	8.44%	8.22%
Total Company	6.14%	6.14%

A. Generation

Q. YOU INDICATE THAT ONE OF THE DIFFERENCES OF YOUR OPINION WITH MR. CONROY IS THE NAMING CONVENTION HE CLAIMS TO USE TO ASSIGN GENERATION-RELATED COSTS TO INDIVIDUAL CLASSES. WHAT NAMING CONVENTION DID MR. CONROY USE WITH RESPECT TO GENERATION COST ALLOCATIONS?

A. Mr. Conroy refers to his approach as a time-differentiated "Modified Base-Intermediate-Peak" approach.

Q. ARE THERE OTHER METHODOLOGIES WHICH MAY BE USED TO ALLOCATE GENERATION-RELATED PLANT AND EXPENSES?

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

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

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

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

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

Q. PLEASE EXPLAIN.

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

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

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

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

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, the sole criterion for assigning one hundred percent of fixed capacity costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year nor does it consider the reasons that cause the current mix and level of generation facilities. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility had a peak load of 15,000 MW and its actual optimal generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 15,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

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

Summer and Winter Coincident Peak ("S/W Peak") -- The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this characteristic. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method.

Twelve Monthly Coincident Peak ("12-CP") -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities.

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

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

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, many P&A studies use an equal weighting of "peak" and average class loads, while some studies weight the peak and average loads based on the system coincident load factor.[1]

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.

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[1] It is generally agreed that the use of system coincident peak demands is an appropriate measure for assigning the "peak" portion of generation facilities under the P&A method.

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

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

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

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

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

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

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

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[2] Capacity factor is the ratio of average utilization (output) over a year to maximum output. Availability factor is the ratio of average utilization during periods when a unit is available for dispatch (i.e., excludes outages) to peak hour output.

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

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

A. Mr. Conroy's Modified BIP method does not follow the generally accepted BIP approach, and in fact, I have never seen Mr. Conroy's method used in any other cases or for utilities other than Kentucky Utilities ("KU") and LG&E. However, I would be reluctant to say his approach is totally unreasonable.

Whereas Mr. Conroy's Modified BIP method does allocate a portion of generation facilities based on energy (34.35%) and a portion on peak demands (32.39% on winter peak and 33.26% on summer peak), his approach does not reflect the actual mix of supply resources utilized by LG&E. At this point, it should be noted that LG&E's and KU's generation resources are centrally dispatched. Both Mr. Conroy and I have recognized this combined central dispatch in our allocation studies. When I refer to

LG&E's actual generation resources, I am referring to the joint resources of LG&E and KU and not the individual legal ownership of these plants for booking purposes.

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

Mr. Conroy'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. Conroy's approach would classify a utility's generation investment exactly the same regardless of its actual portfolio mix of plants. Mr. Conroy'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 a given system's generation resources.

Q. PLEASE EXPLAIN THE ACTUAL COMPOSITION OF KU's AND LG&E's COMBINED GENERATION RESOURCES.

A. The Companies combined generation capacity is about 9,500 MW. The following is a summary of this generation portfolio by fuel type:

Fuel	MW Capacity	% Of Total
Coal	7,016	74%
Gas/Oil	2,487	26%
Hydro	19	<1%
Total	9,492	100%

As can be seen above, about 74% of the Companies' generation comes from very low running cost coal plants. Furthermore, the combined LG&E and KU peak native load is about 6,200 MW, which is lower than the capacity of the combined Companies coal plants. This is especially relevant for cost allocation purposes since these coal plants tend to be base load plants in nature. That is, they operate with low variable operating expenses per unit (KWH) and have very high availability factors in the 80% to 90% range. This actual mix of generation assets is dissimilar to most electric utilities in the United States which rely on a much higher percentage of intermediate (high variable cost) plants primarily utilizing natural gas for fuel. Indeed, Kentucky ratepayers and shareholders alike are very fortunate to have an abundance of low cost electric energy resources.

Q. DOES MR. CONROY'S COST ALLOCATION METHODOLOGY REFLECT THE FACT THAT KU'S AND LG&E's COMBINED GENERATION PORTFOLIO IS COMPRISED PRIMARILY OF BASE LOAD UNITS?

A. No.

Q. DID YOU CONDUCT AN ANALYSIS OF KU'S AND LG&E's COMBINED GENERATION FACILITIES UTILIZING THE INDUSTRY ACCEPTED BIP APPROACH?

A. Yes.

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

A. During the discovery phase of this proceeding, LG&E provided the order of economic dispatch for each of its generation units.[3] With this information, I was able to separate each generation unit into Base, Intermediate, Peak, or Hydro. Base load units are classified as 100% energy-related as they are designed and utilized to meet energy requirements throughout the year; i.e., they are low-cost units that serve energy needs and are not installed to meet short time period peak load requirements. Conversely, peak load (peaker) units are classified as 100% demand-related because of their high cost of output; i.e., they are dispatched and utilized only to meet peak load requirements. Intermediate plants operate at higher variable costs per unit than base load units yet are considerably

[3] Economic Order of dispatch is based on variable running costs. That is, the unit with the lowest running costs (primarily fuel) per unit of KWH output is dispatched first, followed by the next least expensive generation facility, and so forth.

less costly to operate than peak units, and are dispatched during periods of Intermediate demand (higher than base load but lower than peak period loads). I have followed the industry practice of classifying these units between energy and peak demand based on each facility's capacity factor. Finally, I have classified the Companies' Hydro facilities as 100% energy-related as they are run of the river or flood control facilities and have little or no ability to reliably meet peaking requirements.

The results of my BIP generation classification is presented in my Schedule GAW-2. My BIP generation classification study results in the following aggregate generation classification:

Energy-related:	74.51%
Demand-related:	25.49%

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

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Conroy's Modified BIP are presented below. It should be noted that the following OAG results only reflect adjustments to generation and production costs, they do not reflect my adjustments to distribution plant allocations which are explained later in my testimony:

Class	OAG Traditional BIP	Conroy Modified BIP
Residential	4.05%	3.59%
General Service	12.01%	10.33%
PS-Primary	10.76%	12.41%
PS-Secondary	9.97%	10.60%
TOD-Primary	3.82%	5.56%
TOD-Secondary	5.68%	7.17%
RTS-Transmission	4.09%	4.65%
Sp. Contract #1	0.50%	0.59%
Sp. Contract #2	-0.15%	1.24%
Street Lighting	7.49%	8.72%
Lighting Energy	2.88%	12.41%
Traffic Signals	7.17%	8.44%
Total Company	6.14%	6.14%

B. Distribution

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

A. Mr. Conroy has allocated Distribution plant and expenses partially on the basis of number of customers and partially on the basis of peak demand. I concur with Mr. Conroy's selection of customer and demand allocators for Distribution plant. However, there is often controversy regarding the portion of Distribution plant that should be allocated on number of customers and the portion that should be allocated on demand. This separation between customer-related and demand-related Distribution plant is referred to as the classification of Distribution plant.

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

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

Q. WHY IS 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 energy needs of its 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. 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 urban area, while the rural portion of the service territory consists almost entirely of Residential customers, it may be unreasonable to allocate the total Company's investment based only 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 overwhelming 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 LG&E's system, the following characteristics are exhibited:

Category	Customers	KWH	Peak Demand
	Percentage of Total Jurisdictional Distribution System		
Residential	71%	37%	49%
Comm./Ind. Secondary Voltage	9%	38%	35%
Comm./Ind. Primary/Transmission Voltage	<1%	24%	15%
Lighting	20%	1%	1%
	100%		

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 LG&E's different types of customers:

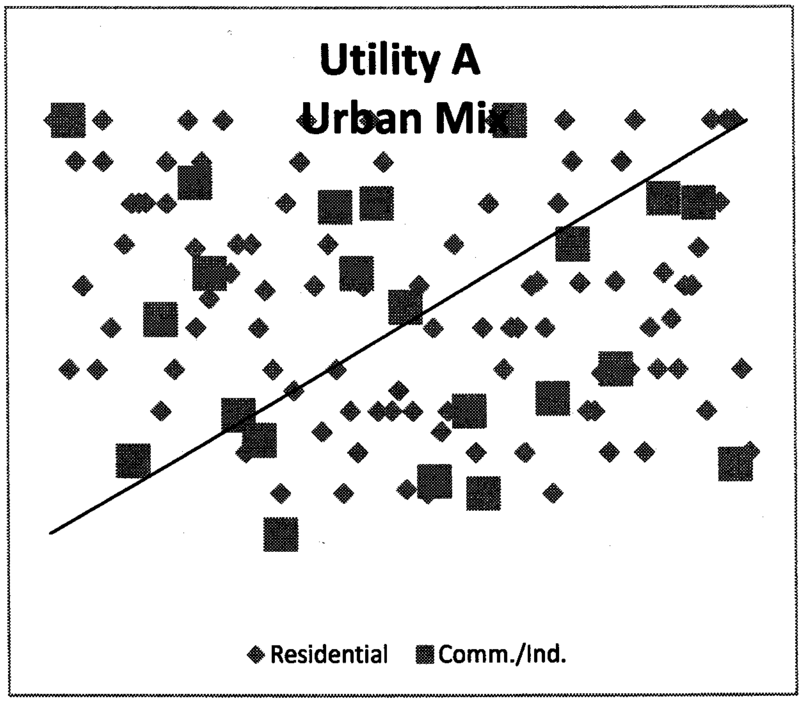
Category	Average Annual KWH Per Customer (KWH)
Residential	12,844
Comm./Ind. Secondary Voltage	99,185
Comm./Ind. Primary/Transmission Voltage	14,635,024

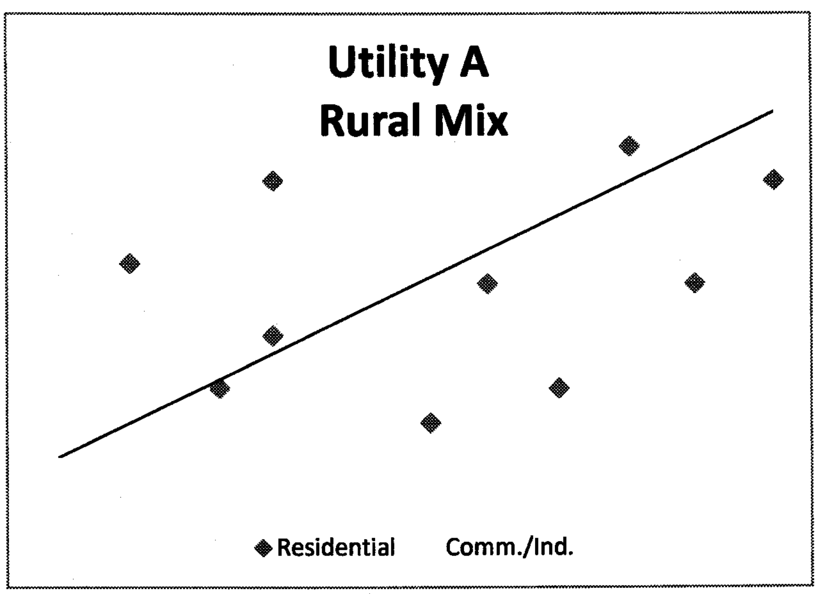
With the above relationships explained, in order to understand the concepts of density and class customer mix, consider examples of two hypothetical electric utilities each of which are comprised of only two distribution lines: one line serving a densely populated area (urban) and another line serving 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 non-Residential customers are located on the urban (densely populated) distribution line such that the rural line only serves Residential customers as shown graphically below:



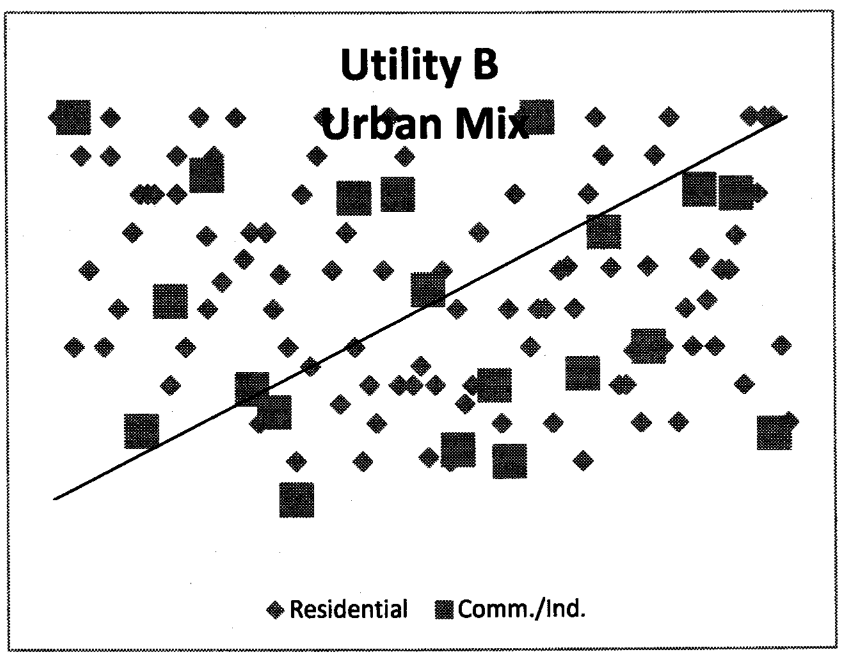


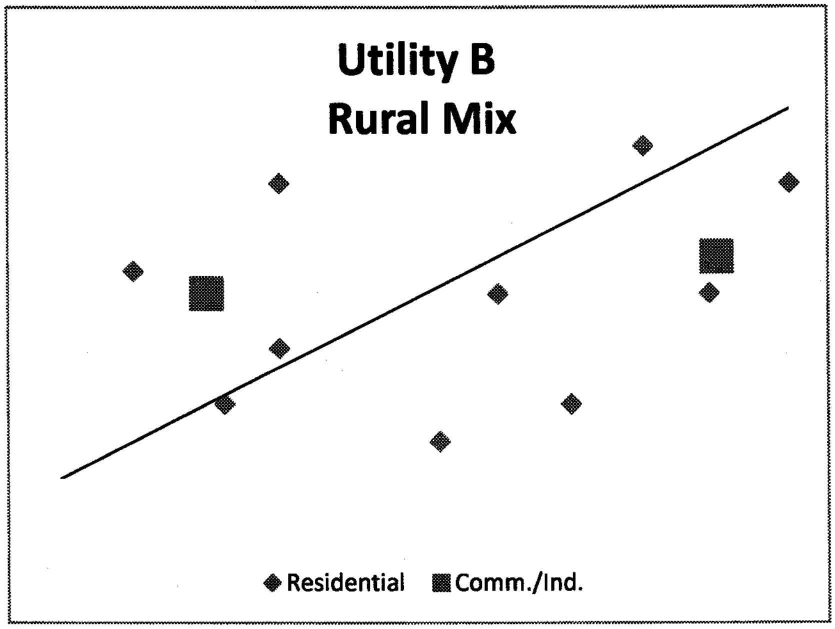
The urban line is much shorter in total distance, yet, it serves the majority of customers (and loads) <u>and</u> many more miles of line are required to serve relatively few Residential only customers in rural areas. It would be unfair, and inconsistent with cost causation to allocate total system line costs only on utilization (KW) because non-Residential 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 on both the urban and rural lines, the proportion (mix) of customers is the same. 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.

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 universally 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 30 plus years practicing utility costing and pricing across the Country, I have not seen a 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 Principles of Public Utility Rates, 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.[4]

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

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

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[4] Bonbright, Principles of Public Utility Rates, Second Edition, page 491.

system. The 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 LG&E's DISTRIBUTION SYSTEM.

A. For accounting purposes, LG&E'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. WHAT RELATIVE CUSTOMER/DEMAND PERCENTAGES DID MR. CONROY USE IN THIS CASE?

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

LG&E Classification of Distribution Plant

	($000)		
Account	(1) Total Gross Plant	(2) Percent Customer	(3) Customer Allocation (1) x (2)
Overhead Lines	371,611	54.57%	202,788
Underground Lines	212,882	75.21%	160,108
Total	584,493	62.10%	362,896

As can be seen above, Mr. Conroy's classification allocates 54.57% of its Overhead lines (poles plus conductors) based on number of customers and 75.21% of Underground lines (conduit and conductors) on a customer count basis. On a collective basis, Mr. Conroy allocates about 62% of these distribution costs (plant and expenses) based on number of customers and about 38% of its costs based on utilization and relative size (demand). In other words, about 62% of LG&E's investment in joint distribution lines is allocated to classes based on customer counts regardless of size, utilization, or demands placed upon the LG&E system.

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

A. Yes, I have.

Q. PLEASE EXPLAIN.

A. Mr. Conroy 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 utilization, is due to the possibility that the mix of customer classes varies significantly across the urban and rural portions of a 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. I analyzed KU's customer densities and mix because KU is more rural than LG&E and Mr. Conroy utilized the same data and results for classifying KU's and LG&E's distribution plant; i.e., Mr. Conroy's classifications of distribution lines is the same for KU and LG&E.

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 rural, suburban, and urban areas, I calculated the number of total KU customers per square mile for each non-Post Office Box ("P.O. 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 by rate class throughout its service area and delineate between very rural (sparsely populated) to very urban (densely populated) areas. As a further refinement, I also evaluated the distribution of customers on a stratified basis. That is, for each rate class I separated small geographical areas (zip codes) into four separate strata (lowest to highest customer densities). I examined each stratum (by rate class) to determine if any significant differences in customer mix occur within each stratum.

This analysis of the distribution of the various customer classes 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 the KU service area. In other words, the percentage of Residential customers (by zip-code) should decline as customer density per square mile increases from the most rural areas to the most urban areas of KU's service territory. Similarly, if Mr. Conroy's assumption is correct, we should see a distinct positive correlation between non-Residential customer mixes and customer densities by zip-code. A summary of the approach and data utilized for this analysis is provided below:

			Percent of Total Distribution Customers[5]			
Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Avg.	Std. Deviation	Number	% of Class
Residential						
Strata 1	.03 Min to 7.17 Max	67	63.5%	14.2%	12,452	3.0%
Strata 2	7.19 Min to 13.77 Max	67	65.6%	6.8%	37,435	9.1%
Strata 3	13.83 Min to 33.64 Max	67	66.0%	6.8%	79,477	19.3%
Strata 4	33.68 Min to 3994.81 Max	67	77.0%	11.1%	282,414	68.6%
Total		268			411,778	100%
Non-Residential						
Strata 1	.03 Min to 7.17 Max	67	18.0%	12.3%	3,529	4.1%
Strata 2	7.19 Min to 13.77 Max	67	18.0%	4.4%	10,265	11.9%
Strata 3	13.83 Min to 33.64 Max	67	18.0%	4.8%	21,672	25.1%
Strata 4	33.68 Min to 3994.81 Max	67	13.9%	7.1%	50,920	58.9%
Total		268			86,386	100%

[5] 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. That is, there are no distinct differences in the mix of customers (by class) across the rural and urban portions of KU's service area. The relationship of Residential customers relative to non-Residential customers is relatively constant throughout KU's service area. While the rural areas of KU's service area are comprised mainly of Residential customers, this relationship also remains true for the more dense population areas of KU's territory as well. More importantly, in the less dense portions of KU's service territory (rural areas), KU serves a proportionate number of non-Residential customers.

In summary, each customer class is represented in a reasonably proportional manner in both rural and urban areas within KU's service area. As a result, it cannot be said that the less populated portions of KU's service area (which require significant investment to serve few customers) are dedicated to any one class of customers. As such, KU's distribution plant and expenses should be assigned to classes based only on utilization and any consideration of customer counts is improper for the allocation of distribution plant, as such, this study indicates that KU's distribution plant should be classified as 100% 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 the 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-3.

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. HOW DID MR. CONROY CLASSIFY DISTRIBUTION PLANT BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

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

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

A. Under accepted industry practices, which are well documented in various cost allocation manuals,[6] the zero-intercept method is very straight-forward. First, various types of equipment are separated by capacity size and type. Next, historical accounting costs are trended by vintage year to reflect cost differences over time. For each size and type of equipment, the total dollars and total units (feet or number of units) are considered as well as the capacity (size) of each type of equipment. Because the overall objective is to estimate the cost of a "zero-size" piece of equipment, total costs are divided by total units (feet or unit) for each type of equipment to derive an average cost per foot or per unit. A regression model is then developed based on the following general form:

cost/unit = a + b (size)

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

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

The above industry standard is in stark contrast to Mr. Conroy's method presented in his Conroy Exhibits C4, C5, and C6. Mr. Conroy refers to his approach as a "weighted regression analysis." Although this "weighted regression analysis" is a clever arithmetic exercise, it violates theoretical statistical principles of linear regression and skews his results. Moreover, on page 29 of his direct testimony, Mr. Conroy states:

> "the feet of conductor and number of transformers on LG&E's system are not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted regression analysis in the determination of the zero intercept."

It is interesting that Mr. Conroy finds LG&E's system to be typical of other utilities, yet, his approach varies dramatically from the industry practice that has been used by countless utilities, commissions, and analysts for decades when a classification study is found to be appropriate.

To understand the bias in Mr. Conroy's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead Conductors as an example, consider Mr. Conroy's analysis presented in his Exhibit C4. Although not shown in his exhibit, Mr. Conroy's equation for Overhead Conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 0.8901(\text{feet}^{0.5}) + 0.0040\ (\text{size x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if size is set to zero, the second term [$0.0040(\text{size x feet}^{0.5})$] becomes zero. If we then ask what is the cost for a foot of a zero size conductor we see that $\text{feet}^{0.5} = 1^{\ 0.5} = 1$, such that the cost for one foot becomes \$0.8901. This is the zero-intercept used by Mr. Conroy.

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

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

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

$$\text{cost/feet} = 1.75 + 0.805(\text{size})$$

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

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

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

Q. DO YOU HAVE OTHER CONCERNS REGARDING MR. CONROY'S ZERO-INTERCEPT ANALYSES USED TO CLASSIFY DISTRIBUTION PLANT?

A. Yes. The data utilized by Mr. Conroy to conduct his statistical (zero-intercept) analyses is so questionable that no credibility can be given to any results obtained, regardless of the specific method utilized. My first concern relates to the accuracy of the data used by Mr. Conroy. To illustrate, consider Mr. Conroy's data used for Account No. 365, Overhead Conductors, as shown in Conroy Exhibit C4. Mr. Conroy's database indicates that the LGE/KU distribution systems are comprised of 97,432,621 linear feet of Overhead Conductors. Of this amount, Mr. Conroy's data includes 0.3 million linear feet of #8 wire, 15.0 million linear feet of #6 wire, and 11.5 million linear feet of #4 wire. These wire sizes are extremely small and not typically utilized to carry current throughout a primary or secondary distribution system. Indeed, these wires are smaller than most residential service lines. I cannot be certain if such small wires are actually installed within the Companies distribution system, but if they are, they are almost certainly ground wires or individual customer service lines.[7] My next data concern relates to the average cost per linear foot calculated and used by Mr. Conroy in his analysis. For example, and again referring to Conroy Exhibit C4, consider his average cost for small conductors. We see that his database utilizes an average cost of #1 conductor of $6.81 per foot while his calculated average cost of much larger 1/0 and 2/0 conductors are only $4.72 and $1.05, respectively. In other words, as conductor sizes increase, the average cost decreases. Finally, the database and mix of conductors used by Mr. Conroy in this case are much different than the data used in prior LG&E/KU cases. My Schedule GAW-4 provides the data utilized by the Company in the 2009 case. As can be seen by comparing these two data sets, the amounts and mix of plant (conductors) is vastly different between these two cases. For example, the following is a sample comparison of various size conductors utilized in this case to those utilized for the same purpose during the 2009 case:

Overhead Conductor Quantity
(Linear Feet)

Conductor Size	Current Case	2009 Case
#2	9,402,756	971,519
#1	115,720	88,940
1/0	247,264	39,898
2/0	648,440	713,507
3/0	2,032,233	1,954,687
Sum of All Wires in Database	97,430,621	4,699,122

Q. ARE THERE ANY OTHER DEFICIENCIES IN THE ZERO-INTERCEPT DATA UTILIZED BY MR. CONROY?

A. Yes. When a zero-intercept or minimum-size study is performed for Overhead or Underground Conductors, it is important to identify and state the various sizes of conductors on a circuit foot, not linear foot, basis. This is because all electric distribution

[7] The maximum capacity of #8 wire is only 100 amps, #6 is 140 amps, and #4 wire is 180 amps: less than a modern single-family home service circuit panel.

systems are comprised of both single-phase and multi-phase (3-phase) circuits. While some single-phase circuits are comprised of only two wires, current practices are to generally install three-wire single-phase circuits, while virtually all three-phase circuits require four conductors. Furthermore, three-phase circuits tend to be comprised of larger size conductors. Most important is the fact that the analyst is attempting to estimate the theoretical cost per foot of zero size circuit which would be comprised of only two wires. When historical data is stated only on a linear foot basis it is impossible to estimate the cost of a zero size circuit.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING ZERO-INTERCEPT ANALYSES OF LG&E's DISTRIBUTION PLANT ACCOUNTS?

A. Yes. I question why the data Mr. Conroy used for his Overhead Conductors (Account 365) and Underground Conductors (Account 367) analyses are exactly the same for LG&E and KU, and different for Line Transformers (Account 368). The data used for the analyses clearly should be different between LG&E and KU, and in fact, were different in the LG&E/KU 2008 rate case.

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 entirely likely that all of KU's and LG&E's distribution system should be classified as 100% demand-related. Furthermore, I completely disagree with the analyses performed by Mr. Conroy. In this regard, I have conducted my CCOSS utilizing a 100% demand classification of distribution plant. In this way, we can test and evaluate the sensitivity of various distribution plant classifications and their effects on class rates of return.

Q. WHAT ARE THE CCOSS RESULTS UTILIZING THE INDUSTRY ACCEPTED BIP APPROACH TO ALLOCATE GENERATION PLANT AND ALSO CLASSIFIES DISTRIBUTION PLANT AS 100% DEMAND-RELATED?

A. The following provides a summary of my CCOSS results at current rates as well as a comparison to those obtained by Mr. Conroy:

ROR At Current Rates			
Class	Watkins CCOSS	Conroy CCOSS	Average Results
Residential	5.19%	3.59%	4.39%
General Service	11.49%	10.33%	10.91%
PS-Primary	9.25%	12.41%	10.83%
PS-Secondary	8.12%	10.60%	9.36%
TOD-Primary	2.65%	5.56%	4.11%
TOD-Secondary	4.24%	7.17%	5.71%
RTS-Transmission	4.09%	4.65%	4.37%
Sp. Contract #1	-0.48%	0.59%	0.06%
Sp. Contract #2	-0.99%	1.24%	0.13%
Street Lighting	8.31%	8.72%	8.40%
Lighting Energy	1.58%	12.41%	7.00%
Traffic Signals	8.22%	8.44%	8.33%
Total	6.14%	6.14%	6.14%

As can be seen above, in a relative sense, my class rates of return at current rates are generally consistent with those obtained by Mr. Conroy. That is, the classes that are earning at, below, or above, the system average ROR are generally consistent across both studies. The only real exceptions are the TOD-Secondary and Lighting Energy classes. With regard to the TOD-Secondary class, the ROR dispersion (4.24% vs. 7.17%) is not so great as to cause a major difference of opinion in terms of this classes' profitability. With regard to Lighting Energy, there is a significant difference in achieved ROR's (1.58% vs. 12.41%). However, because this rate is of an ancillary service nature; i.e., customers generally receive this service in conjunction with other rate schedules, and the fact that the major reason for the vastly different ROR findings is due to differences in the level of costs that are allocated based on customer counts, this wide disparity does not cause significant concern. The details of my CCOSS are presented in my Schedule GAW-5.

III. ELECTRIC CLASS REVENUE INCREASE DISTRIBUTION

Q. HOW DOES MR. CONROY PROPOSE TO ASSIGN LG&E's PROPOSED OVERALL $61.8 MILLION INCREASE IN SALES REVENUE ACROSS RATE CLASSES?

A. Mr. Conroy proposes to assign somewhat larger percentage increases to those classes whose ROR's at current rates are below the system average ROR and somewhat smaller percentage increases to those classes whose ROR's are greater than the system average ROR. A summary of Mr. Conroy's proposed class increases is as follows:

LG&E Proposed Revenue Increases

Class	Percent Increase	Percent of System Avg.
Residential	8.60%	125%
General Service	5.09%	74%
PS-Primary	0.17%	2%
PS-Secondary	5.02%	73%
TOD-Primary	7.20%	104%
TOD-Secondary	6.52%	95%
RTS-Transmission	7.54%	110%
Lighting	5.01%	73%
Special Contracts	9.44%	137%
Total System	6.89%	100%

Q. IS MR. CONROY'S PROPOSED CLASS REVENUE DISTRIBUTION REASONABLE?

A. In general, yes. My only exception is the PS-Primary class. While both Mr. Conroy's and my CCOSS studies indicate that this class is achieving an ROR above the system average ROR, Mr. Conroy proposes virtually no increase to this class. Given the size and magnitude of LG&E's proposed increase, I recommend that the PS-Primary class share somewhat in the overall increase. In this regard, I recommend that this class' revenue should be increased at 50% of the system average percentage increase or 3.45% at the Company's overall requested increase of 6.89%. Furthermore, because of the absolute size of the Residential class, I recommend that the additional revenue collected from PS-Primary be credited to the Residential increase.

Q. SHOULD THE COMMISSION AUTHORIZE AN OVERALL INCREASE LESS THAN THE 6.89% REQUESTED BY LG&E, HOW SHOULD THE FINAL INCREASE BE ASSIGNED TO INDIVIDUAL CLASSES?

A. I recommend that any reduction in the overall increase be scaled-back in proportion to the Company's proposed class increases with the adjustment to PS-Primary noted above.

IV. <u>NATURAL GAS CLASS COST OF SERVICE</u>

Q. HAVE YOU EXAMINED MR. CONROY'S NATURAL GAS CLASS COST OF SERVICE STUDY?

A. Yes.

Q. WHAT METHODOLOGY DID MR. CONROY USE FOR PURPOSES OF HIS NATURAL GAS CCOSS?

A. Mr. Conroy used what is known as the Peak Responsibility method to allocate Mains costs. Furthermore, Mr. Conroy separated LG&E's Mains into "high pressure" and "low pressure" systems. Finally, Mr. Conroy classified both high pressure and lower pressure Mains as partially customer-related and partially demand-related. In short, Mr. Conroy has allocated Mains investment costs based partially on customer counts and partially on contributions to estimated design day demand.

Q. DO YOU HAVE ANY MAJOR DISAGREEMENTS WITH MR. CONROY'S NATURAL GAS CCOSS?

A. Yes.

Q. PLEASE OUTLINE YOUR DISAGREEMENTS.

A. I disagree with Mr. Conroy's use of the Peak Responsibility method to allocate distribution Mains (low and high pressure).

Q. PLEASE EXPLAIN PEAK RESPONSIBILITY METHOD.

A. The Peak Responsibility method is similar in concept to the 1-CP method previously discussed for the electric industry. The major difference is that whereas the 1-CP electric method is generally based on actual loads and demands, the Peak Responsibility method is based on estimated loads at design day temperatures. In other words, design day demands are not known historical loads, but rather estimated class demands under the most extreme weather conditions.

Q. IS THERE A METHOD THAT IS PREFERRED OVER THE PEAK RESPONSIBILITY METHOD FOR LG&E's NATURAL GAS OPERATIONS?

A. Yes. The Peak and Average method is far superior for LG&E's natural gas operations.

Q. PLEASE EXPLAIN WHY THE PEAK AND AVERAGE METHOD IS PREFERRED.

A. There are several reasons why the Peak and Average Method is preferred and why the Peak Responsibility method is not appropriate for LG&E. The first is the recognition of how and why natural gas consumers are customers of LG&E. Customers connect to LG&E's system in order to meet their natural gas needs throughout the year. Indeed, the Company's Mains are utilized each and every day of the year and recognition of annual usage (throughput) is a logical basis for cost assignment.

Another shortcoming of the Peak Responsibility method using design day demand is that the "design day" is a moving target over time. That is, whereas natural gas Mains are planned and installed to serve customers in excess of fifty years into the future, design day demand (as used by Mr. Conroy) is a function of the mix of customers, usage per customer, and number of customers today. In addition LG&E's commercial customers have obviously changed over the last few decades. Yet, Mr. Conroy assumes the entire Company system was optimally designed and installed to meet today's mix and level of customers.

Q. ARE THERE OTHER ASPECTS OF MR. CONROY'S GAS CCOSS IN WHICH YOU DISAGREE?

A. Yes. LG&E's largest natural gas investment relates to distribution mains. In this regard, differences in the allocation of mains-related costs can have a profound impact on calculated class rates of return. In stark contrast to prior LG&E gas CCOSSs, Mr. Conroy has classified the majority of mains-related costs based on number of customers in this case. Specifically, in this case, Mr. Conroy classifies low and medium pressure mains as 66% customer-related and high pressure mains as 45% customer-related. This compares to the Company's previous studies in which the vast majority of mains were classified primary as demand-related. For example, in LG&E's last rate case, low pressure mains were classified as 85.2% demand/14.8% customer while high pressure mains were classified as 93.0% demand/7.0% customer.

Q. DID MR. CONROY EMPLOY THE SAME INAPPROPRIATE "WEIGHTING" APPROACH FOR LG&E's GAS CLASSIFICATION AS HE DID FOR ELECTRIC DISTRIBUTION PLANT CLASSIFICATIONS?

A. Yes.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE CLASSIFICATION AND ALLOCATION OF LG&E's NATURAL GAS DISTRIBUTION MAINS?

A. Consistent with prior Company sponsored LG&E CCOSS studies in which the vast preponderance of mains investment was classified as demand-related, I recommend that distribution mains be classified as 100% demand-related. Furthermore, and in support of my recommendation, it should be noted that LG&E's service area is such that it is more urban/suburban than its electric operations and unlike electric operations in which service must be provided along virtually all roadways, gas mains are only extended and service is only provided to areas in which there are sufficient customer densities and loads.

Q. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY THAT UTILIZES THE PEAK AND AVERAGE METHOD AND CLASSIFIES DISTRIBUTION MAINS AS 100% DEMAND-RELATED?

A. Yes.

Q. **PLEASE PRESENT THE RESULTS OF YOUR NATURAL GAS CCOSS.**

A. The following is a summary of class rates of return at current rates utilizing my recommended Peak and Average method to allocate distribution Mains. Also provided are Mr. Conroy's results using his Peak Responsibility method.

	ROR at Current Rates	
Class	OAG Peak & Average	Conroy Peak Responsibility
RSG	5.77%	4.28%
CGS	5.83%	10.22%
IGS	5.17%	15.81%
AAGS	1.67%	16.69%
FT	12.07%	48.63%
SP	14.45%	41.30%
Total Company	5.92%	5.92%

The details of my recommended natural gas CCOSS are provided in my Schedule GAW-6.

V. **NATURAL GAS CLASS REVENUE DISTRIBUTION**

Q. **PLEASE DESCRIBE LG&E's PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL NATURAL GAS REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.**

A. LG&E witness Conroy presents the Company's proposed distribution of requested \$17.2 million revenue increase to customer classes. A summary of Mr. Conroy's proposed natural gas revenue increase for each customer class is shown below. Note, that the percentage increases reflect increases to Base (non-gas) rates.

Rate Class	Current Base Rate (Non-Gas) Revenue ($000)	LG&E Proposed Natural Gas Increases ($000) Amount	Percent
Sales:			
Residential (RGS)	$88,402	$11,950	13.5%
Commercial (CGS)	$30,977	$4,187	13.5%
Industrial (IGS)	$1,758	$238	13.5%
As-Available (AAGS)	$233	$32	13.5%
Transportation:			
Firm Transportation (FT)	$5,002	$333	6.5%
Special Contracts:			
Intra-Company	$4,932	$458	9.3%
Special Contracts	$164	$4	2.4%
Total LG&E	$131,529	$17,203	13.1%

Q. ARE MR. CONROY'S PROPOSED NATURAL GAS CLASS REVENUE INCREASES REASONABLE?

A. When all factors are considered, I do not object to Mr. Conroy's class revenue increases as his proposed class revenue increases reasonably reflect both his and my CCOSS findings.

VI. RESIDENTIAL RATE DESIGN

Q. DOES LG&E PROPOSE ANY SIGNIFICANT INCREASES TO ITS ELECTRIC AND NATURAL GAS RESIDENTIAL CUSTOMER CHARGES?

A. Yes. LG&E proposes to significantly increase its Residential electric customer charge from $8.50 to $13.00 per month. With regard to Residential natural gas rates, the Company proposes to increase the customer charge from $12.50 to $15.50 per month. These proposed increases to customer charges reflect a 53% increase for electric and a 24% increase for natural gas.

Q. MR. WATKINS, HAVE YOU IDENTIFIED A COMMON OBJECTIVE IN LG&E's RESIDENTIAL RATE DESIGN PROPOSALS?

A. Yes. It is clear from the testimony of Mr. Conroy that the primary objective of LG&E's Residential rate design is to guarantee revenue collection and profitability associated with fixed monthly customer charges.

Q. WHY DOES LG&E DESIRE MORE RESIDENTIAL REVENUE FROM CUSTOMER CHARGES?

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

Q. OTHER THAN DECOUPLING THE LINK BETWEEN PROFITABILITY AND VOLUMETRIC SALES, DOES MR. CONROY PROVIDE OTHER JUSTIFICATIONS FOR HIS PROPOSAL TO COLLECT SUBSTANTIALLY MORE OF ITS RESIDENTIAL RATE REVENUES FROM FIXED MONTHLY CHARGES?

A. Yes. Mr. Conroy claims that because of the high percentage of fixed cost inherent in providing electric and natural gas service, prices (rate design) should reflect the Company's relationship between fixed and variable costs.

Q. DOES LG&E's PROPOSAL TO COLLECT A SUBSTANTIAL PORTION OF ITS ELECTRIC AND NATURAL GAS MARGIN REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL PRACTICES OF SUCH COMPETITIVE MARKETS?

A. No. 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 the duplication of 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.[8] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

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

A. Economic theory tells us that efficient price signals result when prices are equal to long-run marginal costs. It is well known that in the long-run all costs are variable and, hence, 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 EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS LG&E.

A. Due to LG&E'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 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 always address fairness or equity. From a perspective of fair and equitable pricing of a regulated monopoly's products and services, it is generally agreed that payments for a good or service should be in accordance with the benefits received. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. With respect to electric and natural gas usage, the volume of consumption is the most direct, and in my opinion the best indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy is, and has been, the belief of economists, regulators, and the marketplace for many years. As an illustration, consider utility industry pricing in its

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[8] James C. Bonbright, et al Principles of Public Utility Rates at 141 (2d ed. 1988).

infancy (1800s). In the beginning, 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 the 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 than others paid more in total for the utility service because they used more of the commodity.

Furthermore, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. This includes the manufacturing and transportation industries. Prices for competitive products and services in these industries are invariably established on a volumetric basis, including those that were once regulated; e.g., motor transportation, airline travel, and rail service.

Accordingly, the position of Mr. Conroy that LG&E's fixed costs should be recovered through fixed monthly charges, in my view, is incorrect since pricing should reflect long-run cost incidence wherein all costs are variable or volumetric in nature, and that users requiring more of LG&E's products and services pay more than customers who use less of these products and services.

Q. DOES LG&E's PROPOSAL TO COLLECT A SUBSTANTIALLY GREATER PORTION OF ITS RESIDENTIAL REVENUES AND FROM FIXED MONTHLY CUSTOMER CHARGES COMPORT WITH PROPER RATEMAKING PRINCIPLES?

A. No. Perhaps the most highly regarded, and certainly the most commonly used reference to ratemaking principles is Dr. James Bonbright's treatise entitled Principles of Public Utility Rates. With regard to the collection of revenue solely (or largely) through a fixed customer charge, Dr. Bonbright states:

> . . . there remains a choice as to the unit of service to which the uniform rate shall be applied. Among a variety of alternatives, three receive closest consideration: a uniform charge per customer; a uniform charge per unit of energy (kilowatt-hour); and a uniform charge per unit of the customer's maximum monthly kilowatt demand.
>
> **Uniformity of charge per customer (say, $10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to**

recognize either cost differences or value-of-service differences between large and small customers. [Page 396] **[Emphasis added]**.

Q. EARLIER IN YOUR TESTIMONY YOU EXPLAINED THAT VOLUMETRIC PRICING PREDOMINATES IN COMPETITIVE MARKETS. IS THERE ANY DATA OR EXPERIENCE REGARDING THE PRICING OF UTILITY SERVICES THAT HAVE RECENTLY BEEN DEREGULATED?

A. Yes. Retail electric competition for electric generation services exists in several states. Invariably, customer choice for generation supply is volumetrically priced. However, competition for electric generation alone does not necessarily provide a good apples-to-apples comparison with the bundled services provided by LG&E.

Texas has implemented total retail electric competition for most of the State's ratepayers, including distribution service. Under the Texas model, consumers select their electricity provider for all bundled electric services including generation, transmission, distribution, and metering. The customers' selected service provider supplies all services from the generator to the meter box. Electric providers compete for customers and are free to set their own prices and pricing structure.

Q. HOW ARE COMPETITIVE RESIDENTIAL ELECTRIC RATES STRUCTURED IN TEXAS?

A. Every competitive electric service provider in Texas has a volumetric component within their rate structure. With regard to Residential fixed monthly customer charges, there are two different pricing structures: those with traditional fixed monthly customer charges (regardless of consumption); and, those that have a minimum bill amount. The following is a summary of the current rate structures regarding customer charges for the 28 providers that offer competitive Residential electric service in Texas:

	Number Of Providers	Percentage Of Providers
Fixed charge waived with usage threshold	21	75%
Traditional fixed monthly customer charge	7	25%
Total	28	100%

Of the 7 providers that utilize a traditional fixed monthly customer charge, the average customer charge is $6.94 per month. Regarding the 21 competitive providers that waive a fixed fee with a minimum threshold of usage, the average customer charge is $9.14 per month. The details supporting these amounts are provided in my Exhibit No. GAW-7.

From this data, 25% of the providers have maintained the traditional fixed monthly customer charge, and 75% of the providers waive any fixed fees once a minimum level of consumption (KWH) is achieved.[9]

When prices for a service similar to LG&E's operations are established based on competition and determined by the market (customers and sellers), the resulting rate structure is similar to that found for most other competitive goods and services, i.e., predominantly based on volumetric pricing, and not fixed charge pricing.

Q. HAS MR. CONROY CONDUCTED AN ANALYSIS OF COSTS THAT HE CONTENDS SHOULD BE CONSIDERED IN DEVELOPING THE RESIDENTIAL CUSTOMER CHARGE FOR ELECTRIC SERVICE?

A. Yes.

Q. DO YOU AGREE WITH MR. CONROY'S CUSTOMER COST ANALYSIS?

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Conroy estimates LG&E's monthly electric Residential customer "cost" to be $18.12 and the corresponding natural gas cost to be $19.43. However, Mr. Conroy's analysis includes a significant level of distribution, administrative, general, and other overhead costs. Electric utilities are in the business of providing electric energy to customers. Administrative, general and other overhead costs are a normal cost of business for any enterprise and should be recovered based on the level of service provided (i.e., on a volumetric basis). That is, these costs are incurred in the provision of

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9 As indicated in the notes to Exhibit No. GAW-7 customer charges are waived with minimum monthly usages ranging from of 500 KWH to 2,000 KWH.

services rendered. As such, these costs should be recovered in relation to the level of services provided.

Q. HOW ARE ADMINISTRATIVE, GENERAL AND OVERHEAD EXPENSES TYPICALLY RECOVERED IN COMPETITIVE MARKETS?

A. As discussed previously, the pricing structures in competitive markets are predominately volumetrically priced. This volumetric pricing recovers all of a business's costs: fixed; variable; administrative; general; overhead; profit; etc.

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. Such is obviously not the case with regulated monopoly utilities. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopolist. 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. That is, competitive markets and consumers in the U.S. have demanded volumetric based prices for generations: 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. HAVE YOU CONDUCTED AN ANALYSIS OF THE COSTS THAT SHOULD BE CONSIDERED IN DETERMINING LG&E's RESIDENTIAL CUSTOMER CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE?

A. Yes. As I discussed earlier, there is no doubt that the majority of LG&E's non-fuel or non-gas costs are fixed in the short-run and that efficient, competitive pricing dictates volumetric pricing. However, traditional ratemaking has recognized a minimum level of fixed customer charges to reflect the direct costs of maintaining a customer's account. These direct customer costs include the Company's investment in meters and service lines as well as the operating expenses associated with meter reading, customer service, accounting and customer records and collections. I have conducted a traditional direct customer cost analysis for LG&E which is presented in my Schedules GAW-8 (Electric) and GAW-9 (Gas). These studies indicate a monthly LG&E customer cost of $3.23 per month for electric service and $8.10 for natural gas service.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING LG&E's RESIDENTIAL CUSTOMER CHARGES?

A. Although my customer cost analyses indicate that reductions to LG&E's electric and natural gas customer charges are warranted, in the interest of gradualism and rate continuity I recommend that LG&E's current Residential electric and natural gas customer charges be maintained at the current levels of $8.50/mth for electric service and $12.50/mth for natural gas service.

Q. ARE YOU AWARE THAT THE COMPANY HAS REQUESTED A GAS LINE TRACKER AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ITS PROPOSED GAS LINE PROGRAM?

A. Yes.

Q. WHAT IS YOUR POSITION ON THE REQUESTS?

A. I have no position at this time. However, I have been advised by the OAG that he may have concerns with the company's requests.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

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

POSITIONS

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

EXPERIENCE

I. Public Utility Regulation

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

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

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

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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.

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market

GLENN A. WATKINS

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

**EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS**

PDF	YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
Yes	1985	SAVANNAH ELECT. & PWR CO.	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
Yes	1990	CENTRAL MAINE PWR CO.	ME. PUC	89-68	MARGINAL COST OF SERVICE
Yes	1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	VA. SCC	PUE900034	CLASS COST OF SERVICE
No	1990	WARNER FRUEHAUF	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
Yes	1991	W. VA. WATER	WVA PSC	91-140-W-42T	RATE DESIGN
Yes	1992	S.C. WORKERS COMPENSATION	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
No	1992	GRASS v. ATLAS PLUMBING, et.al.	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
Yes	1992	VIRGINIA NATURAL GAS	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
Yes	1992	ALLSTATE INSURANCE COMPANY (DIRECT)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
Yes	1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
No	1993	MOUNTAIN FORD v FORD MOTOR COMPANY	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
No	1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
Yes	1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
Yes	1993	POTOMAC EDISON CO.	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
Yes	1995	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
Yes	1995	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
Yes	1995	PIEDMONT NATURAL GAS COMPANY	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
Yes	1995	CYCLE WORLD v. HONDA MOTOR CO.	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
No	1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
Yes	1996	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
Yes	1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
Yes	1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
Yes	1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
Yes	1996	VIRGINIA LIABILITY INSURANCE COMPETITION	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
Yes	1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
No	1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
No	1997	NISSAN v. CRUMPLER NISSAN	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
Yes	1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
Yes	1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
Yes	1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTT/	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
Yes	1997	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
Yes	1998	VIRGINIA ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
Yes	1998	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
Yes	1998	AMERICAN ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
No	1998	FREEMAN WRONGFUL DEATH	FfEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
Yes	1998	EASTERN MAINE ELECTRIC COOPERATIVE	MAINE PUC	98-596	REVENUE REQUIREMENT
Yes	1998	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
Yes	1999	CREDIT LIFE & A&H LEGISLATION	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
Yes	1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
Yes	1999	COLUMBIA GAS of VIRGINIA	VA. SCC	PUE980287	RATE STRUCTURE
Yes	1999	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS990165	WORKERS COMPENSATION RATES
No	1999	ROANOKE GAS	VA. SCC	PUE980626	Rate Design/ Weather Norm
Yes	2000	PERSON-SMITH v. DOMINION REALITY	RICHMOND CIRCUIT	n/a	LOST INCOME
Yes	2000	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
No	2000	UNITED CITIES GAS	VA. SCC		Cost Allocations/ Rate Design
Yes	2001	VERMONT WORKERS COMPENSATION RATE CASE	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
No	2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
Yes	2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
No	2001	AMERICAN ELECTRIC POWER RESTRUCTURING	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
Yes	2001	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS010190	WORKERS COMPENSATION RATES
Yes	2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
Yes	2002	HAROLD MORRIS PERSONAL INJURY	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
Yes	2002	PIEDMONT NATURAL GAS	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
Yes	2002	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
Yes	2002	ROANOKE GAS COMPANY	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
Yes	2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	S.C. PSC	2002-223-E	REVENUE RQMT.
Yes	2003	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
Yes	2003	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
Yes	2003	ROANOKE GAS	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
Yes	2003	SOUTHWESTERN VIRGINIA GAS CO.	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
Yes	2004	SOUTH CAROLINA PIPELINE COMPANY	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
Yes	2004	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
Yes	2004	SCE&G FUEL CONTRACT	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT

**EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS**

PDF	YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
Yes	2004	WASHINGTON GAS LIGHT	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
Yes	2004	ATMOS ENERGY	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
Yes	2004	SCE&G RATE CASE (ELECTRIC)	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
No	2004	MEDICAL MALPRACTICE LEGISLATION	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
Yes	2004	ATLAS HONDA v. HONDA MOTOR CO.	VA. DMV	None	NEW DEALER PROTEST
Yes	2004	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
Yes	2004	NATIONAL FUEL GAS DISTRIBUTION	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
Yes	2005	WASHINGTON GAS LIGHT	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
No	2005	Serra Chevrolet	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
No	2005	NEWTOWN ARTESIAN WATER	PA. PUC		REV. RQMT./ RATE STRUCTURE
No	2005	CITY OF BETHLEHEM WATER RATE CASE	PA. PUC		REV. RQMT./ RATE STRUCTURE
Yes	2005	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
Yes	2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
Yes	2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
Yes	2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
Yes	2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
Yes	2006	PPL Gas	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
Yes	2006	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
Yes	2007	Level of Private Pass. Auto Competition	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
Yes	2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
Yes	2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
Yes	2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
Yes	2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
Yes	2007	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
Yes	2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
Yes	2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
Yes	2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
Yes	2008	Puget Sound Energy (Electric)	Wa. UTC	UE-072300	Cost Allocations/Rate Design
Yes	2008	Puget Sound Energy (Gas)	Wa. UTC	UE-072301	Cost Allocations/Rate Design
Yes	2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
Yes	2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
Yes	2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
Yes	2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
Yes	2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
Yes	2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
Yes	2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
Yes	2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
Yes	2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
Yes	2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
Yes	2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
Yes	2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
Yes	2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
Yes	2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
Yes	2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
Yes	2009	Avista Utilities (Electric)	Wa. UTC	UE-090134	Electric rate Design
Yes	2009	Avista Utilities (Gas)	Wa. UTC	UE-090135	Gas Rate design
Yes	2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
Yes	2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
Yes	2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design
Yes	2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
Yes	2009	PacifiCorp	Wa. UTC	UE-090205	Rate Design/Low Income
Yes	2009	Puget Sound Energy (Electric)	Wa. UTC	UE-090704	Cost Allocations/Rate Design
Yes	2009	Puget Sound Energy (Gas)	Wa. UTC	UG-090705	Cost Allocations/Rate Design
Yes	2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
Yes	2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
Yes	2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
Yes	2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design
Yes	2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
Yes	2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
Yes	2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
Yes	2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design
Yes	2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
Yes	2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design

EXPERT TESTIMONY
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PDF	YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
Yes	2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	WORKERS COMPENSATION RATES
Yes	2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
Yes	2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
Yes	2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
Yes	2011	Columbia Gas of Pennsylvania	PA PUC	R-2010-2215623	Cost Allocations/Rate Design
Yes	2011	Owen Electric Cooperative	KY PSC	PUE-2011-00037	Rate Design
Yes	2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
Yes	2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
Yes	2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
Yes	2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	WORKERS COMPENSATION RATES
Yes	2011	Artesian Water Company	DE PSC	11-207	Cost Allocations/Rate Design
Yes	2011	Arizona-American Water Company	AZ. CORP COMM	W-01303A-10-0448	Excess Capacity/Need For Facilities
Yes	2012	Tidewater Utilities, Inc.	DE PSC	11-397	Cost of Capital/Revenue Requirement/Rate Design
	2012	PPL Electric	PA PUC	R-2012-2290597	Cost Allocations/Rate Design

Note: Does not include Expert Reports submitted to Courts or Regulatory agencies in which cases that settled prior to testimony.
Testimony prior to 2003 may be incomplete.

Kentucky Utilities & LG&E
Test Year Generation Statistics

Generating Unit	Fuel	Generator Nameplate (MW)	Net MWH Produced	Generation Order	Total Gross Investment	Total Net Investment	Capacity Factor Net	Capacity Factor Gross		Net Investment Energy	Net Investment Demand
Ghent 2	Coal	556	3,341,264	3	$273,472,042	$83,388,818	68.60%	74.64%	Base	$83,388,818	$0
Ghent 1	Coal	557	3,282,901	7	$457,703,835	$271,488,089	67.28%	72.69%	Base	$271,488,089	$0
Trimble County 1	Coal	566	3,308,126	2	$515,981,742	$278,424,714	66.72%	72.77%	Base	$278,424,714	$0
Mill Creek 4	Coal	544	3,150,394	6	$510,585,061	$228,578,983	66.11%	72.35%	Base	$228,578,983	$0
Mill Creek 1	Coal	356	2,053,056	4	$171,459,453	$52,146,990	65.83%	73.35%	Base	$52,146,990	$0
Trimble County 2	Coal	838	4,740,434	1	$1,019,959,483	$906,947,029	64.58%	69.84%	Base	$906,947,029	$0
Ghent 3	Coal	557	2,940,071	8	$778,865,366	$477,834,135	60.26%	66.46%	Base	$477,834,135	$0
Ghent 4	Coal	556	2,801,767	11	$426,413,546	$238,401,985	57.52%	63.51%	Base	$238,401,985	$0
Cane Run 4	Coal	164	807,948	24	$82,888,694	$16,703,463	56.24%	61.59%	Base	$16,703,463	$0
Mill Creek 2	Coal	356	1,734,022	5	$132,002,570	$40,056,311	55.60%	62.98%	Base	$40,056,311	$0
Mill Creek 3	Coal	463	2,051,810	10	$284,377,385	$122,639,799	50.59%	55.30%	Intermediate	$62,041,669	$60,598,130
Green River 4	Coal	114	501,882	9	$46,859,950	$8,588,941	50.26%	54.36%	Intermediate	$4,316,505	$4,272,436
Cane Run 5	Coal	209	905,328	18	$97,221,510	$23,631,839	49.45%	53.91%	Intermediate	$11,685,656	$11,946,183
Green River 3	Coal	75	320,975	23	$27,716,488	$10,089,303	48.85%	53.38%	Intermediate	$4,929,093	$5,160,210
Cane Run 6	Coal	272	1,138,782	21	$153,644,905	$56,407,604	47.79%	52.62%	Intermediate	$26,959,090	$29,448,514
Brown 2	Coal	180	581,164	25	$59,125,163	$28,891,106	36.86%	41.34%	Intermediate	$10,648,447	$18,242,659
Brown 3	Coal	464	1,298,614	27	$617,105,989	$469,702,193	31.95%	36.04%	Intermediate	$150,065,404	$319,636,789
Brown 1	Coal	114	275,317	32	$76,780,399	$36,383,634	27.57%	33.21%	Intermediate	$10,030,675	$26,352,959
Trimble County 6	Gas	199	93,551	13	$62,918,755	$46,166,154	5.37%	5.44%	Peak	$0	$46,166,154
Trimble County 7	Gas	199	91,965	14	$54,236,860	$39,700,952	5.28%	5.35%	Peak	$0	$39,700,952
Trimble County 9	Gas	199	85,420	16	$54,028,301	$39,977,482	4.90%	4.99%	Peak	$0	$39,977,482
Trimble County 5	Gas	199	62,572	12	$66,804,468	$48,361,256	3.59%	3.68%	Peak	$0	$48,361,256
Trimble County 8	Gas	199	61,973	15	$53,873,686	$39,444,963	3.56%	3.62%	Peak	$0	$39,444,963
Trimble County 10	Gas	199	53,035	17	$60,462,097	$45,235,631	3.04%	3.09%	Peak	$0	$45,235,631
Brown 7	Gas,Oil	177	34,745	20	$60,225,468	$43,404,094	2.24%	2.38%	Peak	$0	$43,404,094
Paddys Run 13	Gas	178	31,743	22	$65,720,461	$45,252,606	2.04%	2.06%	Peak	$0	$45,252,606
Brown 6	Gas,Oil	177	30,756	19	$64,812,407	$50,236,200	1.98%	2.13%	Peak	$0	$50,236,200
Brown 9	Gas,Oil	126	3,807	28	$48,713,646	$23,411,374	0.34%	0.53%	Peak	$0	$23,411,374
Brown 5	Gas	123	3,196	26	$49,685,284	$33,734,583	0.30%	0.50%	Peak	$0	$33,734,583
Brown 11	Gas,Oil	126	2,890	31	$44,740,278	$24,255,858	0.26%	0.41%	Peak	$0	$24,255,858
Brown 8	Gas,Oil	126	2,436	30	$37,227,939	$21,396,169	0.22%	0.36%	Peak	$0	$21,396,169
Brown 10	Gas,Oil	126	1,568	29	$30,167,921	$15,175,125	0.14%	0.29%	Peak	$0	$15,175,125
Cane Run 11	Gas,Oil	16	198	34	$3,557,311	$1,294,371	0.14%	0.14%	Peak	$0	$1,294,371
Haefling 1-3	Gas,Oil	21	169	37	$6,346,312	$2,227,070	0.09%	0.16%	Peak	$0	$2,227,070
Paddys Run 11	Gas	16	100	33	$1,609,957	($136,355)	0.07%	0.11%	Peak	$0	($136,355)
Zorn 1	Gas	18	(49)	36	$1,951,456	($99,370)	-0.03%	0.02%	Peak	$0	($99,370)
Paddys Run 12	Gas	33	(273)	35	$3,990,011	$419,642	-0.09%	0.00%	Peak	$0	$419,642
Tyrone 3	Coal	75	(1,477)		$28,798,957	$6,704,422	-0.22%	0.00%	Peak	$0	$6,704,422
Dix Dam 1-3	Hydro	9	82,033		$28,850,449	$20,621,308	34.68%	34.74%	Hydro	$20,621,308	$0
Ohio Falls 1-8	Hydro	10	185,569		$42,551,883	$33,455,820	24.63%	25.19%	Hydro	$33,455,820	$0
						$3,930,544,291				$2,928,724,184	$1,001,820,107
							Total System			74.51%	25.49%

Sources: Company responses to KU OAG 1-248, KU OAG 1-250, LG&E OAG 1-291, and LG&E OAG 1-293.

<u>CHARGING FOR DISTRIBUTION UTILITY SERVICES: ISSUES IN RATE DESIGN</u>

December 2000

Frederick Weston

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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.

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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]

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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

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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

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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.

Zero Intercept Analysis
Account 365 -- Overhead Conductor

October 31, 2009

Description	Size	Cost	Quantity	Avg Cost
#12 conductor	6.53	15.15	1,515.00	0.01
#8 conductor	16.51	24.24	1,212.00	0.02
#6 conductor	26.24	3,499.99	18,421.00	0.19
#4 conductor	41.74	21,484.56	89,519.00	0.24
#2 conductor	66.36	650,917.73	971,519.00	0.67
#1 conductor	83.69	116,511.40	88,940.00	1.31
1/0 conductor	105.6	55,059.24	39,898.00	1.38
2/0 conductor	133.1	1,027,450.08	713,507.00	1.44
3/0 conductor	167.8	3,127,499.20	1,954,687.00	1.6
4/0 conductor	211.6	182,934.90	112,230.00	1.63
266 MCM Conductor	266	519,829.20	288,794.00	1.8
266.8 MCM Conductor	266.8	37,486.55	20,263.00	1.85
300 MCM Conductor	300	34,118.49	9,557.00	3.57
350 MCM Conductor	350	3,076.00	769.00	4
397 MCM Conductor	397	228,295.60	265,460.00	0.86
500 MCM Conductor	500	52,201.45	7,511.00	6.95
556 MCM Conductor	556	6,433.00	919.00	7
750 MCM Conductor	750	5,745.00	766.00	7.5
795 MCM Conductor	795	452,816.00	113,204.00	4
954 MCM Conductor	954	1,600.00	100.00	16
1000 MCM Conductor	1000	5,478.05	331.00	16.55

Louisville Gas & Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator		Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
	RATE BASE															
	Plant-in-Service															
	Intangible Plant															
301.00	ORGANIZATION	54	PT&D	$2,240	$969	$277	$35	$394	$285	$102	$65	$36	$9	$67	$1	$1
302.00	FRANCHISE AND CONSENTS															
303.00	SOFTWARE															
301.00	ORGANIZATION - COMMON															
302.00	FRANCHISE AND CONSENTS - COMMON															
	Sub-total			$2,240	$969	$277	$35	$394	$285	$102	$65	$36	$9	$67	$1	$1
	Production Plant															
	Steam Production Generation		$2,130,297,618													
	Energy	1	74.5120%	$1,587,327,361	$580,285,842	$191,397,159	$31,325,370	$319,137,524	$256,643,837	$86,770,991	$69,481,435	$29,166,452	$7,837,886	$14,338,541	$517,822	$424,500
	Demand	30	25.4880%	$542,970,257	$265,115,832	$70,969,183	$7,961,186	$94,946,882	$56,078,669	$21,413,813	$14,323,423	$10,124,158	$1,956,478	$0	$4,502	$76,131
330	Hydro Baseload Generation		$42,551,883													
	Energy	1	74.5120%	$31,706,259	$11,590,989	$3,823,085	$625,712	$6,374,650	$5,126,363	$1,733,217	$1,387,865	$582,589	$156,559	$286,407	$10,343	$8,479
	Demand	30	25.4880%	$10,845,624	$5,295,588	$1,417,582	$159,022	$1,896,528	$1,120,150	$427,733	$286,105	$202,226	$39,080	$0	$90	$1,521
340	Other Production Generation		$237,084,259													
	Energy	1	74.5120%	$176,656,223	$64,580,948	$21,300,899	$3,486,251	$35,517,330	$28,562,307	$9,656,884	$7,732,701	$3,245,982	$872,291	$1,595,759	$57,629	$47,243
	Demand	30	25.4880%	$60,428,036	$29,505,169	$7,898,275	$886,013	$10,566,792	$6,241,086	$2,383,178	$1,594,077	$1,126,734	$217,740	$0	$501	$8,473
	Total Production Plant			$2,409,933,760	$956,374,366	$296,806,184	$44,443,555	$468,439,707	$353,772,411	$122,385,816	$94,805,606	$44,448,141	$11,080,034	$16,220,707	$590,888	$566,347
	Transmission Plant															
	Transmission Plant	51		$258,654,497	$102,646,195	$31,855,753	$4,770,059	$50,276,916	$37,969,851	$13,135,482	$10,175,340	$4,770,551	$1,189,203	$1,740,944	$63,419	$60,785
	Total Transmission Plant			$258,654,497	$102,646,195	$31,855,753	$4,770,059	$50,276,916	$37,969,851	$13,135,482	$10,175,340	$4,770,551	$1,189,203	$1,740,944	$63,419	$60,785
	Distribution Plant															
360-362	TOTAL ACCTS 360-362	28		$108,073,255	$51,848,618	$14,709,521	$1,532,963	$17,934,186	$14,351,617	$4,299,894	$0	$2,010,309	$453,888	$887,211	$31,924	$13,122
364-365	OVERHEAD LINES															
	Primary		$278,708,304													
	Customer	19	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	28	100.0000%	$278,708,304	$133,711,532	$37,934,137	$3,953,332	$46,250,171	$37,011,144	$11,088,924	$0	$5,184,353	$1,170,525	$2,288,015	$82,329	$33,841
	Secondary		$92,902,768													
	Customer	18	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	29	100.0000%	$92,902,768	$64,298,073	$12,393,795	$0	$12,356,032	$0	$3,315,515	$0	$0	$0	$512,736	$19,043	$7,574
366-367	UNDERGROUND LINES															
	Primary		$159,661,290													
	Customer	19	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	28	100.0000%	$159,661,290	$76,598,205	$21,731,011	$2,264,712	$26,494,948	$21,202,264	$6,352,419	$0	$2,969,917	$670,549	$1,310,716	$47,163	$19,386
	Secondary		$53,220,430													
	Customer	18	0.0000%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Demand	29	100.0000%	$53,220,430	$36,833,898	$7,099,929	$0	$7,078,297	$0	$1,899,331	$0	$0	$0	$293,727	$10,909	$4,339
368	TRANSFORMERS - POWER POOL		$139,487,571													
	Customer	18	44.3000%	$61,792,994	$53,297,175	$6,700,372	$0	$438,216	$0	$23,732	$0	$0	$0	$1,315,496	$2,615	$15,388
	Demand	29	55.7000%	$77,694,577	$53,772,473	$10,364,930	$0	$10,333,349	$0	$2,772,765	$0	$0	$0	$428,801	$15,926	$6,334
369	SERVICES	27		$28,292,567	$23,403,452	$3,908,605	$0	$834,966	$0	$66,489	$0	$0	$0	$0	$11,483	$67,572
370	METERS	26		$38,125,261	$26,683,502	$7,924,442	$361,592	$2,076,231	$406,914	$124,739	$359,625	$32,694	$65,386	$0	$13,093	$77,042
371	CUSTOMER INSTALLATION															
373	STREET LIGHTING	7		$83,856,546	$0	$0	$0	$0	$0	$0	$0	$0	$0	$83,856,546	$0	$0
374	ASSET RETIRE OBLIGATIONS DIST PLANT	55		$626,515	$333,833	$84,850	$6,665	$96,807	$62,399	$24,285	$0	$8,741	$1,973	$4,722	$171	$70
	Total Distribution Plant			$982,954,507	$520,780,760	$122,851,593	$8,119,264	$123,895,203	$73,034,338	$29,968,095	$359,625	$10,206,013	$2,362,323	$90,897,969	$234,656	$244,669
	General Plant															
	Total General Plant	54		$16,083,154	$6,958,206	$1,988,683	$252,522	$2,830,372	$2,047,100	$728,895	$463,971	$261,735	$64,444	$479,470	$3,915	$3,840
	TOTAL COMMON PLANT	54		$156,297,545	$67,620,478	$19,326,203	$2,454,028	$27,505,813	$19,893,904	$7,083,468	$4,508,909	$2,543,565	$626,277	$4,659,535	$38,050	$37,316
106	COMPLETED CONSTR NOT CLASSIFIED	54		$110,296,327	$47,718,538	$13,638,149	$1,731,763	$19,410,350	$14,038,765	$4,998,674	$3,181,855	$1,794,947	$441,952	$3,288,149	$26,851	$26,333
105	PLANT HELD FOR FUTURE USE-DIST	53		$627,088	$332,239	$78,375	$5,180	$79,040	$46,593	$19,119	$229	$6,511	$1,507	$57,989	$150	$156
105	PLANT HELD FOR FUTURE USE-PROD															
	PROPERTY HELD UNDER CAPITAL LEASE															
	OTHER															
	Construction Work In Progress															
	CWIP Production	51		$104,203,661	$41,352,884	$12,833,669	$1,921,705	$20,254,968	$15,286,844	$5,291,867	$4,099,321	$1,921,903	$479,092	$701,371	$25,550	$24,488
	CWIP Transmission	52		$11,300,039	$4,484,384	$1,391,707	$208,393	$2,196,486	$1,658,818	$573,860	$444,538	$208,415	$51,954	$76,058	$2,771	$2,656
	CWIP Distribution Plant	53		$21,638,589	$11,464,377	$2,704,434	$178,736	$2,727,407	$1,607,765	$659,712	$7,917	$224,673	$52,004	$2,001,012	$5,166	$5,386

Louisville Gas & Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
	CWIP Common Plant	54	$7,669,785	$3,318,251	$948,369	$120,423	$1,349,757	$976,228	$347,598	$221,260	$124,817	$30,732	$228,651	$1,867	$1,831
	Total CWIP		$144,812,074	$60,619,895	$17,878,178	$2,429,257	$26,528,619	$19,539,655	$6,873,038	$4,773,035	$2,479,808	$613,782	$3,007,092	$35,353	$34,361
	TOTAL PLANT-IN-SERVICE		$3,934,849,118	$1,702,431,751	$486,545,216	$61,776,405	$692,437,795	$500,803,248	$178,319,649	$113,495,600	$64,031,500	$15,765,749	$117,344,830	$957,930	$939,446
	TOTAL UTILITY PLANT		$4,079,661,192	$1,763,051,647	$504,423,395	$64,205,662	$718,966,414	$520,342,902	$185,192,687	$118,268,635	$66,511,308	$16,379,531	$120,351,922	$993,283	$973,807
Accumulated Reserve for Depreciation															
	Production	51	$1,236,518,343	$490,708,278	$152,288,954	$22,803,644	$240,352,785	$181,517,884	$62,795,214	$48,644,022	$22,805,997	$5,685,079	$8,322,719	$303,180	$290,588
	Transmission	52	$139,855,579	$55,501,231	$17,224,540	$2,579,191	$27,184,941	$20,530,459	$7,102,411	$5,501,850	$2,579,457	$643,007	$941,336	$34,291	$32,867
	Distribution	53	$416,199,198	$220,507,189	$52,017,396	$3,437,831	$52,459,278	$30,923,947	$12,688,987	$152,271	$4,321,395	$1,000,246	$38,487,704	$99,357	$103,597
	General & Common Plant	54	$81,570,485	$35,290,607	$10,086,196	$1,280,738	$14,355,072	$10,382,475	$3,696,807	$2,353,165	$1,327,467	$326,849	$2,431,775	$19,858	$19,475
	Intangible Plant														
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION		$1,874,143,605	$802,007,305	$231,617,087	$30,101,404	$334,352,075	$243,354,764	$86,283,419	$56,651,307	$31,034,315	$7,655,182	$50,183,534	$456,686	$446,527
Net Utility Plant			$2,205,517,587	$961,044,342	$272,806,308	$34,104,259	$384,614,339	$276,988,138	$98,909,268	$61,617,327	$35,476,992	$8,724,349	$70,168,388	$536,597	$527,281
Rate Base Adjustments and Working Capital															
	Working Capital Assets														
	Cash Working Capital - Operation and Maintenance Expenses	67	$82,477,382	$33,565,652	$10,507,771	$1,476,545	$15,352,947	$11,894,789	$3,956,547	$3,059,094	$1,394,841	$367,800	$854,465	$23,970	$22,963
	Materials and Supplies	57	$90,578,486	$39,189,226	$11,200,056	$1,422,066	$15,939,612	$11,528,269	$4,104,839	$2,612,618	$1,473,977	$362,921	$2,701,226	$22,051	$21,626
	Prepayments	57	$4,350,165	$1,882,120	$537,899	$68,297	$765,523	$553,662	$197,141	$125,475	$70,790	$17,430	$129,730	$1,059	$1,039
	Mill Creek Ash Dredging Project														
	Sub-total		$177,406,033	$74,636,998	$22,245,725	$2,966,907	$32,058,082	$23,976,720	$8,258,527	$5,797,187	$2,939,608	$748,151	$3,685,422	$47,080	$45,627
Other Rate Base Items															
	Less:														
	Accumulated Deferred Income Taxes	57	$406,612,247	$175,922,781	$50,277,720	$6,383,737	$71,553,871	$51,751,091	$18,426,870	$11,728,201	$6,616,770	$1,629,172	$12,125,966	$98,989	$97,079
	FAS 109 Deferred Income Taxes	57	$27,127,029	$11,736,642	$3,354,265	$425,889	$4,773,698	$3,452,560	$1,229,344	$782,444	$441,436	$108,690	$808,981	$6,604	$6,477
	Asset Retirement Obligations - Net Assets	57	$27,021,378	$11,690,932	$3,341,201	$424,231	$4,755,106	$3,439,114	$1,224,556	$779,396	$439,717	$108,266	$805,830	$6,578	$6,451
	Asset Retirement Obligations - Regulatory Liabilities	57	$204,351	$88,413	$25,268	$3,208	$35,961	$26,009	$9,261	$5,894	$3,325	$819	$6,094	$50	$49
	Sub-total		$460,965,005	$199,438,768	$56,998,454	$7,237,066	$81,118,636	$58,668,773	$20,890,030	$13,295,935	$7,501,248	$1,846,947	$13,746,870	$112,221	$110,056
	Less:														
	Customer Advances	68	$960,947	$512,032	$130,143	$10,223	$151,549	$95,707	$37,248	$0	$13,406	$3,027	$7,242	$262	$107
TOTAL RATE BASE			$1,920,997,668	$835,730,540	$237,923,436	$29,823,878	$335,402,235	$242,200,378	$86,240,516	$54,118,579	$30,901,946	$7,622,525	$60,099,697	$471,194	$462,745

Louisville Gas & Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
O & M Expenses															
	Steam Production O&M														
500	OPERATION SUPERVISION & ENGINEERING	60	$2,338,675	$918,795	$287,262	$43,514	$458,574	$347,739	$119,921	$93,321	$43,113	$10,854	$16,426	$598	$559
501	FUEL	2	$347,138,171	$127,310,805	$42,510,000	$6,933,900	$69,885,306	$55,973,032	$17,897,647	$15,195,005	$6,378,577	$1,714,174	$3,135,711	$111,141	$92,874
502	STEAM EXPENSES-- Labor	51	$34,888,636	$13,845,442	$4,296,866	$643,410	$6,781,606	$5,121,567	$1,771,781	$1,372,502	$643,476	$160,406	$234,827	$8,554	$8,199
	STEAM EXPENSES— Other														
504	STEAM TRANSFER EXPENSES	51	$37,603	$14,923	$4,631	$693	$7,309	$5,520	$1,910	$1,479	$694	$173	$253	$9	$9
505	ELECTRIC EXPENSES-Labor	51	$736,005	$292,081	$90,646	$13,573	$143,064	$108,044	$37,377	$28,954	$13,575	$3,384	$4,954	$180	$173
	ELECTRIC EXPENSES— Other														
506	MISC. STEAM POWER EXPENSES	51	$17,654,961	$7,006,314	$2,174,376	$325,590	$3,431,748	$2,591,705	$896,588	$694,537	$325,623	$81,171	$118,831	$4,329	$4,149
507	RENTS	51	$88,736	$35,215	$10,929	$1,636	$17,248	$13,026	$4,506	$3,491	$1,637	$408	$597	$22	$21
509	ALLOWANCES	51	$81,359	$32,287	$10,020	$1,500	$15,814	$11,943	$4,132	$3,201	$1,501	$374	$548	$20	$19
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$3,628,672	$1,330,308	$437,849	$71,455	$728,754	$584,905	$197,894	$158,303	$66,684	$17,877	$32,502	$1,174	$967
511	MAINTENANCE OF STRUCTURES	51	$2,040,568	$809,793	$251,315	$37,632	$396,643	$299,550	$103,628	$80,275	$37,636	$9,382	$13,735	$500	$480
512	MAINTENANCE OF BOILER PLANT	1	$46,350,908	$16,944,694	$5,588,911	$914,720	$9,319,007	$7,494,153	$2,533,765	$2,028,899	$851,678	$228,871	$418,694	$15,121	$12,398
513	MAINTENANCE OF ELECTRIC PLANT	1	$11,612,285	$4,245,151	$1,400,189	$229,165	$2,334,689	$1,877,509	$634,784	$508,300	$213,371	$57,339	$104,895	$3,788	$3,105
514	MAINTENANCE OF MISC STEAM PLANT	1	$1,927,230	$704,545	$232,382	$38,033	$387,476	$311,600	$105,352	$84,360	$35,412	$9,516	$17,409	$629	$515
	Sub-total		$468,523,809	$173,490,352	$57,295,377	$9,254,822	$93,905,238	$74,740,295	$24,309,284	$20,252,627	$8,612,975	$2,293,928	$4,099,381	$146,065	$123,465
	Hydraulic Production O&M														
535	OPERATION SUPERVISION & ENGINEERING	62	$109,553	$43,476	$13,492	$2,020	$21,295	$16,082	$5,564	$4,310	$2,021	$504	$737	$27	$26
536	WATER FOR POWER	51	$38,568	$15,306	$4,750	$711	$7,497	$5,662	$1,959	$1,517	$711	$177	$260	$9	$9
537	HYDRAULIC EXPENSES														
538	ELECTRIC EXPENSES	51	$258,566	$102,611	$31,845	$4,768	$50,260	$37,957	$13,131	$10,172	$4,769	$1,189	$1,740	$63	$61
539	MISC. HYDRAULIC POWER EXPENSES	51	$94,572	$37,531	$11,647	$1,744	$18,383	$13,883	$4,803	$3,720	$1,744	$435	$637	$23	$22
540	RENTS	51	$341,099	$135,364	$42,010	$6,290	$66,302	$50,073	$17,322	$13,419	$6,291	$1,568	$2,296	$84	$80
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$13,044	$4,905	$1,584	$252	$2,593	$2,044	$696	$552	$240	$63	$108	$4	$3
542	MAINTENANCE OF STRUCTURES	51	$309,385	$122,778	$38,104	$5,706	$60,138	$45,417	$15,712	$12,171	$5,706	$1,422	$2,082	$76	$73
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	51	$78,637	$31,207	$9,685	$1,450	$15,285	$11,544	$3,993	$3,094	$1,450	$362	$529	$19	$18
544	MAINTENANCE OF ELECTRIC PLANT	1	$287,064	$104,943	$34,614	$5,665	$57,715	$46,413	$15,692	$12,566	$5,275	$1,417	$2,593	$94	$77
545	MAINTENANCE OF MISC HYDRAULIC PLANT	1	$1,939	$709	$234	$38	$390	$314	$106	$85	$36	$10	$18	$1	$1
	Sub-total		$1,532,427	$598,829	$187,965	$28,646	$299,858	$229,388	$78,978	$61,605	$26,243	$7,147	$11,000	$400	$370
	Other Power Generation Operation Expense														
546	OPERATION SUPERVISION & ENGINEERING	51	$49,813	$19,768	$6,135	$919	$9,683	$7,312	$2,530	$1,960	$919	$229	$335	$12	$12
547	FUEL	2	$17,279,551	$6,337,170	$2,116,027	$345,150	$3,478,692	$2,786,178	$890,894	$756,364	$317,507	$85,327	$156,087	$5,532	$4,623
548	GENERATION EXPENSE	51	$154,402	$61,274	$19,016	$2,847	$30,012	$22,666	$7,841	$6,074	$2,848	$710	$1,039	$38	$36
549	MISC OTHER POWER GENERATION	51	$36,953	$14,665	$4,551	$681	$7,183	$5,425	$1,877	$1,454	$682	$170	$249	$9	$9
550	RENTS	51	$22,784	$9,042	$2,806	$420	$4,429	$3,345	$1,157	$896	$420	$105	$153	$6	$5
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$24,273	$9,633	$2,989	$448	$4,718	$3,563	$1,233	$955	$448	$112	$163	$6	$6
552	MAINTENANCE OF STRUCTURES	51	$96,755	$38,397	$11,916	$1,784	$18,807	$14,203	$4,914	$3,806	$1,785	$445	$651	$24	$23
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$885,069	$351,237	$109,005	$16,322	$172,039	$129,926	$44,947	$34,818	$16,324	$4,069	$5,957	$217	$208
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$61,651	$24,466	$7,593	$1,137	$11,984	$9,050	$3,131	$2,425	$1,137	$283	$415	$15	$14
	Sub-total		$18,611,251	$6,865,651	$2,280,038	$369,709	$3,737,546	$2,961,669	$958,523	$808,753	$342,069	$91,449	$165,050	$5,859	$4,936
	Other Power Supply Expense														
555	PURCHASED POWER														
	'Demand	51	$20,765,592	$8,240,757	$2,557,479	$382,955	$4,036,388	$3,048,338	$1,054,558	$816,908	$382,995	$95,473	$139,768	$5,091	$4,880
	'Energy	1	$48,301,587	$17,657,811	$5,824,121	$953,216	$9,711,197	$7,809,545	$2,640,396	$2,114,286	$887,521	$238,503	$436,315	$15,757	$12,817
555	PURCHASED POWER OPTIONS														
555	BROKERAGE FEES														
555	MISO TRANSMISSION EXPENSES														
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,536,733	$609,847	$189,263	$28,340	$298,708	$225,589	$78,041	$60,454	$28,343	$7,065	$10,343	$377	$361
557	OTHER EXPENSES	51	$1,845,858	$732,523	$227,335	$34,041	$358,795	$270,967	$93,740	$72,615	$34,044	$8,487	$12,424	$453	$434
558	DUPLICATE CHARGES														
	Sub-total		$72,449,770	$27,240,939	$8,798,199	$1,398,552	$14,405,089	$11,354,440	$3,866,737	$3,064,263	$1,332,903	$349,528	$598,851	$21,678	$18,592
Transmission Expenses															
560	OPERATION SUPERVISION AND ENG	51	$1,024,769	$406,676	$126,210	$18,899	$199,193	$150,434	$52,042	$40,314	$18,901	$4,712	$6,897	$251	$241
561	LOAD DISPATCHING	51	$1,912,859	$759,112	$235,587	$35,277	$371,819	$280,803	$97,142	$75,251	$35,280	$8,795	$12,875	$469	$450
562	STATION EXPENSES	51	$1,302,918	$517,059	$160,467	$24,028	$253,259	$191,265	$66,167	$51,256	$24,031	$5,990	$8,770	$319	$306
563	OVERHEAD LINE EXPENSES	51	$145,909	$57,904	$17,970	$2,691	$28,362	$21,419	$7,410	$5,740	$2,691	$671	$982	$36	$34
565	TRANSMISSION OF ELECTRICITY BY OTHERS	51	$2,891,642	$1,147,539	$356,133	$53,327	$562,074	$424,486	$146,849	$113,756	$53,333	$13,295	$19,463	$709	$680
566	MISC. TRANSMISSION EXPENSES	51	$6,311,826	$2,504,828	$777,361	$116,402	$1,226,884	$926,561	$320,539	$248,304	$116,414	$29,020	$42,483	$1,548	$1,483
567	RENTS	51	$25,478	$10,111	$3,138	$470	$4,952	$3,740	$1,294	$1,002	$470	$117	$171	$6	$6
568	MAINTENANCE SUPERVISION AND ENG														
569	STRUCTURES	51	$1,012	$402	$125	$19	$197	$149	$51	$40	$19	$5	$7	$0	$0
570	MAINT OF STATION EQUIPMENT	51	$1,320,531	$524,048	$162,636	$24,353	$256,683	$193,851	$67,062	$51,949	$24,356	$6,071	$8,888	$324	$310
571	MAINT OF OVERHEAD LINES	51	$1,037,324	$411,659	$127,756	$19,130	$201,634	$152,277	$52,679	$40,808	$19,132	$4,769	$6,982	$254	$244
572	UNDERGROUND LINES														
573	MISC PLANT	51	$14,482	$5,747	$1,784	$267	$2,815	$2,126	$735	$570	$267	$67	$97	$4	$3
575	MARKET FACILITATION, MONITORING & COMPLIANCE	51	$753,467	$299,011	$92,797	$13,895	$146,458	$110,607	$38,264	$29,641	$13,897	$3,464	$5,071	$185	$177
	Sub-total		$16,742,217	$6,644,094	$2,061,963	$308,757	$3,254,330	$2,457,717	$850,235	$658,631	$308,789	$76,975	$112,688	$4,105	$3,935
	Distribution Expense - Operating														
580	OPERATION SUPERVISION AND ENGI	64	$2,530,733	$1,490,655	$407,718	$25,897	$269,732	$166,576	$61,045	$9,161	$22,714	$6,606	$47,713	$750	$2,166
581	LOAD DISPATCHING	28	$583,899	$280,128	$79,473	$8,282	$96,895	$77,539	$23,231	$0	$10,861	$2,452	$4,793	$172	$71
582	STATION EXPENSES	28	$1,131,098	$542,649	$153,950	$16,044	$187,700	$150,204	$45,003	$0	$21,040	$4,750	$9,286	$334	$137
583	OVERHEAD LINE EXPENSES	55	$4,528,695	$2,413,074	$613,329	$48,178	$714,213	$451,042	$175,542	$0	$63,180	$14,265	$34,132	$1,235	$505
584	UNDERGROUND LINE EXPENSES	56	$674,010	$359,140	$91,282	$7,170	$106,297	$67,129	$26,126	$0	$9,403	$2,123	$5,080	$184	$75
585	STREET LIGHTING EXPENSE	15													

Louisville Gas & Electric
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Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
586	METER EXPENSES	26	$6,212,508	$4,348,074	$1,291,287	$58,921	$338,322	$66,307	$20,326	$58,601	$5,327	$10,655	$0	$2,134	$12,554
586	METER EXPENSES - LOAD MANAGEMENT														
587	CUSTOMER INSTALLATIONS EXPENSE	7	($192,842)	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	$-0	($192,842)	$-0	$-0
588	MISCELLANEOUS DISTRIBUTION EXP	53	$2,989,237	$1,583,733	$373,601	$24,691	$376,774	$222,103	$91,135	$1,094	$31,037	$7,184	$276,427	$714	$744
588	MISC DISTR EXP -- MAPPING														
589	RENTS	53	$13,309	$7,051	$1,663	$110	$1,678	$989	$408	$5	$138	$32	$1,231	$3	$3
590	MAINTENANCE SUPERVISION AND EN	65	$351,679	$188,619	$47,276	$3,665	$54,249	$34,292	$13,319	$2	$4,803	$1,085	$4,233	$94	$41
591	STRUCTURES	28	$784,053	$376,153	$106,715	$11,121	$130,109	$104,119	$31,195	$0	$14,584	$3,293	$6,437	$232	$95
592	MAINTENANCE OF STATION EQUIPMENT	28	$901,232	$432,370	$122,664	$12,784	$149,555	$119,679	$35,857	$0	$16,764	$3,785	$7,399	$266	$109
593	MAINTENANCE OF OVERHEAD LINES	55	$20,552,385	$10,951,153	$2,783,445	$218,644	$3,241,285	$2,046,945	$796,654	$0	$286,727	$64,737	$154,899	$5,606	$2,291
594	MAINTENANCE OF UNDERGROUND LINES	58	$1,784,778	$951,003	$241,716	$18,987	$281,475	$177,758	$69,162	$0	$24,899	$5,622	$13,451	$487	$199
595	MAINTENANCE OF LINE TRANSFORM	70	$212,121	$162,823	$25,951	$0	$16,380	$0	$4,253	$0	$0	$0	$2,653	$28	$33
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	15	$331,958	$0	$0	$0	$0	$0	$0	$0	$0	$0	$331,958	$0	$0
597	MAINTENANCE OF METERS	26													
598	MISCELLANEOUS DISTRIBUTION EXPENSES	53	$400,476	$212,177	$50,052	$3,308	$50,477	$29,756	$12,210	$147	$4,158	$962	$37,034	$96	$100
	Sub-total		$43,789,329	$24,298,801	$6,390,123	$457,803	$6,035,141	$3,714,437	$1,405,484	$69,009	$515,638	$127,552	$743,882	$12,336	$19,123
	Customer Accounts Expense														
901	SUPERVISION/CUSTOMER ACCTS	6	$1,017,838	$760,219	$189,228	$929	$31,806	$5,028	$8,853	$601	$11	$22	$20,881	$37	$223
902	METER READING EXPENSES	6	$2,161,886	$1,614,704	$401,920	$1,973	$67,556	$10,679	$18,804	$1,277	$23	$46	$44,350	$79	$474
903	RECORDS AND COLLECTION	6	$5,334,272	$3,984,147	$991,703	$4,869	$166,689	$26,349	$46,398	$3,150	$57	$115	$109,431	$195	$1,169
904	UNCOLLECTIBLE ACCOUNTS	6	$3,310,298	$2,472,449	$615,423	$3,022	$103,443	$16,352	$28,793	$1,955	$36	$71	$67,910	$121	$725
905	MISC CUST ACCOUNTS	6	$441,963	$330,100	$82,166	$403	$13,811	$2,183	$3,844	$261	$5	$9	$9,067	$16	$97
	Sub-total		$12,266,257	$9,161,619	$2,280,440	$11,196	$383,305	$60,591	$106,693	$7,245	$132	$263	$251,638	$448	$2,687
	Customer Service & Information Expense														
907	SUPERVISION	6	$171,596	$128,164	$31,902	$157	$5,362	$848	$1,493	$101	$2	$4	$3,520	$6	$38
908	CUSTOMER ASSISTANCE EXPENSES	6	$10,918,539	$8,155,014	$2,029,684	$9,966	$341,190	$53,934	$94,971	$6,449	$117	$234	$223,990	$399	$2,392
908	CUSTOMER ASSISTANCE EXP-INCENTIVES														
909	INFORMATIONAL AND INSTRUCTIONAL	6	$50,475	$37,700	$9,384	$46	$1,577	$249	$439	$30	$1	$1	$1,035	$2	$11
909	INFORM AND INSTRUC -LOAD MGMT														
910	MISCELLANEOUS CUSTOMER SERVICE	6	$317,977	$237,496	$59,116	$290	$9,936	$1,571	$2,766	$188	$3	$7	$6,523	$12	$70
911	DEMONSTRATION AND SELLING EXP														
912	DEMONSTRATION AND SELLING EXP														
913	ADVERTISING EXPENSES	6	$19,134	$14,291	$3,557	$17	$598	$95	$166	$11	$0	$0	$393	$1	$4
915	MDSE-JOBBING-CONTRACT														
916	MISC SALES EXPENSE														
	Sub-total		$11,477,721	$8,572,665	$2,133,842	$10,476	$358,664	$56,696	$99,834	$6,779	$123	$247	$235,461	$419	$2,514
	General Expenses														
920	ADMIN. & GEN. SALARIES-	66	$16,456,591	$7,470,111	$2,204,246	$257,756	$2,772,970	$2,043,766	$718,200	$490,801	$250,540	$64,641	$173,933	$4,244	$5,384
921	OFFICE SUPPLIES AND EXPENSES	66	$5,348,737	$2,427,943	$716,426	$83,776	$901,273	$664,267	$233,430	$159,521	$81,431	$21,010	$56,532	$1,379	$1,750
922	ADMINISTRATIVE EXPENSES TRANSFERRED	66	($2,107,022)	($956,437)	($282,221)	($33,002)	($355,038)	($261,674)	($91,955)	($62,840)	($32,078)	($8,276)	($22,270)	($543)	($689)
923	OUTSIDE SERVICES EMPLOYED	66	$5,267,224	$2,390,942	$705,508	$82,499	$887,538	$654,144	$229,873	$157,090	$80,190	$20,689	$55,670	$1,358	$1,723
924	PROPERTY INSURANCE	23	$4,471,918	$1,932,588	$552,923	$70,379	$788,095	$570,374	$202,999	$129,640	$72,906	$17,954	$131,924	$1,089	$1,067
925	INJURIES AND DAMAGES - INSURANCE	66	$2,448,360	$1,111,380	$327,941	$38,348	$412,554	$304,065	$106,852	$73,020	$37,274	$9,617	$25,877	$631	$801
926	EMPLOYEE BENEFITS	66	$37,074,584	$16,829,200	$4,965,883	$580,691	$6,247,144	$4,604,342	$1,618,013	$1,105,712	$564,433	$145,627	$391,848	$9,561	$12,129
927	FRANCHISE REQUIREMENTS	23	$30,731	$13,281	$3,800	$484	$5,416	$3,920	$1,395	$891	$501	$123	$907	$7	$7
928	REGULATORY COMMISSION FEES	23	$1,173,366	$507,078	$145,079	$18,466	$206,785	$149,658	$53,264	$34,016	$19,130	$4,711	$34,615	$286	$280
929	DUPLICATE CHARGES	66	($153,701)	($69,769)	($20,587)	($2,407)	($25,899)	($19,088)	($6,708)	($4,584)	($2,340)	($604)	($1,624)	($40)	($50)
930	MISCELLANEOUS GENERAL EXPENSES	66	$2,884,284	$1,309,258	$386,330	$45,176	$486,008	$358,203	$125,876	$86,021	$43,911	$11,329	$30,485	$744	$944
931	RENTS AND LEASES	59	$1,598,925	$691,758	$197,707	$25,105	$281,385	$203,515	$72,464	$46,126	$26,021	$6,407	$47,667	$389	$382
935	MAINTENANCE OF GENERAL PLANT	59	$8,999,458	$3,893,520	$1,112,784	$141,301	$1,583,757	$1,145,471	$407,859	$259,618	$146,456	$36,060	$268,291	$2,191	$2,149
	Sub-total		$83,493,455	$37,550,832	$11,015,819	$1,308,571	$14,191,988	$10,420,961	$3,671,562	$2,475,032	$1,288,375	$329,289	$1,193,855	$21,297	$25,876
	TOTAL O & M EXPENSES		$728,886,236	$294,423,782	$92,443,765	$13,148,531	$136,571,159	$106,016,192	$35,347,331	$27,403,942	$12,429,246	$3,276,378	$7,411,805	$212,605	$201,498
	TOTAL O&M EXPENSE Less PURCHASED POWER		$659,819,057	$268,525,213	$84,062,165	$11,812,360	$122,823,573	$95,158,309	$31,652,375	$24,472,749	$11,158,731	$2,942,402	$6,835,722	$191,757	$183,701
	Depreciation Expense														
	Steam Production	51	$74,399,456	$29,525,182	$9,162,998	$1,372,061	$14,461,667	$10,921,659	$3,778,294	$2,926,838	$1,372,203	$342,063	$500,766	$18,242	$17,464
	Hydraulic Production	51	$611,031	$242,466	$75,254	$11,269	$118,771	$89,698	$31,031	$24,038	$11,270	$2,809	$4,113	$150	$144
	Other Production	51	$8,549,263	$3,392,747	$1,052,923	$157,664	$1,661,794	$1,255,011	$434,165	$336,324	$157,680	$39,307	$57,543	$2,096	$2,009
	Transmission - Kentucky System Property	52	$5,608,413	$2,225,680	$690,729	$103,429	$1,090,156	$823,301	$284,817	$220,632	$103,440	$25,786	$37,749	$1,375	$1,318
	Transmission - Virginia Property														
	Distribution	53	$23,264,454	$12,336,375	$2,910,137	$192,331	$2,934,858	$1,730,054	$709,891	$8,519	$241,762	$55,959	$2,153,212	$5,559	$5,796
	General & Common Plant	59	$9,517,748	$4,117,753	$1,176,870	$149,438	$1,674,968	$1,211,440	$431,348	$274,570	$154,891	$38,137	$283,743	$2,317	$2,272
	Intangible Plant														
	TOTAL DEPRECIATION EXPENSES		$121,970,365	$51,840,223	$15,068,912	$1,986,192	$21,942,215	$16,031,164	$5,669,546	$3,790,921	$2,041,245	$504,060	$3,037,125	$29,739	$29,023
	Other Expenses														
	Regulatory Credits														
	Production	51	($3,808,582)	($1,511,423)	($469,063)	($70,237)	($740,307)	($559,091)	($193,415)	($149,828)	($70,244)	($17,511)	($25,635)	($934)	($895)
	Transmission	52	($6,882)	($2,731)	($848)	($127)	($1,338)	($1,010)	($349)	($271)	($127)	($32)	($46)	($2)	($2)
	Distribution	53	($37,081)	($19,646)	($4,634)	($306)	($4,674)	($2,755)	($1,131)	($14)	($385)	($89)	($3,429)	($9)	($9)
	Common	54	($5,617)	($2,430)	($695)	($88)	($989)	($715)	($255)	($162)	($91)	($23)	($167)	($1)	($1)
	Accretion Expense														
	Production	51	$1,613,619	$640,359	$198,732	$29,758	$313,653	$236,875	$81,946	$63,479	$29,761	$7,419	$10,861	$396	$379
	Transmission	52	$4,031	$1,600	$496	$74	$784	$592	$205	$159	$74	$19	$27	$1	$1
	Distribution	53	$29,705	$15,738	$3,713	$245	$3,744	$2,207	$906	$11	$308	$71	$2,747	$7	$7
	Common	54	$4,155	$1,798	$514	$65	$731	$529	$188	$120	$68	$17	$124	$1	$1

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Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
	Property Taxes & Other	23	$21,920,601	$9,473,128	$2,710,339	$344,986	$3,863,109	$2,795,877	$995,067	$635,474	$357,375	$88,010	$646,668	$5,337	$5,232
	Amortization of Investment Tax Credit	23	($2,661,472)	($1,150,172)	($329,074)	($41,886)	($469,036)	($339,459)	($120,815)	($77,156)	($43,390)	($10,686)	($78,515)	($648)	($635)
	Gain on Disposition of Allowances	23	($694)	($300)	($86)	($11)	($122)	($89)	($32)	($20)	($11)	($3)	($20)	($0)	($0)
	Interest	23	$34,922,373	$15,091,927	$4,317,923	$549,608	$6,154,436	$4,454,196	$1,585,271	$1,012,393	$569,345	$140,211	$1,030,226	$8,503	$8,336
	Other Expenses														
	Total Other Expenses		$51,974,156	$22,537,847	$6,427,318	$812,081	$9,119,991	$6,587,157	$2,347,586	$1,484,186	$842,681	$207,403	$1,582,841	$12,651	$12,414
TOTAL EXPENSES Before Income Tax & Proforma Adjustments				$368,801,852	$113,939,995	$15,946,805	$167,633,364	$128,634,513	$43,364,462	$32,679,049	$15,313,173	$3,987,842	$12,031,771	$254,995	$242,936
Calculation of Taxable Income Before Proforma Adjustments															
	Total Operating Revenue		$1,047,904,226	$420,593,153	$154,276,976	$19,956,740	$204,478,419	$132,817,964	$44,224,959	$34,618,863	$14,402,568	$3,479,302	$18,509,064	$255,100	$291,097
	Operating Expenses														
	O&M Expenses		$728,886,236	$294,423,782	$92,443,765	$13,148,531	$138,571,159	$106,016,192	$35,347,331	$27,403,942	$12,429,246	$3,276,378	$7,411,805	$212,605	$201,498
	Depreciation Expense		$121,970,365	$51,840,223	$15,068,912	$1,986,192	$21,942,215	$16,031,164	$5,669,546	$3,790,921	$2,041,245	$504,060	$3,037,125	$29,739	$29,023
	Regulatory Credits		($3,858,162)	($1,536,231)	($475,240)	($70,759)	($747,307)	($563,571)	($195,149)	($150,274)	($70,848)	($17,654)	($29,277)	($946)	($907)
	Accretion Expenses		$1,651,510	$659,495	$203,455	$30,143	$318,912	$240,203	$83,245	$63,768	$30,212	$7,525	$13,759	$405	$389
	Amortization Expense	71	$5,925,055	$2,518,285	$732,015	$96,485	$1,065,905	$778,759	$275,414	$184,155	$99,159	$24,486	$147,537	$1,445	$1,410
	Property & Other Taxes		$21,920,601	$9,473,128	$2,710,339	$344,986	$3,863,109	$2,795,877	$995,067	$635,474	$357,375	$88,010	$646,668	$5,337	$5,232
	Amortization of ITC		($2,661,472)	($1,150,172)	($329,074)	($41,886)	($469,036)	($339,459)	($120,815)	($77,156)	($43,390)	($10,686)	($78,515)	($648)	($635)
	Gain/Disposition of Allowance		($694)	($300)	($86)	($11)	($122)	($89)	($32)	($20)	($11)	($3)	($20)	($0)	($0)
	Assignment of Interuptible Credit	Dir	($472,778)					($102,021)		($370,757)					
	Allocation of Curtailable Service Rider Credits	88	$472,778	$230,843	$61,795	$6,932	$82,673	$48,829	$18,646	$12,472	$8,815	$1,704	$0	$4	$66
	Sub-total Expenses		$873,833,439	$356,459,054	$110,415,882	$15,500,614	$162,627,506	$124,905,885	$42,073,251	$31,492,525	$14,851,803	$3,873,821	$11,149,082	$247,940	$236,076
	Interest	23	$34,922,373	$15,091,927	$4,317,923	$549,608	$6,154,436	$4,454,196	$1,585,271	$1,012,393	$569,345	$140,211	$1,030,226	$8,503	$8,336
	Taxable Income	Tax Income	$139,148,414	$49,042,172	$39,543,172	$3,906,518	$35,696,477	$3,457,904	$566,437	$2,113,945	($1,018,579)	($534,730)	$6,329,756	($1,344)	$46,685
	Income Taxes Before Proforma Adjustments		$51,825,304	$18,265,573	$14,727,706	$1,454,968	$13,295,019	$1,287,883	$210,967	$787,331	($379,366)	($199,158)	$2,357,494	($500)	$17,388
Proforma Adjustments															
	Revenue Adjustments		($64,637,980)	($28,478,314)	($10,913,357)	($1,463,806)	($12,859,229)	($7,724,566)	$206,465	($2,163,206)	($916,812)	($17,801)	($282,342)	($14,038)	($10,975)
	Proforma Expense Adjustments:														
	Eliminate mismatch in fuel cost recovery	2	($39,096,200)	($14,338,293)	($4,787,660)	($780,926)	($7,870,785)	($6,303,925)	($2,015,710)	($1,711,327)	($718,383)	($193,058)	($353,157)	($12,517)	($10,460)
	Remove ECR expenses	49	($801,360)	($320,085)	($120,755)	($16,025)	($158,123)	($98,564)	($32,159)	($26,278)	($11,564)	($2,524)	($14,892)	($173)	($219)
	Eliminate brokered sales expenses	2	($67,301)	($24,682)	($8,242)	($1,344)	($13,549)	($10,852)	($3,470)	($2,946)	($1,237)	($332)	($608)	($22)	($18)
	Adjustment to reflect changes to FAC calculations	43	($2,735,848)	($1,049,969)	($335,521)	($60,221)	($537,796)	($426,450)	($120,981)	($120,421)	($50,378)	($13,420)	($19,358)	($668)	($664)
	Eliminate DSM expenses	48	($10,616,312)	($7,359,138)	($1,749,392)	($96,989)	($1,007,437)	($187,543)	($213,813)	$-0	$-0	$-0	$-0	$-0	$-0
	Year end customer expense adjustment	16	$803,321	$579,960	$72,911	$140	$4,769	$155	$258	$18	$2	$3	$143,147	$285	$1,674
	Annualized depreciation expense adjustment	71	$696,536	$296,044	$86,054	$11,343	$125,305	$91,549	$32,377	$21,649	$11,657	$2,879	$17,344	$170	$166
	Labor expense adjustment	72	$3,272,923	$1,484,309	$437,726	$51,266	$551,973	$406,667	$142,945	$97,549	$49,895	$12,861	$35,824	$843	$1,065
	Pension & post retirement expense adjustment	72	($3,600,003)	($1,632,644)	($481,470)	($56,389)	($607,135)	($447,307)	($157,230)	($107,298)	($54,881)	($14,146)	($39,404)	($927)	($1,172)
	Property insurance expense adjustment	22	$245,960	$107,176	$30,423	$3,803	$42,892	$30,890	$11,030	$6,872	$3,956	$973	$7,825	$60	$59
	Adjustment for transfer of ITO functions	52	($1,504,636)	($597,110)	($185,310)	($27,748)	($292,469)	($220,877)	($76,411)	($59,192)	($27,751)	($6,918)	($10,127)	($369)	($354)
	Normalized storm damage expenses	73	($1,795,723)	($996,451)	($262,048)	($18,774)	($247,490)	($152,322)	($57,636)	($2,830)	($21,145)	($5,231)	($30,505)	($506)	($784)
	Eliminate advertising expenses	74	($539,988)	($216,888)	($81,199)	($10,343)	($105,888)	($66,760)	($22,293)	($17,283)	($7,129)	($1,695)	($10,228)	($129)	($153)
	Remove out of period expense items	69	$944,620	$410,957	$116,995	$14,665	$164,929	$119,098	$42,407	$26,612	$15,196	$3,748	$29,553	$232	$228
	MISO exit fee regulatory asset amortization	52	($1,044,188)	($414,383)	($128,602)	($19,257)	($202,968)	($153,284)	($53,028)	($41,078)	($19,259)	($4,801)	($7,028)	($256)	($245)
	Amortization of rate case expenses	78	($47,037)	($19,000)	($5,966)	($849)	($8,813)	($6,842)	($2,281)	($1,768)	($802)	($211)	($478)	($14)	($13)
	Adjustment for Swap termination regulatory asset	22	$102,858	$44,820	$12,723	$1,591	$17,937	$12,918	$4,613	$2,874	$1,656	$407	$3,272	$25	$25
	2011 Wind Storm regulatory asset amortization	69	$1,610,425	$700,616	$199,458	$25,002	$281,177	$203,043	$72,298	$45,369	$25,906	$6,390	$50,383	$395	$388
	Adjustment for injuries and damages FERC account 925	22	($379,162)	($165,218)	($46,900)	($5,863)	($66,121)	($47,618)	($17,004)	($10,593)	($6,099)	($1,500)	($12,063)	($92)	($91)
	General Management Audit regulatory asset amortization	22	$30,528	$13,302	$3,776	$472	$5,324	$3,834	$1,369	$853	$491	$121	$971	$7	$7
	Federal & State income tax adjustment	89	($3,780,611)	($1,861,511)	($1,375,257)	($177,630)	($1,096,720)	($175,767)	$998,154	($98,646)	($39,961)	$74,232	($27,209)	($143)	($155)
	Federal & State income tax interest adjustment	Tax Income	$28,247	$9,956	$8,027	$793	$7,246	$702	$115	$429	($207)	($109)	$1,285	($0)	$9
	Prior income tax true-ups & adjustments	Tax Income	($608,114)	($214,327)	($172,814)	($17,072)	($156,003)	($15,112)	($2,475)	($9,238)	$4,451	$2,337	($27,663)	$6	($204)
	Adjustment for tax basis depreciation reduction	22	($85,392)	($37,209)	($10,562)	($1,320)	($14,891)	($10,724)	($3,830)	($2,386)	($1,374)	($338)	($2,717)	($21)	($20)
	Adjustment for amortization of investment tax credit	22	$326,330	$142,197	$40,365	$5,046	$56,908	$40,983	$14,635	$9,117	$5,249	$1,291	$10,382	$79	$78
	Sub-total		($58,640,127)	($25,457,570)	($8,743,237)	($1,178,630)	($11,127,728)	($7,414,109)	($1,458,121)	($1,999,942)	($841,712)	($139,041)	($255,449)	($13,735)	($10,852)
	Net Adjustments		($5,997,853)	($3,020,743)	($2,170,120)	($285,176)	($1,731,501)	($310,457)	$1,664,587	($163,264)	($75,100)	$121,240	($26,893)	($303)	($122)
	Total Revenue After Proforma Adjustments		$983,266,246	$392,114,839	$143,363,620	$18,492,934	$191,619,190	$125,093,418	$44,431,425	$32,455,657	$13,485,756	$3,461,501	$18,226,722	$241,062	$280,123
	Total Operating Expenses after Proforma Adjustments		$867,018,616	$349,267,056	$116,400,351	$15,776,952	$164,794,797	$118,779,659	$40,826,097	$30,279,914	$13,630,725	$3,535,622	$13,251,126	$233,705	$242,611
	Net Operating Income after Proforma Adjustments		$116,247,630	$42,847,783	$26,963,269	$2,715,982	$26,824,393	$6,313,759	$3,605,327	$2,175,743	($144,968)	($74,121)	$4,975,596	$7,356	$37,511
	Rate Base Before Proforma Adjustments		$1,920,997,668	$835,730,540	$237,923,436	$29,823,878	$335,402,235	$242,200,378	$86,240,516	$54,118,579	$30,901,946	$7,622,525	$60,099,697	$471,194	$462,745
	ECR Plan Eliminations	51	($20,091,143)	($7,973,105)	($2,474,415)	($370,517)	($3,905,290)	($2,949,331)	($1,020,306)	($790,376)	($370,555)	($92,372)	($135,229)	($4,926)	($4,722)
	Proforma Adjustment to Depr. Reserve	71	($696,536)	($296,044)	($86,054)	($11,343)	($125,305)	($91,549)	($32,377)	($21,649)	($11,657)	($2,879)	($17,344)	($170)	($166)
	Cash Working Capital Adjustment	87	($5,766,234)	($2,604,174)	($766,275)	($89,965)	($976,249)	($722,626)	($253,655)	($171,093)	($88,162)	($22,650)	($68,233)	($1,487)	($1,675)
	Rate Base After Proforma Adjustments		$1,894,443,755	$824,857,217	$234,596,692	$29,352,053	$330,395,391	$238,436,871	$84,934,178	$53,135,461	$30,431,581	$7,504,624	$59,878,891	$464,611	$456,183
	ROR		6.14%	5.19%	11.49%	9.25%	8.12%	2.65%	4.24%	4.09%	-0.48%	-0.99%	8.31%	1.58%	8.22%

Louisville Gas & Electric
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
	Labor O & M Expenses														
Labor Expenses															
Steam Power Generation Operation Expenses															
500	OPERATION SUPERVISION & ENGINEERING	60	$1,479,457	$581,234	$181,724	$27,527	$288,831	$219,981	$75,863	$59,035	$27,274	$6,866	$10,391	$378	$354
501	FUEL	1	$2,373,175	$867,571	$286,153	$46,834	$477,135	$383,702	$129,729	$103,880	$43,606	$11,718	$21,437	$774	$635
502	STEAM EXPENSES	51	$11,440,138	$4,539,982	$1,408,961	$210,977	$2,223,719	$1,679,384	$580,975	$450,049	$210,999	$52,598	$77,001	$2,805	$2,688
504	STEAM TRANSFER EXPENSES														
505	ELECTRIC EXPENSES	51	$490,915	$194,818	$60,461	$9,053	$95,423	$72,065	$24,931	$19,312	$9,054	$2,257	$3,304	$120	$115
506	MISC. STEAM POWER EXPENSES	51	$4,358,335	$1,729,591	$536,770	$80,376	$847,167	$639,793	$221,333	$171,455	$80,384	$20,038	$29,335	$1,069	$1,024
507	RENTS														
	Total Steam Power Operation Expenses		$20,142,020	$7,913,196	$2,474,069	$374,767	$3,932,275	$2,994,926	$1,032,830	$803,732	$371,317	$93,477	$141,468	$5,146	$4,817
Steam Power Generation Maintenance Expenses															
510	MAINTENANCE SUPERVISION & ENGINEERING	61	$1,735,387	$636,210	$209,398	$34,173	$348,522	$279,727	$94,642	$75,708	$31,891	$8,549	$15,544	$561	$462
511	MAINTENANCE OF STRUCTURES	51	$310,285	$123,136	$38,215	$5,722	$60,313	$45,549	$15,757	$12,206	$5,723	$1,427	$2,088	$76	$73
512	MAINTENANCE OF BOILER PLANT	1	$7,287,310	$2,664,052	$878,691	$143,813	$1,465,138	$1,178,234	$398,360	$318,984	$133,901	$35,983	$65,827	$2,377	$1,949
513	MAINTENANCE OF ELECTRIC PLANT	1	$1,619,341	$591,989	$195,257	$31,957	$325,574	$261,820	$88,521	$70,883	$29,755	$7,996	$14,628	$528	$433
514	MAINTENANCE OF MISC STEAM PLANT	1	$149,573	$54,680	$18,035	$2,952	$30,072	$24,183	$8,176	$6,547	$2,748	$739	$1,351	$49	$40
	Total Steam Power Generation Maintenance Expense		$11,101,896	$4,070,067	$1,339,597	$218,617	$2,229,619	$1,789,513	$605,456	$484,328	$204,018	$54,694	$99,438	$3,592	$2,957
	Total Steam Power Generation Expense		$31,243,916	$11,983,264	$3,813,666	$593,384	$6,161,894	$4,784,439	$1,638,286	$1,288,060	$575,335	$148,171	$240,907	$8,738	$7,774
Hydraulic Power Generation Operation Expenses															
535	OPERATION SUPERVISION & ENGINEERING	62	$86,702	$34,407	$10,678	$1,599	$16,853	$12,728	$4,403	$3,411	$1,599	$399	$584	$21	$20
536	WATER FOR POWER														
537	HYDRAULIC EXPENSES														
538	ELECTRIC EXPENSES	51	$212,163	$84,196	$26,130	$3,913	$41,240	$31,145	$10,774	$8,346	$3,913	$975	$1,428	$52	$50
539	MISC. HYDRAULIC POWER EXPENSES	51	$1,053	$418	$130	$19	$205	$155	$53	$41	$19	$5	$7	$0	$0
540	RENTS														
	Total Hydraulic Power Operation Expenses		$299,918	$119,021	$36,938	$5,531	$58,298	$44,027	$15,231	$11,799	$5,532	$1,379	$2,019	$74	$70
Hydraulic Power Generation Maintenance Expenses															
541	MAINTENANCE SUPERVISION & ENGINEERING	63	$9,934	$3,736	$1,206	$192	$1,975	$1,557	$530	$420	$183	$48	$82	$3	$3
542	MAINTENANCE OF STRUCTURES	51	$30,440	$12,080	$3,749	$561	$5,917	$4,469	$1,546	$1,197	$561	$140	$205	$7	$7
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	51	$31,136	$12,356	$3,835	$574	$6,052	$4,571	$1,581	$1,225	$574	$143	$210	$8	$7
544	MAINTENANCE OF ELECTRIC PLANT	1	$122,557	$44,804	$14,778	$2,419	$24,640	$19,815	$6,700	$5,365	$2,252	$605	$1,107	$40	$33
545	MAINTENANCE OF MISC HYDRAULIC PLANT														
	Total Hydraulic Power Generation Maint. Expense		$194,067	$72,975	$23,568	$3,746	$38,585	$30,411	$10,357	$8,207	$3,570	$936	$1,604	$58	$50
	Total Hydraulic Power Generation Expense		$493,985	$191,997	$60,506	$9,277	$96,882	$74,439	$25,588	$20,006	$9,102	$2,315	$3,622	$132	$120
Other Power Generation Operation Expense															
546	OPERATION SUPERVISION & ENGINEERING	51	$37,065	$14,709	$4,565	$684	$7,205	$5,441	$1,882	$1,458	$684	$170	$249	$9	$9
547	FUEL														
548	GENERATION EXPENSE	51	$96,566	$38,322	$11,893	$1,781	$18,770	$14,176	$4,904	$3,799	$1,781	$444	$650	$24	$23
549	MISC OTHER POWER GENERATION	51	$1,649	$654	$203	$30	$321	$242	$84	$65	$30	$8	$11	$0	$0
550	RENTS														
	Total Other Power Generation Expenses		$135,280	$53,685	$16,661	$2,495	$26,296	$19,859	$6,870	$5,322	$2,495	$622	$911	$33	$32
Other Power Generation Maintenance Expense															
551	MAINTENANCE SUPERVISION & ENGINEERING	51	$21,608	$8,575	$2,661	$398	$4,200	$3,172	$1,097	$850	$399	$99	$145	$5	$5
552	MAINTENANCE OF STRUCTURES	51	$57,956	$23,000	$7,138	$1,069	$11,285	$8,508	$2,943	$2,280	$1,069	$266	$390	$14	$14
553	MAINTENANCE OF GENERATING & ELEC PLANT	51	$264,849	$105,104	$32,619	$4,884	$51,481	$38,879	$13,450	$10,419	$4,885	$1,218	$1,783	$65	$62
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	51	$31,948	$12,678	$3,935	$589	$6,210	$4,690	$1,622	$1,257	$589	$147	$215	$8	$8
	Total Other Power Generation Maintenance Expense		$376,361	$149,358	$46,352	$6,941	$73,157	$55,249	$19,113	$14,806	$6,941	$1,730	$2,533	$92	$88
	Total Other Power Generation Expense		$511,641	$203,043	$63,013	$9,436	$99,452	$75,108	$25,983	$20,128	$9,437	$2,352	$3,444	$125	$120
	Total Production Expense		$32,249,542	$12,378,304	$3,937,185	$612,096	$6,358,228	$4,933,985	$1,689,857	$1,328,193	$593,873	$152,838	$247,973	$8,995	$8,014
Purchased Power															
555	PURCHASED POWER														
556	SYSTEM CONTROL AND LOAD DISPATCH	51	$1,105,816	$438,839	$136,192	$20,393	$214,947	$162,331	$56,158	$43,502	$20,395	$5,084	$7,443	$271	$260

Louisville Gas & Electric
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(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
557	OTHER EXPENSES														
	Total Purchased Power Labor		$1,105,816	$438,839	$136,192	$20,393	$214,947	$162,331	$56,158	$43,502	$20,395	$5,084	$7,443	$271	$260
Transmission Labor Expenses															
560	OPERATION SUPERVISION AND ENG	52	$586,814	$232,875	$72,272	$10,822	$114,064	$86,143	$29,801	$23,085	$10,823	$2,698	$3,950	$144	$138
561	LOAD DISPATCHING	52	$1,395,743	$553,896	$171,899	$25,740	$271,303	$204,892	$70,881	$54,908	$25,743	$6,417	$9,394	$342	$328
562	STATION EXPENSES	52	$668,825	$265,421	$82,372	$12,334	$130,005	$98,182	$33,966	$26,311	$12,336	$3,075	$4,502	$164	$157
563	OVERHEAD LINE EXPENSES	52	$21,025	$8,344	$2,589	$388	$4,087	$3,086	$1,068	$827	$388	$97	$142	$5	$5
566	MISC. TRANSMISSION EXPENSES	52	$88,917	$35,286	$10,951	$1,640	$17,284	$13,053	$4,516	$3,498	$1,640	$409	$598	$22	$21
569	MAINTENANCE OF STRUCTURES														
570	MAINT OF STATION EQUIPMENT	52	$259,554	$103,003	$31,967	$4,787	$50,452	$38,102	$13,181	$10,211	$4,787	$1,193	$1,747	$64	$61
571	MAINT OF OVERHEAD LINES	52	$44,707	$17,742	$5,506	$824	$8,690	$6,563	$2,270	$1,759	$825	$206	$301	$11	$11
573	MISC PLANT	52	$2,042	$810	$251	$38	$397	$300	$104	$80	$38	$9	$14	$1	$0
	Total Transmission Labor Expenses		$3,067,627	$1,217,378	$377,807	$56,573	$596,281	$450,320	$155,786	$120,679	$56,578	$14,104	$20,647	$752	$721
Distribution Operation Labor Expense															
580	OPERATION SUPERVISION AND ENGI	64	$1,318,755	$776,774	$212,460	$13,495	$150,978	$86,802	$31,810	$4,774	$11,836	$3,442	$24,863	$391	$1,129
581	LOAD DISPATCHING	28	$452,751	$217,209	$61,623	$6,422	$75,132	$60,123	$18,014	$0	$8,422	$1,901	$3,717	$134	$55
582	STATION EXPENSES	28	$289,546	$138,911	$39,409	$4,107	$48,049	$38,450	$11,520	$0	$5,386	$1,216	$2,377	$86	$35
583	OVERHEAD LINE EXPENSES	55	$1,949,678	$1,038,868	$264,048	$20,741	$307,481	$194,181	$75,574	$0	$27,200	$6,141	$14,694	$532	$217
584	UNDERGROUND LINE EXPENSES	58	$143,329	$76,372	$19,411	$1,525	$22,604	$14,275	$5,556	$0	$2,000	$451	$1,080	$39	$16
585	STREET LIGHTING EXPENSE														
586	METER EXPENSES	26	$2,341,499	$1,638,793	$486,687	$22,208	$127,514	$24,991	$7,661	$22,087	$2,008	$4,016	$0	$804	$4,732
586	METER EXPENSES - LOAD MANAGEMENT														
587	CUSTOMER INSTALLATIONS EXPENSE														
588	MISCELLANEOUS DISTRIBUTION EXP	53	$1,028,668	$545,000	$128,565	$8,497	$129,657	$76,431	$31,362	$376	$10,681	$2,472	$95,125	$246	$256
589	RENTS														
	Total Distribution Operation Labor Expense		$7,524,226	$4,431,927	$1,212,204	$76,994	$861,414	$495,254	$181,496	$27,237	$67,532	$19,641	$141,856	$2,231	$6,440
Distribution Maintenance Labor Expense															
590	MAINTENANCE SUPERVISION AND EN	65	$72,860	$39,078	$9,794	$759	$11,239	$7,105	$2,759	$1	$995	$225	$877	$20	$8
591	MAINTENANCE OF STRUCTURES	28	$1,047	$502	$143	$15	$174	$139	$42	$0	$19	$4	$9	$0	$0
592	MAINTENANCE OF STATION EQUIPMENT	28	$198,076	$95,028	$26,960	$2,810	$32,870	$26,304	$7,881	$0	$3,684	$832	$1,626	$59	$24
593	MAINTENANCE OF OVERHEAD LINES	55	$1,992,241	$1,061,548	$269,813	$21,194	$314,193	$198,420	$77,224	$0	$27,794	$6,275	$15,015	$543	$222
594	MAINTENANCE OF UNDERGROUND LINES	58	$397,833	$211,982	$53,879	$4,232	$62,742	$39,623	$15,421	$0	$5,550	$1,253	$2,998	$109	$44
595	MAINTENANCE OF LINE TRANSFORMER	70	$103,347	$79,328	$12,644	$0	$7,981	$0	$2,072	$0	$0	$0	$1,292	$14	$16
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	15	$7,334	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,334	$0	$0
597	MAINTENANCE OF METERS														
598	MAINTENANCE OF MISC DISTR PLANT	53	$52,506	$27,818	$6,562	$434	$6,618	$3,901	$1,601	$19	$545	$126	$4,855	$13	$13
	Total Distribution Maintenance Labor Expense		$2,825,244	$1,515,284	$379,794	$29,444	$435,816	$275,491	$106,999	$20	$38,588	$8,716	$34,007	$757	$328
	Total Distribution Operation and Maintenance Labor Expenses		$10,349,470	$5,947,211	$1,591,998	$106,438	$1,297,230	$770,745	$288,495	$27,257	$106,120	$28,356	$175,863	$2,988	$6,768
	Transmission and Distribution Labor Expenses		$13,417,097	$7,164,589	$1,969,806	$163,011	$1,893,512	$1,221,065	$444,281	$147,935	$162,699	$42,460	$196,511	$3,740	$7,489
	Production, Transmission and Distribution Labor Expenses		$46,772,455	$19,981,732	$6,043,182	$795,500	$8,466,687	$6,317,381	$2,190,296	$1,519,631	$776,967	$200,383	$451,926	$13,006	$15,763
Customer Accounts Expense															
901	SUPERVISION/CUSTOMER ACCTS	6	$678,685	$506,907	$126,175	$619	$21,208	$3,352	$5,903	$401	$7	$15	$13,923	$25	$149
902	METER READING EXPENSES	6	$232,835	$173,904	$43,287	$213	$7,276	$1,150	$2,025	$138	$3	$5	$4,777	$9	$51
903	RECORDS AND COLLECTION	6	$2,494,338	$1,863,011	$463,727	$2,277	$77,945	$12,321	$21,696	$1,473	$27	$54	$51,170	$91	$546
904	UNCOLLECTIBLE ACCOUNTS														
905	MISC CUST ACCOUNTS	6	$159,695	$119,276	$29,689	$146	$4,990	$789	$1,389	$94	$2	$3	$3,276	$6	$35
	Total Customer Accounts Labor Expense		$3,565,553	$2,663,098	$662,878	$3,255	$111,419	$17,613	$31,014	$2,106	$38	$77	$73,146	$130	$781
Customer Service Expense															
907	SUPERVISION	6	$105,222	$78,590	$19,562	$96	$3,288	$520	$915	$62	$1	$2	$2,159	$4	$23
908	CUSTOMER ASSISTANCE EXPENSES	6	$594,558	$444,073	$110,535	$543	$18,579	$2,937	$5,172	$351	$6	$13	$12,197	$22	$130
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT														
909	INFORMATIONAL AND INSTRUCTIONAL														
909	INFORM AND INSTRUC -LOAD MGMT														
910	MISCELLANEOUS CUSTOMER SERVICE														
911	DEMONSTRATION AND SELLING EXP														
912	DEMONSTRATION AND SELLING EXP														
913	WATER HEATER - HEAT PUMP PROGRAM														
915	MDSE-JOBBING-CONTRACT														

Louisville Gas & Electric
Electric Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
916	MISC SALES EXPENSE														
	Total Customer Service Labor Expense		$699,780	$522,663	$130,097	$639	$21,867	$3,457	$6,087	$413	$8	$15	$14,356	$26	$153
	Sub-Total Labor Exp		$51,037,788	$23,167,493	$6,836,157	$799,393	$8,599,973	$6,338,451	$2,227,397	$1,522,150	$777,013	$200,474	$539,428	$13,162	$16,697
Administrative and General Expense															
920	ADMIN. & GEN. SALARIES-	66	$12,759,896	$5,792,077	$1,709,099	$199,855	$2,150,069	$1,584,668	$556,869	$380,551	$194,260	$50,120	$134,862	$3,291	$4,174
921	OFFICE SUPPLIES AND EXPENSES	66	$28,200	$12,801	$3,777	$442	$4,752	$3,502	$1,231	$841	$429	$111	$298	$7	$9
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	66	($1,186,638)	($538,646)	($158,942)	($18,586)	($199,951)	($147,370)	($51,787)	($35,390)	($18,066)	($4,661)	($12,542)	($306)	($388)
923	OUTSIDE SERVICES EMPLOYED														
924	PROPERTY INSURANCE														
925	INJURIES AND DAMAGES - INSURANCE	66	$49,990	$22,692	$6,696	$783	$8,423	$6,208	$2,182	$1,491	$761	$196	$528	$13	$16
926	EMPLOYEE BENEFITS	66	$346	$157	$46	$5	$58	$43	$15	$10	$5	$1	$4	$0	$0
928	REGULATORY COMMISSION FEES														
929	DUPLICATE CHARGES-CR														
930	MISCELLANEOUS GENERAL EXPENSES	66	$23,307	$10,580	$3,122	$365	$3,927	$2,895	$1,017	$695	$355	$92	$246	$6	$8
931	RENTS AND LEASES														
935	MAINTENANCE OF GENERAL PLANT	59	$1,251,386	$541,399	$154,734	$19,648	$220,223	$159,279	$56,713	$36,100	$20,365	$5,014	$37,306	$305	$299
	Total Administrative and General Expense		$12,926,487	$5,841,057	$1,718,533	$202,512	$2,187,502	$1,609,226	$566,239	$384,298	$198,110	$50,874	$160,703	$3,315	$4,118
	Total Operation and Maintenance Expenses		$63,964,275	$29,008,549	$8,554,690	$1,001,906	$10,787,475	$7,947,676	$2,793,636	$1,906,449	$975,123	$251,348	$700,131	$16,477	$20,815
	Operation and Maintenance Expenses Less Purchase Power		$63,964,275	$29,008,549	$8,554,690	$1,001,906	$10,787,475	$7,947,676	$2,793,636	$1,906,449	$975,123	$251,348	$700,131	$16,477	$20,815

Louisville Gas & Electric
Electric Cost of Service Study
(Revenues)

Acct. No.	Account Description	Allocator	Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	ighting Energ LE	Traffic TE
REVENUE															
	Sales	74	$908,666,506	$364,969,258	$136,637,414	$17,404,836	$178,183,330	$112,340,938	$37,513,761	$29,082,432	$11,996,226	$2,852,383	$17,211,692	$217,184	$257,053
	Intercompany Sales	2	$78,675,999	$28,853,942	$9,634,540	$1,571,511	$15,838,927	$12,685,825	$4,056,354	$3,443,822	$1,445,652	$388,503	$710,683	$25,189	$21,049
	Off-System Sales	82	$46,874,070	$18,135,543	$5,995,058	$880,360	$9,188,146	$6,982,573	$2,335,272	$1,944,553	$859,817	$214,611	$315,338	$11,309	$11,489
	Brokered Purchases														
	Settled Swap Revenue	2	$2,055,720	$753,923	$251,740	$41,062	$413,854	$331,467	$105,988	$89,983	$37,773	$10,151	$18,569	$658	$550
	Settled Swap Expense	2	($4,796,799)	($1,759,197)	($587,409)	($95,814)	($965,684)	($773,442)	($247,312)	($209,966)	($88,140)	($23,687)	($43,330)	($1,536)	($1,283)
	Forfeited Discounts	76	$5,456,486	$4,190,879	$944,054	$10,700	$193,798	$71,158	$40,121	$5,776	$0	$0	$0	$0	$0
	Misc Service Revenues	83	$1,623,075	$1,371,661	$251,414	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Rent From Electric Property	69	$2,958,357	$1,287,034	$366,405	$45,929	$516,523	$372,991	$132,811	$83,343	$47,589	$11,739	$92,554	$726	$713
	Other Electric Revenue	69	$6,683,812	$2,907,794	$827,818	$103,768	$1,166,980	$842,698	$300,060	$188,297	$107,519	$26,521	$209,108	$1,639	$1,610
	Unbilled Revenue	74	($293,000)	($117,685)	($44,059)	($5,612)	($57,455)	($36,224)	($12,096)	($9,378)	($3,868)	($920)	($5,550)	($70)	($83)
	TOTAL REVENUE		**$1,047,904,226**	**$420,593,153**	**$154,276,976**	**$19,956,740**	**$204,478,419**	**$132,817,984**	**$44,224,959**	**$34,618,863**	**$14,402,568**	**$3,479,302**	**$18,509,064**	**$255,100**	**$291,097**
Proforma Adjustments															
	Eliminate unbilled revenues	85	$293,000	$117,685	$44,059	$5,612	$57,455	$36,224	$12,096	$9,378	$3,868	$920	$5,550	$70	$83
	Eliminate rate mechanism revenue accr	85	($1,663,941)	($668,328)	($250,209)	($31,872)	($326,288)	($205,718)	($68,695)	($53,255)	($21,967)	($5,223)	($31,518)	($398)	($471)
	Mismatch in fuel cost recover	2	($35,115,292)	($12,878,319)	($4,300,164)	($701,409)	($7,069,355)	($5,662,038)	($1,810,464)	($1,537,074)	($645,235)	($173,400)	($317,198)	($11,243)	($9,395)
	Annualized FAC roll-in to base rates	43	($3,930,286)	($1,508,372)	($482,005)	($86,513)	($772,592)	($612,633)	($173,801)	($172,996)	($72,373)	($19,279)	($27,809)	($959)	($954)
	Adjustment to reflect changes to FAC c	43	($2,123,450)	($814,941)	($260,417)	($46,741)	($417,415)	($330,993)	($93,901)	($93,466)	($39,102)	($10,416)	($15,025)	($518)	($516)
	Eliminate ECR revenues	49	($4,889,807)	($1,953,120)	($736,830)	($97,782)	($964,846)	($601,427)	($196,228)	($160,348)	($70,565)	($15,401)	($90,867)	($1,057)	($1,335)
	To reflect a full year of the ECR roll-in														
	Remove off-system ECR revenues	82	($539,866)	($208,874)	($69,047)	($10,139)	($105,823)	($80,421)	($26,896)	($22,396)	($9,903)	($2,472)	($3,632)	($130)	($132)
	Adjustment to off-system sales margins	82	($6,108,465)	($2,363,361)	($781,255)	($114,725)	($1,197,367)	($909,945)	($304,324)	($253,407)	($112,048)	($27,967)	($41,094)	($1,474)	($1,497)
	Eliminate brokered sales revenues	2	$2,741,079	$1,005,274	$335,668	$54,752	$551,830	$441,975	$141,324	$119,983	$50,367	$13,535	$24,760	$878	$733
	Eliminate DSM revenue	48	($14,412,912)	($9,990,910)	($2,375,008)	($134,390)	($1,367,715)	($254,612)	($290,277)	$-0	$-0	$-0	$-0	$-0	$-0
	Annualized year end customer revenues	86	$1,202,528	$868,168	$109,144	$209	$7,138	$231	$387	$27	$2	$5	$214,284	$426	$2,507
	Customer rate switching revenue adjust	84	($101,432)	($87,579)	($2,148,925)	($301,015)	($1,256,382)	$453,445	$3,016,796	$0	$0	$221,863	$0	$365	$0
	Adjustment to remove out of period iterr	85	$10,864	$4,364	$1,634	$208	$2,130	$1,343	$449	$348	$143	$34	$206	$3	$3
	Subtotal		($64,637,980)	($28,478,314)	($10,913,357)	($1,463,806)	($12,859,229)	($7,724,566)	$206,465	($2,163,206)	($916,812)	($17,801)	($282,342)	($14,038)	($10,975)
Total Revenue After Adjustments			**$983,266,246**	**$392,114,839**	**$143,363,620**	**$18,492,934**	**$191,619,190**	**$125,093,418**	**$44,431,425**	**$32,455,657**	**$13,485,756**	**$3,461,501**	**$18,226,722**	**$241,062**	**$280,123**

Louisville Gas & Electric
Electric Cost of Service Study
(Allocator Amounts)

Alloc. No	Allocator Description		Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energy LE	Traffic TE
1	Average Demand (Loss Adjusted) Adjusted For Rate Switching	Energy	1,394,754	509,886	168,177	27,525	280,420	225,506	76,244	61,052	25,628	6,887	12,599	455	373
2	Energy (Loss Adjusted)Before Rate Switching		12,251,529,228	4,493,173,553	1,500,303,183	244,717,784	2,466,456,418	1,975,453,293	631,660,709	536,276,503	225,118,793	60,498,256	110,668,466	3,922,488	3,277,782
3	Customers (Monthly Bills)		5,892,216	4,173,228	519,384	1,020	34,920	1,104	1,944	132	12	24	1,146,192	2,040	12,216
4	Average Customers (Bills/12)		5,892,216	4,173,228	519,384	1,020	34,920	1,104	1,944	132	12	24	1,146,192	2,040	12,216
5	Average Customers (Lighting = Lights)		491,018	347,769	43,282	85	2,910	92	162	11	1	2	95,516	170	1,018
6	Weighted Average Customers (Lighting =10 Lights per Cust)	Cust05	465,619	347,769	86,564	425	14,550	2,300	4,050	275	5	10	9,552	17	102
7	Street Lighting	Cust04	95,516	0	0	0	0	0	0	0	0	0	95,516	0	0
8	Average Customers	Cust01	491,018	347,769	43,282	85	2,910	92	162	11	1	2	95,516	170	1,018
9	Average Customers (Lighting = 10 Lights per Cust)	Cust06	403,984	347,769	43,282	85	2,910	92	162	11	1	2	9,552	17	102
10	Average Secondary Customers	Cust07	403,793	347,769	43,282	0	2,910	0	162	0	0	0	9,552	17	102
11	Average Primary Customers	Cust08	403,973	347,769	43,282	85	2,910	92	162	0	1	2	9,552	17	102
12	Year End Customers		488,377	352,585	44,326	85	2,899	94	157	11	1	2	87,026	173	1,018
13	Year End Customers (Lighting = Lights)		488,377	352,585	44,326	85	2,899	94	157	11	1	2	87,026	173	1,018
14	Weighted Year End Customers (Lighting =10 Lights per Cust)	YECust05	471,544	352,585	88,652	425	14,495	2,350	3,925	275	5	10	8,703	17	102
15	Street Lighting	YECust04	83,856,546	0	0	0	0	0	0	0	0	0	83,856,546	0	0
16	Year End Customers	YECust01	488,377	352,585	44,326	85	2,899	94	157	11	1	2	87,026	173	1,018
17	Year End Customers (Lighting = 10 Lights per Cust)	YECust06	406,982	352,585	44,326	85	2,899	94	157	11	1	2	8,703	17	102
18	Year End Secondary Customers	YECust07	406,789	352,585	44,326	0	2,899	0	157	0	0	0	8,703	17	102
19	Year End Primary Customers	YECust08	408,971	352,585	44,326	85	2,899	94	157	0	1	2	8,703	17	102
20	Maximum Class Non-Coincident Peak Demands	NCP	3,163,308	1,469,824	416,991	43,457	508,405	406,845	121,895	99,607	56,989	12,867	25,151	905	372
21															
22	Net Utility Plant	UPT	2,205,517,587	961,044,342	272,806,308	34,104,259	384,614,339	276,988,138	98,909,268	61,617,327	35,476,992	8,724,349	70,168,388	536,597	527,281
23	Total Utility Plant	TUP	4,079,661,192	1,763,051,647	504,423,395	64,205,662	718,966,414	520,342,902	185,192,687	118,268,635	66,511,308	16,379,531	120,351,922	993,283	973,807
24															
25															
26	Meter Cost - Weighted Cost of Meters	C03	30,717,106	$21,496,606	$6,384,636	$291,331	$1,672,797	$327,846	$100,501	$289,746	$26,341	$52,681	$0	$10,549	$62,072
27	Customer Services - Weighted cost of Services	C02	134,946,465	$111,626,948	$18,642,791	$0	$3,982,520	$0	$317,130	$0	$0	$0	$0	$54,771	$322,295
28	Maximum Class Demands (Primary)	NCPP	3,063,701	1,469,824	416,991	43,457	508,405	406,845	121,895	0	56,989	12,867	25,151	905	372
29	Sum of the Individual Customer Demands (Secondary)	SICD	4,317,584	2,988,203	575,992	0	574,237	0	154,086	0	0	0	23,829	885	352
30	Summer Peak Period Demand Allocator	SCP	2,653,133	1,295,444	346,779	38,901	463,942	274,019	104,635	69,989	49,470	9,560	0	22	372
31	Winter Peak Period Demand Allocator	WCP	1,690,104	681,511	269,020	27,396	315,495	207,553	79,282	73,466	30,160	5,837	0	12	372
32															
33															
34															
35															
36															
37															
38															
39															
40															
41															
42															
43	FAC Roll-In		(8,285,846)	(3,179,957)	(1,016,165)	(162,388)	(1,628,781)	(1,291,556)	(366,407)	(364,710)	(152,577)	(40,644)	(58,627)	(2,022)	(2,012)
44															
45															
46															
47															
48	Remove DSM Revenues	DSMREV	14,423,888	9,998,518	2,376,817	134,492	1,368,757	254,606	290,498	0	0	0	0	0	0
49	Remove ECR Revenues	ECRREV	5,979,130	2,388,225	900,977	119,565	1,179,789	735,409	239,943	196,069	86,285	18,832	111,110	1,293	1,633
50															
51	Gross Production Plant		2,409,933,760	956,374,368	296,806,184	44,443,555	468,439,707	353,772,411	122,385,816	94,805,606	44,448,141	11,080,034	16,220,707	590,888	568,347
52	Gross Transmission Plant		258,654,497	102,646,195	31,855,753	4,770,059	50,276,916	37,969,851	13,135,482	10,175,340	4,770,551	1,189,203	1,740,944	63,419	60,785
53	Gross Distribution Plant		982,954,507	520,780,760	122,851,593	8,119,264	123,895,203	73,034,338	29,968,095	359,625	10,206,013	2,362,323	90,897,969	234,656	244,669
54	Total Prod.,Trans., Distrib Plant		3,651,542,764	1,579,801,321	451,513,530	57,332,878	642,611,825	464,776,600	165,489,392	105,340,572	59,424,705	14,631,559	108,859,620	888,962	871,801
55	Dist. Overhead Lines Gross Plant		371,611,072	198,009,605	50,327,932	3,953,332	58,606,203	37,011,144	14,404,440	0	5,184,353	1,170,525	2,800,750	101,372	41,415
56															
57	Gross Total Plant in Service		3,934,849,118	1,702,431,751	486,545,216	61,776,405	692,437,795	500,803,248	178,319,649	113,495,600	64,031,500	15,765,749	117,344,830	957,930	939,446
58	Dist. Underground Lines Gross Plant		212,881,720	113,432,103	28,830,941	2,264,712	33,573,244	21,202,264	8,251,751	0	2,969,917	670,549	1,604,442	58,072	23,725
59	Gross General Plant		16,083,154	6,958,206	1,988,683	252,522	2,830,372	2,047,100	728,895	463,971	261,735	64,444	479,470	3,915	3,840
60	Labor Accts 501-507		18,662,563	7,331,962	2,292,346	347,240	3,643,444	2,774,945	956,968	744,697	344,043	86,611	131,077	4,768	4,463
61	Labor Accts 511-514		9,366,509	3,433,857	1,130,198	184,444	1,881,097	1,509,786	510,814	408,621	172,127	46,144	83,895	3,030	2,495
62	Labor Accts 536-540		213,216	84,614	26,260	3,932	41,445	31,300	10,828	8,388	3,932	980	1,435	52	50
63	Labor Accts 542-545		184,133	69,240	22,361	3,554	36,610	28,855	9,827	7,787	3,388	888	1,522	55	47
64	Labor Accts 581-588		6,205,471	3,655,153	999,743	63,500	710,436	408,451	149,686	22,463	55,696	16,198	116,984	1,840	5,311
65	Labor Accts 591-598		2,752,384	1,476,206	370,000	28,685	424,577	268,387	104,240	19	37,593	8,491	33,130	737	320
66	Labor Accts 500-916		51,037,788	23,167,493	6,836,157	799,393	8,599,973	6,338,451	2,227,397	1,522,150	777,013	200,474	539,428	13,162	16,697
67	O&M less Purchased Power		659,819,057	266,525,213	84,062,165	11,812,360	122,823,573	95,158,309	31,652,375	24,472,749	11,158,731	2,942,402	8,835,722	191,757	183,701
68	Dist. Lines Gross Plant		584,492,792	311,441,707	79,158,873	6,218,044	92,179,448	58,213,406	22,656,190	0	8,154,270	1,841,074	4,405,193	159,444	65,141
69	Rate Base		1,920,997,668	835,730,540	237,923,436	29,823,878	335,402,235	242,200,378	86,240,516	54,118,579	30,901,946	7,622,525	60,099,897	471,194	462,745
70	Gross Transformer Plant		139,487,571	107,069,648	17,065,301	0	10,771,585	0	2,796,497	0	0	0	1,744,296	18,541	21,722
71	Depreciation Expense	DET	121,970,365	51,840,223	15,068,912	1,986,192	21,942,215	16,031,164	5,669,546	3,790,921	2,041,245	504,060	3,037,125	29,739	29,023
72	Total Labor	LBT	63,964,275	29,006,549	8,554,690	1,001,906	10,787,475	7,947,676	2,793,636	1,906,449	975,123	251,348	700,131	16,477	20,815
73	Distribution O&M		43,789,329	24,298,801	6,390,123	457,803	6,035,141	3,714,437	1,405,484	69,009	515,638	127,552	743,882	12,336	19,123
74	Sales Revenue	R01	908,031,044	364,714,022	136,541,859	17,392,664	178,058,720	112,262,374	37,487,526	29,062,094	11,987,837	2,850,388	17,199,655	217,032	256,873
75															
76	Late Payment Revenue		5,456,486	4,190,879	944,054	10,700	193,798	71,158	40,121	5,776	0	0	0	0	0
77															
78	O&M Expenses	OMT	728,886,236	294,423,782	92,443,765	13,148,531	136,571,159	106,016,192	35,347,331	27,403,942	12,429,246	3,276,378	7,411,805	212,605	201,498
79															
80															
81															
82	Off-System Sales	RS01	46,874,069	18,135,543	5,995,058	880,360	9,188,146	6,962,573	2,335,272	1,944,553	859,817	214,611	315,338	11,309	11,489
83	Misc. Service Revenue		1.00000	0.84510	0.15490	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
84	Rate Switching Allocator		(101,432)	(87,579)	(2,148,925)	(301,015)	(1,256,382)	453,445	3,016,796	0	0	221,863	0	365	0
85	Billing Determinant Rev net of CSR & HEA		908,031,044	364,714,022	136,541,859	17,392,664	178,058,720	112,262,374	37,487,526	29,062,094	11,987,837	2,850,388	17,199,655	217,032	256,873
86	Year End Rev Adjustment		488,377	352,585	44,326	85	2,899	94	157	11	1	2	87,026	173	1,018
87	O&M less Fuel & Purchased Power		$312,680,886	$141,214,408	$41,552,165	$4,878,460	$52,938,268	$39,185,276	$13,754,728	$9,277,744	$4,780,153	$1,228,228	$3,700,012	$80,616	$90,827
88	Intermediate & Peak Production Plant Allocated Amount		$614,243,917	$299,916,588	$80,285,041	$9,006,221	$107,410,202	$63,439,904	$24,224,723	$16,203,604	$11,453,118	$2,213,297	$0	$5,093	$86,124
89	Proforma Adjustments Before Income Tax		($10,117,393)	(4,981,638)	(3,680,361)	(475,360)	(2,934,961)	(470,375)	2,671,165	(263,988)	(106,940)	198,653	(72,814)	(382)	(414)

Louisville Gas & Electric
Electric Cost of Service Study
(Allocator Percentages)

Alloc. No	Allocator Description		Total System	Residential Rate RS	Gen. Service GSS	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Sp. Contract No. 1	Sp. Contract No. 2	St. Lighting RLS, LS, DSK	Lighting Energ LE	Traffic TE
1	Average Demand (Loss Adjusted) Adjusted For Rate Switching		100.0000%	36.5574%	12.0578%	1.9735%	20.1053%	16.1683%	5.4665%	4.3773%	1.8375%	0.4938%	0.9033%	0.0326%	0.0267%
2	Energy (Loss Adjusted)Before Rate Switching	0	100.0000%	36.6744%	12.2458%	1.9974%	20.1318%	16.1241%	5.1558%	4.3772%	1.8375%	0.4938%	0.9033%	0.0320%	0.0268%
3	Customers (Monthly Bills)		100.0000%	70.8261%	8.8147%	0.0173%	0.5926%	0.0187%	0.0330%	0.0022%	0.0002%	0.0004%	19.4526%	0.0346%	0.2073%
4	Average Customers (Bills/12)		100.0000%	70.8261%	8.8147%	0.0173%	0.5926%	0.0187%	0.0330%	0.0022%	0.0002%	0.0004%	19.4526%	0.0346%	0.2073%
5	Average Customers (Lighting = Lights)		100.0000%	70.8261%	8.8147%	0.0173%	0.5926%	0.0187%	0.0330%	0.0022%	0.0002%	0.0004%	19.4526%	0.0346%	0.2073%
6	Weighted Average Customers (Lighting =10 Lights per Cust)	Cust05	100.0000%	74.6696%	18.5912%	0.0913%	3.1249%	0.4940%	0.8698%	0.0591%	0.0011%	0.0021%	2.0515%	0.0037%	0.0219%
7	Street Lighting	Cust04	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
8	Average Customers	Cust01	100.0000%	70.8261%	8.8147%	0.0173%	0.5926%	0.0187%	0.0330%	0.0022%	0.0002%	0.0004%	19.4526%	0.0346%	0.2073%
9	Average Customers (Lighting = 10 Lights per Cust)	Cust06	100.0000%	86.0848%	10.7138%	0.0210%	0.7203%	0.0228%	0.0401%	0.0027%	0.0002%	0.0005%	2.3643%	0.0042%	0.0252%
10	Average Secondary Customers	Cust07	100.0000%	86.1255%	10.7188%	0.0000%	0.7207%	0.0000%	0.0401%	0.0000%	0.0000%	0.0000%	2.3655%	0.0042%	0.0252%
11	Average Primary Customers	Cust08	100.0000%	86.0871%	10.7141%	0.0210%	0.7203%	0.0228%	0.0401%	0.0000%	0.0002%	0.0005%	2.3644%	0.0042%	0.0252%
12	Year End Customers		100.0000%	72.1953%	9.0762%	0.0174%	0.5936%	0.0192%	0.0321%	0.0023%	0.0002%	0.0004%	17.8194%	0.0354%	0.2084%
13	Year End Customers (Lighting = Lights)		100.0000%	72.1953%	9.0762%	0.0174%	0.5936%	0.0192%	0.0321%	0.0023%	0.0002%	0.0004%	17.8194%	0.0354%	0.2084%
14	Weighted Year End Customers (Lighting =10 Lights per Cust)	YECust05	100.0000%	74.7724%	18.8004%	0.0901%	3.0739%	0.4984%	0.8324%	0.0583%	0.0011%	0.0021%	1.8456%	0.0036%	0.0216%
15	Street Lighting	YECust04	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
16	Year End Customers	YECust01	100.0000%	72.1953%	9.0762%	0.0174%	0.5936%	0.0192%	0.0321%	0.0023%	0.0002%	0.0004%	17.8194%	0.0354%	0.2084%
17	Year End Customers (Lighting = 10 Lights per Cust)	YECust06	100.0000%	86.2105%	10.8381%	0.0208%	0.7088%	0.0230%	0.0384%	0.0027%	0.0002%	0.0005%	2.1279%	0.0042%	0.0249%
18	Year End Secondary Customers	YECust07	100.0000%	86.2512%	10.8433%	0.0000%	0.7092%	0.0000%	0.0384%	0.0000%	0.0000%	0.0000%	2.1289%	0.0042%	0.0249%
19	Year End Primary Customers	YECust08	100.0000%	86.2128%	10.8384%	0.0208%	0.7089%	0.0230%	0.0384%	0.0000%	0.0002%	0.0005%	2.1279%	0.0042%	0.0249%
20	Maximum Class Non-Coincident Peak Demands	NCP	100.0000%	46.4648%	13.1821%	1.3738%	16.0719%	12.8614%	3.8534%	3.1488%	1.8016%	0.4068%	0.7951%	0.0286%	0.0118%
21															
22	Net Utility Plant	SICD	100.0000%	43.5745%	12.3693%	1.5463%	17.4387%	12.5589%	4.4846%	2.7938%	1.6086%	0.3956%	3.1815%	0.0243%	0.0239%
23	Total Utility Plant	SCP	100.0000%	43.2156%	12.3843%	1.5738%	17.6232%	12.7546%	4.5394%	2.8990%	1.6303%	0.4015%	2.9500%	0.0243%	0.0239%
24															
25															
26	Meter Cost - Weighted Cost of Meters	0	100.0000%	69.9890%	20.7853%	0.9484%	5.4458%	1.0673%	0.3272%	0.9433%	0.0858%	0.1715%	0.0000%	0.0343%	0.2021%
27	Customer Services - Weighted cost of Services		100.0000%	82.7194%	13.8150%	0.0000%	2.9512%	0.0000%	0.2350%	0.0000%	0.0000%	0.0000%	0.0000%	0.0406%	0.2388%
28	Maximum Class Demands (Primary)		100.0000%	47.9754%	13.6107%	1.4184%	16.5945%	13.2795%	3.9787%	0.0000%	1.8601%	0.4200%	0.8209%	0.0295%	0.0121%
29	Sum of the Individual Customer Demands (Secondary)		100.0000%	69.2101%	13.3406%	0.0000%	13.3000%	0.0000%	3.5688%	0.0000%	0.0000%	0.0000%	0.5519%	0.0205%	0.0082%
30	Summer Peak Period Demand Allocator		100.0000%	48.8270%	13.0705%	1.4862%	17.4866%	10.3281%	3.9438%	2.6380%	1.8646%	0.3603%	0.0000%	0.0008%	0.0140%
31	Winter Peak Period Demand Allocator	0	100.0000%	40.3236%	15.9174%	1.6210%	18.6672%	12.2805%	4.6910%	4.3468%	1.7845%	0.3454%	0.0000%	0.0007%	0.0220%
32															
33															
34															
35															
36															
37															
38															
39															
40															
41															
42															
43	FAC Roll-In	0	100.0000%	38.3782%	12.2639%	2.2012%	19.6574%	15.5875%	4.4221%	4.4016%	1.8414%	0.4905%	0.7076%	0.0244%	0.0243%
44															
45															
46															
47															
48	Remove DSM Revenues	0	100.0000%	69.3192%	16.4783%	0.9324%	9.4895%	1.7686%	2.0140%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
49	Remove ECR Revenues	0 0 ***	100.0000%	39.9427%	15.0687%	1.9997%	18.7318%	12.2998%	4.0130%	3.2792%	1.4431%	0.3150%	1.8583%	0.0216%	0.0273%
50															
51	Gross Production Plant	0 0 ***	100.0000%	39.6847%	12.3159%	1.8442%	19.4379%	14.6798%	5.0784%	3.9340%	1.8444%	0.4598%	0.6731%	0.0245%	0.0235%
52	Gross Transmission Plant	0 0 ***	100.0000%	39.6847%	12.3159%	1.8442%	19.4379%	14.6798%	5.0784%	3.9340%	1.8444%	0.4598%	0.6731%	0.0245%	0.0235%
53	Gross Distribution Plant	0 0 ***	100.0000%	52.9812%	12.4962%	0.8260%	12.6044%	7.4301%	3.0488%	0.0366%	1.0383%	0.2403%	9.2474%	0.0239%	0.0249%
54	Total Prod.,Trans., Distrib Plant	0 0 ***	100.0000%	43.2639%	12.3650%	1.5701%	17.5984%	12.7282%	4.5320%	2.8848%	1.6274%	0.4007%	2.9812%	0.0243%	0.0239%
55	Dist. Overhead Lines Gross Plant	0 0 ***	100.0000%	53.2841%	13.5432%	1.0638%	15.7708%	9.9596%	3.8762%	0.0000%	1.3951%	0.3150%	0.7537%	0.0273%	0.0111%
56															
57	Gross Total Plant in Service	0 0 ***	100.0000%	43.2655%	12.3650%	1.5700%	17.5976%	12.7274%	4.5318%	2.8844%	1.6273%	0.4007%	2.9822%	0.0243%	0.0239%
58	Dist. Underground Lines Gross Plant	0 0 ***	100.0000%	53.2841%	13.5432%	1.0638%	15.7708%	9.9596%	3.8762%	0.0000%	1.3951%	0.3150%	0.7537%	0.0273%	0.0111%
59	Gross General Plant	0 0 ***	100.0000%	43.2639%	12.3650%	1.5701%	17.5984%	12.7282%	4.5320%	2.8848%	1.6274%	0.4007%	2.9812%	0.0243%	0.0239%
60	Labor Accts 501-507	0 0 ***	100.0000%	39.2870%	12.2831%	1.8806%	19.5227%	14.8690%	5.1277%	3.9903%	1.8435%	0.4641%	0.7024%	0.0255%	0.0239%
61	Labor Accts 511-514	0 0 ***	100.0000%	36.6810%	12.0684%	1.9692%	20.0832%	16.1190%	5.4536%	4.3626%	1.8377%	0.4927%	0.8957%	0.0324%	0.0266%
62	Labor Accts 536-540	0 0 ***	100.0000%	39.6847%	12.3159%	1.8442%	19.4379%	14.6798%	5.0784%	3.9340%	1.8444%	0.4598%	0.6731%	0.0245%	0.0235%
63	Labor Accts 542-545	0 0 ***	100.0000%	37.6032%	12.1441%	1.9302%	19.8821%	15.6705%	5.3367%	4.2290%	1.8398%	0.4824%	0.8263%	0.0299%	0.0257%
64	Labor Accts 581-588	0 0 ***	100.0000%	58.9021%	16.1107%	1.0233%	11.4485%	6.5821%	2.4122%	0.3620%	0.8975%	0.2610%	1.8853%	0.0296%	0.0856%
65	Labor Accts 591-598	0 0 ***	100.0000%	53.6337%	13.4429%	1.0422%	15.4258%	9.7511%	3.7872%	0.0007%	1.3658%	0.3085%	1.2037%	0.0268%	0.0116%
66	Labor Accts 500-916	0 0 ***	100.0000%	45.3928%	13.3943%	1.5663%	16.8502%	12.4191%	4.3642%	2.9824%	1.5224%	0.3928%	1.0569%	0.0258%	0.0327%
67	O&M less Purchased Power	DET 0 ***	100.0000%	40.6968%	12.7402%	1.7902%	18.6147%	14.4219%	4.7971%	3.7090%	1.6912%	0.4459%	1.0360%	0.0291%	0.0278%
68	Dist. Lines Gross Plant	LBT 0 ***	100.0000%	53.2841%	13.5432%	1.0638%	15.7708%	9.9596%	3.8762%	0.0000%	1.3951%	0.3150%	0.7537%	0.0273%	0.0111%
69	Rate Base	0 0 ***	100.0000%	43.5050%	12.3854%	1.5525%	17.4598%	12.6061%	4.4894%	2.8172%	1.6086%	0.3968%	3.1266%	0.0245%	0.0241%
70	Gross Transformer Plant	R01 0 ***	100.0000%	76.7593%	12.2343%	0.0000%	7.7222%	0.0000%	2.0048%	0.0000%	0.0000%	0.0000%	1.2505%	0.0133%	0.0156%
71	Depreciation Expense	0 0 ***	100.0000%	42.5023%	12.3546%	1.6264%	17.9896%	13.1435%	4.6483%	3.1061%	1.6736%	0.4133%	2.4901%	0.0244%	0.0238%
72	Total Labor	0 0 ***	100.0000%	45.3512%	13.3742%	1.5664%	16.8848%	12.4252%	4.3675%	2.9805%	1.5245%	0.3930%	1.0946%	0.0258%	0.0325%
73	Distribution O&M	0 0 ***	100.0000%	55.4902%	14.5929%	1.0455%	13.7822%	8.4825%	3.2097%	0.1576%	1.1775%	0.2913%	1.6988%	0.0282%	0.0437%
74	Sales Revenue	OMT 0 ***	100.0000%	40.1654%	15.0371%	1.9154%	19.6093%	12.3633%	4.1284%	3.2006%	1.3202%	0.3139%	1.8942%	0.0239%	0.0283%
75															
76	Late Payment Revenue	0 0 ***	100.0000%	76.8055%	17.3015%	0.1961%	3.5517%	1.3041%	0.7353%	0.1059%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
77															
78	O&M Expenses	RS01 0 ***	100.0000%	40.3937%	12.6829%	1.8039%	18.7370%	14.5450%	4.8495%	3.7597%	1.7052%	0.4495%	1.0169%	0.0292%	0.0276%
79															
80															
81															
82	Off-System Sales	0 0 ***	100.0000%	38.6899%	12.7697%	1.8781%	19.6018%	14.8965%	4.9820%	4.1485%	1.8343%	0.4578%	0.6727%	0.0241%	0.0245%
83	Misc. Service Revenue	0 0 ***	100.0000%	84.5100%	15.4900%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
84	Rate Switching Allocator	0 0 ***	100.0000%	86.3426%	2118.5868%	296.7653%	1238.6446%	-447.0433%	-2974.2054%	-0.0000%	-0.0000%	-216.7308%	-0.0000%	-0.3598%	-0.0000%
85	Billing Determinant Rev net of CSR & HEA	0 0 ***	100.0000%	40.1654%	15.0371%	1.9154%	19.6093%	12.3633%	4.1284%	3.2006%	1.3202%	0.3139%	1.8942%	0.0239%	0.0283%
86	Year End Rev Adjustment	0 0 ***	100.0000%	72.1953%	9.0762%	0.0174%	0.5936%	0.0192%	0.0321%	0.0023%	0.0002%	0.0004%	17.8194%	0.0354%	0.2084%
87	O&M less Fuel & Purchased Power	0 0 ***	100.0000%	45.1625%	13.2890%	1.5602%	16.9304%	12.5320%	4.3990%	2.9672%	1.5288%	0.3928%	1.1833%	0.0258%	0.0290%
88	Intermediate & Peak Production Plant Allocated Amount	0 0 ***	100.0000%	48.8270%	13.0705%	1.4862%	17.4866%	10.3281%	3.9438%	2.6380%	1.8646%	0.3603%	0.0000%	0.0008%	0.0140%
89	Proforma Adjustments Before Income Tax	0 0 ***	100.0000%	49.2384%	36.3766%	4.6984%	29.0091%	4.6492%	-26.4019%	2.6092%	1.0570%	-1.9635%	0.7197%	0.0038%	0.0041%

Louisville Gas & Electric
Gas Cost of Service Study
(Rate Base)

Acct.	No.	Account Description	Allocator	Alloc	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Plant-in-Service											
		Underground Storage Plant									
350-357		Underground Storage Plant	7		$75,948,560	$51,228,177	$23,151,495	$1,568,887	$0	$0	$0
	358	Asset Retire Obligations Gas Plant	7		$5,201,173	$3,508,251	$1,585,480	$107,442	$0	$0	$0
		Sub-total			$81,149,733	$54,736,429	$24,736,975	$1,676,329	$0	$0	$0
		Transmission Plant									
365-371		Transmission	8		$22,558,415	$15,215,910	$6,876,510	$465,994	$0	$0	$0
		Total Transmission Plant			$22,558,415	$15,215,910	$6,876,510	$465,994	$0	$0	$0
		Distribution Plant									
	374	Land and Land Rights	9		$133,743	$78,555	$34,911	$2,208	$973	$16,403	$693
	375	Structures and Improvements	9		$900,463	$528,892	$235,051	$14,865	$6,550	$110,438	$4,666
	376	Mains		$315,318,356							
		L/M Pressure		$287,462,918							
		Demand	20	100.00%	$287,462,918	$182,367,648	$86,340,952	$6,733,869	$1,736,346	$10,284,102	$0
		Customer	13	0.00%	$0	$0	$0	$0	$0	$0	$0
		H Pressure		$27,855,439							
		Demand	19	100.00%	$27,855,439	$14,548,012	$6,860,427	$536,988	$226,786	$5,384,937	$298,289
		Customer	12	0.00%	$0	$0	$0	$0	$0	$0	$0
	378	Meas. & Reg. Station Equip.- Gen.	9		$11,741,524	$6,896,450	$3,064,932	$193,830	$85,409	$1,440,055	$60,847
	379	Meas. & Reg. Station Equip.- City Gate	9		$4,383,870	$2,574,891	$1,144,337	$72,369	$31,889	$537,666	$22,718
	380	Services	14		$187,198,266	$157,404,538	$29,237,187	$272,186	$80,682	$199,179	$4,493
	381	Meters	15		$39,833,752	$32,895,014	$6,602,586	$263,973	$37,009	$35,170	$0
	382	Meter Installations									
	383	House Regulators	15		$23,145,111	$19,113,408	$3,836,385	$153,379	$21,504	$20,435	$0
	384	House Regulators Installations									
	385	Indust. Meas. & Reg. Station Equip.	15		$944,360	$779,860	$156,531	$6,258	$877	$834	$0
	387	Other Equipment	15		$51,112	$42,209	$8,472	$339	$47	$45	$0
	388	Asset Retire Obligations Gas Plant - City Gate	9		$2,963	$1,740	$773	$49	$22	$363	$15
	388	Asset Retire Obligations Gas Plant - Mains	45	30405	$11,928,647	$7,449,415	$3,525,854	$275,060	$74,266	$592,767	$11,284
		Total Distribution Plant			$595,582,168	$424,680,632	$141,048,399	$8,525,374	$2,302,360	$18,622,396	$403,007
		Other Plant-In-Service									
	117	Gas Stored Underground/Non-Current	7		$2,139,990	$1,443,448	$652,336	$44,206	$0	$0	$0
301-303		Intangible Plant	34		$387	$274	$96	$6	$1	$10	$0
389-399		General Plant	34		$8,980,221	$6,352,030	$2,217,308	$136,994	$29,567	$239,147	$5,175
		Common Utility Plant	34		$66,023,986	$46,701,119	$16,301,993	$1,007,198	$217,379	$1,758,247	$38,050
		Sub-total			$77,144,584	$54,496,871	$19,171,732	$1,188,404	$246,947	$1,997,404	$43,226
TOTAL PLANT-IN-SERVICE					$776,434,900	$549,129,842	$191,833,617	$11,856,101	$2,549,307	$20,619,800	$446,233
Construction Work In Progress											
		Underground Storage	7		$6,808,906	$4,592,685	$2,075,567	$140,653	$0	$0	$0
		Transmission	8		$543,238	$366,420	$165,596	$11,222	$0	$0	$0
		Distribution Mains	45		$20,758,360	$12,963,553	$6,135,728	$478,662	$129,239	$1,031,540	$19,637

Louisville Gas & Electric
Gas Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Allocator	Alloc	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Other Distribution	35		$10,182,047	$7,260,322	$2,411,357	$145,749	$39,361	$318,368	$6,890
	General									
	Common	34		$39,317,146	$27,810,419	$9,707,803	$599,784	$129,449	$1,047,032	$22,659
	Sub-total			$77,609,697	$52,993,399	$20,496,052	$1,376,071	$298,049	$2,396,940	$49,186
TOTAL	**GAS PLANT AT ORIGINAL COST**			**$854,044,597**	**$602,123,242**	**$212,329,669**	**$13,232,172**	**$2,847,356**	**$23,016,740**	**$495,418**
LESS										
Depreciation Reserve										
	Underground Storage	7		$31,115,896	$20,988,030	$9,485,098	$642,768	$0	$0	$0
	Transmission	8		$12,306,066	$8,300,583	$3,751,274	$254,209	$0	$0	$0
	Distribution	50		$192,425,924	$135,388,469	$46,798,488	$2,896,106	$791,315	$6,416,048	$135,499
	General and Intangible	34		$4,908,558	$3,471,998	$1,211,973	$74,880	$16,161	$130,717	$2,829
	Common	34		$29,360,397	$20,767,656	$7,249,380	$447,894	$96,667	$781,880	$16,921
	Sub-total			$270,116,841	$188,916,735	$68,496,213	$4,315,857	$904,142	$7,328,645	$155,249
Other Rate Base Items										
	Customer Advances for Construction	36		$6,368,917	$4,490,669	$1,551,792	$95,601	$25,903	$201,114	$3,837
	Accum. Deferred Income Taxes	34		$86,384,999	$61,103,190	$21,329,334	$1,317,806	$284,416	$2,300,469	$49,784
	FAS 109 Deferred Income Taxes	34		$3,417,946	$2,417,635	$843,926	$52,141	$11,253	$91,021	$1,970
	Asset Retirement Obligation - Net Assets	37		$20,308,114	$14,203,271	$5,149,730	$324,478	$67,976	$550,987	$11,672
	Asset Retirement Obligation - Liabilities									
	Asset Retirement Obligation - Regulatory Assets									
	Asset Retirement Obligation - Regulatory Liabilities	37		$2,155,824	$1,507,759	$546,674	$34,445	$7,216	$58,490	$1,239
	Accum Depr. Reclassification									
	Total Other Rate Base Items			$118,635,800	$83,722,524	$29,421,455	$1,824,471	$396,765	$3,202,083	$68,503
PLUS										
	Materials and Supplies	34		$55,133	$38,998	$13,613	$841	$182	$1,468	$32
	Prepayments	34		$691,403	$489,054	$170,714	$10,547	$2,276	$18,412	$398
	Gas Stored Underground	7		$36,144,520	$24,379,895	$11,017,980	$746,646	$0	$0	$0
	Cash Working Capital	38		$8,164,483	$5,775,390	$1,972,266	$121,004	$22,396	$264,661	$8,766
	Sub-total			$45,055,539	$30,683,336	$13,174,573	$879,038	$24,854	$284,541	$9,196
ADJUSTMENTS										
	Unamortized Debt	-								
	Regulatory	-								
	Customer Advances for Construction	-								
	Depreciation Adjustment	-								
NET COST RATE BASE				**$510,347,495**	**$360,167,319**	**$127,586,574**	**$7,970,883**	**$1,571,303**	**$12,770,554**	**$280,863**

Louisville Gas & Electric
Gas Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
O & M Expenses										
807-813	**Procurement Expenses**		$744,962							
	Demand	6	11.74%	$87,459	$51,370	$22,830	$1,444	$636	$10,727	$453
	Commodity	1	88.26%	$657,503	$300,598	$152,238	$14,496	$5,923	$173,573	$10,674
	Sub-total			$744,962	$351,967	$175,068	$15,940	$6,560	$184,300	$11,128
	Storage Operating Expenses									
814	Operations Supervision and Engineer	48	$466,755	$524,637	$349,662	$162,690	$12,285	$0	$0	$0
815	Maps and Records	-								
816	Well Expenses	7		$364,846	$246,093	$111,216	$7,537	$0	$0	$0
817	Lines Expenses	7		$553,668	$373,456	$168,775	$11,437	$0	$0	$0
818	Compressor Station Exp - Payroll	2		$1,522,429	$1,009,176	$475,715	$37,538	$0	$0	$0
819	Compressor Station Fuel and Power	2		$627,559	$415,992	$196,094	$15,473	$0	$0	$0
820	Measurement and Regulator Station	-								
821	Purification of Natural Gas	2		$1,270,760	$842,352	$397,076	$31,332	$0	$0	$0
823	Gas losses	-								
824	Other Expenses	2		$15,691	$10,401	$4,903	$387	$0	$0	$0
825	Storage Well Royalties	7		$47,558	$32,079	$14,497	$982	$0	$0	$0
826	Rents	7		$35,483	$23,934	$10,816	$733	$0	$0	$0
	Sub-total			$4,962,632	$3,303,144	$1,541,784	$117,704	$0	$0	$0
	Storage Maintenance Expenses									
830	Maintenance Super and Eng.	49	$324,950	$383,841	$255,657	$119,139	$9,045	$0	$0	$0
831	Maintenance of Structures	-								
832	Maintenance of Reservoirs	7		$814,235	$549,211	$248,204	$16,820	$0	$0	$0
833	Maintenance of Lines	7		$173,506	$117,032	$52,890	$3,584	$0	$0	$0
834	Main of Compressor Station Equipment	2		$691,885	$458,631	$216,194	$17,059	$0	$0	$0
835	Main of Meas and Reg Sta. Equip	7		$32,820	$22,137	$10,004	$678	$0	$0	$0
836	Main of Purification Equip	2		$880,092	$583,389	$275,003	$21,700	$0	$0	$0
837	Main of Other Equipment	7		$43,201	$29,140	$13,169	$892	$0	$0	$0
	Sub-total			$3,019,579	$2,015,196	$934,604	$69,779	$0	$0	$0
	Transmission Expense									
850-867	Transmission Expense	8		$2,026,620	$1,366,979	$617,777	$41,864	$0	$0	$0
	Sub-total			$2,026,620	$1,366,979	$617,777	$41,864	$0	$0	$0
	Distribution Expense									
870	Operation Supr and Engr	-								
871	Dist Load Dispatching	4		$481,434	$220,102	$111,471	$10,614	$4,337	$127,093	$7,816
872	Compr. Station Labor and Exp.	-								
873	Compr. Station Fuel and Power	-								
874.01	Other Mains/Serv. Expenses	36		$2,952,758	$2,081,965	$719,442	$44,322	$12,009	$93,241	$1,779
874.02	Leak Survey-Mains	-								
874.03	Leak Survey - Service	-								
874.04	Locate Main per Request	-								

Louisville Gas & Electric
Gas Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
874.05	Check Stop Box Access	-								
874.06	Patrolling Mains	-								
874.07	Check/Grease Valves	-								
874.08	Opr. Odor Equipment	-								
874.09	Locate and Inspect Valve Boxes	-								
874.1	Cut Grass - Right of Way	-								
875	Meas and Reg Station Exp.- General	9		$754,896	$443,392	$197,053	$12,462	$5,491	$92,585	$3,912
876	Meas and Reg Station Exp.- Industrial	15		$285,484	$235,755	$47,320	$1,892	$265	$252	$0
877	Meas and Reg Station Exp. - City Gate	9		$122,422	$71,905	$31,956	$2,021	$891	$15,015	$634
878	Meter and House Reg. Expense	15		$718,284	$593,164	$119,058	$4,760	$667	$634	$0
879	Customer Installation Expense	15		$485,598	$401,011	$80,490	$3,218	$451	$429	$0
880	Other Expenses	35		$3,223,073	$2,298,216	$763,302	$46,136	$12,460	$100,778	$2,181
881	Rents	35		$9,921	$7,074	$2,350	$142	$38	$310	$7
	Sub-total			$9,033,870	$6,352,585	$2,072,442	$125,568	$36,610	$430,336	$16,329
	Distribution Maintenance Expenses									
885	Maintenance Supr and Engr	-								
886	Maintenance Structures	9		$570,798	$335,261	$148,997	$9,423	$4,152	$70,006	$2,958
887	Maintenance Mains	45		$9,579,520	$5,982,390	$2,831,502	$220,892	$59,641	$476,033	$9,062
888	Maintenance Comp. Station Equip.	-								
889	Maintenance Meas and Reg. General	9		$100,383	$58,961	$26,203	$1,657	$730	$12,312	$520
890	Maintenance Meas and Reg - Industrial	15		$221,727	$183,104	$36,752	$1,469	$206	$196	$0
891	Maintenance Meas and Reg.-City Gate	9		$319,701	$187,778	$83,453	$5,278	$2,326	$39,210	$1,657
892	Maintenance Services	14		$1,056,214	$888,111	$164,963	$1,536	$455	$1,124	$25
893	Maintenance Meters and House Reg.	-								
894	Maintenance Other Equipment	35		$422,328	$301,142	$100,018	$6,045	$1,633	$13,205	$286
	Sub-total			$12,270,671	$7,936,747	$3,391,888	$246,300	$69,143	$612,086	$14,508
Total O&M Expense				**$32,058,333**	**$21,326,618**	**$8,733,562**	**$617,155**	**$112,312**	**$1,226,721**	**$41,965**
Customer Accounts Expense										
901	Supervision	17		$832,776	$698,810	$123,629	$1,032	$67	$9,118	$120
902	Meter Reading	17		$1,768,816	$1,484,273	$262,587	$2,192	$143	$19,367	$255
903	Customer Records and Collection	17		$4,364,163	$3,662,115	$647,876	$5,407	$352	$47,784	$629
904	Uncollectible Accounts	17		$828,312	$695,064	$122,966	$1,026	$67	$9,069	$119
905	Misc. Cust Accounts Expense	17		$320,243	$268,727	$47,541	$397	$26	$3,506	$46
	Sub-total			$8,114,310	$6,808,989	$1,204,598	$10,054	$655	$88,845	$1,169
Customer Service & Information Expenses										
907-910	Customer Service	18		$2,938,592	$2,465,871	$436,244	$3,641	$237	$32,175	$423
	Sub-total			$2,938,592	$2,465,871	$436,244	$3,641	$237	$32,175	$423
Sales Expenses										
911-916	Sales Expenses	18		$6,347	$5,326	$942	$8	$1	$69	$1
	Sub-total			$6,347	$5,326	$942	$8	$1	$69	$1

Louisville Gas & Electric
Gas Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Total Customer Accounting Expenses										
Administrative & General Expenses										
920	Admin and General Salaries	39		$3,861,279	$2,705,961	$935,303	$58,610	$11,131	$144,815	$5,459
921	Office Supplies and Expense	39		$1,253,647	$878,548	$303,666	$19,029	$3,614	$47,017	$1,772
922	Admin. Expenses Transferred	39		($389,615)	($273,040)	($94,375)	($5,914)	($1,123)	($14,612)	($551)
923	Outside Services Employed	39		$1,156,536	$810,493	$280,143	$17,555	$3,334	$43,375	$1,635
924	Property Insurance	40		$107,371	$75,699	$26,694	$1,664	$358	$2,894	$62
925	Injuries and Damages	39		$621,607	$435,618	$150,569	$9,435	$1,792	$23,313	$879
926	Employee Pensions and Benefits	39		$9,315,870	$6,528,505	$2,256,547	$141,405	$26,855	$349,387	$13,171
927	Franchise Requirement	40		$567,069	$399,798	$140,983	$8,786	$1,891	$15,283	$329
928	Regulatory Commission Fee	40		$236,219	$166,540	$58,728	$3,660	$788	$6,366	$137
929	Duplicate Charges -Credit	39		($527,144)	($369,419)	($127,688)	($8,002)	($1,520)	($19,770)	($745)
930.1	General Advertising Expense	40		$205,864	$145,139	$51,181	$3,190	$686	$5,548	$119
930.2	Misc. General Expense	39		$282,072	$197,674	$68,325	$4,282	$813	$10,579	$399
931	Rents	40		$399,731	$281,821	$99,380	$6,193	$1,333	$10,773	$232
935	Maintenance of General Plant	34		$3,641,303	$2,575,623	$899,075	$55,548	$11,989	$96,969	$2,099
	Sub-total			$20,731,809	$14,558,962	$5,048,531	$315,442	$61,941	$721,937	$24,997
Total Oper. & Maint Expenses				**$63,849,391**	**$45,165,766**	**$15,423,878**	**$946,298**	**$175,145**	**$2,069,748**	**$68,555**
Depreciation Expense										
	Underground Storage Plant									
350-357	Underground Storage Plant	7		$1,269,757	$856,466	$387,062	$26,230	$0	$0	$0
358	Asset Retire Obligations Gas Plant	7		$609,257	$410,951	$185,721	$12,586	$0	$0	$0
	Sub-total			$1,879,014	$1,267,417	$572,782	$38,815	$0	$0	$0
	Transmission Plant									
365-371	Transmission	8		$130,619	$88,104	$39,817	$2,698	$0	$0	$0
	Sub-total			$130,619	$88,104	$39,817	$2,698	$0	$0	$0
	Distribution Plant									
374	Land and Land Rights	9		$30	$18	$8	$0	$0	$4	$0
375	Structures and Improvements	9		$48,371	$28,411	$12,626	$799	$352	$5,933	$251
376	Mains	45		$5,716,998	$3,570,253	$1,689,823	$131,827	$35,593	$284,093	$5,408
378	Meas. & Reg. Station Equip.- Gen.	9		$306,178	$179,835	$79,923	$5,054	$2,227	$37,552	$1,587
379	Meas. & Reg. Station Equip.- City Gate	9		$101,578	$59,662	$26,515	$1,677	$739	$12,458	$526
380	Services	14		$6,809,068	$5,725,364	$1,063,461	$9,900	$2,935	$7,245	$163
381	Meters	15		$1,489,670	$1,230,181	$246,918	$9,872	$1,384	$1,315	$0
382	Meter Installations	15								
383	House Regulators	15		$506,813	$418,530	$84,006	$3,359	$471	$447	$0
384	House Regulators Installations	15								
385	Indust. Meas. & Reg. Station Equip.	15		$8,877	$7,331	$1,471	$59	$8	$8	$0
387	Other Equipment	15		$1,694	$1,399	$281	$11	$2	$1	$0
388	Asset Retire Obligations Gas Plant - City Gate	9		$74	$43	$19	$1	$1	$9	$0

Louisville Gas & Electric
Gas Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
388	Asset Retire Obligations Gas Plant - Mains	45		$373,549	$233,281	$110,413	$8,614	$2,326	$18,563	$353
	L/M Pressure									
	Demand	11								
	Customer	13								
	H Pressure									
	Demand	10								
	Customer	12								
	Sub-total			$15,362,900	$11,454,308	$3,315,464	$171,173	$46,037	$367,628	$8,289
	Other Plant-In-Service									
117	Gas Stored Underground/Non-Current	-								
301-303	Intangible Plant	34								
389-399	General Plant	34		$233,576	$165,217	$57,672	$3,563	$769	$6,220	$135
	Common Utility Plant	34		$3,789,063	$2,680,139	$935,558	$57,802	$12,475	$100,904	$2,184
	Common Utility Plant Amortization	34		$2,456,201	$1,737,359	$606,461	$37,469	$8,087	$65,410	$1,416
	Sub-total			$6,478,840	$4,582,715	$1,599,691	$98,835	$21,331	$172,534	$3,734
TOTAL DEPRECIATION EXPENSE				**$23,851,373**	**$17,392,543**	**$5,527,755**	**$311,521**	**$67,368**	**$540,162**	**$12,023**
Regulatory Credits and Accretion										
	Regulatory Credits	34		($2,104,902)	($1,488,872)	($519,722)	($32,110)	($6,930)	($56,054)	($1,213)
	Accretion	34		$1,059,702	$749,565	$261,651	$16,166	$3,489	$28,220	$611
	Amortization of Income Tax Credits	34		($132,894)	($94,001)	($32,813)	($2,027)	($438)	($3,539)	($77)
	Sub-total			($1,178,094)	($833,308)	($290,883)	($17,972)	($3,879)	($31,373)	($679)
Taxes Other Than Income										
	Property Taxes	40								
	Unemployment Insurance	40		$6,572,639	$4,633,878	$1,634,067	$101,833	$21,913	$177,134	$3,813
	Federal Old Age & Survivor Insurance	41								
	Public Service Commission Fee	40								
	Miscellaneous	40								
	Sub-total			$6,572,639	$4,633,878	$1,634,067	$101,833	$21,913	$177,134	$3,813
	Interest Expense	40		$9,337,962	$6,583,502	$2,321,572	$144,678	$31,132	$251,661	$5,417
Total Expenses Before Proforma Adjustments				$93,095,309	$66,358,880	$22,294,817	$1,341,681	$260,547	$2,755,672	$83,712
Pro-Forma Adjustments to Expenses										
Eliminate DSM Expenses		47		($2,685,996)	($2,617,803)	($62,448)	$0	($1,075)	($4,670)	$0
Year-End Customer Adjustment		44		$90,963	$61,455	$31,482	($1,975)	$0	$0	$0
Depreciation Expenses		42		$1,239,999	$904,214	$287,380	$16,196	$3,502	$28,082	$625
Labor Adjustment		41		$818,232	$573,778	$198,459	$12,424	$2,382	$30,079	$1,110
Pensions/Post Retirement Benefits Adjmt.		41		($900,001)	($631,117)	($218,292)	($13,666)	($2,620)	($33,085)	($1,221)
Property Insurance Adjmt.		43		$65,342	$46,114	$16,335	$1,021	$201	$1,635	$36
General Management audit regulatory asset		43		$9,941	$7,016	$2,485	$155	$31	$249	$5

Louisville Gas & Electric
Gas Cost of Service Study
(Expenses)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Eliminate Advertising Expenses	40		($212,211)	($149,614)	($52,759)	($3,288)	($708)	($5,719)	($123)
	Rate Case Expenses	38		$23,863	$16,880	$5,765	$354	$65	$774	$26
	Swap termination regulatory asset	43		$27,325	$19,284	$6,831	$427	$84	$684	$15
	Gas Supply Uncollectible Accounts Expense	33		($440,662)	($278,510)	($141,747)	($12,984)	($5,651)	($1,661)	($111)
	Interest Rate Swap Amortization									
	Normalize 925 Injuries/Damages Adjmt.	41		($108,523)	($76,101)	($26,322)	($1,648)	($316)	($3,989)	($147)
	Adjustment to correct Edison Electric invoice									
	Property Tax Adjmt.									
	Federal & State Income Tax Adjmt.	Net Pro Forma Adjustments		($1,107,402)	($724,630)	($335,455)	($31,663)	($14,013)	($1,229)	($412)
	Federal & State Income Tax Interest Adjmt.	40		$67,221	$47,393	$16,712	$1,041	$224	$1,812	$39
	Prior Income tax true-ups & adjustments	43		($113,553)	($80,138)	($28,388)	($1,774)	($350)	($2,841)	($62)
	Adjustment for amortization of investment tax credit	42		$7,274	$5,304	$1,686	$95	$21	$165	$4
	Remove out of period items.	43		($169,206)	($119,414)	($42,301)	($2,643)	($521)	($4,234)	($93)
Total Expense Adjustments				($3,387,394)	($2,995,889)	($340,577)	($37,926)	($18,742)	$6,050	($309)
Operating Income Before Income Taxes				$44,610,194	$30,530,942	$10,965,941	$596,192	$22,770	$2,429,552	$64,798
	Interest Expense	40		$9,337,962	$6,583,502	$2,321,572	$144,678	$31,132	$251,661	$5,417
Taxable Income				$35,272,232	$23,947,441	$8,644,368	$451,514	($8,363)	$2,177,891	$59,381
Income Taxes		Taxable Income		$14,475,575	$9,827,929	$3,547,612	$185,299	($3,432)	$893,797	$24,370
Net Operating Income (Pro-Forma)				$30,134,619	$20,703,014	$7,418,329	$410,892	$26,202	$1,535,754	$40,428
Unadjusted Net Cost Rate Base				$510,347,495	$360,167,319	$127,586,574	$7,970,883	$1,571,303	$12,770,554	$280,863
Depreciation Adjustment		42		($1,239,999)	($904,214)	($287,380)	($16,196)	($3,502)	($28,082)	($625)
Cash Working Capital Adjustment		38		($435,117)	($307,793)	($105,110)	($6,449)	($1,194)	($14,105)	($467)
Net Cost Rate Base				$508,672,379	$358,955,312	$127,194,084	$7,948,238	$1,566,607	$12,728,367	$279,771
Rate of Return -- Pro-Forma				5.92%	5.77%	5.83%	5.17%	1.67%	12.07%	14.45%

Louisville Gas & Electric
Gas Cost of Service Study
(Revenues)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Operating Revenues									
	Sales and Transportation	28	REV01	$271,922,589	$182,956,905	$75,428,219	$5,929,322	$2,067,816	$5,339,384	$200,941
	Interdepartmental Sales	28	REV01	$7,290,452	$4,905,214	$2,022,288	$158,970	$55,440	$143,153	$5,387
	Forfeited Discounts	Dir	REVFD	$2,474,416	$1,928,929	$494,023	$49,719	$1,745	$0	$0
	Miscellaneous Revenue	31	REVMISC	$332,763	$95,489	$237,274	$0	$0	$0	$0
	Unbilled Revenue	28		($5,710,375)	($3,842,095)	($1,583,993)	($124,516)	($43,424)	($112,127)	($4,220)
	Accrued Revenue	28		($635,460)	($427,555)	($176,269)	($13,856)	($4,832)	($12,478)	($470)
	Ft Knox Revenues	28		$267,562	$180,023	$74,219	$5,834	$2,035	$5,254	$198
	Total Operating Revenues			$275,941,947	$185,796,910	$76,495,761	$6,005,473	$2,078,779	$5,363,186	$201,837
	Pro-Forma Adjustments to Revenues									
	Temperature Normalization		Dir	$2,313,122	$132,253	$1,802,536	$114,219	$18,543	$267,001	($21,430)
	Year-End Customer Adjustment	44		$387,739	$261,960	$134,196	($8,417)	$0	$0	$0
	Rate Switching		Dir	($48,271)	$0	($17,639)	($30,632)	$0	$0	$0
	Adjustment to reflect contract cancellation	28		($247,029)	($166,208)	($68,523)	($5,387)	($1,879)	($4,851)	($183)
	Adjustment to eliminate Gas Supply Cost Recoveries	33		($146,406,353)	($92,532,515)	($47,094,137)	($4,313,682)	($1,877,537)	($551,768)	($36,714)
	Adjustment to eliminate unbilled revenues	28		$5,710,375	$3,842,095	$1,583,993	$124,516	$43,424	$112,127	$4,220
	Adjustment to eliminate accrued revenues	28		$635,460	$427,555	$176,269	$13,856	$4,832	$12,478	$470
	Removal of DSM Revenues	47		($3,968,881)	($3,868,118)	($92,275)	$0	($1,588)	($6,900)	$0
		Dir								
	Total Revenue Adjustments			($141,623,838)	($91,902,978)	($43,575,580)	($4,105,526)	($1,814,204)	($171,913)	($53,637)
	Total Adjusted Revenue			$134,318,109	$93,893,933	$32,920,181	$1,899,947	$264,575	$5,191,273	$148,200

Louisville Gas & Electric
Gas Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Labor Expenses											
807-813	**Procurement Expenses**		$495,110								
	Demand	6	11.74%	$58,126		$34,141	$15,173	$960	$423	$7,129	$301
	Commodity	1	88.26%	$436,984		$199,781	$101,179	$9,634	$3,937	$115,359	$7,094
	Sub-total			$495,110		$233,921	$116,352	$10,594	$4,360	$122,488	$7,396
Storage Expenses											
Operation											
814	Operations Supervision and Engineer	48	$332,069	$379,908		$253,203	$117,810	$8,896	$0	$0	$0
815	Maps and Records	-									
816	Well Expenses	7		$124,556		$84,014	$37,969	$2,573	$0	$0	$0
817	Lines Expenses	7		$266,927		$180,045	$81,368	$5,514	$0	$0	$0
818	Compressor Station Exp - Payroll	2		$376,942		$249,864	$117,784	$9,294	$0	$0	$0
819	Compressor Station Fuel and Power	-									
820	Measurement and Regulator Station	-									
821	Purification of Natural Gas	2		$493,112		$326,870	$154,083	$12,158	$0	$0	$0
823	Gas losses	-									
824	Other Expenses	-									
825	Storage Well Royalities	-									
826	Rents	-									
	Total Storage Operation Labor			$1,641,445		$1,093,997	$509,013	$38,435	$0	$0	$0
Storage Expense											
Maintenance											
830	Maintenance Super and Eng.	49	$232,292	$279,461		$186,135	$86,741	$6,585	$0	$0	$0
831	Maintenance of Structures	-									
832	Maintenance of Resevoirs	7		$136,874		$92,323	$41,723	$2,827	$0	$0	$0
833	Maintenance of Lines	7		$73,990		$49,907	$22,554	$1,528	$0	$0	$0
834	Main of Compressor Station Equipment	2		$350,853		$232,571	$109,631	$8,651	$0	$0	$0
835	Main of Meas and Reg Sta. Equip	7		$18,337		$12,369	$5,590	$379	$0	$0	$0
836	Main of Purification Equip	2		$316,939		$210,090	$99,034	$7,815	$0	$0	$0
837	Main of Other Equipment	7		$21,491		$14,496	$6,551	$444	$0	$0	$0
	Total Maintenance Labor			$1,197,945		$797,890	$371,825	$28,229	$0	$0	$0
	Total Storage Labor			$2,839,390		$1,891,888	$880,838	$66,664	$0	$0	$0
Transmission											
850-867	Transmission Expenses	8		$616,794		$416,035	$188,018	$12,741	$0	$0	$0
Distribution Expenses											
Operation											
870	Operation Supr and Engr	-									
871	Dist Load Dispatching	4		$339,244		$155,096	$78,549	$7,479	$3,056	$89,556	$5,508
872	Compr. Station Labor and Exp.	-									
873	Compr. Station Fuel and Power	-									
874.01	Other Mains/Serv. Expenses	36		$527,072		$371,634	$128,422	$7,912	$2,144	$16,644	$318
874.02	Leak Survey-Mains	-									
874.03	Leak Survey - Service	-									
874.04	Locate Main per Request	-									
874.05	Check Stop Box Access	-									

Louisville Gas & Electric
Gas Cost of Service Study
(Labor)

Acct.	No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	874.06	Patrolling Mains	-									
	874.07	Check/Grease Valves	-									
	874.08	Opr. Odor Equipment	-									
	874.09	Locate and Inspect Valve Boxes	-									
	874.1	Cut Grass - Right of Way	-									
	875	Meas and Reg Station Exp.- General	9		$401,227		$235,663	$104,734	$6,623	$2,919	$49,209	$2,079
	876	Meas and Reg Station Exp.- Industrial	15		$188,171		$155,393	$31,190	$1,247	$175	$166	$0
	877	Meas and Reg Station Exp. - City Gate	9		$32,505		$19,092	$8,485	$537	$236	$3,987	$168
	878	Meter and House Reg. Expense	15		$490,795		$405,302	$81,351	$3,252	$456	$433	$0
	879	Customer Installation Expense	15		$234,588		$193,725	$38,884	$1,555	$218	$207	$0
	880	Other Expenses	35		$1,298,940		$926,211	$307,621	$18,593	$5,021	$40,615	$879
	881	Rents	-									
		Total Operations Distribution Labor			$3,512,542		$2,462,115	$779,234	$47,199	$14,225	$200,817	$8,952
		Total Operations Transmission and Distribution Labor			$4,129,336		$2,878,150	$967,252	$59,940	$14,225	$200,817	$8,952
Maintenance Expense -- Distribution												
	885	Maintenance Supr and Engr	-									
	886	Maintenance Structures	9		$17,911		$10,520	$4,675	$296	$130	$2,197	$93
	887	Maintenance Mains	45		$3,615,007		$2,257,564	$1,068,519	$83,358	$22,507	$179,640	$3,420
	888	Maintenance Comp. Station Equip.	-									
	889	Maintenance Meas and Reg. General	9		$62,064		$36,454	$16,201	$1,025	$451	$7,612	$322
	890	Maintenance Meas and Reg - Industrial	15		$145,376		$120,053	$24,097	$963	$135	$128	$0
	891	Maintenance Meas and Reg.-City Gate	9		$177,909		$104,496	$46,440	$2,937	$1,294	$21,820	$922
	892	Maintenance Services	14		$507,170		$426,451	$79,211	$737	$219	$540	$12
	893	Maintenance Meters and House Reg.	-									
	894	Maintenance Other Equipment	35		$166,265		$118,555	$39,376	$2,380	$643	$5,199	$113
		Total Maintenance Labor			$4,691,701		$3,074,092	$1,278,519	$91,696	$25,379	$217,135	$4,881
		Total Transmission & Distribution Labor			$8,821,037		$5,952,242	$2,245,771	$151,635	$39,604	$417,952	$13,833
Customer Accounts Expense												
	901	Supervision	17		$555,288		$465,961	$82,434	$688	$45	$6,080	$80
	902	Meter Reading	17		$190,502		$159,857	$28,281	$236	$15	$2,086	$27
	903	Customer Records and Collections	17		$2,040,683		$1,712,406	$302,947	$2,528	$165	$22,344	$294
	904	Uncollectible Accounts	-									
	905	Misc. Cust Account Expenses	17		$130,637		$109,622	$19,394	$162	$11	$1,430	$19
Total Customer Accounts Labor					$2,917,110		$2,447,845	$433,055	$3,614	$235	$31,940	$420
Customer Service Expenses												
907-910		Customer Service	18		$266,898		$223,963	$39,622	$331	$22	$2,922	$38
Sales Expenses												
911-916		Sales Expenses	-									
Administrative & General												
	920	Admin and General Salaries	39		$2,993,016		$2,097,487	$724,987	$45,431	$8,628	$112,251	$4,231
	921	Office Supplies and Expense	39		$7,050		$4,941	$1,708	$107	$20	$264	$10
	922	Admin. Expenses Transferred	39		($236,354)		($165,636)	($57,251)	($3,588)	($681)	($8,864)	($334)

Louisville Gas & Electric
Gas Cost of Service Study
(Labor)

Acct. No.	Account Description	Allocator	Alloc	TOTAL SYSTEM	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
923	Outside Services Employed	-									
924	Property Insurance	-									
925	Injuries and Damages	39		$6,587		$4,616	$1,596	$100	$19	$247	$9
926	Employee Pensions and Benefits	39		$6		$4	$2	$0	$0	$0	$0
927	Franchise Requirement	-									
928	Regulatory Commission Fee	-									
929	Duplicate Charges -Credit	-									
930.1	General Advertising Expense	-									
930.2	Misc. General Expense	-									
931	Rents	-									
935	Maintenance of General Plant	34		$1,328,128		$939,433	$327,928	$20,261	$4,373	$35,369	$765
	Total Administrative and General Labor			**$4,098,434**		**$2,880,846**	**$998,969**	**$62,311**	**$12,359**	**$139,267**	**$4,682**
	Total Labor Expense			**$19,437,979**		**$13,630,705**	**$4,714,607**	**$295,150**	**$56,579**	**$714,569**	**$26,369**

Louisville Gas and Electric
Gas Cost of Service Study
(Allocation Amount)

Acct.	No.	Account Description	Allocator	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	1	Procurement Expenses	COM01		38,180,054	17,455,191	8,840,212	841,764	343,961	10,079,083	619,843
	2	Storage	COM02		18,974,756	12,577,844	5,929,064	467,848	0	0	0
	3	Transmission	COM03		18,974,756	12,577,844	5,929,064	467,848	0	0	0
	4	Distribution	COM04		38,180,054	17,455,191	8,840,212	841,764	343,961	10,079,083	619,843
	5	Low Pressure Customer ThroughPut			28,790,634	17,455,191	8,828,700	824,035	206,193	1,476,514	0
	6	Procurement Expenses	DEM01		514,838	302,393	134,390	8,499	3,745	63,143	2,668
	7	Storage	DEM02		12,229,953	8,249,244	3,728,072	252,637	0	0	0
	8	Transmission	DEM03		12,229,953	8,249,244	3,728,072	252,637	0	0	0
	9	Distribution Structures	DEM04		514,838	302,393	134,390	8,499	3,745	63,143	2,668
	10	High Pressure Distribution Mains	DEM05		514,838	302,393	134,390	8,499	3,745	63,143	2,668
	11	Low/Medium Pressure Distribution Mains	DEM05a		456,423	302,393	134,215	8,320	2,245	9,250	0
	12	High Pressure Distrib Mains (yr-end cust.)	CUST01		318,272	292,094	25,873	214	14	76	1
	13	Low/Med Pres. Distrib Mains (yr-end cust.)	CUST01a		318,210	292,094	25,872	211	3	30	0
	14	Services	CUST02		207,276,808	174,287,460	32,373,114	301,380	89,336	220,543	4,975
	15	Meters	CUST03		79,575,508	65,714,058	13,189,924	527,336	73,932	70,258	0
	16	Customer Count (Average)			317,295	291,228	25,761	215	14	76	1
	17	Customer Accounts	CUST04		347,058	291,228	51,522	430	28	3,800	50
	18	Customer Service	CUST05		347,058	291,228	51,522	430	28	3,800	50
	19	High Pressure Peak & Avg			100.0000%	52.2268%	24.6287%	1.9278%	0.8142%	19.3317%	1.0708%
	20	Low/Med Pressure Peak & Avg			100.0000%	63.4404%	30.0355%	2.3425%	0.6040%	3.5775%	0.0000%
	21										
	22										
	23										
	24										
	25										
	26										
	27										
	28	Actual Revenue	REV01		270,632,419	182,088,844	75,070,341	5,901,190	2,058,005	5,314,051	199,988
	29	Actual Net Revenue	REVUC		127,893,686	91,874,358	29,155,957	1,695,570	227,502	4,776,105	164,194
	30	DSM Allocation	REVADJ4		3,968,881	3,868,118	92,275	0	1,588	6,900	0
	31	Miscellaneous Revenue Allocation	REVMISC		332,763	95,489	237,274				
	32										
	33	GSC Revenue	REVGSC		142,738,734	90,214,487	45,914,384	4,205,620	1,830,503	537,946	35,794
	34	PTD Plant			699,290,316	494,632,971	172,661,885	10,667,697	2,302,360	18,622,396	403,007
	35	Dist Plant			595,582,168	424,680,632	141,048,399	8,525,374	2,302,360	18,622,396	403,007
	36	Mains + Services			502,516,623	354,320,198	122,438,567	7,543,043	2,043,814	15,868,219	302,782
	37	Depreciation Reserve			270,116,841	188,916,735	68,496,213	4,315,857	904,142	7,328,645	155,249
	38	O&M Expense			63,849,391	45,165,766	15,423,878	946,298	175,145	2,069,748	68,555
	39	Labor Excl. A&G			15,339,545	10,749,859	3,715,638	232,839	44,220	575,302	21,687
	40	Total Plant + CWIP			854,044,597	602,123,242	212,329,669	13,232,172	2,847,356	23,016,740	495,418
	41	Total Labor			19,437,979	13,630,705	4,714,607	295,150	56,579	714,569	26,369
	42	Depreciation Expenses			23,851,373	17,392,543	5,527,755	311,521	67,368	540,162	12,023
	43	Rate Base	RBT		510,347,495	360,167,319	127,586,574	7,970,883	1,571,303	12,770,554	280,863
	44	Year-End Customer Adjustment	REVADJ2		387,739	$261,960	$134,196	($8,417)	$0	$0	$0
	45	Mains	Mains		315,318,357	196,915,659	93,201,380	7,270,857	1,963,132	15,669,040	298,289
	46										
	47	DSM Revenue			(3,968,881)	($3,868,118)	($92,275)	$0	($1,588)	($6,900)	
	48	Labor Accts 815-826			1,261,537	840,795	391,203	29,539	0	0	0
	49	Labor Accts 831-837			918,484	611,756	285,084	21,644	0	0	0
	50	Distribution Depr Reserve Basis			163,053,641	114,722,498	39,655,072	2,454,038	670,527	5,436,689	114,817
	51				0						
	52				0						
	53				0						

Louisville Gas and Electric
Gas Cost of Service Study
(Allocation Amount)

Acct.	No.	Account Description	Allocator	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	54				0						
	55				0						
	56				0						
	57				0						
	58				0						
	59				0						
	60				0						
	61				0						
	62				0						
	63				0						
	64				0						
	65										
	66										
	67	Memo: Develop Peak & Avg.									
	68										
	69	High Pressure:									
	70	Peak			100.0000%	58.7356%	26.1034%	1.6508%	0.7274%	12.2646%	0.5182%
	71	Avg			100.0000%	45.7181%	23.1540%	2.2047%	0.9009%	26.3988%	1.6235%
		Peak & Avg.			100.0000%	52.2268%	24.6287%	1.9278%	0.8142%	19.3317%	1.0708%
		Low/Med Pressure									
		Peak			100.0000%	66.2528%	29.4058%	1.8229%	0.4919%	2.0266%	0.0000%
		Avg			100.0000%	60.6280%	30.6652%	2.8622%	0.7162%	5.1285%	0.0000%
		Peak & Avg.			100.0000%	63.4404%	30.0355%	2.3425%	0.6040%	3.5775%	0.0000%

Louisville Gas and Electric
Gas Cost of Service Study
(Allocation Amount)

Acct. No.	Account Description	Allocator	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses	COM01		100.0000%	45.7181%	23.1540%	2.2047%	0.9009%	26.3988%	1.6235%
2	Storage	COM02		100.0000%	66.2873%	31.2471%	2.4656%	0.0000%	0.0000%	0.0000%
3	Transmission	COM03		100.0000%	66.2873%	31.2471%	2.4656%	0.0000%	0.0000%	0.0000%
4	Distribution	COM04		100.0000%	45.7181%	23.1540%	2.2047%	0.9009%	26.3988%	1.6235%
5	Low Pressure Customer ThroughPut		0	100.0000%	60.6280%	30.6652%	2.8622%	0.7162%	5.1285%	0.0000%
6	Procurement Expenses	DEM01		100.0000%	58.7356%	26.1034%	1.6508%	0.7274%	12.2646%	0.5182%
7	Storage	DEM02		100.0000%	67.4512%	30.4831%	2.0657%	0.0000%	0.0000%	0.0000%
8	Transmission	DEM03		100.0000%	67.4512%	30.4831%	2.0657%	0.0000%	0.0000%	0.0000%
9	Distribution Structures	DEM04		100.0000%	58.7356%	26.1034%	1.6508%	0.7274%	12.2646%	0.5182%
10	High Pressure Distribution Mains	DEM05		100.0000%	58.7356%	26.1034%	1.6508%	0.7274%	12.2646%	0.5182%
11	Low/Medium Pressure Distribution Mains	DEM05a		100.0000%	66.2528%	29.4058%	1.8229%	0.4919%	2.0266%	0.0000%
12	High Pressure Distrib Mains (yr-end cust.)	CUST01		100.0000%	91.7750%	8.1292%	0.0672%	0.0044%	0.0239%	0.0003%
13	Low/Med Pres. Distrib Mains (yr-end cust.)	CUST01a		100.0000%	91.7928%	8.1305%	0.0663%	0.0009%	0.0094%	0.0000%
14	Services	CUST02		100.0000%	84.0844%	15.6183%	0.1454%	0.0431%	0.1064%	0.0024%
15	Meters	CUST03		100.0000%	82.5808%	16.5754%	0.6627%	0.0929%	0.0883%	0.0000%
16	Customer Count (Average)		0	100.0000%	91.7846%	8.1189%	0.0678%	0.0044%	0.0240%	0.0003%
17	Customer Accounts	CUST04		100.0000%	83.9134%	14.8454%	0.1239%	0.0081%	1.0949%	0.0144%
18	Customer Service	CUST05		100.0000%	83.9134%	14.8454%	0.1239%	0.0081%	1.0949%	0.0144%
19	High Pressure Peak & Avg		0	100.0000%	52.2268%	24.6287%	1.9278%	0.8142%	19.3317%	1.0708%
20	Low/Med Pressure Peak & Avg		0	100.0000%	63.4404%	30.0355%	2.3425%	0.6040%	3.5775%	0.0000%
21										
22										
23										
24										
25										
26										
27										
28	Actual Revenue	REV01		100.0000%	67.2827%	27.7389%	2.1805%	0.7604%	1.9636%	0.0739%
29	Actual Net Revenue	REVUC		100.0000%	71.8365%	22.7970%	1.3258%	0.1779%	3.7344%	0.1284%
30	DSM Allocation	REVADJ4		100.0000%	97.4612%	2.3250%	0.0000%	0.0400%	0.1739%	0.0000%
31	Miscellaneous Revenue Allocation	REVMISC		100.0000%	28.6958%	71.3042%	0.0000%	0.0000%	0.0000%	0.0000%
32										
33	GSC Revenue	REVGSC		100.0000%	63.2025%	32.1667%	2.9464%	1.2824%	0.3769%	0.0251%
34	PTD Plant		0	100.0000%	70.7336%	24.6910%	1.5255%	0.3292%	2.6630%	0.0576%
35	Dist Plant		0	100.0000%	71.3051%	23.6824%	1.4314%	0.3866%	3.1268%	0.0677%
36	Mains + Services		0	100.0000%	70.5091%	24.3651%	1.5011%	0.4067%	3.1578%	0.0603%
37	Depreciation Reserve		0	100.0000%	69.9389%	25.3580%	1.5978%	0.3347%	2.7131%	0.0575%
38	O&M Expense		0	100.0000%	70.7380%	24.1567%	1.4821%	0.2743%	3.2416%	0.1074%
39	Labor Excl. A&G		0	100.0000%	70.0794%	24.2226%	1.5179%	0.2883%	3.7504%	0.1414%
40	Total Plant + CWIP		0	100.0000%	70.5026%	24.8617%	1.5494%	0.3334%	2.6950%	0.0580%
41	Total Labor		0	100.0000%	70.1241%	24.2546%	1.5184%	0.2911%	3.6761%	0.1357%
42	Depreciation Expenses		0	100.0000%	72.9205%	23.1758%	1.3061%	0.2824%	2.2647%	0.0504%
43	Rate Base	RBT		100.0000%	70.5730%	24.9999%	1.5619%	0.3079%	2.5023%	0.0550%
44	Year-End Customer Adjustment	REVADJ2		100.0000%	67.5609%	34.6099%	-2.1708%	0.0000%	0.0000%	0.0000%
45	Mains	Mains		100.0000%	62.4498%	29.5579%	2.3059%	0.6226%	4.9693%	0.0946%
46										
47	DSM Revenue		0	100.0000%	97.4612%	2.3250%	-0.0000%	0.0400%	0.1739%	-0.0000%
48	Labor Accts 815-826		0	100.0000%	66.6484%	31.0100%	2.3415%	0.0000%	0.0000%	0.0000%
49	Labor Accts 831-837		0	100.0000%	66.6049%	31.0386%	2.3565%	0.0000%	0.0000%	0.0000%
50	Distribution Depr Reserve Basis		0	100.0000%	70.3587%	24.3203%	1.5050%	0.4112%	3.3343%	0.0704%

Schedule GAW-7

LOUISVILLE GAS & ELECTRIC
Competitive Fixed Charges For Electric Residential Rates In Texas

COMPANY		MONTHLY CHARGE	
No Waiver of Customer Charge:			
1 Andeler		$3.95	
2 APG&E		$8.95	
3 CPL Retail		$4.97	
4 Direct Energy		$5.00	
5 Gexa		$4.79	
6 Smartcom	< 500 kwh	$12.95	
Smartcom	> 500 kwh	$9.95	
7 TriEagle		$4.95	
Customer Charge Waived w/Minimum Usage:			
8 4Change		$9.95	1/
9 Ambit Texas		$9.98	1/
10 Amigo - Plan 1		$9.95	1/
Amigo - Plan 2		$6.95	4/
11 APNA - Plan 1		$9.95	1/
APNA - Plan 2		$12.95	1/
12 Bounce		$6.95	1/
13 Brilliant		$10.99	1/
14 Cirro		$5.75	1/
15 Dynowatt		$6.95	1/
16 Infinite		$18.55	1/
17 Just Energy - Plan 1		$9.95	1/
Just Energy - Plan 2		$14.95	2/
18 Pennywise		$9.95	1/
19 Potentia		$9.99	1/
20 Southwest Power		$7.95	1/
21 Spark		$8.99	1/
22 Star		$4.99	3/
23 Stream	< 699 kwh	$9.95	1/
Stream	700-999 kwh	$4.95	1/
24 Tara		$6.95	4/
25 Texpo		$7.95	1/
26 TRUE		$9.95	1/
27 Veteran		$5.00	1/
28 YEP		$7.95	1/
AVERAGE: CUST. CHARGE WAIVED W/ MINIMUM USAGE		**$9.14**	
AVERAGE: NO WAIVER TO CUST. CHARGE W/ MINIMUM USAGE		**$6.94**	

1/ Waived if usage is at least 1,000 kwh.
2/ Waived if usage is at least 2,000 kwh.
3/ Waived if usage is at least 500 kwh.
4/ Waived if usage is at least 800 kwh.

Louisville Gas & Electric
Residential Electric Customer Costs

	Residential Amount	
Rate Base:		
Gross Plant		
Services	23,403,452	
Meters	26,683,502	
Total	50,086,954	
Depreciation Reserve		
Services	17,266,223	1/
Meters	14,184,447	1/
Total	31,450,671	
Net Rate Base	18,636,284	
Operation & Maintenance Expenses		
Meter Operations	4,348,074	
Meter Maint.	0	
Meter Reading	1,614,704	
Records & Collections	3,984,147	
Misc. Customer Accts.	330,100	
Total	10,277,026	
Depreciation Expense		
Services	826,142	2/
Meters	779,158	2/
Total	1,605,300	
Revenue Requirement:		
Interest	355,021	
Equity Return	792,042	
Income Tax @ effective rate	470,068	
Revenue for Return	1,617,131	
Total Customer Revenue Requirement	13,499,457	
Number of Bills	4,173,228	
Monthly Cost	**$3.23**	

	Pct	Cost	Weighted Cost
Debt	50.00%	0.0381	1.91%
Equity	50.00%	8.50%	4.25%
Total	100.00%		6.16%

Effective Tax Rate

Tax	Taxable Income	
$51,825,304	$139,148,414	37.24%

1/ Calculated Per Company Response toOAG 1-316.
2/ Calculated Per Mr. Spanos Depreciation rates Exhibit JJS-LGE, Part III.

Louisville Gas & Electric
Residential Gas Customer Charge

		Residential Amount	
Rate Base:			
Gross Plant			
Services		157,404,538	
Meters		32,895,014	
House Regulators		19,113,408	
	Total	209,412,961	
Depreciation Reserve			
Services		60,126,561	1/
Meters		6,572,440	1/
House Regulators		597,350	1/
	Total	67,296,350	
Net Rate Base		142,116,611	
Operation & Maintenance Expenses			
Meter & House Regulators Expense		593,164	
Customer Installations		401,011	
Maint. Services		888,111	
Maint. Meters & House Regulators		0	
Meter Reading		1,484,273	
Cust. Records & Collections		3,662,115	
Misc. Cust Accounts		268,727	
	Total	7,297,401	
Depreciation Expense			
Services		5,965,632	2/
Meters		1,325,669	2/
House Regulators		783,650	2/
	Total	8,074,951	
Revenue Requirement			
Interest		2,707,321	
Equity Return		6,039,956	
Income Tax @ effective rate		4,204,129	
	Revenue for Return	12,951,407	
Total Customer Revenue Requirement		28,323,759	
Number of Bills		3,494,736	
Monthly Cost		**$8.10**	

	Pct	Cost	Weighted Cost
LT- Debt	50.00%	3.81%	1.91%
Equity	50.00%	8.50%	4.25%
Total	100.00%		6.16%

Effective Tax Rate

Tax	Taxable Income	
$14,475,575	$35,272,232	41.04%

1/ Calculated Per Company Response to OAG 1-340
2/ Calculated Per Mr. Spanos Depreciation rates Exhibit JJS-LGE, Part III.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	)	CASE No. 2012-00222

AFFIDAVIT OF GLENN A. WATKINS

Commonwealth of Virginia)

Glenn A. Watkins, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix 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 A. Watkins

SUBSCRIBED AND SWORN to before me this ____ day of ____________, 2012.

NOTARY PUBLIC

My Commission Expires: 10-31-14

JENNIFER R. DOLEN
COMMONWEALTH OF VIRGINIA
Expires 10-31-14
ID# 7315146
NOTARY PUBLIC