COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	**CASE NO. 2003-00433**
AND	)	
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)	**CASE NO. 2003-00434**

DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2004

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than twenty-nine years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. **Would you please discuss your experience in electric utility restructuring proceedings?**

A. I have been extensively involved in electric utility restructuring since 1995. This involvement includes participation in eight proceedings in Pennsylvania, seven of which involved detailed implementation analyses associated with restructuring. In these cases, I addressed stranded costs, regulatory policy associated with retail competition and restructuring implementation, and rate unbundling. The utilities included PECO Energy, Pennsylvania Power & Light Company, West Penn Power Company, Metropolitan Edison Company, Pennsylvania Electric Company and Duquesne Light Company.

I have also been involved in restructuring proceedings in the State of Maryland associated with Baltimore Gas & Electric Company and Potomac Edison Company. In addition, I participated in a generic proceeding before the Maryland Public Service Commission on electric utility restructuring and have testified before the Maryland Legislature on this issue.

In 1999, I was involved in restructuring proceedings in West Virginia associated with the Appalachian Power subsidiary of AEP and Monongahela Power Company, a subsidiary of Allegheny Power Company. I also participated in restructuring proceedings in Connecticut involving United Illuminating Company and Connecticut Light and Power Company. In 2000, I participated in electric restructuring proceedings in Ohio involving First Energy Corporation and Cinergy.

In Louisiana, I have been involved in the Entergy Gulf States, Inc. ("EGSI") stranded cost proceeding and in the Commission's generic proceeding on retail competition. I have addressed issues on stranded cost quantification, standard offer tariffs, load profiling and other issues.

To date, I have presented testimony in 13 electric restructuring proceedings.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers ("KIUC"), a group of large industrial customers taking service on the LG&E and KU systems.

Q. How have you organized your testimony with regard to LG&E and KU issues?

A. For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic principles associated with cost allocation and rate design as well as a number of other issues, including interruptible and curtailable rates. However, since the revenue requirement requests and the specific cost of service study results for LG&E and KU rate classes are different, I will be presenting separate analyses and discussions of these results.

For the purposes of organizing my testimony, when I am discussing an issue that is common to both LG&E and KU, I will refer to these companies as ("the Company" or the "Companies"). For a specific LG&E and KU issues I will refer to each Company by name (LG&E or KU).

Q. What is the purpose of your testimony?

A. I am presenting testimony on a variety of cost of service and rate design issues raised by the Company's filings in this case. The first issue that I address concerns the Company's filed cost of service study using the base-intermediate-peak ("BIP") class cost of service methodology. I will discuss some specific corrections that I have made to the Company's study due to data anomalies that were uncovered in our analysis (in the case of the KU study), as well as three corrections to the methodology itself (LG&E and KU). In addition, I will discuss some general concerns that KIUC has with the BIP method from a methodological standpoint. However, in order to facilitate the principle recommendation that KIUC is making with regard to rate class revenue allocation in this case, KIUC will accept the BIP method as the basis for our revenue apportionment recommendation to rate classes.

In order to develop an understanding of the subsidies that are currently being paid and received by various rate classes on the Company's two systems, I also present a number of alternative cost of service studies based on: 1) the average and excess method, 2) the summer/winter coincident peak method, 2) the summer coincident peak method and 4) the 12 CP method. The purpose of these presentations is to show that under a variety of cost of service studies, the Company's current rate design and its revenue apportionment proposal does not adequately address the subsidies currently in the Company's rates. As I will show, under each of these alternative cost of service studies, <u>the residential class is substantially underpaying its costs</u> while large commercial and industrial customers are substantially over paying for electric service. Regulatory commissions are sometimes reluctant to rely on a single cost of service study to form a strict revenue apportionment policy. However, in this case, I will show that under a number of cost of service methodologies that are commonly used in the electric utility industry, residential customers are substantially underpaying for electric service and large consumers are substantially overpaying.

My testimony specifically addresses the revenue allocation or apportionment methodology relied upon by the Company in this case to establish the increases for each rate schedule. Though the Company apparently considers the cost of service results from the BIP method, it has arbitrarily decided that the residential class should not receive an increase greater than 1% above the system average. This criterion does not adequately mitigate the significant disparities between rates and cost of service among the rate classes for either KU or LG&E. I will recommend an alternative methodology that should be adopted that would specifically reduce the subsidies by 25% through the allocation of any increase approved by the Commission. In this manner, the revenue apportionment will move class rates of return under the BIP method towards cost of service, although at a relatively slow pace.

The next set of issues that I will address concerns the Company's proposed rate design for large commercial and industrial customers. KIUC generally accepts the Company's rate design proposals and recommends that the basic structure proposed by each of the Companies be adopted. The Company has reduced energy charges and applied increases in this case to the demand charges of these large customer rates.

Following this general policy, KIUC is recommending that any reduction in the allocated increase to each of these large rate schedules be applied only to the demand charges, leaving the energy charge as proposed by the Company. I will also address the proposed new riders being offered by the Company in each of its jurisdictions that would be applicable to large commercial and industrial customers. For the most part, these new riders do not have a material current impact on customers in this case, but could do so in the future. My testimony on these issues does not recommend rejecting the riders, but rather a clarification of the Company's intention, where applicable, not to apply the riders to existing customer arrangements.

The next issue that I address concerns the Company's proposal to modify its interruptible rates under the curtailable service rider ("CSR"). The Company is proposing to substantially modify its interruptible and curtailable rates by increasing the maximum number of hours of interruption to 500 hours per year and reducing substantially (in the case of KU) the notice period required for interruption requests. The Company is proposing to increase the interruptible credit for both LG&E and KU. I will address each of these issues as well as some additional modifications to each Company's CSR tariff. In particular, my analysis of the Company's responses to KIUC data requests indicates that the maximum annual hours of interruption should be substantially less than the Company's proposed 500-hour annual maximum. I will also discuss a KIUC proposal to offer a buy-through option that would permit interruptible customers to purchase power at market rates in the event of a call for interruption, when such interruption is for the purpose of economic savings to each of the Companies, rather than for reliability.

The final issue that I will address concerns the special contract between MeadWestvaco and Kentucky Utilities Company. KU's cost of service study, and all of the cost-of-service studies that I developed consistently show that the KU special contract customer class is being substantially overcharged. Despite this, KU proposes a rate increase to MeadWestvaco that exceeds both the system average increase and the increase for Rate Schedule LCI-TOD, the otherwise most nearly applicable tariff. KU's proposal is based on an incomplete and flawed analysis which ignores the contractual consideration provided by the customer and which would effectively negate the value of the Commission approved contract. Therefore, each special contract in the rate class should receive a below average increase based on my 25% subsidy reduction proposal. This increase approximates the increase I have proposed for LCI-TOD.

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- The BIP cost of service method, though lacking in some respects is adequate to use in the determination of a fair apportionment of any authorized rate increase for LG&E and KU. However, certain corrections should be made to the studies submitted by LG&E and KU.

- Based on the BIP cost of service study, as well as four alternative studies, substantial subsidies are being paid by other rate classes to the residential class, for both LG&E and KU. Regardless of the cost study methodology, these substantial subsidies are present in each Company's rates.

- LG&E's and KU's proposed revenue apportionment method does not adequately address the subsidy problem. KIUC is recommending that the Commission adopt a revenue apportionment method that would explicitly reduce the amount of current dollar subsidies paid and received by 25% in this case.

- KIUC generally supports the Company's proposed large commercial and industrial rate design. Any changes in the allocated revenue increase to LG&E's and KU's large commercial and industrial power rates should be applied to the demand charges proposed by the Companies. Thus for example, if the Commission reduces the targeted revenue requirement assignment to KU's rate LCI-TOD by $1 million, this decrease from the amount of increase proposed by KU should be used to proportionately decrease the proposed LCI-TOD demand charges.

- LG&E's and KU's proposed curtailable service rider ("CSR") should be modified by : 1) reducing the annual maximum hours of interruption to 175 hours, 2) increasing the required notice period to 1 hour, 3) adjusting the interruptible credit to reflect fuel savings benefits provided by interruptible load during actual interruptions and 4) implementing a buy-through option that would permit CSR customers to continue operating during economic interruptions if they elect to purchase replacement energy at market prices.

- Each of the cost of service studies that I developed, as well as the Company's study, consistently show that the KU special contract class is paying well in excess of cost. KU's attempt to unilaterally renegotiate the MeadWestvaco contract in this case by negating the economic value of the contract should be rejected. Therefore, each customer in that class should receive the same percentage increase based upon my 25% subsidy reduction proposal.

II. COST OF SERVICE STUDY ISSUES

Q. Have you reviewed the Company's proposed "base-intermediate-peak" cost allocation methodology?

A. Yes. The BIP method is the class cost allocation method used by LG&E in prior cases and is being proposed for use by KU for the first time in this proceeding. Though the Commission has accepted the BIP method in past LG&E proceedings, the Commission has not accepted the method for KU in prior cases.

The basic methodology, as discussed by Company witness Steven Seelye, first functionalizes the Company's production and transmission demand-related costs into three periods. Under the Company's BIP functionalization, which is used in both the LG&E and KU studies, total system production and transmission demand-related costs are assigned as follows:

	Assignment of Total P&T Costs
Base	**33.58%**
Intermediate	**39.97%**
Peak	**26.45%**

These functional allocators for the base, intermediate and peak periods are identical for both LG&E and KU under the Company's methodology. Once the total production and transmission demand-related costs have been functionalized to these three categories, they are allocated to rate classes using three different class allocation factors. For the 33.58% of production and transmission demand-related costs that are assigned to the base period, costs are allocated using class energy use. For the intermediate period costs that comprise 39.97% of all production and transmission demand-related costs, costs are allocated to classes based on class contribution to the winter system peak demand. Finally, for peak period costs that comprise 26.45% of the Company's total production and transmission demand-related costs under the BIP method, costs are assigned based on each customer classes' contribution to the summer coincident peak.

Under the BIP method, 33.6% of the costs are assigned based on class energy and 40% of the costs are assigned on the basis of contribution to winter peak. Only 26% of the total production and transmission demand-related costs for either of the two operating companies are assigned based on customer class contributions to the summer peak.

This is somewhat ironic, since it is the summer peak that drives the Company's planning requirements to acquire new generating capacity. In fact, based on the Company's 2001 integrated resource planning document, the summer peak for the combined Company is expected to exceed the winter peak by about 1000 mWs for each of the years through 2016. Placing this into perspective, the Company needs an additional 1000 mWs of generating capacity to meet the summer peak, relative to the requirements associated with the winter peak. Despite this fact, the Company has allocated 40% of its costs based on customer class contributions to the winter peak while allocating only 26% based on class contributions to the summer peak.

Q. Has the Company provided any information that suggests that its proposed BIP methodology is not consistent with the way the Company actually plans its production facilities?

A. Yes. In response to supplemental data request 14 of KIUC, the Company discussed an alternative cost of service methodology that it considered, but did not use in this case. This methodology, entitled "Unserved Load Methodology," is described by the Company as a method that reflects the allocation of costs on the basis of unserved load hours, based on production simulation model results. According to the response, the Company's analysis indicated that 71.43% of the unserved load hours occurred during the summer peak period while 28.57% of the unserved load hours occurred during the winter peak period. Under the unserved load methodology, 71.43% of the Company's production costs would be assigned based on summer peak contributions, while 28.57% would be assigned on winter peak period contributions. This is in contrast to the Company's BIP method that assigns 40% of the costs based on the winter peak and only 26% on the summer peak. In its response to KIUC No. 14, the Company contrasts the two cost of service methods as follows:

> **While the unserved load methodology offers a good representation of how the Company's production facilities are planned, the BIP methodology offers a good representation of how the production system is utilized.**

The Company goes on to state in its response that it selected the BIP method because it had previously been accepted by the Commission.

Q. In its response (referenced above), the Company has identified two alternative characteristics of cost allocation methods. One of these characteristics is an allocation based on planning criteria, the other is based on a utilization criteria. Do you have any comments on these two characteristics associated with cost allocation methods?

A. I generally agree with the Company's characterization of the two methodologies. The BIP method assigns substantial cost responsibility to customer behavior at the time of the winter peak, even though from a planning perspective, the Company appears to agree that the summer peak is driving its costs. From an economic efficiency standpoint, it would not appear to be particularly rational for rates to be set based on class behavior at the time of the winter peak, when the Company is incurring costs because of customer demand at the time of the summer peak. Under the Company's BIP methodology, even if a customer used no electricity during any peak hour during the summer period, the customer or customer class would be assigned almost 74% of the costs that a similar customer would be assigned who used energy during the summer peak, as well as during the winter and off-peak periods. This would not seem to be an efficient cost allocation method and one that would provide consumers with reasonable price signals related to the costs of providing service.

The Company has characterized the BIP method as a method that provides a good representation of "how the production system is utilized." Without agreeing or disagreeing with this characterization, I would note that allocating costs based on how the system is utilized is closer to a value of service method for assigning costs as compared to a cost of service method, which should reflect how costs are actually being incurred to serve customers.

Q. Are there any indications in the Company's rate design that the summer peak is a more significant factor affecting the Company's costs than the winter peak?

A. Yes. LG&E's Rate LP-TOD is a good illustration. Under the Company's proposed rate design, the peak period demand charge for the summer months is $9.65 per kW, while the corresponding peak period demand charge for the winter months is $7.11 per kW. This rate design reflects a rational response to the incurrence of costs on the Company's system. Further, it also reflects the fact that market prices during the summer months in the LG&E/KU region are much higher than in the winter and other months of the year. The Company is signaling its customers that summer peak demands for Rate Schedule LP-TOD customers are 36% more costly than winter peak demands while the Company's cost allocation methodology <u>implies the reverse</u>. The BIP method weights contributions to the winter peak significantly more than contributions to the summer peak.

Q. What is your recommendation with regard to the use of the Company's BIP methodology to allocate costs to rate classes in this proceeding?

A. Though I do not agree with the underlying methodology associated with the BIP method, KIUC is willing to utilize this methodology in order to establish a proposal to apportion the Company's authorized revenue increase to rate classes. As I will discuss subsequently, under a variety of cost allocation methodologies, the results all indicate that certain rate classes are substantially underpaying relative to the cost to serve these classes (principally the residential class), while other rate classes are substantially overpaying rates, relative to the costs to actually provide service to these customers (large commercial and industrial customers). Under each of these alternative allocation methods, similar patterns are produced with respect to relative class rates of return. In each case, the residential class is shown to be receiving substantial subsidies that are paid by other customers, particularly large customers on the LG&E and KU systems.

Q. Before discussing the alternative cost of service studies that you have developed, would you please discuss the corrections that you indicated you have made to the Company's BIP method?

A. For both the LG&E and KU BIP class cost of service studies, I have made three methodological adjustments to the Company's analysis. These adjustments produce studies that more properly reflect the underlying assumptions relied upon by the Company's in these studies. In addition, I have made two data corrections that I found to be required in the KU BIP study.

Q. Would you please begin your discussion of the common adjustments that you have made to the LG&E and KU BIP cost of service studies?

A. The first adjustment that I made involves the removal of the ECR related rate base from each of the studies. As discussed by the Company in its testimony and data responses, the Company removed ECR related costs and revenues from each of the class cost of service studies, since these costs are being recovered in the ECR rider. With regard to the investment costs associated with the ECR rider, the Company adjusted its capitalization by removing the associated amounts that are being recovered through the ECR. However, the Company did not make any corresponding adjustments to the rate base of each of the Operating Companies. All of the ECR related investments continue to be included in the Company's rate base and only the capitalization, which affects the required rate of return at proposed rates, has been adjusted. Since these ECR rate base items are not uniform among the customer classes, it is appropriate to also remove these investments from rate base to produce a consistent cost of service study. These ECR rate base adjustments are based on the corresponding adjustments that the Company made to its capitalization.

The second adjustment that I made concerns the treatment of the curtailable service rider ("CSR") credit in the Company's cost of service study. The methodology used by the Company to reflect interruptible and curtailable credits paid to certain of its customers is to reduce the expenses associated with these credit payments for rate classes containing customers taking service under the CSR and then allocating this credit cost as a expense to all rate classes. This methodology, which I generally support, is consistent with the Company's underlying economic rational for setting the interruptible credit. The Company is using the avoided cost associated with a combustion turbine to set the CSR credit level. Since the CSR credits paid to customers are essentially payments for combustion turbine capacity, the Company reasonably treated this cost as an expense that is assignable to all customer classes. For cost of service purposes, the Company credits this expense to the customer classes actually providing the interruptible credits and allocates the total to all customer classes (including the aforementioned classes that provide the credits).

In this case, the Company is proposing to increase the CSR credit. However, the Company has not included the increased "expense" associated with this credit in its present rate cost of service study, although it has reflected this amount in the proposed rate analysis. A proper cost of service study would reflect a proformed level of CSR expenses and expense credits at the proposed CSR credit rate in the cost of service study at "present rates." This would provide a consistent basis to analyze the contribution of each customer class to the Company's overall rate of return. Under the Company's method, there is an unequal level of expenses in present and proposed rates that should be adjusted.

The final common adjustment made to both the LG&E and KU BIP cost of service studies is to change the methodology used to allocate the CSR related expenses to customer classes. The Company has used the total BIP allocator to assign the CSR credit expenses to customer classes. A more appropriate allocator for these peaking costs would be the summer coincident peak allocator since these costs are associated with combustion turbine capacity that is designed to meet the Company's peak demand needs during the summer period that drives the Company's capacity requirements.

Q. Would you please discuss the additional corrections that you made to the KU BIP cost of service study?

A. Based on a review of the KU BIP cost of service study and the accompanying workpapers, two data anomalies were discovered related to incorrect kW demands used to develop the allocation factors. The first problem occurs for the all electric schools and Rate 33 classes, wherein the summer and winter peak demands (used to allocate peak and intermediate costs) where inadvertently set to "zero" for these classes. It appears that this was an error in the spreadsheet. The second error concerns the failure to include any NCP kW demand for Rate Schedule HLFS secondary load. NCP demand is used to assign costs associated with secondary and primary distribution service. Though the Company did assign demand for HLFS primary customers, no HLFS secondary demand was assigned.

Q. Have you made these corrections to the Company's filed BIP class cost of service studies?

A. Yes. Baron Exhibit ____(SJB-2) contains the corrected KU BIP class cost of service study, while Baron Exhibit ____(SJB-7) contains the corrected LG&E BIP class cost of service study. Both of these studies reflect the aforementioned changes that I have just discussed. Though, in total, these changes do not have a significant impact on the cost of service study results, I believe they each represent a reasonable adjustment (and in the case of KU, a required correction) to the Company's studies.

Q. **Would you please describe the additional studies that you have developed to assess the contributions of each customer class to the Company's overall cost of service**

A. Yes. Baron Exhibits ____(SJB-3), ____(SJB-4). (SJB-5) and ____(SJB-6) contain the results of three alternative cost of service studies for KU. Each of these studies incorporates the corrections that I previously discussed with regard to the Company's BIP cost of service study.

The first alternate cost of service study utilizes a traditional average and excess demand method ("A&E"). The A&E methodology, which allocates production and transmission demand costs in this study is presented in Exhibit ___(SJB-3). This traditional cost of service method allocates demand related costs based on each class's contribution to average demands and the class contribution to excess demands, which is defined as the class peak mW in excess of the average demand mW for the class. The calculation of each class's allocation factor is two-fold.

First, production and transmission demand costs are assigned into two functional categories in a manner similar to the BIP method. The functional allocator used in the A&E method is the system load factor (about 60% for KU, 51% for LG&E). The costs that are allocated using class contribution to average demand is the amount equal to the system load factor (in percent) times the total production and transmission demand costs. The remaining amount of production and transmission demand related costs [(1 – load factor) times total demand costs] is allocated on each classes' relative excess demand. Excess demand is defined as the class non-coincident peak minus the class average demand.

Q. What is the rationale for the A&E methodology?

A. The A&E method recognizes that production and transmission demand costs are incurred for both an energy and a demand basis. However, unlike the BIP method, the energy share of costs is equal to the system load factor. For the remaining amount of costs, however, the allocation is based on each customer classes' excess demand. Though this excess demand is based on the class non-coincident peak, rather than the coincident peak, it is a measure of the relative load factor of the class compared to the system load factor. For a 100% load factor customer, for example, the excess demand would be zero and there would be no allocation of the excess component of costs. One of the reasons why the class non-coincident demand is used for the excess portion is that if the class coincident peak demand is used, the A&E method becomes identical to a single coincident peak method.

Q. Would you please discuss the remaining cost of service studies that you have developed for KU?

A. Baron Exhibit ____(SJB-4) contains the results of a summer/winter average coincident peak cost of service study, while Exhibit ___(SJB-5) contains the results of a single summer coincident peak study. Exhibit ____(SJB-6) contains the results of a 12 CP study. Each of these studies represents additional cost of service methodologies that have been used to allocate production and transmission demand costs. In fact, the summer winter average method is similar to the unserved load methodology that I referenced earlier in my testimony except that it is based on an equal weighting between the summer and winter peaks instead of the 73/27% weighting that the Company computed using the unserved load method.

Q. What do the studies show with regard to the rate of return paid by the residential class and the all-electric residential class?

A. As can be seen from each of the exhibits summarizing the studies evaluated, the residential and all electric residential classes pay substantially below the average system rate of return. Under each of these methods, the residential class barely covers its cost of service expenses and provides only a small portion of its share of KU's return. In fact, in a number of cases, the all-electric residential class produces a negative rate of return, while the residential class produces a negative rate of return under the summer CP method. Even under the Company's BIP method, which generally favors low load factor classes such as the residential class because of its use of an energy allocator for a substantial part of the costs, the Company's residential class is only paying a rate of return on investment of 0.84%, compared to the system average rate of return of 4.27%. This is in contrast to the rate of return paid by large commercial and industrial customers on Rate LCI-TOD. These customers are paying rates of return of between 8% and 10%, compared to the system average rate of return of 4.27%. The Company's coal mining rates are paying rates of return even higher than this level. Similar results are shown for the special contracts class that contains large industrial customer load.

Q. Is there an alternative way to present this cost of service information so that it could be used to assess the relative contribution of each customer class to the Company's overall costs?

A. Yes. Table 1 below shows a summary for the five cost of service studies of the relative class rates of return under present rates.

Table 1
Kentucky Utilities
Class Rate of Return Indices under Present Rates

		Corrected BIP	Average & Excess	Sum/Win CP	Summer CP	12 CP
Total System		1.000	1.000	1.000	1.000	1.000
Residential	Rate RS	0.196	0.119	0.175	(0.025)	0.220
All Electric Residential	Rate FERS	0.113	(0.083)	(0.058)	0.624	0.231
General Service	GS	1.454	0.960	1.361	0.983	1.099
Combined Light & Power	LP,HLF, M	2.120	2.568	2.323	1.878	1.985
Large Comm/Ind TOD	LCI-TOD	1.902	2.444	2.393	2.121	1.768
Coal Mining Power Primary	MPP	3.179	2.874	3.511	3.860	2.726
Coal Mining Power Transmission	MPT	2.848	3.153	3.196	3.612	2.596
Large Power Mine TOD Pri	LMPP	2.370	1.673	2.830	3.216	1.654
Large Power Mine TOD Trans	LMPT	2.405	2.292	2.605	2.999	2.509
Combination Off-Peak	CWH	(3.264)	(3.254)	(3.234)	(3.215)	(3.211)
All Elcetric School	AES	1.084	0.490	1.010	0.515	0.718
Electric Space Heating Rider	33	0.452	(0.021)	0.410	0.018	0.050
Street Lighting	St Lt	(0.128)	(0.190)	(0.122)	(0.004)	(0.052)
Decorative Street Lighting	Dec St Lt	0.769	0.733	0.778	0.854	0.823
Private Outdoor Lighting	PO Lt	2.143	1.932	2.260	3.078	2.726
Customer Outdoor Lighting	C O Lt	1.643	1.449	1.736	2.447	2.142
Special Contracts		2.060	2.810	1.941	1.347	3.719

This type of analysis is commonly referred to as a rate of return index presentation. For the total system, the rate of return index is 1.0. For the residential class, under the corrected BIP method, the rate of return index is 0.196. This means that residential customers are paying a rate of return at approximately 20% of the system average. This is in contrast to the rate of return index for the large commercial/industrial time-of-day class that has a rate of return index of 1.9. For this class, customers are paying a return on investment equal to 190% of the system average. A similar result occurs for the special contact class.

Q. What conclusions do you draw from these relative rate of return indices using a variety of cost of service methods?

A. Regardless of the cost of service method, residential and residential all electric customers are paying rates of return substantially below the system average rate of return. Under each method, residential customers are barely contributing any amount to the Company's overall return on investment. At the same time, large industrial customers under Rate Schedule LCI-TOD and special contracts are paying rates of return two or more times the system average rate of return at present rates. The fact that this result occurs under a variety of cost of service methodologies suggests that it is not simply the selection of a cost of service method that is producing these results, but rather it is a clear indicator that substantial subsidies exist in KU rate.

Q. Have you prepared similar analyses for LG&E?

A. Yes. Baron Exhibits ____(SJB-7), ____(SJB-8), ____(SJB-9), (SJB-10) and ____(SJB-11) contain cost of service study results for LG&E reflecting the same five study methodologies. The corrected BIP method that I previously discussed presented in Exhibit (SJB-7), while Exhibits (SJB-8) through (SJB-11) contain the LG&E A&E results, the summer/winter CP results, the summer CP results.

Q. Do the LG&E cost of service study results, under each of the five methods, lead to similar conclusions with regard to subsidies being paid to residential customers?

A. Yes. As can be seen, the rate of return for residential customers is in the range of 1.7% based on the corrected BIP method, compared to an overall system rate of return of 4.59%. For large customers on Rates LP and LP-TOD, the rate of return under the corrected BIP method is 5.82%, while under the four alternative methods the rate of return rises to between 7% and 9%.[1] Table 2 summarizes these class rates of return using the relative rate of return indices.

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[1] These reflect a combined rate of return for LP/LP-TOD rates.

Table 2
Louisville Gas & Electric Company
Class Rate of Return Indices under Present Rates

		Corrected BIP	Average & Excess	Sum/Win CP	Summer CP	12 CP
Total System		1.000	1.000	1.000	1.000	1.000
Residential	Rate R	0.368	0.367	0.255	0.312	0.509
Water Heating	Rate WH	(1.606)	(1.825)	(1.599)	(1.531)	(1.599)
General Service	Rate GS	2.095	1.558	1.875	1.341	1.630
Rate LC/LC-TOD		1.649	1.778	1.699	1.583	1.350
Rate LP/LP-TOD		1.269	1.529	1.761	2.051	1.274
Street Lighting	Rate PSL	0.705	0.634	0.916	1.508	1.246
Street Lighting	Rate SLE	0.103	(0.301)	0.802	9.501	3.024
Street Lighting	Rate OL	0.790	0.721	0.967	1.434	1.232
Street Lighting	Rate TLE	2.424	3.796	3.422	4.400	2.664
Special Contracts		1.344	1.451	1.758	1.708	1.452

As can be seen, the residential class is producing a relative rate of return of .368 which means that residential customers are paying a rate of return of about 37% of the system average rate of return. This is in contrast to large power customers who are paying a rate of return of approximately 130% of the system average under the BIP method and relative rates of return of 150% to 200% under the alternative methods. For special contracts, similar results are also shown. Again, for LG&E as in the case of KU, under a variety of cost of service methods, residential customers are receiving substantial subsidies from other customer classes.

Q. Has KU proposed increases for each of its customer classes to address the subsidy problem that you have just identified?

A. No. Table 3 shows the proposed increases requested by KU in this case. Based on the Company's overall increase request of $58.9 million, total revenues will increase by 8.7% or 14.2% on a non-fuel basis. For residential customers, the Company is proposing to increase rate revenues by 9% (.3% higher than the system average) or 13.7% on a non-fuel basis. Since the increase requested by the Company in this case is related to non-fuel costs, it is appropriate to look at the impact of the Company's increase on non-fuel rate revenues. On this basis, despite the fact that the residential class is not paying even close to cost of service at present rates, the Company is actually proposing a smaller increase to non-fuel rate revenues for residential customers than the system average increase. The final column of the table shows the rate of return index at proposed rates under the Company's revenue apportionment recommendation. As can be seen, the Company is proposing to move the residential class to a rate of return index of 0.493. This means that under the Company's proposed rates, residential customers will continue to pay a rate of return on allocated investment at about 44% of the system average rate of return.

Table 3

Kentucky Utilities
KU Proposed Increase

	KU Proposed Increase	Percent Increase on Total Rate Revenues	Percent Increase on Non-Fuel Rate Revenues	ROR Index at Proposed Rates (1)
Total System	58,911,660	8.7%	14.2%	1.000
Residential	10,917,610	9.0%	13.7%	0.439
All Electric Residential	13,171,979	10.0%	15.7%	0.391
General Service	5,663,282	8.6%	11.9%	1.262
Combined Light & Power	18,928,419	8.3%	14.4%	1.813
Large Comm/Ind TOD	6,910,666	8.2%	16.6%	1.702
Coal Mining Power Primary	405,257	8.5%	14.6%	2.529
Coal Mining Power Trans	319,850	8.5%	16.4%	2.333
Large Power Mine TOD Pri	165,746	8.5%	15.6%	2.012
Large Power Mine TOD Trans	347,607	8.5%	17.6%	1.995
Combination Off-Peak	96,148	23.2%	45.8%	(1.873)
All Electric School	-	0.0%	0.0%	0.684
Electric Space Heating Rider	129,034	19.3%	31.9%	1.046
Street Lighting	512,748	9.5%	10.8%	0.060
Decorative Street Lighting	76,631	9.5%	9.9%	0.666
Private Outdoor Lighting	517,636	8.2%	9.8%	1.639
Customer Outdoor Lighting	72,319	8.1%	9.8%	1.289
Special Contracts	676,728	4.7%	9.7%	1.525

(1) ROR index using Corrected BIP Cost of Service Study

Focusing on the large commercial/industrial time of day rate, the Company is proposing an increase in total rate revenues of 8.2% and 16.6% on non-fuel rate revenues, well above the system average increase of 14.2% on non-fuel rate revenues. As can be seen, the proposed rate of return index for these large customers is 1.7 (170% of system average). For special contract customers, the Company is proposing a lower overall revenue increase for the class, on both a total rate revenue and a non-fuel rate revenue basis. However, the rate of return index at proposed rates still continues to be 1.5 (150% of the system average). More importantly, as I will discuss, for one of the special contract customers, MeadWestvaco, the proposed non-fuel increase is 50% above the system average (22% compared to the system average increase of 14.2%).

Q. Is the Company proposing a similar revenue apportionment approach for LG&E?

A. Yes. Table 4 shows a similar analysis for the LG&E proposed increases. The Company is proposing an overall increase of 11.4% on total rate revenues and 15% on non-fuel revenues. For residential customers, with a test year relative rate at return of about half that of system average at present rates, customers will receive an increase of 12.3% on total revenues and 15.6% on non-fuel rate revenues, almost about the same as the system average. At proposed rates, the rate of return index for residential customers under the BIP method advocated by the Company is about 0.56. This means that these residential customers will contribute a rate of return on investment at about 56% of the level of the system average. Again, this can be

Table 4

Louisville Gas & Electric Company
Proposed Increase on Non-fuel Revenues
LG&E Proposed Increase

		LG&E Proposed Increase	Percent Increase on Total Rate Revenues	Percent Increase on Non-Fuel Rate Revenues	ROR Index at Proposed Rates (1)
Total System		64,260,364	11.4%	15.0%	1.000
Residential	Rate R	26,277,410	12.3%	15.6%	0.557
Water Heating	Rate WH	156,774	21.7%	30.1%	(0.770)
General Service	Rate GS	8,974,815	11.0%	13.7%	1.776
Rate LC/LC-TOD		13,708,637	10.6%	14.3%	1.449
Rate LP/LP-TOD		10,638,506	10.8%	15.9%	1.199
Street Lighting	Rate PSL	586,307	12.3%	14.0%	0.690
Street Lighting	Rate SLE	17,030	12.3%	18.4%	0.376
Street Lighting	Rate OL	726,051	12.3%	13.7%	0.739
Street Lighting	Rate TLE	56,796	10.4%	13.8%	2.015
Special Contracts		3,118,038	11.4%	14.9%	1.283

(1) ROR index using Corrected BIP Cost of Service Study

contrasted to the Company's proposal for Rate LP time-of-day customers who are receiving an increase on total rate revenues of 10.8% and non-fuel rate revenues of 15.9% (in excess of the system average). Again, the Company is proposing a rate of return index for these customers at proposed rates of about 1.2, which means that these customers will continue to pay a rate of return at a level of 120% of the Company's required rate of return. Similar results are shown for special contract customers.

Q. What overall conclusions have you drawn from your analysis of the Company's proposed increases in this case for both KU and LG&E?

A. Both LG&E and KU have failed to adequately address the subsidy problem in their recommended apportionment of the overall revenue increases in this case. Even under the BIP cost of service study methodology advocated by the Company as the basis to measure the relationship between rates and cost of service, there is no material mitigation n in the subsidy problem under the Companies' proposals.

Q. Have you developed an alternative methodology to apportion the Company's authorized revenue requirement increase in this case?

A. Yes. I am recommending a methodology that would specifically provide for mitigation of the subsidies under present rates paid and received by each rate class. The methodology that I recommend is a "25% subsidy reduction method," wherein the subsidies paid and received by each rate class at present rates are reduced by 25% in the apportionment of the authorized revenue requirement increase, if any.

Though the alternative cost of service methods that I have looked at (A&E, S/W average, and summer CP and 12 CP) generally produced more favorable results to large industrial and commercial customers, I am relying on the Company's BIP methodology as corrected, to apportion the revenue increase. Under a 25% subsidy reduction methodology, the proposed increases for each customer class are specifically designed to mitigate 25% of the subsidy at proposed rates. Baron Exhibits ___(SJB-12) and ___(SJB-13) present the results of the 25% subsidy reduction methodology for KU and LG&E respectively.

Q. Would you please explain the revenue requirement methodology that you are recommending in Exhibits (SJB-12) and (SJB-13)?

A. The methodologies are identical for both Companies and for the purposes of explaining the approach, I will refer to the KU analysis presented in Exhibit (SJB-12). Pages 1 through 3 of Exhibit (SJB-12) contain the results for each KU rate class or rate group (a group of rate schedules with related rate design objectives).[2] To simplify the explanation of Exhibit (SJB-12), I will focus on the large commercial/industrial TOD rate schedule. The first set of rows in the exhibit shows the rate of return at present rates under the Company's BIP cost of service study, corrected for the problems that I previously addressed. As shown, for the LCI-TOD rate, the rate of return at present rates is 8.12%, compared to the system average rate of return of 4.27%.

[2] Following the approach of the Company, certain rate classes have been grouped together for the purposes of assigning a revenue increase target for the class or rate schedule. As discussed by the Company in data responses, certain rate schedules have been grouped together by the Company to insure that there is no incentive or disincentive for customers switching due to a change in the relative rates among these schedules.

The second set of rows develops the rate of return at KU's proposed rate increase for each customer class or rate grouping. For the LCI–TOD rate, the Company's is proposing an increase of $6.9 million that would produce a rate of return at proposed rates to 11.51%. This compares to an overall KU rate of return for all rate classes at proposed rates of 6.76%. As I show in Table 3, the rate of return index at proposed rates recommended by KU in this case for the large commercial and industrial TOD rate is 1.7 (the ratio of 11.51% to 6.76%). Despite the Company's proposal to assign a slightly lower overall revenue increase for this class (8.2%) than the system average increase (8.7%), the Company's proposal does very little to reduce the subsidies paid by LCI-TOD customers. Again, it is important to remember that this subsidy analysis is premised on the Company's recommended cost allocation methodology in this case, the BIP method.

The next portion of Exhibit (SJB-12) is designed to calculate the increase that would be appropriate if current subsidies (at present rates) are reduced by 25%, after the proposed rate increase. As can be seen for the LCI-TOD class, the subsidy that KU is recommending at proposed rates for these customers is $9.67 million. This compares to the current subsidy of $7.8 million. KU is proposing to actually increase the subsidy paid by LCI-TOD customers by 23%. Ironically, the Company

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KIUC recommends adopting this general approach.

is also proposing to increase the subsidies received by residential customers by almost $2 million and the subsidies received by "all electric residential" customers by an additional $2 million. Despite the Company's proposal in this case to increase residential rates by approximately 1% above the system average as recognition of the large subsidies being received by these rate schedules, the Company's increase recommendation actually moves subsidies in the opposite direction. Subsidies are increased for residential customers on Rate RS and Rate FERS.

Continuing with the discussion of the 25% subsidy reduction methodology, the base rate increase required for a 25% subsidy reduction is computed and shown to be $3.122 million for Rate LCI-TOD. This produces a rate of return at proposed rates for this rate class of 9.65%, reflecting a 25% subsidy reduction. As can be seen in the fourth set of rows (bottom portion of the exhibit), the amount of subsidies after the increase under KIUC methodology for LCI-TOD would be $5.8 million, which is a 25% reduction from the current subsidy of $7.8 million.

The final three rows of the exhibit summarize the results of the analysis. The Company is proposing an overall increase of 8.7% on total rate revenues. For Rate Schedule LCI-TOD, KU is proposing an 8.21% increase. This contrasts with a 3.27% reduction that would be required if the Company were to achieve equalized rates of return at proposed rates. Since the KIUC recommended apportionment method only reduces subsidies by 25% (as opposed to 100% that would be required for equalized rates of return), KIUC is proposing an increase for LCI-TOD of 3.71%, assuming that the Company received its entire revenue requirement request in this case. For residential customers, the Company is proposing a 9.01% increase, while a 25% subsidy reduction methodology produces a 14.4% increase for Rate RS customers. However, it is important to recognize that these percent increases are premised on the Company receiving its entire $59 million revenue increase request in this case. To the extent that the Company receives an amount less than its request, as recommended by other KIUC witnesses in this case, the 25% subsidy reduction revenue apportionment methodology would produce lower increases for each customer class.

Table 5 shows the allocation of the increase using the KIUC proposed methodology, based on the Company's $58.9 million revenue increase request. The column labeled "Allocation of Increase" shows the apportionment of the $58.91 million increase to each rate class using the 25% subsidy methodology. KIUC recommends using this allocation apportionment (the percentages shown on Table 5) for any increase granted KU in this case. Finally, in the event that KU receives a revenue decrease in this proceeding, KIUC would recommend following the 25% subsidy reduction method, with the caveat that no rate class or group of rate classes should receive an increase.

Table 5
Kentucky Utilities
KIUC Proposed Increase using "25% Subsidy Reduction" (1)

(Assuming 100% of KU Requested Increase)

		Proposed Increase $ Amount	Proposed Increase % Total Rev	Allocation Of Increase
Total System		58,911,660	8.7%	100.000%
Residential	Rate RS	17,484,557	14.4%	29.679%
All Electric Residential	Rate FERS	21,185,839	16.1%	35.962%
General Service	GS	4,905,523	7.5%	8.327%
Combined Lit & Pow	LP,HLF,M	7,857,308	3.5%	13.337%
Large Comm/Ind TOD	LCI-TOD	3,122,526	3.7%	5.300%
Coal Mining Pow Pri	MPP	23,193	0.5%	0.039%
Coal Mining Pow Trans	MPT	48,456	1.3%	0.082%
Lg Pow Mine TOD Pri	LMPP	49,345	2.5%	0.084%
Lg Pow Mine TOD Trns	LMPT	108,077	2.6%	0.183%
Combination Off-Peak	CWH	536,171	129.4%	0.910%
All Elcetric School	AES	328,759	8.3%	0.558%
Electric Space Heat	33	77,318	11.6%	0.131%
Street Lighting	St Lt	1,988,224	36.8%	3.375%
Decorative St Lighting	Dec St Lt	171,660	21.3%	0.291%
Private Outdoor Lighting	PO Lt	340,841	5.4%	0.579%
Customer Outdoor Lgt	C O Lt	76,820	8.6%	0.130%
Special Contracts		607,042	4.2%	1.030%

(1) Based on Corrected BIP Cost of Service Study

Q. Is the methodology that you are recommending for LG&E, as shown in Exhibit (SJB-13), identical to the method you have just discussed for KU?

A. Yes. Baron Exhibit (SJB-13), pages 1 and 2, presents an identical analysis for LG&E using the corrected BIP cost of service study results that I previously discussed. Table 6 shows the KIUC recommended apportionment of LG&E's $64.26 million revenue increase.

Table 6
Louisville Gas & Electric Company

KIUC Proposed Increase using "25% Subsidy Reduction" (1)
(Assuming 100% of LGE Requested Increase)

		Proposed Increase		Allocation
		$ Amount	% Total Rev	of Increase
Total System		64,260,364	11.4%	100.000%
Residential	Rate R	37,864,144	17.7%	58.923%
Water Heating	Rate WH	477,652	66.1%	0.743%
General Service	Rate GS	3,767,827	4.6%	5.863%
Rate LC/LC-TOD		8,926,641	6.9%	13.891%
Rate LP/LP-TOD		8,710,760	8.9%	13.555%
Street Lighting	Rate PSL	999,777	20.9%	1.556%
Street Lighting	Rate SLE	27,656	19.9%	0.043%
Street Lighting	Rate OL	1,222,512	20.7%	1.902%
Street Lighting	Rate TLE	16,316	3.0%	0.025%
Special Contracts		2,247,079	8.2%	3.497%

(1) Based on Corrected BIP Cost Study

Assuming the Company receives a lower authorized revenue increase, as recommended by KIUC, the allocation percentages shown in Table 6 should be used to apportion the increase. Finally, as in the case of KU, if the Company were to receive a revenue decrease in this proceeding, the decrease should be allocated to reduce subsidies by 25%, subject to the caveat that no customer class or group of classes should receive an increase.

Q. KIUC is proposing that the Commission adopt a specific methodology in this case to address the subsidy problem that you have identified in both the KU and LGE rates. Do you believe that your proposal to reduce subsidies by 25% is consistent with the economic development objectives of the State of Kentucky?

A. Yes. The Kentucky Cabinet for Economic Development ("KCED") has issued a White Paper that specifically addresses the significance of low cost electricity in Kentucky as a factor in attracting and keeping industry in the State. According to the White Paper:

> **"In Kentucky, we provide a wealth of information about power for companies considering us in the site selection process. And we are often asked about it since we have been ranked the least expensive for industrial users of electricity, Strong said"** [*Shedding Light on Energy: How Supply and Costs Affect Business Decisions*, KCED White Paper, http://www.thinkkentucky.com/kyedc/pdfs/Whitepaper_energy.pdf.]

In this case, KIUC is only requesting that the Commission recognize that the reduction of subsidies is a reasonable policy objective and that it should be implemented gradually (25% reduction) beginning in this case for both KU and LGE.

III. RATE DESIGN ISSUES

Q. Have you reviewed the Company's proposed rate design for large commercial and industrial customers on the KU and LG&E systems?

A. Yes. In both cases (LG&E and KU), the proposed rate design results in a reduction in the energy charges of the large customer rates and increases in the demand charges. As a general rate design policy matter, KIUC supports the Company's basic rate design for Rate Schedules LP and LP-TOD in the case of LG&E and LCI-TOD on the KU system. For both Companies, the rate design philosophy recognizes that the Company's cost of service results support lower energy charges and higher demand charges, every thing else being equal.

Q. Under the assumption that the Commission authorizes a lower revenue increase than requested by each of the Companies and/or adopts the KIUC recommendation to reduce subsidies by 25%, the revenue requirement target for each of the large commercial and industrial rates would be reduced, compared to the targets used by the Company. What is your recommendation as to how KU's proposed LCI-TOD and LG&E's proposed LP-TOD and LP rates should be adjusted in the event of a lower revenue requirement target?

A. Since KIUC generally supports the Company's proposal to decrease the energy charges of each of the rates and apply any authorized revenue increases to the demand charges, KIUC would recommend continuing this policy in the event that the revenue increases required from each of these rate schedules is lower than proposed by the Company. In order to accomplish this objective, KIUC recommends that any adjustment to the target revenue increase required pursuant to the Commission's decision in this proceeding be applied on an equal percentage basis to reduce the demand charges <u>proposed</u> by the Company in its filing. For the energy charges of the respective rates, KIUC recommends the Company's proposed levels.

Q. Do you have any examples of how this rate design methodology would be implemented?

A. Yes. Baron Exhibit ____(SJB-14), pages 1 and 2 show the proposed rate design for KU Rate Schedule LCI-TOD, primary and transmission. The methodology recommended by KIUC is to apply the decrease in targeted revenue requirements for the LCI-TOD rate class to the demand charges of both rates, on an equal percentage basis. In addition, KIUC would maintain, on a constant dollar basis, the proposed voltage differential between the primary and transmission rates.

Under the Company's LCI-TOD rate design proposal, this class receives an increase of $6,910,666 (see Table 3). Under the KIUC methodology of reducing subsidies by 25%, LCI-TOD would receive an increase of $3,122,526 (assuming KU is authorized all of its requested increase). The KIUC rate design recommendation is to apply the reduced revenue increase target ($3,788,140) to the Company's proposed LCI-TOD demand charges. Since KIUC wants to maintain the absolute voltage differentials between primary and transmission, as proposed by the Company, the $3.788 million reduction in the revenue increase target is applied to the demand charges recommended by KU in this case on an across-the-board basis, holding constant the voltage differentials recommended by KU. Page 1 of Exhibit (SJB-14) shows the results of this analysis. As can be seen in columns 7 and 8, KIUC is recommending that the customer charge and the energy charge be maintained at the proposed KU levels. All of the revenue adjustment that KIUC is recommending for Rate LCI-TOD is applied to the on- and off-peak demand charges.

Under the Company's proposal, the on-peak demand charge is $5.52, while the charge under the KIUC adjusted rate is $4.79. The end result is to produce an increase for the primary portion of LCI-TOD of $2.4 million as compared to the Company's proposed increase of $5.38 million.

Page 2 of the exhibit shows a similar analysis for Rate LCIT-TOD, which is the transmission voltage portion of Rate Schedule LCI-TOD. This rate design follows the same methodology as shown on page 1 of the exhibit. The end result is that the proposed on-peak and off-peak demand charges for the primary rate code differ from the corresponding charges for the transmission rate code by exactly the same differential as proposed by the Company for Rate LCI-TOD.

Q. Have you performed a similar analysis as an illustration for LG&E's Rate Schedule LP-TOD?

A. Yes. In the case of the LP-TOD rate schedule, the Company has indicated in data responses that its rate design philosophy is to group the LP-TOD and LP schedules together, to maintain the relationship between the two rates. Following KIUC's adoption of the Company's general rate design philosophy, I have prepared an analysis of the recommended changes to Rates LP and LP-TOD that reflects the reduced revenue requirement target recommended by KIUC, but maintains the Company's basic rate design philosophy. Baron Exhibit ____(SJB-15) shows the results of this adjusted rate design for Rate Schedules LP and LP-TOD. All of the target revenue requirement change (in the form of a reduction from that proposed by LG&E) has been applied to the demand charges of the rate, while maintaining differentials on a voltage basis and among Rate Schedules LP and LP-TOD.

Q. Each of the Companies is proposing new tariffs or changes in tariffs associated with riders that would be applicable to large commercial and industrial customers. Have you reviewed these proposals for new riders?

A. Yes. Both LG&E and KU are proposing three riders that would be applicable to KIUC members, under certain circumstances. The first of these riders is the excess facilities rider that provides a mechanism for customers to pay for contributions in aid of construction monthly, rather than in a single payment. For LG&E, the Company is proposing to implement an excess facilities rider for new construction projects but would continue to apply the existing facilities rider to existing customer facilities. As such, for LG&E, there is no cost impact from the proposed excess facilities rider on existing customers. KIUC does not object to the Company's proposal for the LG&E rider, as long as the provision regarding applicability is maintained in the tariff.

For KU, there is no current excess facilities charge rider. Rather, current customers pay a lease rate associated with contributions in aid of construction. Under the excess facilities rider for KU, which is a new rider, the lease rate would be reduced. KIUC does not object to KU's excess facilities rider.

Q. Would you please discuss the Company's proposed redundant capacity tariff?

A. For both KU and LG&E, the redundant capacity rider is new and, according to the Company, does not have any test year revenues associated with the rider. Based on discovery responses from the Company, no existing customer facilities would be charged under this redundant capacity rider.

It appears that the redundant capacity rider is designed to reflect additional costs that the Company incurs on its distribution system associated with redundant distribution feeders that would be paid for through the excess facilities rider. For specifically assigned distribution facilities (e.g., a separate distribution feeder), customers are required to pay for this investment through a contribution in aid of construction, pursuant to the excess facilities rider. The redundant capacity rider is designed to recover incremental costs associated with the distribution system that may be incurred as a result of providing an alternative distribution feeder to a customer location.

Though in principle, KIUC does not object to the redundant capacity rider, KIUC recommends a change to the redundant capacity rider, in the event that the Commission approves the tariff. The change that KIUC recommends is: for each instance wherein the Company proposes to charge a redundant capacity fee, the Company must provide to the customer an analysis that shows that the Company will in fact require additional distribution facilities (above the customer provided contributions) in order to provide the redundant distribution capacity to the customer. Under the Company's proposal, the Company would simply be able to charge the customer an additional charge (in the form of a reservation charge) for the assumed additional distribution network facilities that are required to provide the customer with a redundant service, beyond the customer specific costs paid for through the excess facilities rider. KIUC recommends that the Company be required to demonstrate to the customer that such additional costs are being incurred to provide the so-called redundant capacity. This requirement would provide the customer an opportunity to review and, potentially challenge, the Company's redundant capacity charges pursuant to this tariff. KIUC does not believe that this change to the redundant capacity tariff is burdensome and would provide customers, who would otherwise incur these costs, a basis to evaluate whether the Company will actually incur additional distribution costs associated with the customer's specific request for service.

Q. What is the third new rider being proposed by the Company in this case?

A. The third rider being proposed by both LG&E and KU is associated with intermittent and fluctuating loads. Both LG&E and KU have indicated in responses to KIUC data requests that there were no test year revenues on this rider and that each of the Companies does not know what the revenues will be in the future. KIUC does not object to this tariff. However, since the Company has indicated that it does not know what revenues there will be in the future associated with the tariff, KIUC proposes that in no event should this tariff be applied to existing loads and load characteristics for any customer, currently taking service during the test year. Thus, if the Commission approves this tariff, it would not apply to any existing KU or LG&E customer unless the customer changed its load or load characteristics from the level or behavior that occurred during the test year.

Q. Are there any additional rate design issues that you would like to address?

A. Yes. KIUC believes that the KU and LGE fuel roll-in procedure should be modified in a manner that recognizes the differential in fuel costs among rate schedules on the basis of service voltage.

In the current case, both KU and LGE have allocated test year fuel expense on the basis of class energy, adjusted for losses. This is the appropriate method to assign cost responsibility for these energy related costs. However, no such loss adjustments are made to rolled-in fuel costs during the roll-in of fuel costs to base rates that occurs periodically for both Companies. KIUC believes that in future fuel roll-in proceedings, the Company be required to roll-in fuel costs into base rates on a voltage differentiated basis, following the concept used by the Company in this case to allocate fuel expense to rate schedules.

Q. Is KIUC recommending that the fuel clause itself be voltage differentiated?

A. No, not at this time.

IV. INTERRUPTIBLE AND CURTAILABLE SERVICE

Q. Have you reviewed the Company's proposal to change the interruptible and curtailable service riders applicable to large commercial and industrial customers?

A. Yes. LG&E is proposing to eliminate its current interruptible service rider and replace it with a curtailable service rider ("CSR"). The LG&E proposal, in addition to changing the title of the rider, would result in an increase in the current interruptible credit from \$3.30 per kW for primary customers to \$4.05 per kW and an increase for transmission customers in the credit from \$3.30 per kW to \$3.98 per kW. In addition, the maximum annual hours of interruption is being increased from 250 hours to 500 hours per year. Finally, the penalty for unauthorized use during an interruption is being increased from \$15.00 per kW of monthly billing demand to \$16.00 per kW for each non-compliance request. This \$16.00 per kW non-compliance charge would apply to each request for interruption (in the event the customer failed to comply), as compared to the current penalty charge that applied on a monthly basis to billing demand, rather than on each non-compliance event. The Company is also proposing to continue its current 10-minute notice to interrupt requirement in the tariff.

For KU, the proposed changes in the interruptible tariff are more substantial. KU currently has a curtailable service rider that incorporates two levels of interruption. For those customers electing a 75 or 100-hour maximum annual interruption level, the Company is proposing to increase the primary voltage interruptible credit from \$1.60 per kW to \$4.19 per kW. The transmission credit for these customers would increase from a \$1.55 per kW to \$4.09 per kW. For customers who elect 150 hours or 200 hours of maximum annual curtailment, the primary credit would increase from \$3.20 per kW to \$4.19 per kW, while the transmission voltage credit would increase from \$3.10 per kW to \$4.09 per kW.

However, as in the case of LG&E, the proposed KU CSR tariff permits annual interruptions of up to 500 hours per year for both primary and transmission voltage CSR customers. Thus, for these KU customers, the annual maximum hours of interruption would increase by 250% to 500%.

Q. What is the basis for the Company's proposed CSR credits, applicable to both LG&E and KU?

A. The Company is proposing to revise its interruptible and curtailable service rates to reflect a credit based on the avoided cost associated with a simple cycle combustion turbine. The credit for both LG&E and KU is determined based on the cost of a new CT and reflects the Company's view that interruptible load is a substitute for otherwise required peaking capacity.

Q. Do you believe that the Company's proposed CSR tariff is reasonable, based on its avoided CT cost methodology?

A. In part. First, as I will discuss subsequently, I do not believe that the Company's proposed 500 hour maximum potential hours of interruption is reasonable, based on a review of the Company's expected operation of combustion turbines on the LG&E/KU system. Second, the Company's proposed 10 minute notice provision, which appears to reflect the requirement in ECAR for interruptible load to qualify as spinning reserve, is not reasonable in light of the proposed credit that the Company is offering. Combustion turbines, even in a hot-start mode, cannot start-up in 10 minutes unless they are already running. Thus, the Company's proposed 10-minute notice requirement is not reasonable.

The third concern that I have with the Company's proposal is that it does not offer curtailable service customers the option of electing to "buy-through" an interruption at prevailing market rates, if such power is available. Finally, the interruptible credit should include an additional component to reflect fuel savings provided during actual interruptions.

Q. Would you please discuss the first concern that you have with the Company's CSR tariff, the increase in the maximum annual hours of potential interruption to 500 hours?

A. The Company is proposing to increase the maximum annualized hours of interruptions on the LG&E system by 100% (from 250 hours per year to 500 hours per year), while increasing the KU maximum annual hours of interruption from either 100 or 200 hours to 500 hours. The Company's proposal appears to be based on its expectations for the operating characteristics of combustion turbines on its system.

Q. Have you performed an analysis to determine a reasonable level of annual maximum interruptions that should be reflected in the Company's CSR tariff?

A. Yes. Baron Exhibit ____(SJB-16) shows an analysis of the actual and expected operation of the Company's combustion turbine capacity (LG&E and KU combined) for the test year and for calendar year 2004, based on projections developed by the Company. As can be seen from this exhibit, during the test year, the Company's combustion turbines ran from 0 hours per year up to 375 hours per year. For calendar year 2004, based on production cost simulations prepared by the Company, the Company's CT's ran from a low of 0 hours per year up to 370 hours per year for Brown Unit 6. In order to develop a reasonable estimate of the expectations of the Company's combustion turbine fleet during the test year and the first rate effective calendar year (2004), I developed an analysis that averaged the hours of operation of the Company's CTs for the two years, on a mW weighted basis. The results of that analysis, shown in Exhibit (SJB-16), demonstrate that on average, the Company's combustion turbine capacity operates at 174 hours per year. In fact, this value is high because I did not include in the calculation any combustion turbine capacity whose output in either the test year or in calendar year 2004 is expected to be 0 hours. If that capacity had been included, the weighted average hours of CT operation would be much lower.

Q. Under your proposed methodology for determining the appropriate level of maximum annual hours of interruption, are the Company's larger CTs given more weight in the calculation?

A. Yes. The Company's newer CTs tend to be larger and are weighted at a higher level in the calculation than the Company's smaller combustion turbines. As shown in Exhibit (SJB-16), these larger units also have the lowest heat rates, which tend to drive the operation of these units to a higher level.

Q. What is your recommendation for modifying the Company's proposed CSR tariff with regard to maximum annual hours of interruption?

A. Based on the analysis that I prepared, I am recommending that the maximum annual hours of interruption be set at 175 hours per year, for both LG&E and KU.

Q. The Company's production cost analysis shows that in future years, beyond 2004, some of the Company's CTs will operate in the 400 to 600 hour range annually. Does this information justify the Company's 500 hour maximum hours of interruption?

A. No. These projections are based on production cost simulation model that is, in turn, based on assumptions regarding load on the system, natural gas prices, market conditions and other factors. As such, it is reasonable to rely on the test year results and rate effective period, rather than a longer term forecast for setting rates.

Q. You indicated previously that the Company is proposing to utilize a 10-minute notice requirement for interruption in its KU and LG&E tariffs. Do you believe that this is reasonable?

A. No. Though it is necessary for interruptible load to be curtailed within 10 minutes if it is qualify as ECAR operating reserve, the Company's interruptible credit does not provide any compensation to interruptible customers for operating reserve associated benefits. More significantly, the Company's combustion turbine capacity cannot start from a cold start or even a hot start within 10 minutes. If standard combustion turbine capacity is going to provide spinning reserve capability, it must be running to do so.

Since the Company's proposed interruptible credit and the philosophy underlying its CSR tariff is to utilize interruptible load as a substitute for combustion turbine capacity, it is only reasonable to provide a notice provision for interruption equivalent to the start-up time constraint underlying the Company's combustion turbines. Also, if the Company were to offer a 10 minute interruption notice option, then it also should provide customers with the economic benefits (in terms of avoided costs) provided by substituting interruptible load for resources that would otherwise be operating to provide operating reserves on the system. For example, if the Company were utilizing combustion turbine capacity to satisfy a portion of its spinning reserve requirements, there would be an economic cost associated with doing so since, presumably, this capacity would have to operate at minimum or above in order to qualify for spinning reserve. Alternatively, if the Company were to allocate a portion of its committed units to spinning reserve (by not fully loading such units in merit order), then there is also an economic cost.

Q. What is your recommendation with regard to the Company's 10-minute notice provision?

A. The Company's CSR tariff should be modified to reflect a notice provision commensurate with an average expected start-up time the Company's CTs. It is my understanding that the start-up time for new combustion turbines would be in the range of 30 minutes for a hot start and up to several hours for a cold start. I would recommend that the notice provision be modified to a 1 hour notice.

Q. You indicated previously that the Company has developed its proposed CSR interruptible credit based on the avoided costs associated with a new combustion turbine. Has the Company fully reflected the avoided cost associated with combustion turbine capacity in its interruptible credit calculation?

A. Not entirely. Though I do not object to the Company's calculation of the fixed combustion turbine costs that would be avoided by interruptible load, the Company has not recognized the economic benefits provided by interruptible load that are associated with fuel savings. Based on the results shown in Exhibit (SJB-16), the mW weighted average heat rate for combustion turbine capacity on the LG&E/KU system is approximately 10,704 Btu per kWh. At a $5.00 per million Btu cost of natural gas, combustion turbines would have operating costs for each hour that they run equal to about 5 cents per kWh. This is substantially greater than the energy charge in either the LCI-TOD rate on the KU system or the LP-TOD energy charge for LG&E. Since interruptible load, when actually interrupted, will avoid the otherwise applicable operation of a CT (at perhaps 5 cents per kWh), but the customer only saves the energy charge of the otherwise applicable tariff, there is a mismatch between the economic benefits provided and the interruptible credit in

Rate CSR. I am recommending that the Company's CSR tariff be revised to include an additional credit based on the actual hours of interruption that reflects the fuel savings provided by interruptible customers, relative to the avoided energy charges in their otherwise applicable rates.

Q. Do you have any additional changes to the Company's proposed CSR tariff that you recommend?

A. Yes. The final change that I propose to the Company's CSR tariff is the implementation of a "buy-through" option that would permit customers on Rider CSR to elect a buy-through of the interruption at market-base rates plus a reasonable administrative fee payable to the Company. This option would only be available in the event that the Company elects to interrupt for economic reasons. In the event of a reliability based interruption, it would not be appropriate to offer the customer a buy-through of the interruption.

This buy-through provision is essentially a right-of-first refusal that the Company would offer its customers, compared to third party off-system customers for the energy and capacity otherwise available to serve these interruptible customers. Essentially, if LG&E or KU would otherwise have to purchase off-system to serve the interruptible load and chooses to interrupt instead, the customer would be offered the option to specifically pay for these off-system purchases in lieu of interruption. From the standpoint of the Company, there would be no costs, nor would there be a cost to the Company's firm customers. As I indicated, the administrative costs imposed on the Company to actually administer this buy-through provision should reasonably be recoverable from such customers. In the event that the Company might be able to make an additional off-system sale and chooses to interrupt CSR customers, the buy-through provision would amount to the Company making such sale to the customer directly, for which the customer would compensate the Company. Again, neither the Company nor its firm customers would be affected by this provision.

Q. Have you developed an alternative CSR tariff for each of the two operating companies that reflect the changes that you are recommending?

A. Yes. Baron Exhibit ____(SJB-17), contains the proposed KIUC CSR rider for Kentucky Utilities, in a redline version. Baron Exhibit ____(SJB-18) shows a corresponding CSR for LG&E, reflecting the KIUC recommended modifications as a redline version.

V. SPECIAL CONTRACT ISSUES

Q. Would you please address the concerns that you have identified with KU's proposed increase to special contract customer MeadWestvaco in this case?

A. As shown in KU's Seelye Exhibit 15, page 22 of 31, KU is proposing to increase the MeadWestvaco special contract by 9.53%, an amount that exceeds both the system average increase and the proposed increase for Rate Schedule LCI-TOD, the otherwise most nearly applicable tariff rate for this customer. KU is proposing to increase the LCI-TOD rate by 8.2% on a total revenue basis and 16.6% on a non-fuel rate revenue basis. The proposed increase for MeadWestvaco on a non-fuel rate revenue basis exceeds 22%.

Q. What cost of service evidence have you developed regarding the KU special contract customer class?

A. As discussed earlier, I have performed five cost of service studies. The KU special contract class shows a rate of return index far in excess of unity in all five studies. The results were: 1) Corrected BIP - 2.06; 2) Average and Excess - 2.81; 3) Summer/Winter Peak- 1.941; 4) Summer CP - 1.347; and 5) 12 CP - 3.719.

Q. Why is the Company proposing to increase the MeadWestvaco contract by an amount greater than the system average increase and the increase being proposed for Rate LCI-TOD?

A. It was not specifically addressed in testimony. However, based on KU responses to data requests, it appears that the Company relied on a MeadWestvaco specific cost analysis in determining the proposed increase.

.Q. Do you believe that the proposal by KU to increase the MeadWestvaco special contract by 9.53% is reasonable?

A. No. First of all, the approach that should be used by the Company is to apply the increase to the special contract class as a whole. As the Company and I have both shown, the special contract class is paying rates far in excess of cost. Accordingly, that class should receive a below system average increase. Individual customers within that class should not be singled out for particularized adverse treatment. Second the specific cost analysis performed by KU on the MeadWestvaco contract is incomplete, and thus flawed. A valid cost of service study for a particular special contract must include all aspects of the contractual relationship between the parties. In every contract there are benefits and detriments to each party and a valid cost of service study would attempt to take that into account. For example, under the special contract, MeadWestvaco's self generation options are severely restricted. Because of the substantial steam generation inherent in the paper production process, this limitation is costly to MeadWestvaco and represents a corresponding benefit to KU. Neither KU nor I have attempted to do a complete cost of service analysis that captures such issues. . That type of complex analysis is ordinarily done only once; when the Commission initially approves the contract.

Q. Does the KU revenue increase proposal effectively negate the value of the Commission approved special contract to MeadWestvaco?

A. Yes. The MeadWestvaco special contract represents the results of a bargain between the utility and MeadWestvaco in which mutual consideration was given. The MeadWestvaco special contract is the only rate option available to this customer since its plant load exceeds the 50 mw limit contained in the standard tariff that is otherwise most applicable - LCI-TOD.

KU's proposal in this case effectively reduces the difference between the MeadWestvaco special contract and the most nearly applicable tariff rate, based on an incomplete cost of service methodology that was not even in effect at the time the contract was negotiated. If this were the standard applicable to setting the special contract rate, the Company could propose any cost of service study that might allocate substantial costs to MeadWestvaco and result in a contract rate exceeding the most nearly comparable tariff rate. By proposing an increase to the MeadWestvaco special contract rate in excess of the LCI-TOD rate, the Company has attempted to unilaterally diminish the value of the contract. This is all the more burdensome because of MeadWestvaco's limited options since its load is too large for LCI-TOD, as that rate is currently structured. Therefore, the percentage increase to the MeadWestvaco contract should approximate the percentage increase approved for the otherwise most nearly applicable tariff rate; which in this case is LCI-TOD.

Q. Should the LCI-TOD rate be modified to permit a customer whose demands exceed 50 mW to take service under the rate?

A. Yes. Though MeadWestvaco does not desire to shift its special contract load to LCI-TOD, there is no valid reason why such an option should not be available. KIUC proposes that the LCI-TOD demand limits be increased to 75 mW, which would permit MeadWestvaco to take service under this rate, at its option.

Q. Would you summarize your recommendation regarding the appropriate increase for the MeadWestvaco contract?

A. Each contract in the special contract rate class should receive the same percentage increase and that increase should be well below system average based upon the class cost studies and my 25% subsidy reduction proposal. This proposal results in the special contract class and the otherwise most nearly applicable tariff, LCI-TOD, getting nearly the same increase,

Q. Does that complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 2003-00433
AND	)))	
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL USERS COMMITTEE

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

March 2004

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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EXHIBITS

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ROSWELL, GEORGIA

March 2004

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91 Note: No testimony was prefiled on this.	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Comission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

**Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004**

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI 98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
of
Stephen J. Baron
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and The Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBIT (SJB-2)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual			$	768,801,159 $	137,843,272 $	147,767,846 $	69,080,018 $	2,812,620
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	675,000 $	122,243 $	129,125 $	61,916 $	2,528
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728) $	(5,723,277) $	(6,590,128) $	(2,393,685) $	(109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		1,417,623 $	181,543 $	182,116 $	96,991 $	4,709
Remove ECR revenues		ECRREV		(25,039,979) $	(4,562,377) $	(4,715,925) $	(2,291,842) $	(91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813 $	3,208,163 $	3,428,757 $	1,647,196 $	66,930
Remove off-system ECR revenues			PLPPT	(776,418) $	(128,949) $	(192,222) $	(56,708) $	(2,269)
Eliminate brokered sales			Energy	(22,575,669) $	(3,600,306) $	(4,145,611) $	(1,505,781) $	(68,786)
Eliminate ESM revenues collected		ESMREV		(4,604,742) $	(915,119) $	(611,110) $	(428,633) $	(15,263)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	1,630,147 $	295,220 $	311,841 $	149,529 $	6,105
Eliminate DSM Revenue		DSMREV		(2,942,935) $	(1,508,819) $	(1,089,604) $	(222,733) $	(10,743)
Year end adjustment		YREND		251,167 $	(417,181) $	1,771,704 $	815,724 $	-
Merger savings			R01	(2,564,269) $	(464,390) $	(490,535) $	(235,213) $	(9,603)
Adjustment for rate switching, increased interruptible credit		RATESW		(3,005,567)				
VDT Amortization and Surcredit			VDTREV	85,337 $	15,547 $	16,258 $	7,821 $	304
Total Pro-Forma Operating Revenue			(13,497,703) $	693,449,939 $	124,345,569 $	135,772,513 $	64,724,599 $	2,585,654

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

Exhibit ___ (SJB-2)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				177,000,631	39,766,392	602,350	75,082,958	21,281,348	13,981,260	26,319,442
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	154,859	34,715	526	64,896	18,376	12,117	22,783
Adjustment for Mismatch in fuel cost recovery			Energy	(8,518,255)	(2,093,467)	(31,617)	(4,365,021)	(1,268,707)	(801,803)	(1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		365,749	85,293	2,524	194,737	94,994	53,661	62,851
Remove ECR revenues		ECRREV		(5,734,057)	(1,290,905)	(19,498)	(2,401,012)	(688,721)	(446,972)	(838,688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		4,133,949	917,554	14,085	1,735,487	492,058	316,548	606,165
Remove off-system ECR revenues			PLPPT	(167,224)	(39,075)	(583)	(76,777)	(20,709)	(13,584)	(26,230)
Eliminate brokered sales			Energy	(5,358,526)	(1,316,924)	(19,889)	(2,745,877)	(798,098)	(504,385)	(954,481)
Eliminate ESM revenues collected		ESMREV		(1,152,341)	(264,123)	(3,814)	(474,129)	(137,016)	(89,283)	(160,668)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	373,990	83,837	1,271	156,727	44,379	29,263	55,022
Eliminate DSM Revenue		DSMREV		(98,441)	(12,123)	(472)	-	-	-	-
Year end adjustment		YREND		(597,774)	117,795	273,166	-	-	-	(537,561)
Merger savings			R01	(588,297)	(131,879)	(2,000)	(246,535)	(69,809)	(46,031)	(86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			(42,856)		(64,186)	(120,793)		
VDT Amortization and Surcredit			VDTREV	19,479	4,382	66	8,140	2,334	1,514	2,828
Total Pro-Forma Operating Revenue			(13,497,703)	159,833,741	35,818,617	816,116	66,869,408	18,829,635	12,492,305	22,947,608

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Coal Mining Power Primary MPP		Coal Mining Power Transmission MPT		Large Power Mine Power TOD Primary LMPP		Large Power Mine Power TOD Transmission LMPT		Combination Off-Peak CWH
Cost of Service Summary -- Pro-Forma													
Operating Revenues													
Total Operating Revenue -- Actual				$	5,648,629	$	4,555,273	$	2,206,126	$	5,430,525	$	502,279
Pro-Forma Adjustments:													
Eliminate unbilled revenue			R01	$	4,976	$	3,978	$	1,924	$	4,748	$	432
Adjustment for Mismatch in fuel cost recovery			Energy	$	(268,036)	$	(234,296)	$	(118,074)	$	(276,483)	$	(28,144)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$	12,843	$	13,496	$	2,865	$	11,438	$	1,179
Remove ECR revenues		ECRREV		$	(182,407)	$	(145,445)	$	(70,105)	$	(172,666)	$	(15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$	132,466	$	105,333	$	51,614	$	127,076	$	11,770
Remove off-system ECR revenues			PLPPT	$	(5,165)	$	(4,531)	$	(2,123)	$	(5,583)	$	(637)
Eliminate brokered sales			Energy	$	(168,612)	$	(147,387)	$	(74,276)	$	(173,926)	$	(17,704)
Eliminate ESM revenues collected		ESMREV		$	(33,089)	$	(25,314)	$	(11,418)	$	(28,011)	$	(2,590)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$	12,018	$	9,606	$	4,648	$	11,466	$	1,042
Eliminate DSM Revenue		DSMREV		$	-	$	-	$	-	$	-	$	-
Year end adjustment		YREND		$	(234,645)	$	(275,257)	$	-	$	(703,778)	$	(22,542)
Merger savings			R01	$	(18,905)	$	(15,111)	$	(7,311)	$	(18,037)	$	(1,639)
Adjustment for rate switching, increased interruptible credit		RATESW											
VDT Amortization and Surcredit			VDTREV	$	619	$	493	$	236	$	579	$	52
Total Pro-Forma Operating Revenue			(13,497,703)	$	4,900,693	$	3,840,839	$	1,984,106	$	4,207,348	$	427,775

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue -- Actual				$ 4,464,245	$ 770,054	$ 818,282	$ 5,641,223	$ 817,184	$ 6,590,968	$ 970,465	$ 18,847,769
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	$ 3,911	$ 675	$ 717	$ 5,345	$ 790	$ 6,178	$ 907	$ 16,335
Adjustment for Mismatch in fuel cost recovery			Energy	$ (217,983)	$ (37,387)	$ (37,004)	$ (87,643)	$ (5,009)	$ (135,957)	$ (21,106)	$ (1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 9,719	$ 881	$ 1,457	$ (1,021)	$ (74)	$ (3,573)	$ (2,582)	$ 45,827
Remove ECR revenues		ECRREV		$ (143,373)	$ (23,364)	$ (26,381)	$ (196,772)	$ (29,280)	$ (227,715)	$ (33,264)	$ (691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 104,270	$ 17,741	$ 19,017	$ 144,134	$ 21,362	$ 166,721	$ 24,687	$ 493,730
Remove off-system ECR revenues			PLPPT	$ (4,931)	$ (846)	$ (1,028)	$ (1,650)	$ (94)	$ (2,562)	$ (398)	$ (22,541)
Eliminate brokered sales			Energy	$ (137,125)	$ (23,519)	$ (23,278)	$ (55,133)	$ (3,151)	$ (85,526)	$ (13,277)	$ (634,093)
Eliminate ESM revenues collected		ESMREV		$ (21,999)	$ 1,124	$ (4,856)	$ (37,564)	$ (5,954)	$ (43,690)	$ (6,279)	$ (133,593)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 9,445	$ 1,630	$ 1,730	$ 12,909	$ 1,908	$ 14,921	$ 2,192	$ 39,449
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Year end adjustment		YREND		$ -	$ (19,849)	$ -	$ 16,889	$ 12,240	$ 71,430	$ (19,194)	$ -
Merger savings			R01	$ (14,857)	$ (2,564)	$ (2,722)	$ (20,307)	$ (3,001)	$ (23,470)	$ (3,447)	$ (62,054)
Adjustment for rate switching, increased interruptible credit		RATESW									$ (2,777,732)
VDT Amortization and Surcredit			VDTREV	$ 491	$ 81	$ 90	$ 667	$ 102	$ 802	$ 115	$ 2,335
Total Pro-Forma Operating Revenue			(13,497,703)	$ 4,051,813	$ 684,657	$ 746,024	$ 5,421,077	$ 807,012	$ 6,328,527	$ 898,820	$ 14,115,482

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Operating Expenses								
Operation and Maintenance Expenses				$ 548,721,322	$ 106,395,052	$ 115,314,028	$ 44,174,222	$ 1,487,883
Depreciation and Amortization Expenses				88,376,624	19,523,170	23,225,147	8,505,560	201,876
Regulatory Credits and Accretion Expenses				(8,656,053)	(1,437,613)	(2,143,031)	(632,221)	(25,292)
Property Taxes			NPT	8,211,450	1,794,460	2,152,528	782,026	18,984
Other Taxes				5,761,996	1,259,177	1,510,435	548,750	13,321
Gain Disposition of Allowances				(246,288)	(39,277)	(45,226)	(16,427)	(750)
State and Federal Income Taxes			TXINCPF	26,916,596	$ (931,127)	$ (2,033,485)	$ 4,158,791	$ 378,191
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 4,582,475	$ 934,980	$ 771,944	$ 449,462	$ 11,972
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(31,644,777)	$ (5,046,623)	$ (5,810,987)	$ (2,110,684)	$ (96,419)
Remove ECR expenses			ECRREV	(248,458)	$ (45,272)	$ (46,795)	$ (22,742)	$ (908)
Eliminate brokered sales expenses			Energy	(24,729,742)	$ (3,943,832)	$ (4,541,167)	$ (1,649,456)	$ (75,349)
Eliminate DSM Expenses			DSMREV	(2,946,471)	$ (1,510,632)	$ (1,090,913)	$ (223,001)	$ (10,756)
Year end adjustment			YREND	151,410	$ (251,488)	$ 1,068,029	$ 491,740	$ -
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	2,091,278	$ 461,982	$ 549,582	$ 201,269	$ 4,777
Labor adjustment			LBT	1,002,076	$ 247,020	$ 252,112	$ 100,391	$ 2,144
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	(473,014)	$ (168,017)	$ (153,325)	$ (69,375)	$ (554)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	58,333	$ 10,564	$ 11,159	$ 5,351	$ 218
Amortization of rate case expenses			OMT	352,456	$ 58,340	$ 74,069	$ 28,374	$ 956
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	2,895,000	$ 713,643	$ 728,353	$ 290,030	$ 6,195
Adjustment for merger savings			LBT	18,968,825	$ 4,675,980	$ 4,772,367	$ 1,900,356	$ 40,591
Adjustment for merger amortization expenses			LBT	(2,726,510)	$ (672,108)	$ (685,963)	$ (273,150)	$ (5,834)
Adjustment for MISO schedule 10 expenses			PLTRT	843,344	$ 140,064	$ 208,792	$ 61,596	$ 2,464
Adjustment for effect of accounting change			DET	8,434,618	$ 1,863,281	$ 2,216,596	$ 811,766	$ 19,267
Adjustment for IT staff reduction			LBT	(601,682)	$ (148,320)	$ (151,377)	$ (60,278)	$ (1,288)
Adjustment to remove Alstom expenses			PLPPT	(3,126,995)	$ (519,337)	$ (774,169)	$ (228,390)	$ (9,137)
Adjustment for corporate lease expense			LBT	-	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	120,391	$ 21,803	$ 23,030	$ 11,043	$ 451
Adjustment for OMU Nox expense			PLPPT	1,959,879	$ 325,500	$ 485,219	$ 143,146	$ 5,726
Adjustment for ice storm			SDALL	(5,277,336)	$ (1,874,536)	$ (1,710,617)	$ (774,008)	$ (6,178)
Adjustment for management audit fee			OMT	163,982	$ 31,796	$ 34,461	$ 13,201	$ 445
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(705,035)	$ (115,317)	$ (135,875)	$ (49,242)	$ (2,113)
VDT Amortization and Surcredit			VDTREV	(466,280)	$ (84,947)	$ (88,836)	$ (42,731)	$ (1,661)
Total Expense Adjustments				(35,904,718)	(5,820,456)	(4,766,255)	(1,444,794)	(126,962)
Total Operating Expenses		TOE		$ 633,180,928	$ 121,678,365	$ 133,986,084	$ 56,525,369	$ 1,959,223
Net Operating Income (Adjusted)				$ 60,259,011	$ 2,667,204	$ 1,786,429	$ 8,199,229	$ 626,432
Net Cost Rate Base				$ 1,412,033,543	$ 318,616,683	$ 371,840,037	$ 139,068,150	$ 3,144,534
Rate of Return				4.27%	0.84%	0.48%	5.90%	19.92%

BIP Prod Trans Allocation
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KENTUCKY UTILITIES
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Class Allocation

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Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Operating Expenses										
Operation and Maintenance Expenses				$ 118,555,031	$ 26,795,526	$ 396,971	$ 54,387,992	$ 15,141,209	$ 9,976,981	$ 18,800,670
Depreciation and Amortization Expenses				15,264,780	3,243,751	43,985	6,274,319	1,547,803	1,141,137	2,128,807
Regulatory Credits and Accretion Expenses				(1,864,336)	(435,639)	(6,505)	(855,965)	(230,883)	(151,439)	(292,427)
Property Taxes			NPT	1,433,504	306,242	4,177	592,905	147,074	107,660	201,249
Other Taxes				1,005,893	214,891	2,931	416,043	103,202	75,545	141,217
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8,707)	(5,503)	(10,413)
State and Federal Income Taxes			TXINCPF	$ 11,964,223	$ 2,866,184	$ 91,969	$ 3,804,648	$ 1,463,006	$ 772,961	$ 1,368,681
Specific Assignment of Curtailable Service Rider Credit				-	(181,381)	-	(271,654)	(499,037)	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 1,097,059	$ 240,238	$ 4,049	$ 441,260	$ 101,228	$ 78,321	$ 145,724
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (7,511,155)	$ (1,845,959)	$ (27,879)	$ (3,848,951)	$ (1,118,710)	$ (707,007)	$ (1,337,916)
Remove ECR expenses			ECRREV	$ (56,898)	$ (12,809)	$ (193)	$ (23,825)	$ (6,834)	$ (4,435)	$ (8,322)
Eliminate brokered sales expenses			Energy	$ (5,869,813)	$ (1,442,579)	$ (21,787)	$ (3,007,876)	$ (874,249)	$ (552,511)	$ (1,045,554)
Eliminate DSM Expenses			DSMREV	$ (98,559)	$ (12,138)	$ (473)	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (360,354)	$ 71,010	$ 164,672	$ -	$ -	$ -	$ (324,056)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 361,214	$ 76,758	$ 1,041	$ 148,471	$ 36,626	$ 27,003	$ 50,374
Labor adjustment			LBT	$ 179,334	$ 32,574	$ 438	$ 63,114	$ 16,111	$ 11,823	$ 21,741
Medical Expense (See Functional Assignment)										
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (42,357)	$ (5,656)	$ -	$ (9,718)	$ -	$ (2,245)	$ (3,009)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 13,383	$ 3,000	$ 45	$ 5,608	$ 1,588	$ 1,047	$ 1,969
Amortization of rate case expenses			OMT	$ 76,151	$ 17,211	$ 255	$ 34,935	$ 9,726	$ 6,408	$ 12,076
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 518,096	$ 94,107	$ 1,266	$ 182,338	$ 46,544	$ 34,157	$ 62,810
Adjustment for merger savings			LBT	$ 3,394,708	$ 616,612	$ 8,296	$ 1,194,727	$ 304,969	$ 223,806	$ 411,550
Adjustment for merger amortization expenses			LBT	$ (487,943)	$ (88,630)	$ (1,192)	$ (171,726)	$ (43,835)	$ (32,169)	$ (59,155)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 181,639	$ 42,444	$ 634	$ 83,395	$ 22,494	$ 14,754	$ 28,491
Adjustment for effect of accounting change			DET	$ 1,456,863	$ 309,582	$ 4,198	$ 598,818	$ 147,722	$ 108,910	$ 203,172
Adjustment for IT staff reduction			LBT	$ (107,678)	$ (19,559)	$ (263)	$ (37,896)	$ (9,673)	$ (7,099)	$ (13,054)
Adjustment to remove Alstom expenses			PLPPT	$ (673,490)	$ (157,374)	$ (2,350)	$ (309,217)	$ (83,406)	$ (54,707)	$ (105,639)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 27,620	$ 6,192	$ 94	$ 11,575	$ 3,278	$ 2,161	$ 4,064
Adjustment for OMU Nox expense			PLPPT	$ 422,118	$ 98,636	$ 1,473	$ 193,805	$ 52,276	$ 34,288	$ 66,211
Adjustment for ice storm			SDALL	$ (472,573)	$ (63,098)	$ -	$ (108,425)	$ -	$ (25,051)	$ (33,566)
Adjustment for management audit fee			OMT	$ 35,429	$ 8,008	$ 119	$ 16,254	$ 4,525	$ 2,982	$ 5,618
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (164,991)	$ (39,950)	$ (607)	$ (81,996)	$ (23,318)	$ (14,958)	$ (28,356)
VDT Amortization and Surcredit			VDTREV	$ (106,432)	$ (23,944)	$ (363)	$ (44,478)	$ (12,752)	$ (8,271)	$ (15,454)
Total Expense Adjustments				(9,285,690)	(2,335,563)	127,424	(5,111,070)	(1,526,920)	(941,114)	(2,106,003)
Total Operating Expenses		TOE		$ 138,112,005	$ 30,699,881	$ 664,784	$ 59,648,521	$ 16,237,976	$ 11,054,549	$ 20,377,504
Net Operating Income (Adjusted)				$ 21,721,736	$ 5,118,735	$ 151,332	$ 7,220,887	$ 2,591,659	$ 1,437,756	$ 2,570,104
Net Cost Rate Base				$ 239,144,564	$ 50,208,069	$ 672,621	$ 97,104,812	$ 23,755,976	$ 17,747,416	$ 32,944,387
Rate of Return				9.08%	10.20%	22.50%	7.44%	10.91%	8.10%	7.80%

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Class Allocation

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Operating Expenses								
Operation and Maintenance Expenses				$ 3,428,058	$ 2,916,973	$ 1,481,351	$ 3,476,565	$ 1,174,358
Depreciation and Amortization Expenses				435,106	340,395	180,928	418,249	274,136
Regulatory Credits and Accretion Expenses				(57,578)	(50,518)	(23,673)	(62,245)	(7,097)
Property Taxes			NPT	41,043	32,334	17,056	39,737	24,659
Other Taxes				28,800	22,689	11,968	27,883	17,303
Gain Disposition of Allowances				(1,839)	(1,608)	(810)	(1,897)	(193)
State and Federal Income Taxes			TXINCPF	$ 532,175	$ 361,526	$ 159,250	$ 365,060	$ (444,979)
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 26,400	$ 23,067	$ 10,168	$ 29,038	$ 4,940
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	$ (236,347)	$ (206,595)	$ (104,115)	$ (243,795)	$ (24,816)
Remove ECR expenses			ECRREV	$ (1,810)	$ (1,443)	$ (696)	$ (1,713)	$ (156)
Eliminate brokered sales expenses			Energy	$ (184,700)	$ (161,450)	$ (81,363)	$ (190,521)	$ (19,393)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (141,450)	$ (165,932)	$ -	$ (424,256)	$ (13,589)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 10,296	$ 8,055	$ 4,281	$ 9,897	$ 6,487
Labor adjustment			LBT	$ 4,273	$ 3,325	$ 1,810	$ 4,004	$ 4,242
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (860)	$ -	$ (395)	$ -	$ (3,556)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 430	$ 344	$ 166	$ 410	$ 37
Amortization of rate case expenses			OMT	$ 2,202	$ 1,874	$ 952	$ 2,233	$ 754
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 12,344	$ 9,607	$ 5,228	$ 11,568	$ 12,254
Adjustment for merger savings			LBT	$ 80,880	$ 62,948	$ 34,254	$ 75,796	$ 80,293
Adjustment for merger amortization expenses			LBT	$ (11,625)	$ (9,048)	$ (4,924)	$ (10,895)	$ (11,541)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 5,610	$ 4,922	$ 2,306	$ 6,064	$ 691
Adjustment for effect of accounting change			DET	$ 41,526	$ 32,487	$ 17,268	$ 39,917	$ 26,163
Adjustment for IT staff reduction			LBT	$ (2,565)	$ (1,997)	$ (1,087)	$ (2,404)	$ (2,547)
Adjustment to remove Alstom expenses			PLPPT	$ (20,800)	$ (18,250)	$ (8,552)	$ (22,486)	$ (2,564)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 888	$ 709	$ 343	$ 847	$ 77
Adjustment for OMU Nox expense			PLPPT	$ 13,037	$ 11,438	$ 5,360	$ 14,093	$ 1,607
Adjustment for ice storm			SDALL	$ (9,598)	$ -	$ (4,411)	$ -	$ (39,675)
Adjustment for management audit fee			OMT	$ 1,024	$ 872	$ 443	$ 1,039	$ 351
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (5,092)	$ (4,454)	$ (2,206)	$ (5,309)	$ (571)
VDT Amortization and Surcredit			VDTREV	$ (3,381)	$ (2,696)	$ (1,291)	$ (3,165)	$ (286)
Total Expense Adjustments				(445,720)	(435,284)	(136,629)	(738,674)	14,263
Total Operating Expenses		TOE		$ 3,986,444	$ 3,209,576	$ 1,699,608	$ 3,553,714	$ 1,057,389
Net Operating Income (Adjusted)				$ 914,249	$ 631,263	$ 284,498	$ 653,634	$ (629,614)
Net Cost Rate Base				$ 6,738,314	$ 5,192,612	$ 2,812,219	$ 6,367,053	$ 4,518,731
Rate of Return				13.57%	12.16%	10.12%	10.27%	-13.93%

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Description	Ref	Name	Allocation Vector	All Electric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Operating Expenses											
Operation and Maintenance Expenses				3,150,511	590,795	602,027	3,408,568	323,214	2,924,595	462,005	13,356,738
Depreciation and Amortization Expenses				514,052	93,849	135,562	1,853,401	214,910	932,522	149,201	1,733,976
Regulatory Credits and Accretion Expenses				(54,972)	(9,429)	(11,457)	(18,394)	(1,051)	(28,558)	(4,433)	(251,298)
Property Taxes			NPT	47,953	8,730	12,521	165,497	19,146	84,062	13,444	164,462
Other Taxes				33,649	6,126	8,786	116,130	13,434	58,987	9,434	115,403
Gain Disposition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(933)	(145)	(6,918)
State and Federal Income Taxes			TXINCPF	172,489	5,722	(1,865)	(358,755)	50,715	814,753	94,631	1,261,832
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-	(3,630,403)
Allocation of Curtailable Service Rider Credits			SCP	38,263	6,563	6,225	-	-	-	-	161,576
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	(192,211)	(32,967)	(32,629)	(77,281)	(4,417)	(119,883)	(18,611)	(888,821)
Remove ECR expenses			ECRREV	(1,423)	(232)	(262)	(1,953)	(291)	(2,260)	(330)	(6,866)
Eliminate brokered sales expenses			Energy	(150,209)	(25,763)	(25,499)	(60,394)	(3,452)	(93,686)	(14,544)	(694,595)
Eliminate DSM Expenses			DSMREV	-	-	-	-	-	-	-	-
Year end adjustment			YREND	-	(11,965)	-	10,181	7,379	43,060	(11,571)	-
Depreciation adjustment			DET	-	-	-	-	-	-	-	-
Adjustment for change in depreciation rate			DET	12,164	2,221	3,208	43,857	5,085	22,066	3,531	41,032
Labor adjustment			LBT	4,860	1,081	1,254	19,837	2,244	10,760	1,724	15,859
Medical Expense (See Functional Assignment)											-
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Storm damage adjustment			SDALL	(2,563)	(552)	(1,032)	(3,854)	(302)	(4,091)	(639)	(912)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	-	-	-	-	-	-	-
Adjustment for amortization of ESM audit expense			R01	338	58	62	462	68	534	78	1,412
Amortization of rate case expenses			OMT	2,024	379	387	2,189	208	1,879	297	8,579
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	-	-	-	-	-	-	-
Adjustment for VDT net savings to shareholders			LBT	14,041	3,122	3,624	57,308	6,482	31,087	4,981	45,816
Adjustment for merger savings			LBT	91,999	20,454	23,742	375,496	42,475	203,690	32,637	300,200
Adjustment for merger amortization expenses			LBT	(13,224)	(2,940)	(3,413)	(53,972)	(6,105)	(29,278)	(4,691)	(43,150)
Adjustment for MISO schedule 10 expenses			PLTRT	5,356	919	1,116	1,792	102	2,782	432	24,483
Adjustment for effect of accounting change			DET	49,061	8,957	12,938	176,888	20,511	88,999	14,240	165,490
Adjustment for IT staff reduction			LBT	(2,918)	(649)	(753)	(11,911)	(1,347)	(6,461)	(1,035)	(9,522)
Adjustment to remove Alstom expenses			PLPPT	(19,859)	(3,406)	(4,139)	(6,645)	(380)	(10,317)	(1,602)	(90,781)
Adjustment for corporate lease expense			LBT	-	-	-	-	-	-	-	-
Adjustment for sales tax refund			R01	698	120	128	953	141	1,102	162	2,913
Adjustment for OMU Nox expense			PLPPT	12,447	2,135	2,594	4,165	238	6,466	1,004	56,898
Adjustment for ice storm			SDALL	(28,599)	(6,163)	(11,514)	(43,003)	(3,368)	(45,541)	(7,132)	(10,180)
Adjustment for management audit fee			OMT	942	177	180	1,019	97	874	138	3,992
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(4,423)	(759)	(775)	(1,569)	(90)	(2,434)	(378)	(20,253)
VDT Amortization and Surcredit			VDTREV	(2,682)	(445)	(490)	(3,643)	(557)	(4,383)	(630)	(12,760)
Total Expense Adjustments				(224,183)	(46,221)	(31,273)	429,923	64,722	94,866	(1,939)	(1,111,166)
Total Operating Expenses		TOE		3,676,265	655,878	720,273	5,595,768	685,056	4,880,294	722,198	11,794,204
Net Operating Income (Adjusted)				375,547	28,779	25,751	(174,691)	121,956	1,448,234	176,622	2,321,278
Net Cost Rate Base				8,113,397	1,490,422	2,176,766	31,905,511	3,716,038	15,836,075	2,518,660	26,400,496
Rate of Return				**4.63%**	**1.93%**	**1.18%**	**-0.55%**	**3.28%**	**9.15%**	**7.01%**	**8.79%**

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Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBIT (SJB-3)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual				$ 768,801,159	$ 138,098,905	$ 147,748,544	$ 69,494,810	$ 2,833,889
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	675,000	$ 122,243	$ 129,125	$ 61,916	$ 2,528
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728)	$ (5,723,277)	$ (6,590,128)	$ (2,393,685)	$ (109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		1,417,623	$ 181,543	$ 182,116	$ 96,991	$ 4,709
Remove ECR revenues		ECRREV		(25,039,979)	$ (4,562,377)	$ (4,715,925)	$ (2,291,842)	$ (91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813	$ 3,208,163	$ 3,428,757	$ 1,647,196	$ 66,930
Remove off-system ECR revenues			PLPPT	(776,418)	$ (138,218)	$ (191,523)	$ (71,748)	$ (3,040)
Eliminate brokered sales			Energy	(22,575,669)	$ (3,600,306)	$ (4,145,611)	$ (1,505,781)	$ (68,786)
Eliminate ESM revenues collected		ESMREV		(4,604,742)	$ (915,119)	$ (611,110)	$ (428,633)	$ (15,263)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	1,630,147	$ 295,220	$ 311,841	$ 149,529	$ 6,105
Eliminate DSM Revenue		DSMREV		(2,942,935)	$ (1,508,819)	$ (1,089,604)	$ (222,733)	$ (10,743)
Year end adjustment		YREND		251,167	$ (417,181)	$ 1,771,704	$ 815,724	$ -
Merger savings			R01	(2,564,269)	$ (464,390)	$ (490,535)	$ (235,213)	$ (9,603)
Adjustment for rate switching, increased interruptible credit		RATESW		(3,005,567)				
VDT Amortization and Surcredit			VDTREV	85,337	$ 15,547	$ 16,258	$ 7,821	$ 304
Total Pro-Forma Operating Revenue			(13,506,972)	$ 693,449,939	$ 124,591,934	$ 135,753,911	$ 65,124,351	$ 2,606,152

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Combined Light & Power LPS		Combined Light & Power LPP		Combined Light & Power LPT		Large Comm/Ind TOD Primary LCIP		Large Comm/Ind TOD Transmission LCIT		High Load Factor Secondary HLFS		High Load Factor Primary HLFP
Cost of Service Summary – Pro-Forma																	
Operating Revenues																	
Total Operating Revenue – Actual				$	176,693,980	$	39,734,620	$	602,907	$	74,911,352	$	21,247,884	$	13,940,078	$	26,226,061
Pro-Forma Adjustments:																	
Eliminate unbilled revenue			R01	$	154,859	$	34,715	$	526	$	64,896	$	18,376	$	12,117	$	22,783
Adjustment for Mismatch in fuel cost recovery			Energy	$	(8,518,255)	$	(2,093,467)	$	(31,617)	$	(4,365,021)	$	(1,268,707)	$	(801,803)	$	(1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$	365,749	$	85,293	$	2,524	$	194,737	$	94,994	$	53,661	$	62,851
Remove ECR revenues		ECRREV		$	(5,734,057)	$	(1,290,905)	$	(19,498)	$	(2,401,012)	$	(688,721)	$	(446,972)	$	(838,688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$	4,133,949	$	917,554	$	14,085	$	1,735,487	$	492,058	$	316,548	$	606,165
Remove off-system ECR revenues			PLPPT	$	(156,106)	$	(37,923)	$	(604)	$	(70,555)	$	(19,496)	$	(12,090)	$	(22,844)
Eliminate brokered sales			Energy	$	(5,358,526)	$	(1,316,924)	$	(19,889)	$	(2,745,877)	$	(798,098)	$	(504,385)	$	(954,481)
Eliminate ESM revenues collected		ESMREV		$	(1,152,341)	$	(264,123)	$	(3,814)	$	(474,129)	$	(137,016)	$	(89,283)	$	(160,668)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$	373,990	$	83,837	$	1,271	$	156,727	$	44,379	$	29,263	$	55,022
Eliminate DSM Revenue		DSMREV		$	(98,441)	$	(12,123)	$	(472)	$	-	$	-	$	-	$	-
Year end adjustment		YREND		$	(597,774)	$	117,795	$	273,166	$	-	$	-	$	-	$	(537,561)
Merger savings			R01	$	(588,297)	$	(131,879)	$	(2,000)	$	(246,535)	$	(69,809)	$	(46,031)	$	(86,551)
Adjustment for rate switching, increased interruptible credit		RATESW				$	(42,856)			$	(64,186)	$	(120,793)				
VDT Amortization and Surcredit			VDTREV	$	19,479	$	4,382	$	66	$	8,140	$	2,334	$	1,514	$	2,828
Total Pro-Forma Operating Revenue			(13,506,972)	$	159,538,209	$	35,787,997	$	816,653	$	66,704,024	$	18,797,384	$	12,452,617	$	22,857,613

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Cost of Service Summary – Pro-Forma								
Operating Revenues								
Total Operating Revenue – Actual				$ 5,657,368	$ 4,549,667	$ 2,216,400	$ 5,433,524	$ 506,788
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	$ 4,976	$ 3,978	$ 1,924	$ 4,748	$ 432
Adjustment for Mismatch in fuel cost recovery			Energy	$ (268,036)	$ (234,296)	$ (118,074)	$ (276,483)	$ (28,144)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 12,843	$ 13,496	$ 2,865	$ 11,438	$ 1,179
Remove ECR revenues		ECRREV		$ (182,407)	$ (145,445)	$ (70,105)	$ (172,666)	$ (15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 132,466	$ 105,333	$ 51,614	$ 127,076	$ 11,770
Remove off-system ECR revenues			PLPPT	$ (5,481)	$ (4,328)	$ (2,496)	$ (5,692)	$ (800)
Eliminate brokered sales			Energy	$ (168,612)	$ (147,387)	$ (74,276)	$ (173,926)	$ (17,704)
Eliminate ESM revenues collected		ESMREV		$ (33,089)	$ (25,314)	$ (11,418)	$ (28,011)	$ (2,590)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 12,018	$ 9,606	$ 4,648	$ 11,466	$ 1,042
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ (234,645)	$ (275,257)	$ -	$ (703,778)	$ (22,542)
Merger savings			R01	$ (18,905)	$ (15,111)	$ (7,311)	$ (18,037)	$ (1,639)
Adjustment for rate switching, increased interruptible credit		RATESW						
VDT Amortization and Surcredit			VDTREV	$ 619	$ 493	$ 236	$ 579	$ 52
Total Pro-Forma Operating Revenue			(13,506,972)	$ 4,909,115	$ 3,835,436	$ 1,994,007	$ 4,210,238	$ 432,121

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue -- Actual				$ 4,499,169	$ 776,044	$ 810,389	$ 5,650,884	$ 817,736	$ 6,601,431	$ 972,090	$ 18,776,639
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	$ 3,911	$ 675	$ 717	$ 5,345	$ 790	$ 6,178	$ 907	$ 16,335
Adjustment for Mismatch in fuel cost recovery			Energy	$ (217,983)	$ (37,387)	$ (37,004)	$ (87,643)	$ (5,009)	$ (135,957)	$ (21,106)	$ (1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 9,719	$ 881	$ 1,457	$ (1,021)	$ (74)	$ (3,573)	$ (2,582)	$ 45,827
Remove ECR revenues		ECRREV		$ (143,373)	$ (23,364)	$ (26,381)	$ (196,772)	$ (29,280)	$ (227,715)	$ (33,264)	$ (691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 104,270	$ 17,741	$ 19,017	$ 144,134	$ 21,362	$ 166,721	$ 24,687	$ 493,730
Remove off-system ECR revenues			PLPPT	$ (6,197)	$ (1,063)	$ (741)	$ (2,000)	$ (114)	$ (2,941)	$ (457)	$ (19,961)
Eliminate brokered sales			Energy	$ (137,125)	$ (23,519)	$ (23,278)	$ (55,133)	$ (3,151)	$ (85,526)	$ (13,277)	$ (634,093)
Eliminate ESM revenues collected		ESMREV		$ (21,999)	$ 1,124	$ (4,856)	$ (37,564)	$ (5,964)	$ (43,690)	$ (6,279)	$ (133,593)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 9,445	$ 1,630	$ 1,730	$ 12,909	$ 1,908	$ 14,921	$ 2,192	$ 39,449
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ -	$ (19,849)	$ -	$ 16,889	$ 12,240	$ 71,430	$ (19,194)	$ -
Merger savings			R01	$ (14,857)	$ (2,564)	$ (2,722)	$ (20,307)	$ (3,001)	$ (23,470)	$ (3,447)	$ (62,054)
Adjustment for rate switching, increased interruptible credit		RATESW									$ (2,777,732)
VDT Amortization and Surcredit			VDTREV	$ 491	$ 81	$ 90	$ 667	$ 102	$ 802	$ 115	$ 2,335
Total Pro-Forma Operating Revenue			(13,506,972)	$ 4,085,470	$ 690,430	$ 738,418	$ 5,430,388	$ 807,544	$ 6,338,611	$ 900,385	$ 14,046,931

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Operating Expenses								
Operation and Maintenance Expenses				$ 548,721,322	$ 107,522,919	$ 120,479,725	$ 46,905,956	$ 1,655,416
Depreciation and Amortization Expenses				88,376,624	20,215,410	23,172,879	9,628,793	259,472
Regulatory Credits and Accretion Expenses				(8,656,053)	(1,540,948)	(2,135,228)	(799,894)	(33,890)
Property Taxes			NPT	8,211,450	1,860,240	2,147,561	888,762	24,457
Other Taxes				5,761,996	1,305,335	1,506,949	623,647	17,162
Gain Disposition of Allowances				(246,288)	(39,277)	(45,226)	(16,427)	(750)
State and Federal Income Taxes			TXINCPF	26,916,596	$ (1,673,726)	$ (4,042,011)	$ 2,599,323	$ 287,430
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP1	$ 4,582,475	$ 934,980	$ 771,944	$ 449,462	$ 11,972
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(31,644,777)	$ (5,046,623)	$ (5,810,987)	$ (2,110,684)	$ (96,419)
Remove ECR expenses			ECRREV	(248,468)	$ (45,272)	$ (46,795)	$ (22,742)	$ (908)
Eliminate brokered sales expenses			Energy	(24,729,742)	$ (3,943,832)	$ (4,541,167)	$ (1,649,456)	$ (75,349)
Eliminate DSM Expenses			DSMREV	(2,946,471)	$ (1,510,632)	$ (1,090,913)	$ (223,001)	$ (10,756)
Year end adjustment			YREND	151,410	$ (251,488)	$ 1,068,029	$ 491,740	$ -
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	2,091,278	$ 478,362	$ 548,346	$ 227,849	$ 6,140
Labor adjustment			LBT	1,002,076	$ 250,942	$ 251,816	$ 106,754	$ 2,471
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	(473,014)	$ (168,017)	$ (153,325)	$ (69,375)	$ (554)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	58,333	$ 10,564	$ 11,159	$ 5,351	$ 218
Amortization of rate case expenses			OMT	352,456	$ 69,064	$ 77,387	$ 30,129	$ 1,063
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	2,895,000	$ 724,972	$ 727,498	$ 308,413	$ 7,138
Adjustment for merger savings			LBT	18,968,825	$ 4,750,213	$ 4,766,762	$ 2,020,807	$ 46,767
Adjustment for merger amortization expenses			LBT	(2,726,510)	$ (682,778)	$ (685,157)	$ (290,463)	$ (6,722)
Adjustment for MISO schedule 10 expenses			PLTRT	843,344	$ 150,132	$ 208,032	$ 77,932	$ 3,302
Adjustment for effect of accounting change			DET	8,434,618	$ 1,929,348	$ 2,211,607	$ 918,967	$ 24,764
Adjustment for IT staff reduction			LBT	(601,682)	$ (150,674)	$ (151,199)	$ (64,099)	$ (1,483)
Adjustment to remove Alstom expenses			PLPPT	(3,126,995)	$ (556,667)	$ (771,350)	$ (288,961)	$ (12,243)
Adjustment for corporate lease expense			LBT	-	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	120,391	$ 21,803	$ 23,030	$ 11,043	$ 451
Adjustment for OMU Nox expense			PLPPT	1,959,879	$ 348,897	$ 483,452	$ 181,110	$ 7,673
Adjustment for ice storm			SDALL	(5,277,336)	$ (1,874,536)	$ (1,710,617)	$ (774,008)	$ (6,178)
Adjustment for management audit fee			OMT	163,982	$ 32,133	$ 36,005	$ 14,018	$ 495
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(705,035)	$ (116,752)	$ (144,138)	$ (53,008)	$ (2,350)
VDT Amortization and Surcredit			VDTREV	(466,280)	$ (84,947)	$ (88,836)	$ (42,731)	$ (1,661)
Total Expense Adjustments				(35,904,718)	(5,665,788)	(4,781,363)	(1,194,417)	(114,142)
Total Operating Expenses		TOE		$ 633,180,928	$ 122,919,145	$ 137,075,229	$ 59,085,206	$ 2,107,127
Net Operating Income (Adjusted)				$ 60,269,011	$ 1,672,788	$ (1,321,318)	$ 6,039,145	$ 499,025
Net Cost Rate Base				$ 1,412,033,543	$ 328,764,003	$ 371,073,844	$ 155,533,255	$ 3,988,815
Rate of Return				4.27%	0.51%	-0.36%	3.88%	12.51%

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

Exhibit ____ (SJB-3)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Operating Expenses										
Operation and Maintenance Expenses				$ 114,460,537	$ 26,120,793	$ 391,342	$ 52,102,212	$ 14,624,123	$ 9,449,840	$ 17,751,732
Depreciation and Amortization Expenses				14,434,387	3,157,715	45,493	5,809,620	1,457,184	1,029,621	1,875,937
Regulatory Credits and Accretion Expenses				(1,740,378)	(422,796)	(6,730)	(786,596)	(217,355)	(134,792)	(254,680)
Property Taxes			NPT	1,354,595	298,066	4,320	548,746	138,463	97,063	177,219
Other Taxes				950,523	209,154	3,032	385,057	97,160	68,109	124,355
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8,707)	(5,503)	(10,413)
State and Federal Income Taxes			TXINCPF	$ 13,932,976	$ 3,168,662	$ 93,531	$ 4,904,205	$ 1,705,478	$ 1,028,417	$ 1,890,385
Specific Assignment of Curtailable Service Rider Credit				-	(181,381)	-	(271,654)	(499,037)	-	-
Allocation of Curtailable Service Rider Credits			SCP1	$ 1,097,059	$ 240,238	$ 4,049	$ 441,260	$ 101,228	$ 78,321	$ 145,724
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (7,511,155)	$ (1,845,959)	$ (27,879)	$ (3,848,951)	$ (1,118,710)	$ (707,007)	$ (1,337,916)
Remove ECR expenses			ECRREV	$ (56,898)	$ (12,809)	$ (193)	$ (23,825)	$ (6,834)	$ (4,435)	$ (8,322)
Eliminate brokered sales expenses			Energy	$ (5,869,813)	$ (1,442,579)	$ (21,787)	$ (3,007,876)	$ (874,249)	$ (552,511)	$ (1,045,554)
Eliminate DSM Expenses			DSMREV	$ (98,559)	$ (12,138)	$ (473)	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (360,354)	$ 71,010	$ 164,672	$ -	$ -	$ -	$ (324,056)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 341,564	$ 74,722	$ 1,077	$ 137,474	$ 34,482	$ 24,364	$ 44,391
Labor adjustment			LBT	$ 174,630	$ 32,087	$ 447	$ 60,482	$ 15,597	$ 11,191	$ 20,309
Medical Expense (See Functional Assignment)										
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (42,357)	$ (5,656)	$ -	$ (9,718)	$ -	$ (2,245)	$ (3,009)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 13,383	$ 3,000	$ 45	$ 5,608	$ 1,588	$ 1,047	$ 1,969
Amortization of rate case expenses			OMT	$ 73,521	$ 16,778	$ 251	$ 33,466	$ 9,393	$ 6,070	$ 11,402
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 504,506	$ 92,699	$ 1,291	$ 174,732	$ 45,061	$ 32,332	$ 58,672
Adjustment for merger savings			LBT	$ 3,305,659	$ 607,386	$ 8,457	$ 1,144,894	$ 295,251	$ 211,847	$ 384,434
Adjustment for merger amortization expenses			LBT	$ (475,143)	$ (87,303)	$ (1,216)	$ (164,563)	$ (42,438)	$ (30,450)	$ (55,257)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 169,562	$ 41,192	$ 656	$ 76,637	$ 21,177	$ 13,133	$ 24,813
Adjustment for effect of accounting change			DET	$ 1,377,610	$ 301,371	$ 4,342	$ 554,467	$ 139,073	$ 98,266	$ 179,038
Adjustment for IT staff reduction			LBT	$ (104,854)	$ (19,266)	$ (268)	$ (36,316)	$ (9,365)	$ (6,720)	$ (12,194)
Adjustment to remove Alstom expenses			PLPPT	$ (628,711)	$ (152,735)	$ (2,431)	$ (284,158)	$ (78,520)	$ (48,694)	$ (92,003)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 27,620	$ 6,192	$ 94	$ 11,575	$ 3,278	$ 2,161	$ 4,064
Adjustment for OMU Nox expense			PLPPT	$ 394,051	$ 95,728	$ 1,524	$ 178,099	$ 49,213	$ 30,519	$ 57,664
Adjustment for ice storm			SDALL	$ (472,573)	$ (63,098)	$ -	$ (108,425)	$ -	$ (25,051)	$ (33,566)
Adjustment for management audit fee			OMT	$ 34,206	$ 7,806	$ 117	$ 15,570	$ 4,370	$ 2,824	$ 5,305
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (158,899)	$ (38,919)	$ (597)	$ (78,596)	$ (22,541)	$ (14,176)	$ (26,816)
VDT Amortization and Surcredit			VDTREV	$ (106,432)	$ (23,944)	$ (363)	$ (44,478)	$ (12,752)	$ (8,271)	$ (15,454)
Total Expense Adjustments				(9,469,436)	(2,354,437)	127,766	(5,213,900)	(1,546,926)	(965,804)	(2,162,086)
Total Operating Expenses		TOE		$ 134,961,804	$ 30,221,647	$ 662,586	$ 57,888,992	$ 15,851,611	$ 10,645,271	$ 19,538,175
Net Operating Income (Adjusted)				$ 24,576,405	$ 5,566,350	$ 154,067	$ 8,815,032	$ 2,945,773	$ 1,807,345	$ 3,319,438
Net Cost Rate Base				$ 226,972,096	$ 48,946,899	$ 694,716	$ 90,292,938	$ 22,427,620	$ 16,112,733	$ 29,237,650
Rate of Return				10.83%	11.37%	22.18%	9.76%	13.13%	11.22%	11.35%

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

Exhibit ____ (SJB-3)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Operating Expenses								
Operation and Maintenance Expenses				$ 3,484,867	$ 2,866,264	$ 1,550,678	$ 3,501,953	$ 1,202,960
Depreciation and Amortization Expenses				458,769	325,215	208,749	426,370	286,346
Regulatory Credits and Accretion Expenses				(61,110)	(48,252)	(27,826)	(63,458)	(8,920)
Property Taxes			NPT	43,292	30,892	19,699	40,508	25,819
Other Taxes				30,378	21,677	13,823	28,425	18,117
Gain Disposition of Allowances				(1,839)	(1,608)	(810)	(1,897)	(193)
State and Federal Income Taxes			TXINCPF	$ 499,613	$ 388,025	$ 119,969	$ 351,568	$ (461,502)
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP1	$ 26,400	$ 23,067	$ 10,168	$ 29,038	$ 4,940
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	$ (236,347)	$ (205,595)	$ (104,115)	$ (243,795)	$ (24,816)
Remove ECR expenses			ECRREV	$ (1,810)	$ (1,443)	$ (696)	$ (1,713)	$ (156)
Eliminate brokered sales expenses			Energy	$ (184,700)	$ (161,450)	$ (81,363)	$ (190,521)	$ (19,393)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (141,450)	$ (165,932)	$ -	$ (424,256)	$ (13,589)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 10,856	$ 7,696	$ 4,940	$ 10,089	$ 6,776
Labor adjustment			LBT	$ 4,407	$ 3,239	$ 1,967	$ 4,050	$ 4,311
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (860)	$ -	$ (395)	$ -	$ (3,556)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 430	$ 344	$ 166	$ 410	$ 37
Amortization of rate case expenses			OMT	$ 2,238	$ 1,841	$ 996	$ 2,249	$ 773
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 12,731	$ 9,359	$ 5,683	$ 11,701	$ 12,454
Adjustment for merger savings			LBT	$ 83,418	$ 61,320	$ 37,237	$ 76,667	$ 81,602
Adjustment for merger amortization expenses			LBT	$ (11,990)	$ (8,814)	$ (5,352)	$ (11,020)	$ (11,729)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 5,954	$ 4,701	$ 2,711	$ 6,183	$ 869
Adjustment for effect of accounting change			DET	$ 43,785	$ 31,038	$ 19,923	$ 40,693	$ 27,329
Adjustment for IT staff reduction			LBT	$ (2,646)	$ (1,945)	$ (1,181)	$ (2,432)	$ (2,588)
Adjustment to remove Alstom expenses			PLPPT	$ (22,076)	$ (17,431)	$ (10,052)	$ (22,924)	$ (3,222)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 888	$ 709	$ 343	$ 847	$ 77
Adjustment for OMU Nox expense			PLPPT	$ 13,836	$ 10,925	$ 6,300	$ 14,368	$ 2,020
Adjustment for ice storm			SDALL	$ (9,598)	$ -	$ (4,411)	$ -	$ (39,675)
Adjustment for management audit fee			OMT	$ 1,041	$ 857	$ 463	$ 1,047	$ 359
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (5,171)	$ (4,381)	$ (2,302)	$ (5,345)	$ (610)
VDT Amortization and Surcredit			VDTREV	$ (3,381)	$ (2,696)	$ (1,291)	$ (3,165)	$ (286)
Total Expense Adjustments				(440,445)	(438,658)	(130,429)	(736,868)	16,985
Total Operating Expenses		TOE		$ 4,039,922	$ 3,166,621	$ 1,764,022	$ 3,575,639	$ 1,084,553
Net Operating Income (Adjusted)				$ 859,192	$ 668,815	$ 229,986	$ 634,600	$ (652,432)
Net Cost Rate Base				$ 7,085,179	$ 4,970,085	$ 3,220,039	$ 6,486,097	$ 4,697,715
Rate of Return				12.27%	13.46%	7.14%	9.78%	-13.89%

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Operating Expenses											
Operation and Maintenance Expenses				3,372,049	628,793	553,535	3,532,608	330,304	3,082,355	486,496	12,663,868
Depreciation and Amortization Expenses				608,624	110,069	114,189	1,879,564	216,405	960,855	153,599	1,541,360
Regulatory Credits and Accretion Expenses				(69,089)	(11,850)	(8,266)	(22,299)	(1,274)	(32,788)	(5,090)	(222,545)
Property Taxes			NPT	56,940	10,271	10,490	167,983	19,288	86,755	13,862	146,158
Other Taxes				39,955	7,207	7,361	117,874	13,534	60,876	9,727	102,560
Gain Disposition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(933)	(145)	(6,918)
State and Federal Income Taxes			TXINCPF	44,515	(16,228)	26,438	(418,832)	47,282	740,480	83,101	1,617,497
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-	(3,630,403)
Allocation of Curtailable Service Rider Credits			SCP1	38,263	6,563	6,225	-	-	-	-	161,576
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	(192,211)	(32,967)	(32,629)	(77,281)	(4,417)	(119,883)	(18,611)	(888,821)
Remove ECR expenses			ECRREV	(1,423)	(232)	(262)	(1,953)	(291)	(2,260)	(330)	(6,866)
Eliminate brokered sales expenses			Energy	(150,209)	(25,763)	(25,499)	(60,394)	(3,452)	(93,686)	(14,544)	(694,595)
Eliminate DSM Expenses			DSMREV	-	-	-	-	-	-	-	-
Year end adjustment			YREND	-	(11,965)	-	10,181	7,379	43,060	(11,571)	-
Depreciation adjustment			DET	-	-	-	-	-	-	-	-
Adjustment for change in depreciation rate			DET	14,402	2,605	2,702	44,477	5,121	22,737	3,635	36,474
Labor adjustment			LBT	5,396	1,172	1,133	19,985	2,252	10,921	1,749	14,768
Medical Expense (See Functional Assignment)											-
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Storm damage adjustment			SDALL	(2,563)	(552)	(1,032)	(3,854)	(302)	(4,091)	(639)	(912)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	-	-	-	-	-	-	-
Adjustment for amortization of ESM audit expense			R01	338	58	62	462	68	534	78	1,412
Amortization of rate case expenses			OMT	2,166	404	356	2,269	212	1,980	312	8,134
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	-	-	-	-	-	-	-
Adjustment for VDT net savings to shareholders			LBT	15,589	3,387	3,274	57,736	6,507	31,551	5,053	42,664
Adjustment for merger savings			LBT	102,141	22,193	21,450	378,302	42,635	206,728	33,109	279,545
Adjustment for merger amortization expenses			LBT	(14,681)	(3,190)	(3,083)	(54,376)	(6,128)	(29,714)	(4,759)	(40,181)
Adjustment for MISO schedule 10 expenses			PLTRT	6,731	1,155	805	2,173	124	3,194	496	21,682
Adjustment for effect of accounting change			DET	58,087	10,505	10,898	179,385	20,654	91,703	14,659	147,107
Adjustment for IT staff reduction			LBT	(3,240)	(704)	(680)	(12,000)	(1,352)	(6,557)	(1,050)	(8,867)
Adjustment to remove Alstom expenses			PLPPT	(24,958)	(4,281)	(2,986)	(8,056)	(460)	(11,844)	(1,839)	(80,394)
Adjustment for corporate lease expense			LBT	-	-	-	-	-	-	-	-
Adjustment for sales tax refund			R01	698	120	128	953	141	1,102	162	2,913
Adjustment for OMU Nox expense			PLPPT	15,643	2,683	1,872	5,049	289	7,424	1,152	50,388
Adjustment for ice storm			SDALL	(28,599)	(6,163)	(11,514)	(43,003)	(3,368)	(45,641)	(7,132)	(10,180)
Adjustment for management audit fee			OMT	1,008	188	165	1,056	99	921	145	3,785
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(4,726)	(811)	(709)	(1,753)	(100)	(2,671)	(415)	(19,249)
VDT Amortization and Surcredit			VDTREV	(2,682)	(445)	(490)	(3,643)	(557)	(4,383)	(630)	(12,760)
Total Expense Adjustments				(203,096)	(42,604)	(36,039)	435,715	65,053	101,124	(968)	(1,153,955)
Total Operating Expenses		TOE		3,886,664	691,965	673,678	5,692,011	690,556	4,998,723	740,583	11,219,199
Net Operating Income (Adjusted)				198,807	(1,535)	64,740	(261,623)	116,988	1,339,887	159,803	2,827,732
Net Cost Rate Base				9,499,702	1,728,194	1,863,467	32,289,016	3,737,956	16,251,399	2,583,135	23,576,990
Rate of Return				2.09%	-0.09%	3.47%	-0.81%	3.13%	8.24%	6.19%	11.99%

Avg Excess Prod Trans Allocation
All other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 2003-00433
AND	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)	CASE NO. 2003-00434

EXHIBIT (SJB-4)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual			$	768,801,159 $	138,042,992 $	148,047,263 $	69,229,545 $	2,810,354
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	675,000 $	122,243 $	129,125 $	61,916 $	2,528
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728) $	(5,723,277) $	(6,590,128) $	(2,393,685) $	(109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		1,417,623 $	181,543 $	182,116 $	96,991 $	4,709
Remove ECR revenues		ECRREV		(25,039,979) $	(4,562,377) $	(4,715,925) $	(2,291,842) $	(91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813 $	3,208,163 $	3,428,757 $	1,647,196 $	66,930
Remove off-system ECR revenues			PLPPT	(776,418) $	(136,190) $	(202,354) $	(62,130) $	(2,186)
Eliminate brokered sales			Energy	(22,575,669) $	(3,600,306) $	(4,145,611) $	(1,505,781) $	(68,786)
Eliminate ESM revenues collected		ESMREV		(4,604,742) $	(915,119) $	(611,110) $	(428,633) $	(15,263)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	1,630,147 $	295,220 $	311,841 $	149,529 $	6,105
Eliminate DSM Revenue		DSMREV		(2,942,935) $	(1,508,819) $	(1,089,604) $	(222,733) $	(10,743)
Year end adjustment		YREND		251,167 $	(417,181) $	1,771,704 $	815,724 $	-
Merger savings			R01	(2,564,269) $	(464,390) $	(490,535) $	(235,213) $	(9,603)
Adjustment for rate switching, increased interruptible credit		RATESW		(3,005,567)				
VDT Amortization and Surcredit			VDTREV	85,337 $	15,547 $	16,258 $	7,821 $	304
Total Pro-Forma Operating Revenue			(13,504,945) $	693,449,939 $	124,538,048 $	136,041,798 $	64,868,705 $	2,583,471

Summer/Winter Average CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 176,892,840	$ 39,702,482	$ 601,680	$ 74,869,722	$ 21,186,666	$ 13,936,369	$ 26,236,029
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	$ 154,859	$ 34,715	$ 526	$ 64,896	$ 18,376	$ 12,117	$ 22,783
Adjustment for Mismatch in fuel cost recovery			Energy	$ (8,518,255)	$ (2,093,467)	$ (31,617)	$ (4,365,021)	$ (1,268,707)	$ (801,803)	$ (1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 365,749	$ 85,293	$ 2,524	$ 194,737	$ 94,994	$ 53,661	$ 62,851
Remove ECR revenues		ECRREV		$ (5,734,057)	$ (1,290,905)	$ (19,498)	$ (2,401,012)	$ (688,721)	$ (446,972)	$ (838,688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 4,133,949	$ 917,554	$ 14,085	$ 1,735,487	$ 492,058	$ 316,548	$ 606,165
Remove off-system ECR revenues			PLPPT	$ (163,316)	$ (36,758)	$ (559)	$ (69,046)	$ (17,276)	$ (11,956)	$ (23,205)
Eliminate brokered sales			Energy	$ (5,358,526)	$ (1,316,924)	$ (19,889)	$ (2,745,877)	$ (798,098)	$ (504,385)	$ (954,481)
Eliminate ESM revenues collected		ESMREV		$ (1,152,341)	$ (264,123)	$ (3,814)	$ (474,129)	$ (137,016)	$ (89,283)	$ (160,668)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 373,990	$ 83,837	$ 1,271	$ 156,727	$ 44,379	$ 29,263	$ 55,022
Eliminate DSM Revenue		DSMREV		$ (98,441)	$ (12,123)	$ (472)	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ (597,774)	$ 117,795	$ 273,166	$ -	$ -	$ -	$ (537,561)
Merger savings			R01	$ (588,297)	$ (131,879)	$ (2,000)	$ (246,535)	$ (69,809)	$ (46,031)	$ (86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			$ (42,856)		$ (64,186)	$ (120,793)		
VDT Amortization and Surcredit			VDTREV	$ 19,479	$ 4,382	$ 66	$ 8,140	$ 2,334	$ 1,514	$ 2,828
Total Pro-Forma Operating Revenue			(13,504,945)	$ 159,729,858	$ 35,757,024	$ 815,470	$ 66,663,904	$ 18,738,386	$ 12,449,042	$ 22,867,219

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual				$ 5,638,015	$ 4,546,102	$ 2,199,244	$ 5,422,766	$ 503,555
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	$ 4,976	$ 3,978	$ 1,924	$ 4,748	$ 432
Adjustment for Mismatch in fuel cost recovery			Energy	$ (268,036)	$ (234,296)	$ (118,074)	$ (276,483)	$ (28,144)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 12,843	$ 13,496	$ 2,865	$ 11,438	$ 1,179
Remove ECR revenues		ECRREV		$ (182,407)	$ (145,445)	$ (70,105)	$ (172,666)	$ (15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 132,466	$ 105,333	$ 51,614	$ 127,076	$ 11,770
Remove off-system ECR revenues			PLPPT	$ (4,780)	$ (4,199)	$ (1,874)	$ (5,302)	$ (683)
Eliminate brokered sales			Energy	$ (168,612)	$ (147,387)	$ (74,276)	$ (173,926)	$ (17,704)
Eliminate ESM revenues collected		ESMREV		$ (33,089)	$ (25,314)	$ (11,418)	$ (28,011)	$ (2,590)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 12,018	$ 9,606	$ 4,648	$ 11,466	$ 1,042
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ (234,645)	$ (275,257)	$ -	$ (703,778)	$ (22,542)
Merger savings			R01	$ (18,905)	$ (15,111)	$ (7,311)	$ (18,037)	$ (1,639)
Adjustment for rate switching, increased interruptible credit		RATESW						
VDT Amortization and Surcredit			VDTREV	$ 619	$ 493	$ 236	$ 579	$ 52
Total Pro-Forma Operating Revenue			(13,504,945)	$ 4,890,463	$ 3,832,000	$ 1,977,473	$ 4,199,870	$ 429,005

Summer/Winter Average CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue -- Actual				$ 4,474,128	$ 771,749	$ 821,029	$ 5,630,511	$ 816,571	$ 6,574,367	$ 967,888	$ 18,879,292
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	$ 3,911	$ 675	$ 717	$ 5,345	$ 790	$ 6,178	$ 907	$ 16,335
Adjustment for Mismatch in fuel cost recovery			Energy	$ (217,983)	$ (37,387)	$ (37,004)	$ (87,643)	$ (5,009)	$ (135,957)	$ (21,106)	$ (1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 9,719	$ 881	$ 1,457	$ (1,021)	$ (74)	$ (3,573)	$ (2,582)	$ 45,827
Remove ECR revenues		ECRREV		$ (143,373)	$ (23,364)	$ (26,381)	$ (196,772)	$ (29,280)	$ (227,715)	$ (33,264)	$ (691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 104,270	$ 17,741	$ 19,017	$ 144,134	$ 21,362	$ 166,721	$ 24,687	$ 493,730
Remove off-system ECR revenues			PLPPT	$ (5,289)	$ (907)	$ (1,127)	$ (1,261)	$ (72)	$ (1,960)	$ (304)	$ (23,684)
Eliminate brokered sales			Energy	$ (137,125)	$ (23,519)	$ (23,278)	$ (55,133)	$ (3,151)	$ (85,526)	$ (13,277)	$ (634,093)
Eliminate ESM revenues collected		ESMREV		$ (21,999)	$ 1,124	$ (4,856)	$ (37,564)	$ (5,964)	$ (43,690)	$ (6,279)	$ (133,593)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 9,445	$ 1,630	$ 1,730	$ 12,909	$ 1,908	$ 14,921	$ 2,192	$ 39,449
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ -	$ (19,849)	$ -	$ 16,889	$ 12,240	$ 71,430	$ (19,194)	$ -
Merger savings			R01	$ (14,857)	$ (2,564)	$ (2,722)	$ (20,307)	$ (3,001)	$ (23,470)	$ (3,447)	$ (62,054)
Adjustment for rate switching, increased interruptible credit		RATESW									$ (2,777,732)
VDT Amortization and Surcredit			VDTREV	$ 491	$ 81	$ 90	$ 667	$ 102	$ 802	$ 115	$ 2,335
Total Pro-Forma Operating Revenue			(13,504,945)	$ 4,061,337	$ 686,291	$ 748,672	$ 5,410,754	$ 806,422	$ 6,312,528	$ 896,336	$ 14,145,862

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12 Months Ended
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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Operating Expenses								
Operation and Maintenance Expenses				$ 548,721,322	$ 106,362,519	$ 119,256,735	$ 44,251,501	$ 1,484,596
Depreciation and Amortization Expenses				88,376,624	20,064,000	23,981,791	8,910,473	195,742
Regulatory Credits and Accretion Expenses				(8,656,053)	(1,518,346)	(2,255,980)	(692,665)	(24,376)
Property Taxes			NPT	8,211,450	1,845,852	2,224,429	820,503	18,401
Other Taxes				5,761,996	1,295,239	1,560,887	575,749	12,912
Gain Disposition of Allowances				(246,288)	(39,277)	(45,226)	(16,427)	(750)
State and Federal Income Taxes			TXINCPF	26,916,596	$ (1,152,038)	$ (3,910,688)	$ 3,953,435	$ 382,134
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 4,582,475	$ 934,980	$ 771,944	$ 449,462	$ 11,972
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(31,644,777)	$ (5,046,623)	$ (5,810,987)	$ (2,110,684)	$ (96,419)
Remove ECR expenses			ECRREV	(248,468)	$ (45,272)	$ (46,795)	$ (22,742)	$ (908)
Eliminate brokered sales expenses			Energy	(24,729,742)	$ (3,943,832)	$ (4,541,167)	$ (1,649,456)	$ (75,349)
Eliminate DSM Expenses			DSMREV	(2,945,471)	$ (1,510,632)	$ (1,090,913)	$ (223,001)	$ (10,756)
Year end adjustment			YREND	151,410	$ (251,488)	$ 1,068,029	$ 491,740	$ -
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	2,091,278	$ 474,779	$ 567,487	$ 210,851	$ 4,632
Labor adjustment			LBT	1,002,076	$ 250,084	$ 256,399	$ 102,685	$ 2,110
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	(473,014)	$ (168,017)	$ (153,325)	$ (69,375)	$ (554)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	58,333	$ 10,564	$ 11,159	$ 5,351	$ 218
Amortization of rate case expenses			OMT	352,456	$ 68,319	$ 76,601	$ 28,424	$ 954
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	2,895,000	$ 722,494	$ 740,735	$ 296,657	$ 6,095
Adjustment for merger savings			LBT	18,968,825	$ 4,733,976	$ 4,853,506	$ 1,943,777	$ 39,933
Adjustment for merger amortization expenses			LBT	(2,726,510)	$ (680,445)	$ (697,625)	$ (279,391)	$ (5,740)
Adjustment for MISO schedule 10 expenses			PLTRT	843,344	$ 147,930	$ 219,796	$ 67,485	$ 2,375
Adjustment for effect of accounting change			DET	8,434,618	$ 1,914,897	$ 2,288,809	$ 850,411	$ 18,682
Adjustment for IT staff reduction			LBT	(601,682)	$ (150,159)	$ (153,951)	$ (61,656)	$ (1,267)
Adjustment to remove Alstom expenses			PLPPT	(3,126,995)	$ (548,502)	$ (814,972)	$ (250,225)	$ (8,806)
Adjustment for corporate lease expense			LBT	-	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	120,391	$ 21,803	$ 23,030	$ 11,043	$ 451
Adjustment for OMU Nox expense			PLPPT	1,959,879	$ 343,780	$ 510,793	$ 156,831	$ 5,519
Adjustment for ice storm			SDALL	(5,277,336)	$ (1,874,536)	$ (1,710,617)	$ (774,008)	$ (6,178)
Adjustment for management audit fee			OMT	163,982	$ 31,786	$ 35,639	$ 13,224	$ 444
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(705,035)	$ (114,982)	$ (141,764)	$ (49,153)	$ (2,111)
VDT Amortization and Surcredit			VDTREV	(466,280)	$ (84,947)	$ (88,836)	$ (42,731)	$ (1,661)
Total Expense Adjustments				(35,904,718)	(5,699,021)	(4,598,967)	(1,353,943)	(128,337)
Total Operating Expenses		TOE		$ 633,180,928	$ 122,093,908	$ 136,984,925	$ 56,898,087	$ 1,952,294
Net Operating Income (Adjusted)				$ 60,269,011	$ 2,444,140	$ (943,126)	$ 7,970,617	$ 631,177
Net Cost Rate Base				$ 1,412,033,543	$ 326,544,534	$ 382,931,422	$ 145,003,625	$ 3,054,618
Rate of Return				4.27%	0.75%	-0.25%	5.50%	20.66%

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Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Operating Expenses										
Operation and Maintenance Expenses				$ 117,230,078	$ 26,376,329	$ 389,251	$ 53,278,685	$ 14,752,145	$ 9,739,162	$ 18,395,937
Depreciation and Amortization Expenses				14,972,889	3,070,687	42,170	5,696,889	1,291,409	1,019,576	1,902,929
Regulatory Credits and Accretion Expenses				(1,820,763)	(409,805)	(6,234)	(769,768)	(192,609)	(133,293)	(258,709)
Property Taxes			NPT	1,405,766	289,796	4,005	538,034	122,710	96,108	179,784
Other Taxes				986,430	203,351	2,810	377,540	86,106	67,439	126,155
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8,707)	(5,503)	(10,413)
State and Federal Income Taxes			TXINCPF	$ 12,611,316	$ 3,105,793	$ 95,789	$ 4,490,338	$ 1,726,776	$ 918,998	$ 1,625,425
Specific Assignment of Curtailable Service Rider Credit				-	(181,381)	-	(271,654)	(499,037)	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 1,097,059	$ 240,238	$ 4,049	$ 441,260	$ 101,228	$ 78,321	$ 145,724
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (7,511,155)	$ (1,845,959)	$ (27,879)	$ (3,848,951)	$ (1,118,710)	$ (707,007)	$ (1,337,916)
Remove ECR expenses			ECRREV	$ (56,898)	$ (12,809)	$ (193)	$ (23,825)	$ (6,834)	$ (4,435)	$ (8,322)
Eliminate brokered sales expenses			Energy	$ (5,869,813)	$ (1,442,579)	$ (21,787)	$ (3,007,876)	$ (874,249)	$ (552,511)	$ (1,045,554)
Eliminate DSM Expenses			DSMREV	$ (98,559)	$ (12,138)	$ (473)	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (360,354)	$ 71,010	$ 164,672	$ -	$ -	$ -	$ (324,056)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 354,307	$ 72,662	$ 998	$ 134,807	$ 30,559	$ 24,126	$ 45,029
Labor adjustment			LBT	$ 177,680	$ 31,594	$ 428	$ 59,843	$ 14,658	$ 11,134	$ 20,462
Medical Expense (See Functional Assignment)										
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (42,357)	$ (5,656)	$ -	$ (9,718)	$ -	$ (2,245)	$ (3,009)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 13,383	$ 3,000	$ 45	$ 5,608	$ 1,588	$ 1,047	$ 1,969
Amortization of rate case expenses			OMT	$ 75,300	$ 16,942	$ 250	$ 34,222	$ 9,476	$ 6,256	$ 11,816
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 513,319	$ 91,274	$ 1,236	$ 172,887	$ 42,348	$ 32,168	$ 59,114
Adjustment for merger savings			LBT	$ 3,363,406	$ 598,053	$ 8,101	$ 1,132,806	$ 277,474	$ 210,770	$ 387,328
Adjustment for merger amortization expenses			LBT	$ (483,444)	$ (85,962)	$ (1,164)	$ (162,825)	$ (39,883)	$ (30,295)	$ (55,673)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 177,394	$ 39,927	$ 607	$ 74,997	$ 18,766	$ 12,987	$ 25,206
Adjustment for effect of accounting change			DET	$ 1,429,005	$ 293,065	$ 4,025	$ 543,708	$ 123,251	$ 97,308	$ 181,614
Adjustment for IT staff reduction			LBT	$ (106,686)	$ (18,970)	$ (257)	$ (35,932)	$ (8,801)	$ (6,686)	$ (12,286)
Adjustment to remove Alstom expenses			PLPPT	$ (657,750)	$ (148,042)	$ (2,252)	$ (278,078)	$ (69,580)	$ (48,152)	$ (93,458)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 27,620	$ 6,192	$ 94	$ 11,575	$ 3,278	$ 2,161	$ 4,064
Adjustment for OMU Nox expense			PLPPT	$ 412,252	$ 92,787	$ 1,411	$ 174,289	$ 43,610	$ 30,180	$ 58,576
Adjustment for ice storm			SDALL	$ (472,573)	$ (63,098)	$ -	$ (108,425)	$ -	$ (25,051)	$ (33,566)
Adjustment for management audit fee			OMT	$ 35,033	$ 7,882	$ 116	$ 15,922	$ 4,409	$ 2,910	$ 5,498
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (163,032)	$ (39,372)	$ (595)	$ (80,530)	$ (22,832)	$ (14,643)	$ (27,829)
VDT Amortization and Surcredit			VDTREV	$ (106,432)	$ (23,944)	$ (363)	$ (44,478)	$ (12,752)	$ (8,271)	$ (15,454)
Total Expense Adjustments				(9,350,353)	(2,374,142)	127,021	(5,239,976)	(1,584,226)	(968,248)	(2,156,448)
Total Operating Expenses		TOE		$ 137,073,963	$ 30,306,501	$ 658,645	$ 58,511,391	$ 15,795,796	$ 10,812,561	$ 19,950,386
Net Operating Income (Adjusted)				$ 22,655,896	$ 5,450,523	$ 156,826	$ 8,152,513	$ 2,942,590	$ 1,536,481	$ 2,916,834
Net Cost Rate Base				$ 234,865,824	$ 47,671,184	$ 646,017	$ 88,640,445	$ 19,997,574	$ 15,965,493	$ 29,633,308
Rate of Return				9.65%	11.43%	24.28%	9.20%	14.71%	10.25%	9.84%

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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Operating Expenses								
Operation and Maintenance Expenses				$ 3,395,813	$ 2,890,098	$ 1,458,586	$ 3,459,123	$ 1,173,678
Depreciation and Amortization Expenses				406,362	315,559	162,290	397,238	277,591
Regulatory Credits and Accretion Expenses				(53,287)	(46,811)	(20,891)	(59,109)	(7,613)
Property Taxes			NPT	38,312	29,974	15,285	37,740	24,987
Other Taxes				26,883	21,033	10,725	26,482	17,533
Gain Disposition of Allowances				(1,839)	(1,608)	(810)	(1,897)	(193)
State and Federal Income Taxes			TXINCPF	$ 557,274	$ 382,826	$ 176,255	$ 380,997	$ (446,205)
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 26,400	$ 23,067	$ 10,168	$ 29,038	$ 4,940
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	$ (236,347)	$ (206,595)	$ (104,115)	$ (243,795)	$ (24,816)
Remove ECR expenses			ECRREV	$ (1,810)	$ (1,443)	$ (696)	$ (1,713)	$ (156)
Eliminate brokered sales expenses			Energy	$ (184,700)	$ (161,450)	$ (81,363)	$ (190,521)	$ (19,393)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (141,450)	$ (165,932)	$ -	$ (424,256)	$ (13,589)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 9,616	$ 7,467	$ 3,840	$ 9,400	$ 6,569
Labor adjustment			LBT	$ 4,110	$ 3,185	$ 1,704	$ 3,885	$ 4,261
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (860)	$ -	$ (395)	$ -	$ (3,556)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 430	$ 344	$ 166	$ 410	$ 37
Amortization of rate case expenses			OMT	$ 2,181	$ 1,856	$ 937	$ 2,222	$ 754
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 11,873	$ 9,201	$ 4,923	$ 11,224	$ 12,311
Adjustment for merger savings			LBT	$ 77,798	$ 60,284	$ 32,255	$ 73,543	$ 80,664
Adjustment for merger amortization expenses			LBT	$ (11,182)	$ (8,665)	$ (4,636)	$ (10,571)	$ (11,594)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 5,192	$ 4,561	$ 2,035	$ 5,759	$ 742
Adjustment for effect of accounting change			DET	$ 38,783	$ 30,117	$ 15,489	$ 37,912	$ 26,493
Adjustment for IT staff reduction			LBT	$ (2,468)	$ (1,912)	$ (1,023)	$ (2,333)	$ (2,559)
Adjustment to remove Alstom expenses			PLPPT	$ (19,250)	$ (16,910)	$ (7,547)	$ (21,353)	$ (2,750)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 888	$ 709	$ 343	$ 847	$ 77
Adjustment for OMU Nox expense			PLPPT	$ 12,065	$ 10,599	$ 4,730	$ 13,383	$ 1,724
Adjustment for ice storm			SDALL	$ (9,598)	$ -	$ (4,411)	$ -	$ (39,675)
Adjustment for management audit fee			OMT	$ 1,015	$ 864	$ 436	$ 1,034	$ 351
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (5,056)	$ (4,424)	$ (2,180)	$ (5,292)	$ (568)
VDT Amortization and Surcredit			VDTREV	$ (3,381)	$ (2,696)	$ (1,291)	$ (3,165)	$ (286)
Total Expense Adjustments				(452,152)	(440,842)	(140,798)	(743,380)	15,039
Total Operating Expenses		TOE		$ 3,943,765	$ 3,173,297	$ 1,670,809	$ 3,526,232	$ 1,059,758
Net Operating Income (Adjusted)				$ 946,698	$ 658,703	$ 306,664	$ 673,639	$ (630,752)
Net Cost Rate Base				$ 6,316,969	$ 4,828,552	$ 2,539,011	$ 6,059,060	$ 4,569,377
Rate of Return				14.99%	13.64%	12.08%	11.12%	-13.80%

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Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Operating Expenses											
Operation and Maintenance Expenses				$ 3,145,245	$ 589,892	$ 616,278	$ 3,413,013	$ 323,469	$ 2,931,658	$ 463,102	$ 13,344,427
Depreciation and Amortization Expenses				540,813	98,439	143,003	1,824,395	213,252	887,566	142,222	$ 1,819,340
Regulatory Credits and Accretion Expenses				(58,967)	(10,114)	(12,568)	(14,064)	(804)	(21,847)	(3,392)	$ (264,040)
Property Taxes			NPT	50,496	9,166	13,228	162,741	18,988	79,790	12,781	$ 172,574
Other Taxes				35,433	6,432	9,282	114,196	13,324	55,989	8,968	$ 121,095
Gain Disposition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(933)	(145)	$ (6,918)
State and Federal Income Taxes			TXINCPF	$ 162,996	$ 4,093	$ (10,683)	$ (347,969)	$ 51,332	$ 831,402	$ 97,215	$ 1,229,785
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-	$ (3,630,403)
Allocation of Curtailable Service Rider Credits			SCP	$ 38,263	$ 6,563	$ 6,225	$ -	$ -	$ -	$ -	$ 161,576
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	$ (192,211)	$ (32,967)	$ (32,629)	$ (77,281)	$ (4,417)	$ (119,883)	$ (18,611)	$ (888,821)
Remove ECR expenses			ECRREV	$ (1,423)	$ (232)	$ (262)	$ (1,953)	$ (291)	$ (2,260)	$ (330)	$ (6,866)
Eliminate brokered sales expenses			Energy	$ (150,209)	$ (25,763)	$ (25,499)	$ (60,394)	$ (3,452)	$ (93,686)	$ (14,544)	$ (694,595)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ -	$ (11,965)	$ -	$ 10,181	$ 7,379	$ 43,060	$ (11,571)	$ -
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 12,797	$ 2,329	$ 3,384	$ 43,171	$ 5,046	$ 21,003	$ 3,365	$ 43,051
Labor adjustment			LBT	$ 5,012	$ 1,107	$ 1,296	$ 19,672	$ 2,234	$ 10,506	$ 1,685	$ 16,342
Medical Expense (See Functional Assignment)											$ -
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (2,563)	$ (552)	$ (1,032)	$ (3,854)	$ (302)	$ (4,091)	$ (639)	$ (912)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 338	$ 58	$ 62	$ 462	$ 68	$ 534	$ 78	$ 1,412
Amortization of rate case expenses			OMT	$ 2,020	$ 379	$ 396	$ 2,192	$ 208	$ 1,883	$ 297	$ 8,571
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 14,479	$ 3,197	$ 3,745	$ 56,833	$ 6,455	$ 30,351	$ 4,867	$ 47,213
Adjustment for merger savings			LBT	$ 94,869	$ 20,946	$ 24,540	$ 372,386	$ 42,297	$ 198,869	$ 31,889	$ 309,354
Adjustment for merger amortization expenses			LBT	$ (13,636)	$ (3,011)	$ (3,527)	$ (53,525)	$ (6,080)	$ (28,585)	$ (4,584)	$ (44,465)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 5,745	$ 985	$ 1,224	$ 1,370	$ 78	$ 2,129	$ 330	$ 25,725
Adjustment for effect of accounting change			DET	$ 51,615	$ 9,395	$ 13,648	$ 174,119	$ 20,353	$ 84,709	$ 13,574	$ 173,637
Adjustment for IT staff reduction			LBT	$ (3,009)	$ (664)	$ (778)	$ (11,812)	$ (1,342)	$ (6,308)	$ (1,011)	$ (9,813)
Adjustment to remove Alstom expenses			PLPPT	$ (21,302)	$ (3,654)	$ (4,540)	$ (5,081)	$ (290)	$ (7,892)	$ (1,225)	$ (95,384)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 698	$ 120	$ 128	$ 953	$ 141	$ 1,102	$ 162	$ 2,913
Adjustment for OMU Nox expense			PLPPT	$ 13,351	$ 2,290	$ 2,846	$ 3,184	$ 182	$ 4,947	$ 768	$ 59,783
Adjustment for ice storm			SDALL	$ (28,599)	$ (6,163)	$ (11,514)	$ (43,003)	$ (3,368)	$ (45,641)	$ (7,132)	$ (10,180)
Adjustment for management audit fee			OMT	$ 940	$ 176	$ 184	$ 1,020	$ 97	$ 876	$ 138	$ 3,988
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (4,400)	$ (755)	$ (794)	$ (1,591)	$ (91)	$ (2,469)	$ (383)	$ (20,189)
VDT Amortization and Surcredit			VDTREV	$ (2,682)	$ (445)	$ (490)	$ (3,643)	$ (557)	$ (4,383)	$ (630)	$ (12,760)
Total Expense Adjustments				(218,172)	(45,190)	(29,612)	423,408	64,350	84,769	(3,507)	(1,091,994)
Total Operating Expenses		TOE		$ 3,694,611	$ 659,024	$ 734,899	$ 5,575,119	$ 683,875	$ 4,848,395	$ 717,246	$ 11,855,443
Net Operating Income (Adjusted)				$ 366,726	$ 27,266	$ 13,773	$ (164,365)	$ 122,546	$ 1,464,133	$ 179,090	$ 2,290,420
Net Cost Rate Base				$ 8,505,675	$ 1,557,703	$ 2,285,839	$ 31,480,324	$ 3,691,737	$ 15,177,086	$ 2,416,359	$ 27,651,808
Rate of Return				**4.31%**	**1.75%**	**0.60%**	**-0.52%**	**3.32%**	**9.65%**	**7.41%**	**8.28%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	**CASE NO.**
LOUISVILLE GAS AND ELECTRIC COMPANY	)	**2003-00433**
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	**CASE NO.**
KENTUCKY UTILITIES COMPANY	)	**2003-00434**

EXHIBIT (SJB-5)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual					$ 768,801,159	$ 138,655,960	$ 146,073,598	$ 69,616,315	$ 2,805,997
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01		675,000	$ 122,243	$ 129,125	$ 61,916	$ 2,528
Adjustment for Mismatch in fuel cost recovery			Energy		(35,887,728)	$ (5,723,277)	$ (6,590,128)	$ (2,393,686)	$ (109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI			1,417,623	$ 181,543	$ 182,116	$ 96,991	$ 4,709
Remove ECR revenues		ECRREV			(25,039,979)	$ (4,562,377)	$ (4,715,925)	$ (2,291,842)	$ (91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI			17,986,813	$ 3,208,163	$ 3,428,757	$ 1,647,196	$ 66,930
Remove off-system ECR revenues			PLPPT		(776,418)	$ (158,416)	$ (130,792)	$ (76,153)	$ (2,028)
Eliminate brokered sales			Energy		(22,575,669)	$ (3,600,306)	$ (4,145,611)	$ (1,505,781)	$ (68,786)
Eliminate ESM revenues collected		ESMREV			(4,604,742)	$ (915,119)	$ (611,110)	$ (428,633)	$ (15,263)
Eliminate ESM,FAC,ECR from rate refund acct.			R01		1,630,147	$ 295,220	$ 311,841	$ 149,529	$ 6,105
Eliminate DSM Revenue		DSMREV			(2,942,935)	$ (1,508,819)	$ (1,089,604)	$ (222,733)	$ (10,743)
Year end adjustment		YREND			251,167	$ (417,181)	$ 1,771,704	$ 815,724	$ -
Merger savings			R01		(2,564,269)	$ (464,390)	$ (490,535)	$ (235,213)	$ (9,603)
Adjustment for rate switching, increased interruptible credit		RATESW			(3,005,567)				
VDT Amortization and Surcredit			VDTREV		85,337	$ 15,547	$ 16,258	$ 7,821	$ 304
Total Pro-Forma Operating Revenue				(13,527,170)	$ 693,449,939	$ 125,128,790	$ 134,139,695	$ 65,241,451	$ 2,579,272

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 177,515,062	$ 39,811,312	$ 605,181	$ 75,027,425	$ 21,183,217	$ 13,972,612	$ 26,276,986
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	$ 154,859	$ 34,715	$ 526	$ 64,896	$ 18,376	$ 12,117	$ 22,783
Adjustment for Mismatch in fuel cost recovery			Energy	$ (8,518,255)	$ (2,093,467)	$ (31,617)	$ (4,365,021)	$ (1,268,707)	$ (801,803)	$ (1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 365,749	$ 85,293	$ 2,524	$ 194,737	$ 94,994	$ 53,661	$ 62,851
Remove ECR revenues		ECRREV		$ (5,734,057)	$ (1,290,905)	$ (19,498)	$ (2,401,012)	$ (688,721)	$ (446,972)	$ (838,688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 4,133,949	$ 917,554	$ 14,085	$ 1,735,487	$ 492,058	$ 316,548	$ 606,165
Remove off-system ECR revenues			PLPPT	$ (185,877)	$ (40,704)	$ (686)	$ (74,764)	$ (17,151)	$ (13,270)	$ (24,690)
Eliminate brokered sales			Energy	$ (5,358,526)	$ (1,316,924)	$ (19,889)	$ (2,745,877)	$ (798,098)	$ (504,385)	$ (954,481)
Eliminate ESM revenues collected		ESMREV		$ (1,152,341)	$ (264,123)	$ (3,814)	$ (474,129)	$ (137,016)	$ (89,283)	$ (160,668)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 373,990	$ 83,837	$ 1,271	$ 156,727	$ 44,379	$ 29,263	$ 55,022
Eliminate DSM Revenue		DSMREV		$ (98,441)	$ (12,123)	$ (472)	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ (597,774)	$ 117,795	$ 273,166	$ -	$ -	$ -	$ (537,561)
Merger savings			R01	$ (588,297)	$ (131,879)	$ (2,000)	$ (246,535)	$ (69,809)	$ (46,031)	$ (86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			$ (42,856)		$ (64,186)	$ (120,793)		
VDT Amortization and Surcredit			VDTREV	$ 19,479	$ 4,382	$ 66	$ 8,140	$ 2,334	$ 1,514	$ 2,828
Total Pro-Forma Operating Revenue			(13,527,170)	$ 160,329,520	$ 35,861,908	$ 818,844	$ 66,815,888	$ 18,735,062	$ 12,483,970	$ 22,906,692

Summer CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Coal Mining Power Primary MPP		Coal Mining Power Transmission MPT		Large Power Mine Power TOD Primary LMPP		Large Power Mine Power TOD Transmission LMPT		Combination Off-Peak CWH
Cost of Service Summary -- Pro-Forma													
Operating Revenues													
Total Operating Revenue -- Actual				$	5,629,555	$	4,538,092	$	2,195,076	$	5,412,231	$	507,806
Pro-Forma Adjustments:													
Eliminate unbilled revenue			R01	$	4,976	$	3,978	$	1,924	$	4,748	$	432
Adjustment for Mismatch in fuel cost recovery			Energy	$	(268,036)	$	(234,296)	$	(118,074)	$	(276,483)	$	(28,144)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$	12,843	$	13,496	$	2,865	$	11,438	$	1,179
Remove ECR revenues		ECRREV		$	(182,407)	$	(145,445)	$	(70,105)	$	(172,666)	$	(15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$	132,466	$	105,333	$	51,614	$	127,076	$	11,770
Remove off-system ECR revenues			PLPPT	$	(4,473)	$	(3,908)	$	(1,723)	$	(4,920)	$	(837)
Eliminate brokered sales			Energy	$	(168,612)	$	(147,387)	$	(74,276)	$	(173,926)	$	(17,704)
Eliminate ESM revenues collected		ESMREV		$	(33,089)	$	(25,314)	$	(11,418)	$	(28,011)	$	(2,590)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$	12,018	$	9,606	$	4,648	$	11,466	$	1,042
Eliminate DSM Revenue		DSMREV		$	-	$	-	$	-	$	-	$	-
Year end adjustment		YREND		$	(234,645)	$	(275,257)	$	-	$	(703,778)	$	(22,542)
Merger savings			R01	$	(18,905)	$	(15,111)	$	(7,311)	$	(18,037)	$	(1,639)
Adjustment for rate switching, increased interruptible credit		RATESW											
VDT Amortization and Surcredit			VDTREV	$	619	$	493	$	236	$	579	$	52
Total Pro-Forma Operating Revenue			(13,527,170)	$	4,882,311	$	3,824,281	$	1,973,457	$	4,189,718	$	433,102

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary – Pro-Forma											
Operating Revenues											
Total Operating Revenue – Actual				$ 4,507,053	$ 777,396	$ 819,029	$ 5,595,719	$ 814,583	$ 6,520,320	$ 959,498	$ 18,981,135
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	$ 3,911	$ 675	$ 717	$ 5,345	$ 790	$ 6,178	$ 907	$ 16,335
Adjustment for Mismatch in fuel cost recovery			Energy	$ (217,983)	$ (37,387)	$ (37,004)	$ (87,643)	$ (5,009)	$ (135,957)	$ (21,106)	$ (1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 9,719	$ 881	$ 1,457	$ (1,021)	$ (74)	$ (3,573)	$ (2,582)	$ 45,827
Remove ECR revenues		ECRREV		$ (143,373)	$ (23,364)	$ (26,381)	$ (196,772)	$ (29,280)	$ (227,715)	$ (33,264)	$ (691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 104,270	$ 17,741	$ 19,017	$ 144,134	$ 21,362	$ 166,721	$ 24,687	$ 493,730
Remove off-system ECR revenues			PLPPT	$ (6,483)	$ (1,112)	$ (1,055)	$ -	$ -	$ -	$ -	$ (27,376)
Eliminate brokered sales			Energy	$ (137,125)	$ (23,519)	$ (23,278)	$ (55,133)	$ (3,151)	$ (85,526)	$ (13,277)	$ (634,093)
Eliminate ESM revenues collected		ESMREV		$ (21,999)	$ 1,124	$ (4,856)	$ (37,564)	$ (5,964)	$ (43,690)	$ (6,279)	$ (133,593)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 9,445	$ 1,630	$ 1,730	$ 12,909	$ 1,908	$ 14,921	$ 2,192	$ 39,449
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ -	$ (19,849)	$ -	$ 16,889	$ 12,240	$ 71,430	$ (19,194)	$ -
Merger savings			R01	$ (14,857)	$ (2,564)	$ (2,722)	$ (20,307)	$ (3,001)	$ (23,470)	$ (3,447)	$ (62,054)
Adjustment for rate switching, increased interruptible credit		RATESW								$	(2,777,732)
VDT Amortization and Surcredit			VDTREV	$ 491	$ 81	$ 90	$ 667	$ 102	$ 802	$ 115	$ 2,335
Total Pro-Forma Operating Revenue			(13,527,170)	$ 4,093,069	$ 691,733	$ 746,744	$ 5,377,223	$ 804,505	$ 6,260,441	$ 888,250	$ 14,244,013

Summer CP Prod Trans Allocation
All other KIUC Corrections Included

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Operating Expenses								
Operation and Maintenance Expenses				548,721,322	109,776,204	108,265,181	46,405,462	1,460,330
Depreciation and Amortization Expenses				88,376,624	21,723,882	18,637,218	9,957,822	183,943
Regulatory Credits and Accretion Expenses				(8,656,053)	(1,766,127)	(1,458,160)	(849,010)	(22,615)
Property Taxes			NPT	8,211,450	2,003,584	1,716,557	920,028	17,280
Other Taxes				5,761,996	1,405,920	1,204,512	645,586	12,125
Gain Disposition of Allowances				(246,288)	(39,277)	(45,226)	(16,427)	(750)
State and Federal Income Taxes			TXINCPF	26,916,596	(3,211,541)	2,720,603	2,653,933	396,774
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	4,582,475	934,980	771,944	449,462	11,972
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(31,644,777)	(5,046,623)	(5,810,987)	(2,110,684)	(96,419)
Remove ECR expenses			ECRREV	(248,468)	(45,272)	(46,795)	(22,742)	(908)
Eliminate brokered sales expenses			Energy	(24,729,742)	(3,943,832)	(4,541,167)	(1,649,456)	(75,349)
Eliminate DSM Expenses			DSMREV	(2,945,471)	(1,510,632)	(1,090,913)	(223,001)	(10,756)
Year end adjustment			YREND	151,410	(251,488)	1,068,029	491,740	-
Depreciation adjustment			DET	-	-	-	-	-
Adjustment for change in depreciation rate			DET	2,091,278	514,058	441,017	235,634	4,353
Labor adjustment			LBT	1,002,076	259,488	226,122	108,618	2,043
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	-	-	-	-
Storm damage adjustment			SDALL	(473,014)	(168,017)	(153,325)	(69,375)	(554)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	-	-	-	-
Adjustment for amortization of ESM audit expense			R01	58,333	10,564	11,159	5,351	218
Amortization of rate case expenses			OMT	352,456	70,512	69,541	29,807	938
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	-	-	-	-
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	-	-	-	-
Adjustment for VDT net savings to shareholders			LBT	2,895,000	749,660	653,266	313,798	5,901
Adjustment for merger savings			LBT	18,968,825	4,911,976	4,280,374	2,056,091	38,668
Adjustment for merger amortization expenses			LBT	(2,726,510)	(706,030)	(615,245)	(295,535)	(5,558)
Adjustment for MISO schedule 10 expenses			PLTRT	843,344	172,071	142,066	82,718	2,203
Adjustment for effect of accounting change			DET	8,434,618	2,073,316	1,778,726	950,369	17,555
Adjustment for IT staff reduction			LBT	(601,682)	(155,806)	(135,771)	(65,218)	(1,227)
Adjustment to remove Alstom expenses			PLPPT	(3,126,995)	(638,013)	(526,760)	(306,704)	(8,170)
Adjustment for corporate lease expense			LBT	-	-	-	-	-
Adjustment for sales tax refund			R01	120,391	21,803	23,030	11,043	451
Adjustment for OMU Nox expense			PLPPT	1,959,879	399,882	330,153	192,230	5,120
Adjustment for ice storm			SDALL	(5,277,336)	(1,874,536)	(1,710,617)	(774,008)	(6,178)
Adjustment for management audit fee			OMT	163,982	32,806	32,354	13,868	436
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(705,035)	(119,554)	(127,043)	(52,038)	(2,079)
VDT Amortization and Surcredit			VDTREV	(466,280)	(84,947)	(88,836)	(42,731)	(1,661)
Total Expense Adjustments				(35,904,718)	(5,328,614)	(5,791,622)	(1,120,224)	(130,970)
Total Operating Expenses		TOE		633,180,928	125,499,010	126,021,005	59,046,633	1,928,089
Net Operating Income (Adjusted)				60,269,011	(370,219)	8,118,690	6,194,817	651,183
Net Cost Rate Base				1,412,033,543	350,876,204	304,587,081	160,356,384	2,881,654
Rate of Return				4.27%	-0.11%	2.67%	3.86%	22.60%

Summer CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Operating Expenses										
Operation and Maintenance Expenses				$ 120,695,298	$ 26,982,414	$ 408,746	$ 54,156,947	$ 14,732,940	$ 9,941,001	$ 18,624,035
Depreciation and Amortization Expenses				16,657,830	3,365,392	51,650	6,123,938	1,282,070	1,117,719	2,013,840
Regulatory Credits and Accretion Expenses				(2,072,286)	(453,797)	(7,649)	(833,517)	(191,215)	(147,943)	(275,265)
Property Taxes			NPT	1,565,879	317,801	4,906	578,614	121,823	105,434	190,324
Other Taxes				1,098,782	223,002	3,442	406,015	85,483	73,984	133,551
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8,707)	(5,503)	(10,413)
State and Federal Income Taxes			TXINCPF	$ 10,520,722	$ 2,740,138	$ 84,027	$ 3,960,476	$ 1,738,363	$ 797,227	$ 1,487,812
Specific Assignment of Curtailable Service Rider Credit				-	(181,381)	-	(271,654)	(499,037)	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 1,097,059	$ 240,238	$ 4,049	$ 441,260	$ 101,228	$ 78,321	$ 145,724
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (7,511,155)	$ (1,845,959)	$ (27,879)	$ (3,848,951)	$ (1,118,710)	$ (707,007)	$ (1,337,916)
Remove ECR expenses			ECRREV	$ (56,898)	$ (12,809)	$ (193)	$ (23,825)	$ (5,834)	$ (4,435)	$ (8,322)
Eliminate brokered sales expenses			Energy	$ (5,869,813)	$ (1,442,579)	$ (21,787)	$ (3,007,876)	$ (874,249)	$ (552,511)	$ (1,045,554)
Eliminate DSM Expenses			DSMREV	$ (98,559)	$ (12,138)	$ (473)	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (360,354)	$ 71,010	$ 164,672	$ -	$ -	$ -	$ (324,056)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 394,178	$ 79,636	$ 1,222	$ 144,912	$ 30,338	$ 26,449	$ 47,654
Labor adjustment			LBT	$ 187,226	$ 33,263	$ 482	$ 62,263	$ 14,605	$ 11,690	$ 21,090
Medical Expense (See Functional Assignment)										
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (42,357)	$ (5,656)	$ -	$ (9,718)	$ -	$ (2,245)	$ (3,009)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 13,383	$ 3,000	$ 45	$ 5,608	$ 1,588	$ 1,047	$ 1,969
Amortization of rate case expenses			OMT	$ 77,525	$ 17,331	$ 263	$ 34,786	$ 9,463	$ 6,385	$ 11,963
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 540,895	$ 96,097	$ 1,392	$ 179,877	$ 42,195	$ 33,774	$ 60,929
Adjustment for merger savings			LBT	$ 3,544,093	$ 629,656	$ 9,118	$ 1,178,601	$ 276,473	$ 221,295	$ 399,222
Adjustment for merger amortization expenses			LBT	$ (509,415)	$ (90,505)	$ (1,311)	$ (169,408)	$ (39,739)	$ (31,808)	$ (57,383)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 201,899	$ 44,213	$ 745	$ 81,208	$ 18,630	$ 14,414	$ 26,819
Adjustment for effect of accounting change			DET	$ 1,589,814	$ 321,191	$ 4,929	$ 584,465	$ 122,360	$ 106,674	$ 192,200
Adjustment for IT staff reduction			LBT	$ (112,417)	$ (19,972)	$ (289)	$ (37,385)	$ (8,770)	$ (7,019)	$ (12,663)
Adjustment to remove Alstom expenses			PLPPT	$ (748,612)	$ (163,934)	$ (2,763)	$ (301,107)	$ (69,076)	$ (53,444)	$ (99,439)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 27,620	$ 6,192	$ 94	$ 11,575	$ 3,278	$ 2,161	$ 4,064
Adjustment for OMU Nox expense			PLPPT	$ 469,201	$ 102,747	$ 1,732	$ 188,722	$ 43,294	$ 33,497	$ 62,325
Adjustment for ice storm			SDALL	$ (472,573)	$ (63,098)	$ -	$ (108,425)	$ -	$ (25,051)	$ (33,566)
Adjustment for management audit fee			OMT	$ 36,069	$ 8,064	$ 122	$ 16,184	$ 4,403	$ 2,971	$ 5,566
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (167,673)	$ (40,184)	$ (622)	$ (81,707)	$ (22,806)	$ (14,913)	$ (28,135)
VDT Amortization and Surcredit			VDTREV	$ (106,432)	$ (23,944)	$ (363)	$ (44,478)	$ (12,752)	$ (8,271)	$ (15,454)
Total Expense Adjustments				(8,974,354)	(2,308,377)	129,136	(5,144,679)	(1,586,310)	(946,348)	(2,131,697)
Total Operating Expenses		TOE		$ 140,530,471	$ 30,911,062	$ 678,091	$ 59,387,445	$ 15,776,639	$ 11,013,892	$ 20,177,910
Net Operating Income (Adjusted)				$ 19,799,048	$ 4,950,846	$ 140,753	$ 7,428,444	$ 2,958,424	$ 1,470,078	$ 2,728,782
Net Cost Rate Base				$ 259,564,825	$ 51,991,165	$ 784,972	$ 94,900,421	$ 19,860,683	$ 17,404,133	$ 31,259,117
Rate of Return				7.63%	9.52%	17.93%	7.83%	14.90%	8.45%	8.73%

Summer CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Operating Expenses								
Operation and Maintenance Expenses				3,348,701	2,845,493	1,435,379	3,400,454	1,197,352
Depreciation and Amortization Expenses				383,454	293,871	151,006	368,710	289,103
Regulatory Credits and Accretion Expenses				(49,867)	(43,573)	(19,206)	(54,850)	(9,331)
Property Taxes			NPT	36,135	27,913	14,212	35,029	26,081
Other Taxes				25,356	19,587	9,973	24,580	18,301
Gain Disposition of Allowances				(1,839)	(1,608)	(810)	(1,897)	(193)
State and Federal Income Taxes			TXINCPF	585,697	409,736	190,256	416,392	(460,488)
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	26,400	23,067	10,168	29,038	4,940
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(236,347)	(206,595)	(104,115)	(243,795)	(24,816)
Remove ECR expenses			ECRREV	(1,810)	(1,443)	(696)	(1,713)	(156)
Eliminate brokered sales expenses			Energy	(184,700)	(161,450)	(81,363)	(190,521)	(19,393)
Eliminate DSM Expenses			DSMREV	-	-	-	-	-
Year end adjustment			YREND	(141,450)	(165,932)	-	(424,256)	(13,589)
Depreciation adjustment			DET	-	-	-	-	-
Adjustment for change in depreciation rate			DET	9,074	6,954	3,573	8,725	6,841
Labor adjustment			LBT	3,980	3,062	1,640	3,723	4,326
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	-	-	-	-
Storm damage adjustment			SDALL	(860)	-	(395)	-	(3,556)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	-	-	-	-
Adjustment for amortization of ESM audit expense			R01	430	344	166	410	37
Amortization of rate case expenses			OMT	2,151	1,828	922	2,184	769
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	-	-	-	-
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	-	-	-	-
Adjustment for VDT net savings to shareholders			LBT	11,498	8,846	4,738	10,757	12,499
Adjustment for merger savings			LBT	75,341	57,959	31,045	70,484	81,898
Adjustment for merger amortization expenses			LBT	(10,829)	(8,331)	(4,462)	(10,131)	(11,772)
Adjustment for MISO schedule 10 expenses			PLTRT	4,858	4,245	1,871	5,344	909
Adjustment for effect of accounting change			DET	36,597	28,047	14,412	35,190	27,592
Adjustment for IT staff reduction			LBT	(2,390)	(1,838)	(985)	(2,236)	(2,598)
Adjustment to remove Alstom expenses			PLPPT	(18,015)	(15,741)	(6,938)	(19,815)	(3,371)
Adjustment for corporate lease expense			LBT	-	-	-	-	-
Adjustment for sales tax refund			R01	888	709	343	847	77
Adjustment for OMU Nox expense			PLPPT	11,291	9,866	4,349	12,419	2,113
Adjustment for ice storm			SDALL	(9,598)	-	(4,411)	-	(39,675)
Adjustment for management audit fee			OMT	1,001	850	429	1,016	358
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(4,993)	(4,364)	(2,149)	(5,213)	(600)
VDT Amortization and Surcredit			VDTREV	(3,381)	(2,696)	(1,291)	(3,165)	(286)
Total Expense Adjustments				(457,264)	(445,682)	(143,317)	(749,746)	17,608
Total Operating Expenses		TOE		3,896,772	3,128,805	1,647,660	3,467,710	1,083,372
Net Operating Income (Adjusted)				985,539	695,476	325,797	722,007	(650,270)
Net Cost Rate Base				5,981,173	4,510,623	2,373,597	5,640,885	4,738,120
Rate of Return				16.48%	15.42%	13.73%	12.80%	-13.72%

Summer CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Operating Expenses											
Operation and Maintenance Expenses				$ 3,328,612	$ 621,342	$ 605,136	$ 3,219,253	$ 312,394	$ 2,630,668	$ 416,377	$ 13,911,603
Depreciation and Amortization Expenses				629,973	113,731	137,585	1,730,180	207,867	741,212	119,502	$ 2,095,125
Regulatory Credits and Accretion Expenses				(72,276)	(12,396)	(11,759)	-	-	-	-	$ (305,209)
Property Taxes			NPT	58,968	10,619	12,713	153,788	18,476	65,883	10,622	$ 198,780
Other Taxes				41,378	7,451	8,921	107,913	12,965	46,230	7,453	$ 139,485
Gain Disposition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(933)	(145)	$ (6,918)
State and Federal Income Taxes			TXINCPF	$ 52,369	$ (14,881)	$ (3,961)	$ (231,071)	$ 58,013	$ 1,012,992	$ 125,405	$ 887,604
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-	$ (3,630,403)
Allocation of Curtailable Service Rider Credits			SCP	$ 38,263	$ 6,563	$ 6,225	$ -	$ -	$ -	$ -	$ 161,576
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	$ (192,211)	$ (32,967)	$ (32,629)	$ (77,281)	$ (4,417)	$ (119,883)	$ (18,611)	$ (888,821)
Remove ECR expenses			ECRREV	$ (1,423)	$ (232)	$ (262)	$ (1,953)	$ (291)	$ (2,260)	$ (330)	$ (6,866)
Eliminate brokered sales expenses			Energy	$ (150,209)	$ (25,763)	$ (25,499)	$ (60,394)	$ (3,452)	$ (93,686)	$ (14,544)	$ (694,595)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Year end adjustment			YREND	$ -	$ (11,965)	$ -	$ 10,181	$ 7,379	$ 43,060	$ (11,571)	$ -
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 14,907	$ 2,691	$ 3,256	$ 40,942	$ 4,919	$ 17,539	$ 2,828	$ 49,577
Labor adjustment			LBT	$ 5,517	$ 1,193	$ 1,266	$ 19,138	$ 2,204	$ 9,677	$ 1,556	$ 17,905
Medical Expense (See Functional Assignment)											$ -
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (2,563)	$ (552)	$ (1,032)	$ (3,854)	$ (302)	$ (4,091)	$ (639)	$ (912)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 338	$ 58	$ 62	$ 462	$ 68	$ 534	$ 78	$ 1,412
Amortization of rate case expenses			OMT	$ 2,138	$ 399	$ 389	$ 2,068	$ 201	$ 1,690	$ 267	$ 8,936
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 15,938	$ 3,447	$ 3,657	$ 55,291	$ 6,367	$ 27,956	$ 4,495	$ 51,727
Adjustment for merger savings			LBT	$ 104,430	$ 22,586	$ 23,959	$ 362,283	$ 41,720	$ 183,175	$ 29,452	$ 338,928
Adjustment for merger amortization expenses			LBT	$ (15,010)	$ (3,246)	$ (3,444)	$ (52,073)	$ (5,997)	$ (26,329)	$ (4,233)	$ (48,716)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 7,042	$ 1,208	$ 1,146	$ -	$ -	$ -	$ -	$ 29,736
Adjustment for effect of accounting change			DET	$ 60,124	$ 10,854	$ 13,131	$ 165,128	$ 19,839	$ 70,741	$ 11,405	$ 199,958
Adjustment for IT staff reduction			LBT	$ (3,312)	$ (716)	$ (760)	$ (11,491)	$ (1,323)	$ (5,810)	$ (934)	$ (10,751)
Adjustment to remove Alstom expenses			PLPPT	$ (26,110)	$ (4,478)	$ (4,248)	$ -	$ -	$ -	$ -	$ (110,257)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 698	$ 120	$ 128	$ 953	$ 141	$ 1,102	$ 162	$ 2,913
Adjustment for OMU Nox expense			PLPPT	$ 16,365	$ 2,807	$ 2,662	$ -	$ -	$ -	$ -	$ 69,105
Adjustment for ice storm			SDALL	$ (28,599)	$ (6,163)	$ (11,514)	$ (43,003)	$ (3,368)	$ (45,641)	$ (7,132)	$ (10,180)
Adjustment for management audit fee			OMT	$ 995	$ 186	$ 181	$ 962	$ 93	$ 786	$ 124	$ 4,157
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (4,646)	$ (797)	$ (779)	$ (1,332)	$ (76)	$ (2,066)	$ (321)	$ (20,948)
VDT Amortization and Surcredit			VDTREV	$ (2,682)	$ (445)	$ (490)	$ (3,643)	$ (557)	$ (4,383)	$ (630)	$ (12,760)
Total Expense Adjustments				(198,275)	(41,777)	(30,821)	402,384	63,148	52,110	(8,577)	(1,030,452)
Total Operating Expenses		TOE		$ 3,877,516	$ 690,396	$ 723,785	$ 5,381,845	$ 672,829	$ 4,548,162	$ 670,638	$ 12,421,193
Net Operating Income (Adjusted)				$ 215,552	$ 1,337	$ 22,959	$ (4,622)	$ 131,676	$ 1,712,280	$ 217,613	$ 1,822,820
Net Cost Rate Base				$ 9,812,655	$ 1,781,871	$ 2,206,421	$ 30,099,258	$ 3,612,804	$ 13,031,725	$ 2,083,315	$ 31,694,458
Rate of Return				2.20%	0.08%	1.04%	-0.02%	3.64%	13.14%	10.45%	5.75%

Summer CP Prod Trans Allocation
All other KIUC Corrections Included

Exhibit ____ (SJB-5)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 2003-00433
AND	)))	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	))))	CASE NO. 2003-00434

EXHIBIT (SJB-6)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		All Electric Residential Rate FERS		General Service Secondary GSS		General Service Primary GSP
Cost of Service Summary -- Pro-Forma													
Operating Revenues													
Total Operating Revenue -- Actual				$	768,801,159	$	137,916,946	$	147,101,217	$	69,475,900	$	2,821,048
Pro-Forma Adjustments:													
Eliminate unbilled revenue			R01		675,000	$	122,243	$	129,125	$	61,916	$	2,528
Adjustment for Mismatch in fuel cost recovery			Energy		(35,887,728)	$	(5,723,277)	$	(6,590,128)	$	(2,393,685)	$	(109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI			1,417,623	$	181,543	$	182,116	$	96,991	$	4,709
Remove ECR revenues		ECRREV			(25,039,979)	$	(4,562,377)	$	(4,715,925)	$	(2,291,842)	$	(91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI			17,986,813	$	3,208,163	$	3,428,757	$	1,647,196	$	66,930
Remove off-system ECR revenues			PLPPT		(776,418)	$	(131,620)	$	(168,052)	$	(71,062)	$	(2,574)
Eliminate brokered sales			Energy		(22,575,669)	$	(3,600,306)	$	(4,145,611)	$	(1,505,781)	$	(68,786)
Eliminate ESM revenues collected		ESMREV			(4,604,742)	$	(915,119)	$	(611,110)	$	(428,633)	$	(15,263)
Eliminate ESM,FAC,ECR from rate refund acct.			R01		1,630,147	$	295,220	$	311,841	$	149,529	$	6,105
Eliminate DSM Revenue		DSMREV			(2,942,935)	$	(1,508,819)	$	(1,089,604)	$	(222,733)	$	(10,743)
Year end adjustment		YREND			251,167	$	(417,181)	$	1,771,704	$	815,724	$	-
Merger savings			R01		(2,564,269)	$	(464,390)	$	(490,535)	$	(235,213)	$	(9,603)
Adjustment for rate switching, increased interruptible credit		RATESW			(3,005,567)								
VDT Amortization and Surcredit			VDTREV		85,337	$	15,547	$	16,258	$	7,821	$	304
Total Pro-Forma Operating Revenue			(13,500,374)	$	693,449,939	$	124,416,572	$	135,130,054	$	65,106,127	$	2,593,777

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actual				$ 177,182,345	$ 39,859,272	$ 604,255	$ 75,166,649	$ 21,271,791	$ 13,996,432	$ 26,330,971
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	$ 154,859	$ 34,715	$ 526	$ 64,896	$ 18,376	$ 12,117	$ 22,783
Adjustment for Mismatch in fuel cost recovery			Energy	$ (8,518,255)	$ (2,093,467)	$ (31,617)	$ (4,365,021)	$ (1,268,707)	$ (801,803)	$ (1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 365,749	$ 85,293	$ 2,524	$ 194,737	$ 94,994	$ 53,661	$ 62,851
Remove ECR revenues		ECRREV		$ (5,734,057)	$ (1,290,905)	$ (19,498)	$ (2,401,012)	$ (688,721)	$ (446,972)	$ (838,688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 4,133,949	$ 917,554	$ 14,085	$ 1,735,487	$ 492,058	$ 316,548	$ 606,165
Remove off-system ECR revenues			PLPPT	$ (173,813)	$ (42,443)	$ (652)	$ (79,812)	$ (20,363)	$ (14,134)	$ (26,648)
Eliminate brokered sales			Energy	$ (5,358,526)	$ (1,316,924)	$ (19,889)	$ (2,745,877)	$ (798,098)	$ (504,385)	$ (954,481)
Eliminate ESM revenues collected		ESMREV		$ (1,152,341)	$ (264,123)	$ (3,814)	$ (474,129)	$ (137,016)	$ (89,283)	$ (160,668)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 373,990	$ 83,837	$ 1,271	$ 156,727	$ 44,379	$ 29,263	$ 55,022
Eliminate DSM Revenue		DSMREV		$ (98,441)	$ (12,123)	$ (472)	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ (597,774)	$ 117,795	$ 273,166	$ -	$ -	$ -	$ (537,561)
Merger savings			R01	$ (588,297)	$ (131,879)	$ (2,000)	$ (246,535)	$ (69,809)	$ (46,031)	$ (86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			$ (42,856)	$	$ (64,186)	$ (120,793)		
VDT Amortization and Surcredit			VDTREV	$ 19,479	$ 4,382	$ 66	$ 8,140	$ 2,334	$ 1,514	$ 2,828
Total Pro-Forma Operating Revenue			(13,500,374)	$ 160,008,866	$ 35,908,129	$ 817,952	$ 66,950,064	$ 18,820,425	$ 12,506,927	$ 22,958,719

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual				$ 5,660,987	$ 4,559,871	$ 2,216,475	$ 5,425,560	$ 508,911
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	$ 4,976	$ 3,978	$ 1,924	$ 4,748	$ 432
Adjustment for Mismatch in fuel cost recovery			Energy	$ (268,036)	$ (234,296)	$ (118,074)	$ (276,483)	$ (28,144)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 12,843	$ 13,496	$ 2,865	$ 11,438	$ 1,179
Remove ECR revenues		ECRREV		$ (182,407)	$ (145,445)	$ (70,105)	$ (172,666)	$ (15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 132,466	$ 105,333	$ 51,614	$ 127,076	$ 11,770
Remove off-system ECR revenues			PLPPT	$ (5,613)	$ (4,698)	$ (2,499)	$ (5,403)	$ (877)
Eliminate brokered sales			Energy	$ (168,612)	$ (147,387)	$ (74,276)	$ (173,926)	$ (17,704)
Eliminate ESM revenues collected		ESMREV		$ (33,089)	$ (25,314)	$ (11,418)	$ (28,011)	$ (2,590)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 12,018	$ 9,606	$ 4,648	$ 11,466	$ 1,042
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ (234,645)	$ (275,257)	$ -	$ (703,778)	$ (22,542)
Merger savings			R01	$ (18,905)	$ (15,111)	$ (7,311)	$ (18,037)	$ (1,639)
Adjustment for rate switching, increased interruptible credit		RATESW						
VDT Amortization and Surcredit			VDTREV	$ 619	$ 493	$ 236	$ 579	$ 52
Total Pro-Forma Operating Revenue			(13,500,374)	$ 4,912,603	$ 3,845,270	$ 1,994,079	$ 4,202,563	$ 434,167

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue -- Actual				$ 4,492,389	$ 776,874	$ 817,460	$ 5,609,441	$ 815,367	$ 6,541,571	$ 962,798	$ 18,686,630
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	$ 3,911	$ 675	$ 717	$ 5,345	$ 790	$ 6,178	$ 907	$ 16,335
Adjustment for Mismatch in fuel cost recovery			Energy	$ (217,983)	$ (37,387)	$ (37,004)	$ (87,643)	$ (5,009)	$ (135,957)	$ (21,106)	$ (1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		$ 9,719	$ 881	$ 1,457	$ (1,021)	$ (74)	$ (3,573)	$ (2,582)	$ 45,827
Remove ECR revenues		ECRREV		$ (143,373)	$ (23,364)	$ (26,381)	$ (196,772)	$ (29,280)	$ (227,715)	$ (33,264)	$ (691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		$ 104,270	$ 17,741	$ 19,017	$ 144,134	$ 21,362	$ 166,721	$ 24,687	$ 493,730
Remove off-system ECR revenues			PLPPT	$ (5,951)	$ (1,093)	$ (998)	$ (498)	$ (28)	$ (771)	$ (120)	$ (16,698)
Eliminate brokered sales			Energy	$ (137,125)	$ (23,519)	$ (23,278)	$ (55,133)	$ (3,151)	$ (85,526)	$ (13,277)	$ (634,093)
Eliminate ESM revenues collected		ESMREV		$ (21,999)	$ 1,124	$ (4,856)	$ (37,564)	$ (5,964)	$ (43,690)	$ (6,279)	$ (133,593)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$ 9,445	$ 1,630	$ 1,730	$ 12,909	$ 1,908	$ 14,921	$ 2,192	$ 39,449
Eliminate DSM Revenue		DSMREV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND		$ -	$ (19,849)	$ -	$ 16,889	$ 12,240	$ 71,430	$ (19,194)	$ -
Merger savings			R01	$ (14,857)	$ (2,564)	$ (2,722)	$ (20,307)	$ (3,001)	$ (23,470)	$ (3,447)	$ (62,054)
Adjustment for rate switching, increased interruptible credit		RATESW									$ (2,777,732)
VDT Amortization and Surcredit			VDTREV	$ 491	$ 81	$ 90	$ 667	$ 102	$ 802	$ 115	$ 2,335
Total Pro-Forma Operating Revenue			(13,500,374)	$ 4,078,936	$ 691,230	$ 745,233	$ 5,390,448	$ 805,262	$ 6,280,921	$ 891,430	$ 13,960,186

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
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Class Allocation

12 Months Ended
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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Operating Expenses								
Operation and Maintenance Expenses				$ 548,721,322	$ 105,660,558	$ 113,988,105	$ 45,623,478	$ 1,544,149
Depreciation and Amortization Expenses				88,376,624	19,722,676	21,419,953	9,577,587	224,699
Regulatory Credits and Accretion Expenses				(8,656,053)	(1,467,394)	(1,873,558)	(792,250)	(28,699)
Property Taxes			NPT	8,211,450	1,813,418	1,980,988	883,896	21,153
Other Taxes				5,761,996	1,272,480	1,390,064	620,232	14,843
Gain Disposition of Allowances				(246,288)	(39,277)	(45,226)	(16,427)	(750)
State and Federal Income Taxes			TXINCPF	26,916,596	$ (728,540)	$ (732,082)	$ 3,125,711	$ 346,205
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 4,582,475	$ 934,980	$ 771,944	$ 449,462	$ 11,972
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(31,644,777)	$ (5,046,623)	$ (5,810,987)	$ (2,110,684)	$ (96,419)
Remove ECR expenses			ECRREV	(248,468)	$ (45,272)	$ (46,795)	$ (22,742)	$ (908)
Eliminate brokered sales expenses			Energy	(24,729,742)	$ (3,943,832)	$ (4,541,167)	$ (1,649,456)	$ (75,349)
Eliminate DSM Expenses			DSMREV	(2,946,471)	$ (1,510,632)	$ (1,090,913)	$ (223,001)	$ (10,756)
Year end adjustment			YREND	151,410	$ (251,488)	$ 1,068,029	$ 491,740	$ -
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	2,091,278	$ 466,703	$ 506,866	$ 226,637	$ 5,317
Labor adjustment			LBT	1,002,076	$ 248,151	$ 241,886	$ 106,464	$ 2,274
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	(473,014)	$ (168,017)	$ (153,325)	$ (69,375)	$ (554)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	58,333	$ 10,564	$ 11,159	$ 5,351	$ 218
Amortization of rate case expenses			OMT	352,456	$ 67,868	$ 73,217	$ 29,305	$ 992
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	2,895,000	$ 716,908	$ 698,809	$ 307,575	$ 6,568
Adjustment for merger savings			LBT	18,968,825	$ 4,697,374	$ 4,578,784	$ 2,015,316	$ 43,038
Adjustment for merger amortization expenses			LBT	(2,726,510)	$ (675,183)	$ (658,138)	$ (289,674)	$ (6,186)
Adjustment for MISO schedule 10 expenses			PLTRT	843,344	$ 142,966	$ 182,537	$ 77,187	$ 2,796
Adjustment for effect of accounting change			DET	8,434,618	$ 1,882,322	$ 2,044,309	$ 914,080	$ 21,445
Adjustment for IT staff reduction			LBT	(601,682)	$ (148,998)	$ (145,237)	$ (63,925)	$ (1,365)
Adjustment to remove Alstom expenses			PLPPT	(3,126,995)	$ (530,095)	$ (676,822)	$ (286,200)	$ (10,367)
Adjustment for corporate lease expense			LBT	-	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	120,391	$ 21,803	$ 23,030	$ 11,043	$ 451
Adjustment for OMU Nox expense			PLPPT	1,959,879	$ 332,243	$ 424,206	$ 179,379	$ 6,498
Adjustment for ice storm			SDALL	(5,277,336)	$ (1,874,536)	$ (1,710,617)	$ (774,008)	$ (6,178)
Adjustment for management audit fee			OMT	163,982	$ 31,576	$ 34,065	$ 13,634	$ 461
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(705,035)	$ (114,041)	$ (134,708)	$ (50,991)	$ (2,191)
VDT Amortization and Surcredit			VDTREV	(466,280)	$ (84,947)	$ (88,836)	$ (42,731)	$ (1,661)
Total Expense Adjustments				(35,904,718)	(5,775,189)	(5,170,648)	(1,205,074)	(121,875)
Total Operating Expenses		TOE		$ 633,180,928	$ 121,393,711	$ 131,729,540	$ 58,266,615	$ 2,011,697
Net Operating Income (Adjusted)				$ 60,269,011	$ 3,022,861	$ 3,400,514	$ 5,839,512	$ 582,080
Net Cost Rate Base				$ 1,412,033,543	$ 321,541,172	$ 345,378,280	$ 154,782,645	$ 3,479,092
Rate of Return				**4.27%**	**0.94%**	**0.98%**	**4.42%**	**16.73%**

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

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12 Months Ended
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Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Operating Expenses										
Operation and Maintenance Expenses				$ 118,842,359	$ 27,249,511	$ 403,589	$ 54,932,301	$ 15,226,217	$ 10,073,657	$ 18,924,679
Depreciation and Amortization Expenses				15,756,851	3,495,266	49,142	6,500,949	1,521,924	1,182,222	2,160,026
Regulatory Credits and Accretion Expenses				(1,937,791)	(473,184)	(7,274)	(889,795)	(227,019)	(157,572)	(297,087)
Property Taxes			NPT	1,480,263	330,142	4,667	614,440	144,615	111,564	204,215
Other Taxes				1,038,704	231,662	3,275	431,154	101,477	78,285	143,298
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8,707)	(5,503)	(10,413)
State and Federal Income Taxes			TXINCPF	$ 11,638,614	$ 2,578,996	$ 87,139	$ 3,492,699	$ 1,440,764	$ 717,195	$ 1,306,431
Specific Assignment of Curtailable Service Rider Credit				-	(181,381)	-	(271,654)	(499,037)	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 1,097,059	$ 240,238	$ 4,049	$ 441,260	$ 101,228	$ 78,321	$ 145,724
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (7,511,155)	$ (1,845,959)	$ (27,879)	$ (3,848,951)	$ (1,118,710)	$ (707,007)	$ (1,337,916)
Remove ECR expenses			ECRREV	$ (56,898)	$ (12,809)	$ (193)	$ (23,825)	$ (6,834)	$ (4,435)	$ (8,322)
Eliminate brokered sales expenses			Energy	$ (5,869,813)	$ (1,442,579)	$ (21,787)	$ (3,007,876)	$ (874,249)	$ (552,511)	$ (1,045,554)
Eliminate DSM Expenses			DSMREV	$ (98,559)	$ (12,138)	$ (473)	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (360,354)	$ 71,010	$ 164,672	$ -	$ -	$ -	$ (324,056)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 372,858	$ 82,709	$ 1,163	$ 153,834	$ 36,014	$ 27,975	$ 51,113
Labor adjustment			LBT	$ 182,122	$ 33,999	$ 467	$ 64,398	$ 15,964	$ 12,056	$ 21,918
Medical Expense (See Functional Assignment)										
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (42,357)	$ (5,656)	$ -	$ (9,718)	$ -	$ (2,245)	$ (3,009)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 13,383	$ 3,000	$ 45	$ 5,608	$ 1,588	$ 1,047	$ 1,969
Amortization of rate case expenses			OMT	$ 76,335	$ 17,503	$ 259	$ 35,284	$ 9,780	$ 6,471	$ 12,156
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 526,150	$ 98,223	$ 1,350	$ 186,047	$ 46,120	$ 34,829	$ 63,321
Adjustment for merger savings			LBT	$ 3,447,476	$ 643,584	$ 8,849	$ 1,219,030	$ 302,193	$ 228,212	$ 414,898
Adjustment for merger amortization expenses			LBT	$ (495,528)	$ (92,506)	$ (1,272)	$ (175,219)	$ (43,436)	$ (32,802)	$ (59,636)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 188,796	$ 46,102	$ 709	$ 86,691	$ 22,118	$ 15,352	$ 28,945
Adjustment for effect of accounting change			DET	$ 1,503,825	$ 333,586	$ 4,690	$ 620,447	$ 145,252	$ 112,831	$ 206,152
Adjustment for IT staff reduction			LBT	$ (109,352)	$ (20,414)	$ (281)	$ (38,667)	$ (9,585)	$ (7,239)	$ (13,160)
Adjustment to remove Alstom expenses			PLPPT	$ (700,026)	$ (170,938)	$ (2,628)	$ (321,438)	$ (82,011)	$ (56,923)	$ (107,323)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 27,620	$ 6,192	$ 94	$ 11,575	$ 3,278	$ 2,161	$ 4,064
Adjustment for OMU Nox expense			PLPPT	$ 438,749	$ 107,137	$ 1,647	$ 201,465	$ 51,401	$ 35,677	$ 67,266
Adjustment for ice storm			SDALL	$ (472,573)	$ (63,098)	$ -	$ (108,425)	$ -	$ (25,051)	$ (33,566)
Adjustment for management audit fee			OMT	$ 35,515	$ 8,143	$ 121	$ 16,416	$ 4,550	$ 3,010	$ 5,656
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (165,191)	$ (40,541)	$ (615)	$ (82,745)	$ (23,467)	$ (15,091)	$ (28,537)
VDT Amortization and Surcredit			VDTREV	$ (106,432)	$ (23,944)	$ (363)	$ (44,478)	$ (12,752)	$ (8,271)	$ (15,454)
Total Expense Adjustments				(9,175,410)	(2,279,396)	128,577	(5,060,548)	(1,532,786)	(931,953)	(2,099,076)
Total Operating Expenses		TOE		$ 138,682,191	$ 31,177,487	$ 672,946	$ 60,160,849	$ 16,268,676	$ 11,146,215	$ 20,477,798
Net Operating Income (Adjusted)				$ 21,326,675	$ 4,730,642	$ 145,006	$ 6,789,215	$ 2,551,749	$ 1,360,711	$ 2,480,920
Net Cost Rate Base				$ 246,357,662	$ 53,894,949	$ 748,210	$ 100,426,897	$ 23,376,610	$ 18,349,567	$ 33,402,015
Rate of Return				8.66%	8.78%	19.38%	6.76%	10.92%	7.42%	7.43%

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

KENTUCKY UTILITIES
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Class Allocation

12 Months Ended
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Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH
Operating Expenses								
Operation and Maintenance Expenses				$ 3,523,749	$ 2,966,782	$ 1,554,550	$ 3,474,683	$ 1,203,506
Depreciation and Amortization Expenses				468,571	352,846	208,952	404,804	292,095
Regulatory Credits and Accretion Expenses				(62,573)	(52,377)	(27,856)	(60,238)	(9,776)
Property Taxes			NPT	44,223	33,517	19,719	38,459	26,365
Other Taxes				31,031	23,519	13,837	26,987	18,501
Gain Disposition of Allowances				(1,839)	(1,608)	(810)	(1,897)	(193)
State and Federal Income Taxes			TXINCPF	$ 480,089	$ 336,562	$ 118,359	$ 371,609	$ (464,200)
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-
Allocation of Curtailable Service Rider Credits			SCP	$ 26,400	$ 23,067	$ 10,168	$ 29,038	$ 4,940
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	$ (236,347)	$ (206,595)	$ (104,115)	$ (243,795)	$ (24,816)
Remove ECR expenses			ECRREV	$ (1,810)	$ (1,443)	$ (696)	$ (1,713)	$ (156)
Eliminate brokered sales expenses			Energy	$ (184,700)	$ (161,450)	$ (81,363)	$ (190,521)	$ (19,393)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -
Year end adjustment			YREND	$ (141,450)	$ (165,932)	$ -	$ (424,256)	$ (13,589)
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -
Adjustment for change in depreciation rate			DET	$ 11,088	$ 8,349	$ 4,944	$ 9,579	$ 6,912
Labor adjustment			LBT	$ 4,462	$ 3,396	$ 1,968	$ 3,928	$ 4,343
Medical Expense (See Functional Assignment)								
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Storm damage adjustment			SDALL	$ (860)	$ -	$ (395)	$ -	$ (3,556)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$ -	$ -	$ -	$ -	$ -
Adjustment for amortization of ESM audit expense			R01	$ 430	$ 344	$ 166	$ 410	$ 37
Amortization of rate case expenses			OMT	$ 2,263	$ 1,906	$ 999	$ 2,232	$ 773
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	$ -	$ -	$ -	$ -	$ -
Adjustment for VDT net savings to shareholders			LBT	$ 12,892	$ 9,811	$ 5,686	$ 11,348	$ 12,548
Adjustment for merger savings			LBT	$ 84,469	$ 64,283	$ 37,259	$ 74,354	$ 82,219
Adjustment for merger amortization expenses			LBT	$ (12,141)	$ (9,240)	$ (5,356)	$ (10,687)	$ (11,818)
Adjustment for MISO schedule 10 expenses			PLTRT	$ 6,096	$ 5,103	$ 2,714	$ 5,869	$ 953
Adjustment for effect of accounting change			DET	$ 44,720	$ 33,675	$ 19,942	$ 38,634	$ 27,877
Adjustment for IT staff reduction			LBT	$ (2,679)	$ (2,039)	$ (1,182)	$ (2,358)	$ (2,608)
Adjustment to remove Alstom expenses			PLPPT	$ (22,605)	$ (18,921)	$ (10,063)	$ (21,761)	$ (3,532)
Adjustment for corporate lease expense			LBT	$ -	$ -	$ -	$ -	$ -
Adjustment for sales tax refund			R01	$ 888	$ 709	$ 343	$ 847	$ 77
Adjustment for OMU Nox expense			PLPPT	$ 14,168	$ 11,859	$ 6,307	$ 13,639	$ 2,214
Adjustment for ice storm			SDALL	$ (9,598)	$ -	$ (4,411)	$ -	$ (39,675)
Adjustment for management audit fee			OMT	$ 1,053	$ 887	$ 465	$ 1,038	$ 360
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	$ (5,227)	$ (4,527)	$ (2,308)	$ (5,313)	$ (608)
VDT Amortization and Surcredit			VDTREV	$ (3,381)	$ (2,696)	$ (1,291)	$ (3,165)	$ (286)
Total Expense Adjustments				(438,270)	(432,521)	(130,386)	(741,691)	18,276
Total Operating Expenses		TOE		$ 4,071,380	$ 3,249,788	$ 1,766,531	$ 3,541,753	$ 1,089,511
Net Operating Income (Adjusted)				$ 841,223	$ 595,482	$ 227,548	$ 660,810	$ (655,344)
Net Cost Rate Base				$ 7,228,861	$ 5,375,126	$ 3,223,008	$ 6,169,967	$ 4,781,983
Rate of Return				11.64%	11.08%	7.06%	10.71%	-13.70%

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

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12 Months Ended
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Description	Ref	Name	Allocation Vector	All Elcetric School AES	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Operating Expenses											
Operation and Maintenance Expenses				3,246,942	618,434	596,400	3,295,670	316,763	2,749,015	434,752	12,271,472
Depreciation and Amortization Expenses				590,262	112,317	133,337	1,767,338	209,991	798,757	128,437	1,297,622
Regulatory Credits and Accretion Expenses				(66,348)	(12,185)	(11,125)	(5,547)	(317)	(8,590)	(1,334)	(186,160)
Property Taxes			NPT	55,195	10,485	12,309	157,319	18,678	71,351	11,471	122,997
Other Taxes				38,730	7,357	8,638	110,391	13,107	50,067	8,049	86,307
Gain Disposition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(933)	(145)	(6,918)
State and Federal Income Taxes			TXINCPF	101,641	(13,126)	1,309	(277,175)	55,377	941,592	114,319	1,877,108
Specific Assignment of Curtailable Service Rider Credit				-	-	-	-	-	-	-	(3,630,403)
Allocation of Curtailable Service Rider Credits			SCP	38,263	6,563	6,225	-	-	-	-	161,576
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	(192,211)	(32,967)	(32,629)	(77,281)	(4,417)	(119,883)	(18,611)	(888,821)
Remove ECR expenses			ECRREV	(1,423)	(232)	(262)	(1,953)	(291)	(2,260)	(330)	(6,866)
Eliminate brokered sales expenses			Energy	(150,209)	(25,763)	(25,499)	(60,394)	(3,452)	(93,686)	(14,544)	(694,595)
Eliminate DSM Expenses			DSMREV	-	-	-	-	-	-	-	-
Year end adjustment			YREND	-	(11,965)	-	10,181	7,379	43,060	(11,571)	-
Depreciation adjustment			DET	-	-	-	-	-	-	-	-
Adjustment for change in depreciation rate			DET	13,968	2,658	3,155	41,821	4,969	18,901	3,039	30,706
Labor adjustment			LBT	5,292	1,185	1,242	19,349	2,216	10,003	1,606	13,387
Medical Expense (See Functional Assignment)											-
Adjustment for pension/post retir benefit (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Storm damage adjustment			SDALL	(2,563)	(552)	(1,032)	(3,854)	(302)	(4,091)	(639)	(912)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	-	-	-	-	-	-	-
Adjustment for amortization of ESM audit expense			R01	338	58	62	462	68	534	78	1,412
Amortization of rate case expenses			OMT	2,086	397	383	2,117	203	1,766	279	7,882
Remove Amortization of one-utility costs (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Adjustment for injuries and damages account 925 (See Functional Assignment)			OMT	-	-	-	-	-	-	-	-
Adjustment for VDT net savings to shareholders			LBT	15,288	3,424	3,587	55,899	6,402	28,898	4,641	38,675
Adjustment for merger savings			LBT	100,172	22,434	23,504	366,267	41,948	189,346	30,410	253,407
Adjustment for merger amortization expenses			LBT	(14,398)	(3,225)	(3,378)	(52,646)	(6,029)	(27,216)	(4,371)	(36,424)
Adjustment for MISO schedule 10 expenses			PLTRT	6,464	1,187	1,084	540	31	837	130	18,137
Adjustment for effect of accounting change			DET	56,334	10,719	12,726	168,674	20,041	76,233	12,258	123,844
Adjustment for IT staff reduction			LBT	(3,177)	(712)	(746)	(11,618)	(1,331)	(6,006)	(965)	(8,038)
Adjustment to remove Alstom expenses			PLPPT	(23,968)	(4,402)	(4,019)	(2,004)	(115)	(3,103)	(482)	(67,250)
Adjustment for corporate lease expense			LBT	-	-	-	-	-	-	-	-
Adjustment for sales tax refund			R01	698	120	128	953	141	1,102	162	2,913
Adjustment for OMU Nox expense			PLPPT	15,022	2,759	2,519	1,256	72	1,945	302	42,150
Adjustment for ice storm			SDALL	(28,599)	(6,163)	(11,514)	(43,003)	(3,368)	(45,641)	(7,132)	(10,180)
Adjustment for management audit fee			OMT	970	185	178	985	95	822	130	3,667
Adjustment for Retirement of Green River Units 1 & 2			OMPPT	(4,537)	(793)	(768)	(1,434)	(82)	(2,224)	(345)	(18,752)
VDT Amortization and Surcredit			VDTREV	(2,682)	(445)	(490)	(3,643)	(557)	(4,383)	(630)	(12,760)
Total Expense Adjustments				(207,137)	(42,093)	(31,768)	410,676	63,622	64,951	(6,583)	(1,208,417)
Total Operating Expenses		TOE		3,796,052	687,494	715,072	5,458,071	677,187	4,666,211	688,967	10,785,185
Net Operating Income (Adjusted)				282,883	3,735	30,161	(67,623)	128,075	1,614,710	202,463	3,175,001
Net Cost Rate Base				9,230,542	1,761,139	2,144,158	30,643,939	3,643,943	13,875,266	2,214,289	20,004,120
Rate of Return				**3.06%**	**0.21%**	**1.41%**	**-0.22%**	**3.51%**	**11.64%**	**9.14%**	**15.87%**

Average 12 CP Prod Trans Allocation
All other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 2003-00433
AND	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)	CASE NO. 2003-00434

EXHIBIT (SJB-7)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 768,525,785	$ 291,774,308	$ 1,042,105	$ 106,206,583	$ 8,933,859	$ 132,997,184
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (1,867,000)	$ (715,724)	$ (2,428)	$ (271,251)	$ (21,339)	$ (322,331)
Mismatch in fuel cost recovery			Energy	(4,406,145)	(1,479,166)	(6,691)	(513,321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC Roll-In		FACRI		547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues		ECRREV		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In		ECRRI		723,260	255,297	937	110,897	9,089	133,401
Remove off-system ECR revenues			PLPPT	(1,929,923)	(798,593)	(2,924)	(212,071)	(20,734)	(330,945)
Eliminate brokered sales			Energy	(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
Eliminate ESM revenues		ESMREV		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1,196,285)
Eliminate Rate Refund Acct			R01	(7,150,231)	(2,741,076)	(9,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV		(3,277,501)	(2,771,657)	-	(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment		YREND		2,614,347	1,232,278	(9,993)	(279,531)	-	932,854
Adjustment for Merger savings			R01	(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		(621,927)	-	-	-	-	-
VDT Amortization and Surcredit			VDTREV	44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue				$ 709,631,942	$ 269,278,378	$ 952,526	$ 98,312,757	$ 8,208,359	$ 123,516,811

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 14,652,107	$ 19,054,006	$ 6,245,422	$ 34,323,004	$ 16,876,390	$ 80,727,853
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (34,589)	$ (45,400)	$ (14,766)	$ (83,348)	$ (37,178)	$ (183,683)
Mismatch in fuel cost recovery			Energy	(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI		16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV		(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR Roll-In		ECRRI		14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			PLPPT	(35,905)	(50,917)	(14,985)	(75,351)	(46,325)	(217,365)
Eliminate brokered sales			Energy	(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
Eliminate ESM revenues		ESMREV		(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct			R01	(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue		DSMREV		(14,688)	(16,281)	-	-	-	-
Year End Revenue Adjustment		YREND		-	566,077	-	147,900	-	-
Adjustment for Merger savings			R01	(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV	815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				$ 13,473,965	$ 18,144,692	$ 5,748,275	$ 31,822,823	$ 15,133,047	$ 73,729,592

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 2,667,730	$ 5,832,231	$ 207,928	$ 7,037,493	$ 727,497	$ 39,220,086
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (6,454)	$ (15,890)	$ (464)	$ (19,577)	$ (1,786)	$ (90,792)
Mismatch in fuel cost recovery			Energy	(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Full Year of the FAC Roll-In		FACRI		1,436	(3,891)	156	(1,432)	797	23,036
Remove ECR revenues		ECRREV		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR Roll-In		ECRRI		3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			PLPPT	(6,192)	(8,400)	(669)	(8,714)	(1,481)	(98,352)
Eliminate brokered sales			Energy	(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues		ESMREV		(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct			R01	(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue		DSMREV		-	-	-	-	-	-
Year End Revenue Adjustment		YREND		-	2,999	(1,159)	17,114	5,808	-
Adjustment for Merger savings			R01	(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	-	(90,000)
VDT Amortization and Surcredit			VDTREV	146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				$ 2,464,065	$ 5,453,014	$ 189,714	$ 6,617,260	$ 677,761	$ 35,908,904

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 508,149,420	$ 203,882,981	$ 1,176,453	$ 60,345,199	$ 5,773,024	$ 82,923,255
Depreciation and Amortization Expenses				95,827,965	44,533,075	340,924	11,122,256	851,366	13,983,904
Accretion Expense				462,519	191,388	701	50,824	4,969	79,313
Property and Other Taxes			NPT	12,603,252	5,805,546	42,776	1,456,554	113,849	1,864,962
Amortization of Investment Tax Credit				(4,010,380)	(1,847,336)	(13,611)	(463,478)	(36,227)	(593,435)
Other Expenses				(6,055,342)	(2,789,325)	(20,552)	(699,814)	(54,700)	(896,037)
State and Federal Income Taxes			TXINCPF	27,184,243	$ 89,824	$ (288,624)	$ 8,582,119	$ 521,850	$ 8,264,388
Specific Assignment of Interruptible Credit				(3,519,894)	-	-	-	-	-
Allocation of Interruptible Credits			SCP	3,519,894	$ 1,511,175	$ 2,563	$ 514,921	$ 41,545	$ 625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	(2,005,300)	$ (673,190)	$ (3,045)	$ (233,620)	$ (26,547)	$ (360,271)
Remove ECR expenses			ECRREV	(1,766,344)	$ (670,920)	$ (2,417)	$ (256,487)	$ (20,079)	$ (305,205)
Eliminate brokered sales expenses			Energy	(25,030,766)	$ (8,402,958)	$ (38,013)	$ (2,916,114)	$ (331,372)	$ (4,497,006)
Eliminate DSM Expenses			DSMREV	(3,280,013)	$ (2,773,781)	$ -	$ (109,057)	$ (25,643)	$ (340,540)
Year end Expense adjustment			YREND	1,458,544	$ 687,488	$ (5,575)	$ (155,950)	$ -	$ 520,439
Adjustment to annualize depreciation expense			DET	8,959,741	$ 4,163,762	$ 31,876	$ 1,039,911	$ 79,601	$ 1,307,470
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	918,580	$ 437,787	$ 3,194	$ 114,202	$ 8,491	$ 130,863
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	70,492	$ 46,793	$ 694	$ 9,491	$ 283	$ 5,995
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	333,580	$ 133,841	$ 772	$ 39,614	$ 3,790	$ 54,436
Amortization of ESM audit expenses			R01	58,333	$ 22,362	$ 76	$ 8,475	$ 667	$ 10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	5,640,000	$ 2,687,975	$ 19,612	$ 701,192	$ 52,132	$ 803,485
Adjustment for merger savings			LBT	19,427,401	$ 9,258,932	$ 67,554	$ 2,415,307	$ 179,573	$ 2,767,663
Adjustment for merger amortization expenses			LBT	(2,722,005)	$ (1,297,284)	$ (9,465)	$ (338,413)	$ (25,160)	$ (387,782)
MISO Schedule 10 one time credit			PLTRT	709,577	$ 293,620	$ 1,075	$ 77,972	$ 7,623	$ 121,679
Adjustment cumulative effect of accounting change			DET	5,280,909	$ 2,454,139	$ 18,788	$ 612,928	$ 46,917	$ 770,628
Adjustment for IT staff reduction			LBT	(431,834)	$ (205,808)	$ (1,502)	$ (53,688)	$ (3,992)	$ (61,520)
Remove Alstom Expenses			PLPPT	(2,157,640)	$ (892,821)	$ (3,269)	$ (237,093)	$ (23,181)	$ (369,994)
Adjustment for Obsolete inventory write-off			PLT	(1,373,632)	$ (633,760)	$ (4,661)	$ (158,753)	$ (12,377)	$ (202,830)
Adjustment for corporate office lease			LBT	1,798,420	$ 857,111	$ 6,254	$ 223,588	$ 16,623	$ 256,206
Adjustment for carbide lime write-off			Energy	(1,416,711)	$ (475,597)	$ (2,152)	$ (165,048)	$ (18,755)	$ (254,525)
Adjustment for Cane Run repair refund			PLPPT	3,588,000	$ 1,484,697	$ 5,436	$ 394,269	$ 38,548	$ 615,273
VDT Amortization and Surcredit			VDTREV	(224,718)	$ (87,676)	$ (286)	$ (32,570)	$ (2,549)	$ (38,480)
Total Expense Adjustments				7,834,614	6,414,712	84,946	980,157	(55,406)	546,054
Total Operating Expenses		TOE		$ 641,996,290	$ 257,792,040	$ 1,325,576	$ 81,888,738	$ 7,160,270	$ 106,797,437
Net Operating Income -- Pro-Forma				$ 67,635,652	$ 11,486,338	$ (373,051)	$ 16,424,019	$ 1,048,089	$ 16,719,374
Net Cost Rate Base				$ 1,473,843,556	$ 680,151,878	$ 5,062,926	$ 170,825,435	$ 13,283,070	$ 216,869,731
Rate of Return				4.59%	1.69%	-7.37%	9.61%	1.00%	7.71%

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 9,676,997	$ 12,270,238	$ 4,189,373	$ 21,079,136	$ 12,933,219	$ 58,234,595
Depreciation and Amortization Expenses				1,450,038	2,078,048	622,783	3,224,777	1,688,978	8,610,365
Accretion Expense				8,605	12,203	3,591	18,058	11,102	52,093
Property and Other Taxes			NPT	194,215	278,048	83,186	429,566	228,575	1,155,432
Amortization of Investment Tax Credit				(61,800)	(88,475)	(26,470)	(136,689)	(72,733)	(367,661)
Other Expenses				(93,312)	(133,591)	(39,967)	(206,389)	(109,821)	(555,137)
State and Federal Income Taxes			TXINCPF	$ 745,236	$ 1,070,672	$ 286,102	$ 2,498,379	$ 686,335	$ 2,276,389
Specific Assignment of Interruptible Credit				-	-	-	-	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits			SCP	$ 66,076	$ 84,505	$ 29,945	$ 140,138	$ 60,511	$ 270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (44,786)	$ (54,061)	$ (19,122)	$ (96,898)	$ (63,230)	$ (273,643)
Remove ECR expenses			ECRREV	$ (32,690)	$ (43,382)	$ (14,011)	$ (79,468)	$ (35,195)	$ (177,854)
Eliminate brokered sales expenses			Energy	$ (559,033)	$ (674,807)	$ (238,687)	$ (1,209,515)	$ (789,257)	$ (3,415,692)
Eliminate DSM Expenses			DSMREV	$ (14,699)	$ (16,293)	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 315,814	$ -	$ 82,513	$ -	$ -
Adjustment to annualize depreciation expense			DET	$ 135,576	$ 194,294	$ 58,229	$ 301,511	$ 157,916	$ 805,053
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 13,957	$ 18,905	$ 6,268	$ 31,008	$ 17,191	$ 83,240
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 454	$ 719	$ 221	$ 1,509	$ -	$ 2,235
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 6,353	$ 8,055	$ 2,750	$ 13,838	$ 8,490	$ 38,229
Amortization of ESM audit expenses			R01	$ 1,081	$ 1,418	$ 461	$ 2,604	$ 1,162	$ 5,739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 85,697	$ 116,073	$ 38,487	$ 190,388	$ 105,554	$ 511,087
Adjustment for merger savings			LBT	$ 295,190	$ 399,821	$ 132,571	$ 655,807	$ 363,588	$ 1,760,479
Adjustment for merger amortization expenses			LBT	$ (41,360)	$ (56,020)	$ (18,575)	$ (91,886)	$ (50,943)	$ (246,664)
MISO Schedule 10 one time credit			PLTRT	$ 13,201	$ 18,721	$ 5,510	$ 27,704	$ 17,032	$ 79,919
Adjustment cumulative effect of accounting change			DET	$ 79,909	$ 114,518	$ 34,320	$ 177,712	$ 93,077	$ 474,502
Adjustment for IT staff reduction			LBT	$ (6,562)	$ (8,887)	$ (2,947)	$ (14,577)	$ (8,082)	$ (39,132)
Remove Alstom Expenses			PLPPT	$ (40,142)	$ (56,925)	$ (16,753)	$ (84,242)	$ (51,791)	$ (243,013)
Adjustment for Obsolete inventory write-off			PLT	$ (21,108)	$ (30,225)	$ (9,045)	$ (46,727)	$ (24,803)	$ (125,542)
Adjustment for corporate office lease			LBT	$ 27,326	$ 37,012	$ 12,272	$ 60,709	$ 33,658	$ 162,970
Adjustment for carbide lime write-off			Energy	$ (31,641)	$ (38,193)	$ (13,509)	$ (68,457)	$ (44,671)	$ (193,324)
Adjustment for Cane Run repair refund			PLPPT	$ 66,753	$ 94,662	$ 27,859	$ 140,088	$ 86,124	$ 404,112
VDT Amortization and Surcredit			VDTREV	$ (4,116)	$ (5,407)	$ (1,762)	$ (9,874)	$ (4,381)	$ (21,640)
Total Expense Adjustments				(70,639)	335,809	(15,461)	(16,253)	(188,560)	(408,937)
Total Operating Expenses		TOE		$ 11,915,416	$ 15,907,456	$ 5,133,082	$ 27,030,724	$ 13,600,546	$ 67,870,340
Net Operating Income -- Pro-Forma				$ 1,558,549	$ 2,237,236	$ 615,194	$ 4,792,099	$ 1,532,501	$ 5,859,251
Net Cost Rate Base				$ 22,620,354	$ 32,257,851	$ 9,710,208	$ 50,173,059	$ 26,606,267	$ 134,517,544
Rate of Return				6.89%	6.94%	6.34%	9.55%	5.76%	4.36%

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 1,680,600	$ 2,990,230	$ 160,034	$ 3,323,607	$ 437,073	$ 27,073,406
Depreciation and Amortization Expenses				277,050	1,363,409	29,200	1,730,013	64,211	3,857,568
Accretion Expense				1,484	2,013	160	2,088	355	23,571
Property and Other Taxes			NPT	36,758	169,343	3,883	213,859	8,544	518,157
Amortization of Investment Tax Credit				(11,696)	(53,885)	(1,235)	(68,050)	(2,719)	(164,879)
Other Expenses				(17,661)	(81,362)	(1,865)	(102,751)	(4,105)	(248,953)
State and Federal Income Taxes			TXINCPF	$ 159,620	$ 202,899	$ (3,453)	$ 319,895	$ 59,836	$ 1,712,774
Specific Assignment of Interruptible Credit				-	-	-	-	-	(486,000)
Allocation of Interruptible Credits			SCP	$ 12,085	$ -	$ -	$ -	$ 1,678	$ 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (7,490)	$ (8,992)	$ (698)	$ (9,342)	$ (2,007)	$ (128,357)
Remove ECR expenses			ECRREV	$ (6,339)	$ (15,470)	$ (474)	$ (19,117)	$ (1,746)	$ (85,491)
Eliminate brokered sales expenses			Energy	$ (93,494)	$ (112,246)	$ (8,719)	$ (116,606)	$ (25,054)	$ (1,602,194)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$
Year end Expense adjustment			YREND	$ -	$ 1,673	$ (647)	$ 9,548	$ 3,240	$ -
Adjustment to annualize depreciation expense			DET	$ 25,904	$ 127,476	$ 2,730	$ 161,753	$ 6,004	$ 360,676
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 2,585	$ 5,797	$ 267	$ 6,433	$ 675	$ 37,717
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 164	$ 487	$ 15	$ 508	$ 27	$ 896
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 1,103	$ 1,963	$ 105	$ 2,182	$ 287	$ 17,773
Amortization of ESM audit expenses			R01	$ 202	$ 496	$ 15	$ 612	$ 56	$ 2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 15,871	$ 35,591	$ 1,639	$ 39,498	$ 4,142	$ 231,578
Adjustment for merger savings			LBT	$ 54,668	$ 122,595	$ 5,646	$ 136,052	$ 14,268	$ 797,688
Adjustment for merger amortization expenses			LBT	$ (7,660)	$ (17,177)	$ (791)	$ (19,062)	$ (1,999)	$ (111,765)
MISO Schedule 10 one time credit			PLTRT	$ 2,277	$ 3,089	$ 246	$ 3,204	$ 545	$ 36,161
Adjustment cumulative effect of accounting change			DET	$ 15,268	$ 75,135	$ 1,609	$ 95,338	$ 3,539	$ 212,584
Adjustment for IT staff reduction			LBT	$ (1,215)	$ (2,725)	$ (125)	$ (3,024)	$ (317)	$ (17,731)
Remove Alstom Expenses			PLPPT	$ (6,923)	$ (9,391)	$ (748)	$ (9,742)	$ (1,656)	$ (109,957)
Adjustment for Obsolete inventory write-off			PLT	$ (4,001)	$ (18,620)	$ (422)	$ (23,538)	$ (930)	$ (56,291)
Adjustment for corporate office lease			LBT	$ 5,061	$ 11,349	$ 523	$ 12,595	$ 1,321	$ 73,843
Adjustment for carbide lime write-off			Energy	$ (5,292)	$ (6,353)	$ (493)	$ (6,600)	$ (1,418)	$ (90,682)
Adjustment for Cane Run repair refund			PLPPT	$ 11,512	$ 15,617	$ 1,244	$ 16,200	$ 2,754	$ 182,851
VDT Amortization and Surcredit			VDTREV	$ (738)	$ (1,836)	$ (52)	$ (2,290)	$ (206)	$ (10,853)
Total Expense Adjustments				1,462	208,456	867	274,601	1,524	(258,718)
Total Operating Expenses		TOE		$ 2,139,702	$ 4,801,103	$ 187,590	$ 5,693,263	$ 566,398	$ 32,186,608
Net Operating Income – Pro-Forma				$ 324,363	$ 651,910	$ 2,124	$ 923,997	$ 111,362	$ 3,722,296
Net Cost Rate Base				$ 4,292,210	$ 20,157,813	$ 451,450	$ 25,495,128	$ 1,001,089	$ 60,367,542
Rate of Return				7.56%	3.23%	0.47%	3.62%	11.12%	6.17%

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 2003-00433
AND	)))	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

EXHIBIT (SJB-8)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual				$ 768,525,785	$ 291,603,270	$ 1,158,990	$ 107,524,685	$ 8,982,068	$ 132,709,052
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (1,867,000)	$ (715,724)	$ (2,428)	$ (271,251)	$ (21,339)	$ (322,331)
Mismatch in fuel cost recovery			Energy	(4,406,145)	(1,479,166)	(6,691)	(513,321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC Roll-In		FACRI		547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues		ECRREV		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In		ECRRI		723,260	255,297	937	110,897	9,089	133,401
Remove off-system ECR revenues			PLPPT	(1,929,923)	(792,562)	(7,045)	(258,546)	(22,434)	(320,785)
Eliminate brokered sales			Energy	(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
Eliminate ESM revenues		ESMREV		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1,196,285)
Eliminate Rate Refund Acct			R01	(7,150,231)	(2,741,076)	(9,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV		(3,277,501)	(2,771,657)	-	(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment		YREND		2,614,347	1,232,278	(9,993)	(279,531)	-	932,854
Adjustment for Merger savings			R01	(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		(621,927)	-	-	-	-	-
VDT Amortization and Surcredit			VDTREV	44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue				$ 709,631,942	$ 269,113,371	$ 1,065,289	$ 99,584,383	$ 8,254,868	$ 123,238,838

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$	14,666,854 $	18,848,201 $	6,311,999 $	34,454,413 $	16,765,931 $	79,766,951
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	$	(34,589) $	(45,400) $	(14,766) $	(83,348) $	(37,178) $	(183,683)
Mismatch in fuel cost recovery			Energy		(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI			16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV			(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR Roll-In		ECRRI			14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			PLPPT		(36,425)	(43,661)	(17,332)	(79,984)	(42,430)	(183,484)
Eliminate brokered sales			Energy		(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
Eliminate ESM revenues		ESMREV			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct			R01		(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue		DSMREV			(14,688)	(16,281)	-	-	-	-
Year End Revenue Adjustment		YREND			-	566,077	-	147,900	-	-
Adjustment for Merger savings			R01		(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit		RATESW			-	-	-	-	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV		815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				$	13,488,192 $	17,946,145 $	5,812,504 $	31,949,599 $	15,026,482 $	72,802,571

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual				$ 2,756,699	$ 5,846,370	$ 211,367	$ 7,056,532	$ 715,799	$ 39,146,605
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (6,454)	$ (15,890)	$ (464)	$ (19,577)	$ (1,786)	$ (90,792)
Mismatch in fuel cost recovery			Energy	(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Full Year of the FAC Roll-In		FACRI		1,436	(3,891)	156	(1,432)	797	23,036
Remove ECR revenues		ECRREV		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR Roll-In		ECRRI		3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			PLPPT	(9,329)	(8,899)	(790)	(9,385)	(1,069)	(95,761)
Eliminate brokered sales			Energy	(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues		ESMREV		(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct			R01	(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue		DSMREV		-	-	-	-	-	-
Year End Revenue Adjustment		YREND		-	2,999	(1,159)	17,114	5,808	-
Adjustment for Merger savings			R01	(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	-	(90,000)
VDT Amortization and Surcredit			VDTREV	146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				$ 2,549,898	$ 5,466,655	$ 193,033	$ 6,635,628	$ 666,475	$ 35,838,013

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 508,149,420	$ 204,145,564	$ 1,503,840	$ 63,463,421	$ 5,864,100	$ 81,976,232
Depreciation and Amortization Expenses				95,827,965	44,314,049	490,604	12,810,179	913,101	13,614,930
Accretion Expense				462,519	189,943	1,688	61,962	5,376	76,878
Property and Other Taxes			NPT	12,603,252	5,775,892	63,041	1,685,080	122,207	1,815,007
Amortization of Investment Tax Credit				(4,010,380)	(1,837,901)	(20,060)	(536,196)	(38,887)	(577,539)
Other Expenses				(6,055,342)	(2,775,078)	(30,288)	(809,611)	(58,715)	(872,036)
State and Federal Income Taxes			TXINCPF	27,184,243	$ 62,557	$ (466,405)	$ 6,799,629	$ 465,558	$ 8,756,882
Specific Assignment of Interruptible Credit				(3,519,894)	-	-	-	-	-
Allocation of Interruptible Credits			SCP1	3,519,894	$ 1,511,175	$ 2,563	$ 514,921	$ 41,545	$ 625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	(2,005,300)	$ (673,190)	$ (3,045)	$ (233,620)	$ (26,547)	$ (360,271)
Remove ECR expenses			ECRREV	(1,766,344)	$ (670,920)	$ (2,417)	$ (256,487)	$ (20,079)	$ (305,205)
Eliminate brokered sales expenses			Energy	(25,030,766)	$ (8,402,958)	$ (38,013)	$ (2,916,114)	$ (331,372)	$ (4,497,006)
Eliminate DSM Expenses			DSMREV	(3,280,013)	$ (2,773,781)	$ -	$ (109,057)	$ (25,643)	$ (340,540)
Year end Expense adjustment			YREND	1,458,544	$ 687,488	$ (5,575)	$ (155,950)	$ -	$ 520,439
Adjustment to annualize depreciation expense			DET	8,959,741	$ 4,143,283	$ 45,871	$ 1,197,729	$ 85,373	$ 1,272,971
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	918,580	$ 436,409	$ 4,136	$ 124,822	$ 8,879	$ 128,541
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	70,492	$ 46,793	$ 694	$ 9,491	$ 283	$ 5,995
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	333,580	$ 134,013	$ 987	$ 41,661	$ 3,850	$ 53,814
Amortization of ESM audit expenses			R01	58,333	$ 22,362	$ 76	$ 8,475	$ 667	$ 10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	5,640,000	$ 2,679,514	$ 25,394	$ 766,396	$ 54,517	$ 789,231
Adjustment for merger savings			LBT	19,427,401	$ 9,229,788	$ 87,471	$ 2,639,907	$ 187,788	$ 2,718,566
Adjustment for merger amortization expenses			LBT	(2,722,005)	$ (1,293,201)	$ (12,256)	$ (369,882)	$ (26,311)	$ (380,903)
MISO Schedule 10 one time credit			PLTRT	709,577	$ 291,402	$ 2,590	$ 95,060	$ 8,248	$ 117,944
Adjustment cumulative effect of accounting change			DET	5,280,909	$ 2,442,069	$ 27,036	$ 705,946	$ 50,319	$ 750,295
Adjustment for IT staff reduction			LBT	(431,834)	$ (205,161)	$ (1,944)	$ (58,680)	$ (4,174)	$ (60,429)
Remove Alstom Expenses			PLPPT	(2,157,640)	$ (886,079)	$ (7,877)	$ (289,053)	$ (25,081)	$ (358,636)
Adjustment for Obsolete inventory write-off			PLT	(1,373,632)	$ (630,542)	$ (6,860)	$ (183,550)	$ (13,283)	$ (197,410)
Adjustment for corporate office lease			LBT	1,798,420	$ 854,414	$ 8,097	$ 244,380	$ 17,384	$ 251,661
Adjustment for carbide lime write-off			Energy	(1,416,711)	$ (475,597)	$ (2,152)	$ (165,048)	$ (18,755)	$ (254,525)
Adjustment for Cane Run repair refund			PLPPT	3,588,000	$ 1,473,485	$ 13,099	$ 480,674	$ 41,708	$ 596,385
VDT Amortization and Surcredit			VDTREV	(224,718)	$ (87,676)	$ (286)	$ (32,570)	$ (2,549)	$ (38,480)
Total Expense Adjustments				7,834,614	6,341,917	135,026	1,544,530	(34,780)	422,510
Total Operating Expenses		TOE		$ 641,996,290	$ 257,728,118	$ 1,680,010	$ 85,533,915	$ 7,279,507	$ 105,837,897
Net Operating Income -- Pro-Forma				$ 67,635,652	$ 11,385,253	$ (614,721)	$ 14,050,468	$ 975,361	$ 17,400,941
Net Cost Rate Base				$ 1,473,843,556	$ 676,820,462	$ 7,339,572	$ 196,498,956	$ 14,222,061	$ 211,257,595
Rate of Return				4.59%	1.68%	-8.38%	7.15%	1.00%	8.24%

Average and Excess Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 9,672,397	$ 11,728,441	$ 4,342,362	$ 21,322,155	$ 12,620,140	$ 55,734,309
Depreciation and Amortization Expenses				1,468,922	1,814,501	708,038	3,393,056	1,547,527	7,379,861
Accretion Expense				8,729	10,464	4,154	19,169	10,169	43,973
Property and Other Taxes			NPT	196,772	242,367	94,729	452,349	209,424	988,835
Amortization of Investment Tax Credit				(62,613)	(77,122)	(30,143)	(143,938)	(66,639)	(314,649)
Other Expenses				(94,541)	(116,447)	(45,513)	(217,335)	(100,619)	(475,095)
State and Federal Income Taxes			TXINCPF	$ 740,596	$ 1,370,270	$ 197,818	$ 2,346,968	$ 855,773	$ 3,663,837
Specific Assignment of Interruptible Credit				-	-	-	-	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits			SCP1	$ 66,076	$ 84,505	$ 29,945	$ 140,138	$ 60,511	$ 270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (44,786)	$ (54,061)	$ (19,122)	$ (96,898)	$ (63,230)	$ (273,643)
Remove ECR expenses			ECRREV	$ (32,690)	$ (43,382)	$ (14,011)	$ (79,468)	$ (35,195)	$ (177,854)
Eliminate brokered sales expenses			Energy	$ (559,033)	$ (674,807)	$ (238,687)	$ (1,209,515)	$ (789,257)	$ (3,415,692)
Eliminate DSM Expenses			DSMREV	$ (14,699)	$ (16,293)	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 315,814	$ -	$ 82,513	$ -	$ -
Adjustment to annualize depreciation expense			DET	$ 137,342	$ 169,653	$ 66,200	$ 317,245	$ 144,691	$ 690,004
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 14,076	$ 17,246	$ 6,805	$ 32,067	$ 16,301	$ 75,498
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 454	$ 719	$ 221	$ 1,509	$ -	$ 2,235
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 6,350	$ 7,699	$ 2,851	$ 13,997	$ 8,285	$ 36,587
Amortization of ESM audit expenses			R01	$ 1,081	$ 1,418	$ 461	$ 2,604	$ 1,162	$ 5,739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 86,427	$ 105,892	$ 41,780	$ 196,889	$ 100,090	$ 463,554
Adjustment for merger savings			LBT	$ 297,703	$ 364,752	$ 143,915	$ 678,199	$ 344,766	$ 1,596,745
Adjustment for merger amortization expenses			LBT	$ (41,712)	$ (51,106)	$ (20,164)	$ (95,024)	$ (48,306)	$ (223,723)
MISO Schedule 10 one time credit			PLTRT	$ 13,392	$ 16,053	$ 6,373	$ 29,408	$ 15,600	$ 67,462
Adjustment cumulative effect of accounting change			DET	$ 80,950	$ 99,994	$ 39,019	$ 186,985	$ 85,281	$ 406,691
Adjustment for IT staff reduction			LBT	$ (6,617)	$ (8,108)	$ (3,199)	$ (15,075)	$ (7,663)	$ (35,493)
Remove Alstom Expenses			PLPPT	$ (40,723)	$ (48,812)	$ (19,377)	$ (89,422)	$ (47,436)	$ (205,134)
Adjustment for Obsolete inventory write-off			PLT	$ (21,386)	$ (26,353)	$ (10,297)	$ (49,199)	$ (22,725)	$ (107,465)
Adjustment for corporate office lease			LBT	$ 27,559	$ 33,766	$ 13,322	$ 62,782	$ 31,915	$ 147,813
Adjustment for carbide lime write-off			Energy	$ (31,641)	$ (38,193)	$ (13,509)	$ (68,457)	$ (44,671)	$ (193,324)
Adjustment for Cane Run repair refund			PLPPT	$ 67,719	$ 81,171	$ 32,223	$ 148,702	$ 78,883	$ 341,123
VDT Amortization and Surcredit			VDTREV	$ (4,116)	$ (5,407)	$ (1,762)	$ (9,874)	$ (4,381)	$ (21,640)
Total Expense Adjustments				(64,351)	247,654	13,042	39,968	(235,890)	(820,517)
Total Operating Expenses		TOE		$ 11,931,987	$ 15,304,633	$ 5,314,432	$ 27,352,530	$ 13,263,334	$ 65,073,757
Net Operating Income -- Pro-Forma				$ 1,556,204	$ 2,641,512	$ 498,073	$ 4,597,069	$ 1,763,148	$ 7,728,814
Net Cost Rate Base				$ 22,907,580	$ 28,249,267	$ 11,006,955	$ 52,732,604	$ 24,454,785	$ 115,801,430
Rate of Return				6.79%	9.35%	4.53%	8.72%	7.21%	6.67%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 1,914,697	$ 3,075,140	$ 173,208	$ 3,423,529	$ 405,680	$ 26,784,204
Depreciation and Amortization Expenses				390,982	1,381,515	33,605	1,754,394	49,231	3,763,469
Accretion Expense				2,236	2,133	189	2,249	256	22,950
Property and Other Taxes			NPT	52,183	171,794	4,479	217,160	6,515	505,418
Amortization of Investment Tax Credit				(16,605)	(54,665)	(1,425)	(69,101)	(2,073)	(160,825)
Other Expenses				(25,072)	(82,540)	(2,152)	(104,336)	(3,130)	(242,832)
State and Federal Income Taxes			TXINCPF	$ 30,150	$ 163,835	$ (10,057)	$ 272,880	$ 77,097	$ 1,856,854
Specific Assignment of Interruptible Credit				-	-	-	-	-	(486,000)
Allocation of Interruptible Credits			SCP1	$ 12,085	$ -	$ -	$ -	$ 1,678	$ 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (7,490)	$ (8,992)	$ (698)	$ (9,342)	$ (2,007)	$ (128,357)
Remove ECR expenses			ECRREV	$ (6,339)	$ (15,470)	$ (474)	$ (19,117)	$ (1,746)	$ (85,491)
Eliminate brokered sales expenses			Energy	$ (93,494)	$ (112,246)	$ (8,719)	$ (116,606)	$ (25,054)	$ (1,602,194)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 1,673	$ (647)	$ 9,548	$ 3,240	$ -
Adjustment to annualize depreciation expense			DET	$ 36,556	$ 129,169	$ 3,142	$ 164,033	$ 4,603	$ 351,878
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 3,302	$ 5,911	$ 295	$ 6,586	$ 580	$ 37,125
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 164	$ 487	$ 15	$ 508	$ 27	$ 896
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 1,257	$ 2,019	$ 114	$ 2,247	$ 266	$ 17,583
Amortization of ESM audit expenses			R01	$ 202	$ 496	$ 15	$ 612	$ 56	$ 2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 20,272	$ 36,290	$ 1,809	$ 40,439	$ 3,564	$ 227,943
Adjustment for merger savings			LBT	$ 69,828	$ 125,004	$ 6,232	$ 139,296	$ 12,275	$ 785,167
Adjustment for merger amortization expenses			LBT	$ (9,784)	$ (17,515)	$ (873)	$ (19,517)	$ (1,720)	$ (110,011)
MISO Schedule 10 one time credit			PLTRT	$ 3,430	$ 3,272	$ 291	$ 3,451	$ 393	$ 35,209
Adjustment cumulative effect of accounting change			DET	$ 21,546	$ 76,133	$ 1,852	$ 96,682	$ 2,713	$ 207,398
Adjustment for IT staff reduction			LBT	$ (1,552)	$ (2,779)	$ (139)	$ (3,096)	$ (273)	$ (17,453)
Remove Alstom Expenses			PLPPT	$ (10,430)	$ (9,949)	$ (884)	$ (10,492)	$ (1,195)	$ (107,061)
Adjustment for Obsolete inventory write-off			PLT	$ (5,675)	$ (18,886)	$ (487)	$ (23,896)	$ (710)	$ (54,909)
Adjustment for corporate office lease			LBT	$ 6,464	$ 11,572	$ 577	$ 12,895	$ 1,136	$ 72,684
Adjustment for carbide lime write-off			Energy	$ (5,292)	$ (6,353)	$ (493)	$ (6,600)	$ (1,418)	$ (90,682)
Adjustment for Cane Run repair refund			PLPPT	$ 17,344	$ 16,544	$ 1,469	$ 17,448	$ 1,987	$ 178,034
VDT Amortization and Surcredit			VDTREV	$ (738)	$ (1,836)	$ (52)	$ (2,290)	$ (206)	$ (10,853)
Total Expense Adjustments				39,572	214,544	2,344	282,789	(3,487)	(290,257)
Total Operating Expenses		TOE		$ 2,400,229	$ 4,871,757	$ 200,191	$ 5,779,564	$ 531,768	$ 31,912,662
Net Operating Income -- Pro-Forma				$ 149,669	$ 594,897	$ (7,159)	$ 856,064	$ 134,707	$ 3,925,351
Net Cost Rate Base				$ 6,025,129	$ 20,433,213	$ 518,452	$ 25,865,966	$ 773,242	$ 58,936,288
Rate of Return				**2.48%**	**2.91%**	**-1.38%**	**3.31%**	**17.42%**	**6.66%**

Average and Excess Prod Trans Allocation
All Other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBIT (SJB-9)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 768,525,785	$ 293,491,954	$ 1,027,476	$ 106,759,166	$ 8,907,770	$ 132,960,127
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (1,867,000)	$ (715,724)	$ (2,428)	$ (271,251)	$ (21,339)	$ (322,331)
Mismatch in fuel cost recovery			Energy	(4,406,145)	(1,479,166)	(6,691)	(513,321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC Roll-In		FACRI		547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues		ECRREV		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In		ECRRI		723,260	255,297	937	110,897	9,089	133,401
Remove off-system ECR revenues			PLPPT	(1,929,923)	(859,156)	(2,408)	(231,554)	(19,814)	(329,638)
Eliminate brokered sales			Energy	(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
Eliminate ESM revenues		ESMREV		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1,196,285)
Eliminate Rate Refund Acct			R01	(7,150,231)	(2,741,076)	(9,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV		(3,277,501)	(2,771,657)	-	(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment		YREND		2,614,347	1,232,278	(9,993)	(279,531)	-	932,854
Adjustment for Merger savings			R01	(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		(621,927)	-	-	-	-	-
VDT Amortization and Surcredit			VDTREV	44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue				$ 709,631,942	$ 270,935,461	$ 938,413	$ 98,845,856	$ 8,183,190	$ 123,481,059

Summer Winter CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 14,586,905	$ 18,999,493	$ 6,226,733	$ 34,167,324	$ 16,612,432	$ 79,626,726
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (34,589)	$ (45,400)	$ (14,766)	$ (83,348)	$ (37,178)	$ (183,683)
Mismatch in fuel cost recovery			Energy	(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI		16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV		(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR Roll-in		ECRRI		14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			PLPPT	(33,606)	(48,995)	(14,326)	(69,862)	(37,018)	(178,540)
Eliminate brokered sales			Energy	(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
Eliminate ESM revenues		ESMREV		(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct			R01	(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue		DSMREV		(14,688)	(16,281)	-	-	-	-
Year End Revenue Adjustment		YREND		-	566,077	-	147,900	-	-
Adjustment for Merger savings			R01	(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV	815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				$ 13,411,062	$ 18,092,102	$ 5,730,245	$ 31,672,632	$ 14,878,396	$ 72,667,290

Summer Winter CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 2,662,246	$ 5,749,261	$ 201,481	$ 6,951,301	$ 717,841	$ 38,877,550
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (6,454)	$ (15,890)	$ (464)	$ (19,577)	$ (1,786)	$ (90,792)
Mismatch in fuel cost recovery			Energy	(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Full Year of the FAC Roll-In		FACRI		1,436	(3,891)	156	(1,432)	797	23,036
Remove ECR revenues		ECRREV		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR Roll-In		ECRRI		3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			PLPPT	(5,999)	(5,475)	(442)	(5,675)	(1,141)	(86,275)
Eliminate brokered sales			Energy	(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues		ESMREV		(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct			R01	(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue		DSMREV		-	-	-	-	-	-
Year End Revenue Adjustment		YREND		-	2,999	(1,159)	17,114	5,808	-
Adjustment for Merger savings			R01	(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	-	(90,000)
VDT Amortization and Surcredit			VDTREV	146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				$ 2,458,774	$ 5,372,969	$ 183,495	$ 6,534,107	$ 668,445	$ 35,578,445

Summer Winter CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 508,149,420	$ 208,035,041	$ 1,148,292	$ 61,335,571	$ 5,695,715	$ 82,763,009
Depreciation and Amortization Expenses				95,827,965	46,732,644	322,191	11,829,877	817,957	13,936,448
Accretion Expense				462,519	205,902	577	55,493	4,749	79,000
Property and Other Taxes			NPT	12,603,252	6,103,343	40,239	1,552,358	109,326	1,858,537
Amortization of Investment Tax Credit				(4,010,380)	(1,942,096)	(12,804)	(493,964)	(34,788)	(591,390)
Other Expenses				(6,055,342)	(2,932,404)	(19,333)	(745,844)	(52,526)	(892,950)
State and Federal Income Taxes			TXINCPF	27,184,243	$ (2,267,328)	$ (271,339)	$ 7,957,650	$ 563,172	$ 8,342,628
Specific Assignment of Interruptible Credit				(3,519,894)	-	-	-	-	-
Allocation of Interruptible Credits			SCP	3,519,894	$ 1,511,175	$ 2,563	$ 514,921	$ 41,545	$ 625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	(2,005,300)	$ (673,190)	$ (3,045)	$ (233,620)	$ (26,547)	$ (360,271)
Remove ECR expenses			ECRREV	(1,766,344)	$ (670,920)	$ (2,417)	$ (256,487)	$ (20,079)	$ (305,205)
Eliminate brokered sales expenses			Energy	(25,030,766)	$ (8,402,958)	$ (38,013)	$ (2,916,114)	$ (331,372)	$ (4,497,006)
Eliminate DSM Expenses			DSMREV	(3,280,013)	$ (2,773,781)	$ -	$ (109,057)	$ (25,643)	$ (340,540)
Year end Expense adjustment			YREND	1,458,544	$ 687,488	$ (5,575)	$ (155,950)	$ -	$ 520,439
Adjustment to annualize depreciation expense			DET	8,959,741	$ 4,369,417	$ 30,124	$ 1,106,072	$ 76,478	$ 1,303,033
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	918,580	$ 451,626	$ 3,076	$ 118,654	$ 8,281	$ 130,564
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	70,492	$ 46,793	$ 694	$ 9,491	$ 283	$ 5,995
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	333,580	$ 136,567	$ 754	$ 40,264	$ 3,739	$ 54,331
Amortization of ESM audit expenses			R01	58,333	$ 22,362	$ 76	$ 8,475	$ 667	$ 10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	5,640,000	$ 2,772,944	$ 18,888	$ 728,527	$ 50,842	$ 801,652
Adjustment for merger savings			LBT	19,427,401	$ 9,551,612	$ 65,062	$ 2,509,465	$ 175,128	$ 2,761,348
Adjustment for merger amortization expenses			LBT	(2,722,005)	$ (1,338,292)	$ (9,116)	$ (351,605)	$ (24,537)	$ (386,897)
MISO Schedule 10 one time credit			PLTRT	709,577	$ 315,887	$ 885	$ 85,136	$ 7,285	$ 121,198
Adjustment cumulative effect of accounting change			DET	5,280,909	$ 2,575,353	$ 17,755	$ 651,924	$ 45,076	$ 768,013
Adjustment for IT staff reduction			LBT	(431,834)	$ (212,314)	$ (1,446)	$ (55,781)	$ (3,893)	$ (61,379)
Remove Alstom Expenses			PLPPT	(2,157,640)	$ (960,530)	$ (2,693)	$ (258,876)	$ (22,152)	$ (368,533)
Adjustment for Obsolete inventory write-off			PLT	(1,373,632)	$ (666,073)	$ (4,386)	$ (169,149)	$ (11,886)	$ (202,133)
Adjustment for corporate office lease			LBT	1,798,420	$ 884,205	$ 6,023	$ 232,304	$ 16,212	$ 255,622
Adjustment for carbide lime write-off			Energy	(1,416,711)	$ (475,597)	$ (2,152)	$ (165,048)	$ (18,755)	$ (254,525)
Adjustment for Cane Run repair refund			PLPPT	3,588,000	$ 1,597,293	$ 4,478	$ 430,492	$ 36,838	$ 612,844
VDT Amortization and Surcredit			VDTREV	(224,718)	$ (87,676)	$ (286)	$ (32,570)	$ (2,549)	$ (38,480)
Total Expense Adjustments				7,834,614	7,150,217	78,687	1,216,549	(66,587)	530,139
Total Operating Expenses		TOE		$ 641,996,290	$ 262,596,495	$ 1,289,073	$ 83,222,612	$ 7,078,563	$ 106,650,455
Net Operating Income -- Pro-Forma				$ 67,635,652	$ 8,338,967	$ (350,660)	$ 15,623,243	$ 1,104,627	$ 16,830,605
Net Cost Rate Base				$ 1,473,843,556	$ 713,607,594	$ 4,777,998	$ 181,588,447	$ 12,774,917	$ 216,147,929
Rate of Return				**4.59%**	**1.17%**	**-7.34%**	**8.60%**	**1.00%**	**7.79%**

Summer Winter CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 9,511,059	$ 12,159,165	$ 4,134,166	$ 20,678,871	$ 12,343,825	$ 55,858,289
Depreciation and Amortization Expenses				1,366,543	2,008,241	598,849	3,025,418	1,350,961	7,200,293
Accretion Expense				8,054	11,742	3,433	16,743	8,872	42,788
Property and Other Taxes			NPT	182,911	268,597	79,946	402,575	182,811	964,524
Amortization of Investment Tax Credit				(58,203)	(85,468)	(25,439)	(128,100)	(58,171)	(306,913)
Other Expenses				(87,881)	(129,050)	(38,411)	(193,421)	(87,833)	(463,414)
State and Federal Income Taxes			TXINCPF	$ 837,940	$ 1,137,458	$ 315,637	$ 2,721,299	$ 1,029,708	$ 3,676,863
Specific Assignment of Interruptible Credit				-	-	-	-	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits			SCP	$ 66,076	$ 84,505	$ 29,945	$ 140,138	$ 60,511	$ 270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (44,786)	$ (54,061)	$ (19,122)	$ (96,898)	$ (63,230)	$ (273,643)
Remove ECR expenses			ECRREV	$ (32,690)	$ (43,382)	$ (14,011)	$ (79,468)	$ (35,195)	$ (177,854)
Eliminate brokered sales expenses			Energy	$ (559,033)	$ (674,807)	$ (238,687)	$ (1,209,515)	$ (789,257)	$ (3,415,692)
Eliminate DSM Expenses			DSMREV	$ (14,699)	$ (16,293)	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 315,814	$ -	$ 82,513	$ -	$ -
Adjustment to annualize depreciation expense			DET	$ 127,769	$ 187,767	$ 55,991	$ 282,871	$ 126,312	$ 673,214
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 13,432	$ 18,465	$ 6,118	$ 29,754	$ 15,065	$ 74,369
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 454	$ 719	$ 221	$ 1,509	$ -	$ 2,235
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 6,244	$ 7,982	$ 2,714	$ 13,575	$ 8,103	$ 36,669
Amortization of ESM audit expenses			R01	$ 1,081	$ 1,418	$ 461	$ 2,604	$ 1,162	$ 5,739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 82,472	$ 113,376	$ 37,562	$ 182,687	$ 92,496	$ 456,617
Adjustment for merger savings			LBT	$ 284,080	$ 390,532	$ 129,386	$ 629,280	$ 318,611	$ 1,572,851
Adjustment for merger amortization expenses			LBT	$ (39,803)	$ (54,718)	$ (18,128)	$ (88,169)	$ (44,641)	$ (220,375)
MISO Schedule 10 one time credit			PLTRT	$ 12,356	$ 18,014	$ 5,267	$ 25,686	$ 13,610	$ 65,644
Adjustment cumulative effect of accounting change			DET	$ 75,308	$ 110,671	$ 33,002	$ 166,725	$ 74,449	$ 396,795
Adjustment for IT staff reduction			LBT	$ (6,315)	$ (8,681)	$ (2,876)	$ (13,988)	$ (7,082)	$ (34,961)
Remove Alstom Expenses			PLPPT	$ (37,571)	$ (54,776)	$ (16,016)	$ (78,105)	$ (41,386)	$ (199,606)
Adjustment for Obsolete inventory write-off			PLT	$ (19,882)	$ (29,199)	$ (8,693)	$ (43,798)	$ (19,838)	$ (104,827)
Adjustment for corporate office lease			LBT	$ 26,298	$ 36,152	$ 11,977	$ 58,253	$ 29,494	$ 145,601
Adjustment for carbide lime write-off			Energy	$ (31,641)	$ (38,193)	$ (13,509)	$ (68,457)	$ (44,671)	$ (193,324)
Adjustment for Cane Run repair refund			PLPPT	$ 62,479	$ 91,089	$ 26,634	$ 129,883	$ 68,821	$ 331,931
VDT Amortization and Surcredit			VDTREV	$ (4,116)	$ (5,407)	$ (1,762)	$ (9,874)	$ (4,381)	$ (21,640)
Total Expense Adjustments				(98,565)	312,480	(23,471)	(82,931)	(301,556)	(880,258)
Total Operating Expenses		TOE		$ 11,727,934	$ 15,767,670	$ 5,074,656	$ 26,580,591	$ 12,892,066	$ 64,965,374
Net Operating Income -- Pro-Forma				$ 1,683,128	$ 2,324,432	$ 655,589	$ 5,092,041	$ 1,986,330	$ 7,701,916
Net Cost Rate Base				$ 21,350,378	$ 31,196,075	$ 9,346,178	$ 47,140,776	$ 21,464,989	$ 113,070,176
Rate of Return				**7.88%**	**7.45%**	**7.01%**	**10.80%**	**9.25%**	**6.81%**

Summer Winter CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 1,664,324	$ 2,829,284	$ 147,622	$ 3,156,338	$ 415,971	$ 26,272,879
Depreciation and Amortization Expenses				270,027	1,257,160	20,945	1,619,639	51,847	3,418,925
Accretion Expense				1,438	1,312	106	1,360	273	20,676
Property and Other Taxes			NPT	35,807	154,958	2,765	198,916	6,870	458,770
Amortization of Investment Tax Credit				(11,394)	(49,308)	(880)	(63,295)	(2,186)	(145,982)
Other Expenses				(17,204)	(74,451)	(1,329)	(95,571)	(3,301)	(220,420)
State and Federal Income Taxes			TXINCPF	$ 168,316	$ 301,407	$ 4,164	$ 422,257	$ 72,220	$ 2,172,191
Specific Assignment of Interruptible Credit				-	-	-	-	-	(486,000)
Allocation of Interruptible Credits			SCP	$ 12,085	$ -	$ -	$ -	$ 1,678	$ 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (7,490)	$ (8,992)	$ (698)	$ (9,342)	$ (2,007)	$ (128,357)
Remove ECR expenses			ECRREV	$ (6,339)	$ (15,470)	$ (474)	$ (19,117)	$ (1,746)	$ (85,491)
Eliminate brokered sales expenses			Energy	$ (93,494)	$ (112,246)	$ (8,719)	$ (116,606)	$ (25,054)	$ (1,602,194)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 1,673	$ (647)	$ 9,548	$ 3,240	$ -
Adjustment to annualize depreciation expense			DET	$ 25,247	$ 117,542	$ 1,958	$ 151,433	$ 4,848	$ 319,663
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 2,541	$ 5,128	$ 215	$ 5,738	$ 597	$ 34,957
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 164	$ 487	$ 15	$ 508	$ 27	$ 896
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 1,093	$ 1,857	$ 97	$ 2,072	$ 273	$ 17,247
Amortization of ESM audit expenses			R01	$ 202	$ 496	$ 15	$ 612	$ 56	$ 2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 15,600	$ 31,486	$ 1,320	$ 35,234	$ 3,665	$ 214,633
Adjustment for merger savings			LBT	$ 53,734	$ 108,457	$ 4,547	$ 121,365	$ 12,623	$ 739,321
Adjustment for merger amortization expenses			LBT	$ (7,529)	$ (15,196)	$ (637)	$ (17,005)	$ (1,769)	$ (103,587)
MISO Schedule 10 one time credit			PLTRT	$ 2,206	$ 2,013	$ 162	$ 2,086	$ 420	$ 31,721
Adjustment cumulative effect of accounting change			DET	$ 14,881	$ 69,280	$ 1,154	$ 89,255	$ 2,857	$ 188,411
Adjustment for IT staff reduction			LBT	$ (1,194)	$ (2,411)	$ (101)	$ (2,698)	$ (281)	$ (16,434)
Remove Alstom Expenses			PLPPT	$ (6,706)	$ (6,121)	$ (494)	$ (6,344)	$ (1,276)	$ (96,454)
Adjustment for Obsolete inventory write-off			PLT	$ (3,898)	$ (17,059)	$ (301)	$ (21,916)	$ (748)	$ (49,847)
Adjustment for corporate office lease			LBT	$ 4,974	$ 10,040	$ 421	$ 11,235	$ 1,169	$ 68,440
Adjustment for carbide lime write-off			Energy	$ (5,292)	$ (6,353)	$ (493)	$ (6,600)	$ (1,418)	$ (90,682)
Adjustment for Cane Run repair refund			PLPPT	$ 11,152	$ 10,178	$ 821	$ 10,550	$ 2,121	$ 160,397
VDT Amortization and Surcredit			VDTREV	$ (738)	$ (1,836)	$ (52)	$ (2,290)	$ (206)	$ (10,853)
Total Expense Adjustments				(888)	172,954	(1,891)	237,721	(2,609)	(405,376)
Total Operating Expenses		TOE		$ 2,122,511	$ 4,593,316	$ 171,503	$ 5,477,363	$ 540,763	$ 31,245,346
Net Operating Income -- Pro-Forma				$ 336,263	$ 779,653	$ 11,992	$ 1,056,745	$ 127,683	$ 4,333,099
Net Cost Rate Base				$ 4,185,391	$ 18,541,750	$ 325,889	$ 23,816,316	$ 813,020	$ 53,695,734
Rate of Return				**8.03%**	**4.20%**	**3.68%**	**4.44%**	**15.70%**	**8.07%**

Summer Winter CP Prod Trans Allocation
All Other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBIT (SJB-10)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual				$ 768,525,785	$ 292,624,282	$ 999,032	$ 108,199,109	$ 8,991,846	$ 133,330,572
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (1,867,000)	$ (715,724)	$ (2,428)	$ (271,251)	$ (21,339)	$ (322,331)
Mismatch in fuel cost recovery			Energy	(4,406,145)	(1,479,166)	(6,691)	(513,321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC Roll-In		FACRI		547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues		ECRREV		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In		ECRRI		723,260	255,297	937	110,897	9,089	133,401
Remove off-system ECR revenues			PLPPT	(1,929,923)	(828,562)	(1,405)	(282,326)	(22,779)	(342,700)
Eliminate brokered sales			Energy	(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
Eliminate ESM revenues		ESMREV		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1,196,285)
Eliminate Rate Refund Acct			R01	(7,150,231)	(2,741,076)	(9,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV		(3,277,501)	(2,771,657)	-	(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment		YREND		2,614,347	1,232,278	(9,993)	(279,531)	-	932,854
Adjustment for Merger savings			R01	(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		(621,927)	-	-	-	-	-
VDT Amortization and Surcredit			VDTREV	44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue				$ 709,631,942	$ 270,098,382	$ 910,972	$ 100,235,028	$ 8,264,302	$ 123,838,443

Summer CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 14,661,285	$ 18,923,999	$ 6,286,088	$ 34,365,122	$ 16,503,526	$ 78,762,216
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (34,589)	$ (45,400)	$ (14,766)	$ (83,348)	$ (37,178)	$ (183,683)
Mismatch in fuel cost recovery			Energy	(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI		16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV		(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR Roll-In		ECRRI		14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			PLPPT	(36,229)	(46,333)	(16,419)	(76,836)	(33,178)	(148,058)
Eliminate brokered sales			Energy	(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
Eliminate ESM revenues		ESMREV		(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct			R01	(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue		DSMREV		(14,688)	(16,281)	-	-	-	-
Year End Revenue Adjustment		YREND		-	566,077	-	147,900	-	-
Adjustment for Merger savings			R01	(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV	815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				$ 13,482,820	$ 18,019,270	$ 5,787,507	$ 31,863,456	$ 14,773,330	$ 71,833,262

Summer CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 2,680,042	$ 5,593,988	$ 188,954	$ 6,790,363	$ 711,578	$ 38,913,781
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (6,454)	$ (15,890)	$ (464)	$ (19,577)	$ (1,786)	$ (90,792)
Mismatch in fuel cost recovery			Energy	(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Full Year of the FAC Roll-In		FACRI		1,436	(3,891)	156	(1,432)	797	23,036
Remove ECR revenues		ECRREV		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR Roll-In		ECRRI		3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			PLPPT	(6,626)	-	-	-	(920)	(87,552)
Eliminate brokered sales			Energy	(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues		ESMREV		(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct			R01	(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue		DSMREV		-	-	-	-	-	-
Year End Revenue Adjustment		YREND		-	2,999	(1,159)	17,114	5,808	-
Adjustment for Merger savings			R01	(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	-	(90,000)
VDT Amortization and Surcredit			VDTREV	146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				$ 2,475,943	$ 5,223,172	$ 171,410	$ 6,378,844	$ 662,403	$ 35,613,399

Summer CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 508,149,420	$ 205,851,355	$ 1,076,705	$ 64,959,501	$ 5,907,311	$ 83,695,315
Depreciation and Amortization Expenses				95,827,965	45,621,527	285,767	13,673,828	925,623	14,410,830
Accretion Expense				462,519	198,570	337	67,661	5,459	82,130
Property and Other Taxes			NPT	12,603,252	5,952,910	35,308	1,802,008	123,902	1,922,763
Amortization of Investment Tax Credit				(4,010,380)	(1,894,228)	(11,235)	(573,403)	(39,426)	(611,827)
Other Expenses				(6,055,342)	(2,860,128)	(16,964)	(865,791)	(59,530)	(923,808)
State and Federal Income Taxes			TXINCPF	27,184,243	$ (1,043,177)	$ (231,209)	$ 5,926,115	$ 444,554	$ 7,819,988
Specific Assignment of Interruptible Credit				(3,519,894)	-	-	-	-	-
Allocation of Interruptible Credits			SCP	3,519,894	$ 1,511,175	$ 2,563	$ 514,921	$ 41,545	$ 625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	(2,005,300)	$ (673,190)	$ (3,045)	$ (233,620)	$ (26,547)	$ (360,271)
Remove ECR expenses			ECRREV	(1,766,344)	$ (670,920)	$ (2,417)	$ (256,487)	$ (20,079)	$ (305,205)
Eliminate brokered sales expenses			Energy	(25,030,766)	$ (8,402,958)	$ (38,013)	$ (2,916,114)	$ (331,372)	$ (4,497,006)
Eliminate DSM Expenses			DSMREV	(3,280,013)	$ (2,773,781)	$ -	$ (109,057)	$ (25,643)	$ (340,540)
Year end Expense adjustment			YREND	1,458,544	$ 687,488	$ (5,575)	$ (155,950)	$ -	$ 520,439
Adjustment to annualize depreciation expense			DET	8,959,741	$ 4,265,530	$ 26,719	$ 1,278,478	$ 86,544	$ 1,347,386
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	918,580	$ 444,635	$ 2,847	$ 130,256	$ 8,958	$ 133,549
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	70,492	$ 46,793	$ 694	$ 9,491	$ 283	$ 5,995
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	333,580	$ 135,133	$ 707	$ 42,643	$ 3,878	$ 54,943
Amortization of ESM audit expenses			R01	58,333	$ 22,362	$ 76	$ 8,475	$ 667	$ 10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	5,640,000	$ 2,730,022	$ 17,481	$ 799,758	$ 55,001	$ 819,977
Adjustment for merger savings			LBT	19,427,401	$ 9,403,764	$ 60,215	$ 2,754,826	$ 189,454	$ 2,824,471
Adjustment for merger amortization expenses			LBT	(2,722,005)	$ (1,317,577)	$ (8,437)	$ (385,983)	$ (26,545)	$ (395,741)
MISO Schedule 10 one time credit			PLTRT	709,577	$ 304,638	$ 517	$ 103,803	$ 8,375	$ 126,001
Adjustment cumulative effect of accounting change			DET	5,280,909	$ 2,514,121	$ 15,748	$ 753,540	$ 51,009	$ 794,155
Adjustment for IT staff reduction			LBT	(431,834)	$ (209,028)	$ (1,338)	$ (61,235)	$ (4,211)	$ (62,783)
Remove Alstom Expenses			PLPPT	(2,157,640)	$ (926,327)	$ (1,571)	$ (315,638)	$ (25,467)	$ (383,136)
Adjustment for Obsolete inventory write-off			PLT	(1,373,632)	$ (649,750)	$ (3,850)	$ (196,237)	$ (13,467)	$ (209,102)
Adjustment for corporate office lease			LBT	1,798,420	$ 870,519	$ 5,574	$ 255,018	$ 17,538	$ 261,465
Adjustment for carbide lime write-off			Energy	(1,416,711)	$ (475,597)	$ (2,152)	$ (165,048)	$ (18,755)	$ (254,525)
Adjustment for Cane Run repair refund			PLPPT	3,588,000	$ 1,540,415	$ 2,613	$ 524,884	$ 42,349	$ 637,127
VDT Amortization and Surcredit			VDTREV	(224,718)	$ (87,676)	$ (286)	$ (32,570)	$ (2,549)	$ (38,480)
Total Expense Adjustments				7,834,614	6,778,619	66,505	1,833,234	(30,580)	688,790
Total Operating Expenses		TOE		$ 641,996,290	$ 260,116,624	$ 1,207,777	$ 87,338,074	$ 7,318,859	$ 107,709,214
Net Operating Income -- Pro-Forma				$ 67,635,652	$ 9,981,759	$ (296,805)	$ 12,896,954	$ 945,443	$ 16,129,229
Net Cost Rate Base				$ 1,473,843,556	$ 696,707,368	$ 4,223,971	$ 209,635,156	$ 14,412,525	$ 223,363,330
Rate of Return				**4.59%**	**1.43%**	**-7.03%**	**6.15%**	**1.00%**	**7.22%**

Summer CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				9,698,253	11,969,168	4,283,547	21,176,674	12,069,741	53,682,562
Depreciation and Amortization Expenses				1,461,792	1,911,565	674,858	3,278,713	1,211,500	6,093,225
Accretion Expense				8,682	11,104	3,935	18,414	7,951	35,483
Property and Other Taxes			NPT	195,807	255,508	90,236	436,868	163,929	814,639
Amortization of Investment Tax Credit				(62,306)	(81,303)	(28,713)	(139,012)	(52,163)	(259,220)
Other Expenses				(94,077)	(122,761)	(43,355)	(209,897)	(78,761)	(391,401)
State and Federal Income Taxes			TXINCPF	733,001	1,243,968	231,896	2,442,236	1,183,356	4,896,552
Specific Assignment of Interruptible Credit				-	-	-	-	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits			SCP	66,076	84,505	29,945	140,138	60,511	270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	(44,786)	(54,061)	(19,122)	(96,898)	(63,230)	(273,643)
Remove ECR expenses			ECRREV	(32,690)	(43,382)	(14,011)	(79,468)	(35,195)	(177,854)
Eliminate brokered sales expenses			Energy	(559,033)	(674,807)	(238,687)	(1,209,515)	(789,257)	(3,415,692)
Eliminate DSM Expenses			DSMREV	(14,699)	(16,293)	-	-	-	-
Year end Expense adjustment			YREND	-	315,814	-	82,513	-	-
Adjustment to annualize depreciation expense			DET	136,675	178,728	63,098	306,554	113,273	569,706
Depreciation adjustment			DET	-	-	-	-	-	-
Labor adjustment			LBT	14,031	17,857	6,596	31,348	14,187	67,403
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	454	719	221	1,509	-	2,235
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	6,367	7,857	2,812	13,902	7,923	35,240
Amortization of ESM audit expenses			R01	1,081	1,418	461	2,604	1,162	5,739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	86,151	109,641	40,498	192,472	87,109	413,851
Adjustment for merger savings			LBT	296,754	377,668	139,500	662,984	300,054	1,425,542
Adjustment for merger amortization expenses			LBT	(41,579)	(52,916)	(19,546)	(92,892)	(42,041)	(199,735)
MISO Schedule 10 one time credit			PLTRT	13,320	17,035	6,037	28,250	12,199	54,437
Adjustment cumulative effect of accounting change			DET	80,557	105,343	37,190	180,684	66,764	335,767
Adjustment for IT staff reduction			LBT	(6,596)	(8,395)	(3,101)	(14,737)	(6,670)	(31,687)
Remove Alstom Expenses			PLPPT	(40,503)	(51,800)	(18,356)	(85,902)	(37,093)	(165,527)
Adjustment for Obsolete inventory write-off			PLT	(21,281)	(27,779)	(9,810)	(47,519)	(17,789)	(88,563)
Adjustment for corporate office lease			LBT	27,471	34,961	12,914	61,373	27,776	131,964
Adjustment for carbide lime write-off			Energy	(31,641)	(38,193)	(13,509)	(68,457)	(44,671)	(193,324)
Adjustment for Cane Run repair refund			PLPPT	67,354	86,140	30,525	142,849	61,682	275,260
VDT Amortization and Surcredit			VDTREV	(4,116)	(5,407)	(1,762)	(9,874)	(4,381)	(21,640)
Total Expense Adjustments				(66,710)	280,149	1,949	1,780	(348,197)	(1,250,502)
Total Operating Expenses		TOE		11,940,518	15,551,903	5,244,297	27,145,913	12,580,806	62,494,541
Net Operating Income -- Pro-Forma				1,542,302	2,467,367	543,210	4,717,543	2,192,524	9,338,720
Net Cost Rate Base				22,799,127	29,725,634	10,502,278	50,993,425	19,343,767	96,231,548
Rate of Return				**6.76%**	**8.30%**	**5.17%**	**9.25%**	**11.33%**	**9.70%**

Summer CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 1,709,113	$ 2,438,507	$ 116,096	$ 2,751,303	$ 400,208	$ 26,364,063
Depreciation and Amortization Expenses				292,817	1,058,322	4,904	1,413,546	43,826	3,465,322
Accretion Expense				1,588	-	-	-	221	20,982
Property and Other Taxes			NPT	38,893	128,038	593	171,013	5,784	465,052
Amortization of Investment Tax Credit				(12,376)	(40,742)	(189)	(54,417)	(1,840)	(147,980)
Other Expenses				(18,686)	(61,517)	(285)	(82,165)	(2,779)	(223,438)
State and Federal Income Taxes			TXINCPF	$ 143,208	$ 520,472	$ 21,838	$ 649,315	$ 81,056	$ 2,121,074
Specific Assignment of Interruptible Credit				-	-	-	-	-	(486,000)
Allocation of Interruptible Credits			SCP	$ 12,085	$ -	$ -	$ -	$ 1,678	$ 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (7,490)	$ (8,992)	$ (698)	$ (9,342)	$ (2,007)	$ (128,357)
Remove ECR expenses			ECRREV	$ (6,339)	$ (15,470)	$ (474)	$ (19,117)	$ (1,746)	$ (85,491)
Eliminate brokered sales expenses			Energy	$ (93,494)	$ (112,246)	$ (8,719)	$ (116,606)	$ (25,054)	$ (1,602,194)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 1,673	$ (647)	$ 9,548	$ 3,240	$ -
Adjustment to annualize depreciation expense			DET	$ 27,378	$ 98,951	$ 459	$ 132,164	$ 4,098	$ 324,001
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 2,684	$ 3,877	$ 114	$ 4,442	$ 546	$ 35,249
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 164	$ 487	$ 15	$ 508	$ 27	$ 896
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 1,122	$ 1,601	$ 76	$ 1,806	$ 263	$ 17,307
Amortization of ESM audit expenses			R01	$ 202	$ 496	$ 15	$ 612	$ 56	$ 2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 16,480	$ 23,805	$ 700	$ 27,273	$ 3,355	$ 216,426
Adjustment for merger savings			LBT	$ 56,766	$ 81,999	$ 2,413	$ 93,942	$ 11,556	$ 745,494
Adjustment for merger amortization expenses			LBT	$ (7,954)	$ (11,489)	$ (338)	$ (13,162)	$ (1,619)	$ (104,452)
MISO Schedule 10 one time credit			PLTRT	$ 2,436	$ -	$ -	$ -	$ 338	$ 32,190
Adjustment cumulative effect of accounting change			DET	$ 16,137	$ 58,322	$ 270	$ 77,898	$ 2,415	$ 190,968
Adjustment for IT staff reduction			LBT	$ (1,262)	$ (1,823)	$ (54)	$ (2,088)	$ (257)	$ (16,571)
Remove Alstom Expenses			PLPPT	$ (7,408)	$ -	$ -	$ -	$ (1,029)	$ (97,883)
Adjustment for Obsolete inventory write-off			PLT	$ (4,233)	$ (14,138)	$ (65)	$ (18,888)	$ (630)	$ (50,529)
Adjustment for corporate office lease			LBT	$ 5,255	$ 7,591	$ 223	$ 8,696	$ 1,070	$ 69,011
Adjustment for carbide lime write-off			Energy	$ (5,292)	$ (6,353)	$ (493)	$ (6,600)	$ (1,418)	$ (90,682)
Adjustment for Cane Run repair refund			PLPPT	$ 12,319	$ -	$ -	$ -	$ 1,711	$ 162,772
VDT Amortization and Surcredit			VDTREV	$ (738)	$ (1,836)	$ (52)	$ (2,290)	$ (206)	$ (10,853)
Total Expense Adjustments				6,734	106,456	(7,256)	168,796	(5,292)	(389,859)
Total Operating Expenses		TOE		$ 2,173,375	$ 4,149,537	$ 135,701	$ 5,017,391	$ 522,862	$ 31,348,898
Net Operating Income -- Pro-Forma				$ 302,568	$ 1,073,635	$ 35,709	$ 1,361,453	$ 139,541	$ 4,264,501
Net Cost Rate Base				$ 4,532,030	$ 15,517,408	$ 81,900	$ 20,681,627	$ 691,027	$ 54,401,435
Rate of Return				6.68%	6.92%	43.60%	6.58%	20.19%	7.84%

Summer CP Prod Trans Allocation
All Other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBIT (SJB-11)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 768,525,765	$ 289,945,333	$ 1,027,181	$ 107,368,029	$ 8,963,998	$ 134,147,791
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (1,867,000)	$ (715,724)	$ (2,428)	$ (271,251)	$ (21,339)	$ (322,331)
Mismatch in fuel cost recovery			Energy	(4,406,145)	(1,479,166)	(6,691)	(513,321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC Roll-In		FACRI		547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues		ECRREV		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In		ECRRI		723,260	255,297	937	110,897	9,089	133,401
Remove off-system ECR revenues			PLPPT	(1,929,923)	(734,104)	(2,398)	(253,023)	(21,797)	(371,514)
Eliminate brokered sales			Energy	(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
Eliminate ESM revenues		ESMREV		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1,196,285)
Eliminate Rate Refund Acct			R01	(7,150,231)	(2,741,076)	(9,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV		(3,277,501)	(2,771,657)	-	(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment		YREND		2,614,347	1,232,278	(9,993)	(279,531)	-	932,854
Adjustment for Merger savings			R01	(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		(621,927)	-	-	-	-	-
VDT Amortization and Surcredit			VDTREV	44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue				$ 709,631,942	$ 267,513,891	$ 938,129	$ 99,433,251	$ 8,237,436	$ 124,626,847

12 CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actual				$	14,611,283 $	19,185,651 $	6,326,234 $	34,518,858 $	16,707,671 $	80,517,847
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	$	(34,589) $	(45,400) $	(14,766) $	(83,348) $	(37,178) $	(183,683)
Mismatch in fuel cost recovery			Energy		(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI			16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV			(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR Roll-In		ECRRI			14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			PLPPT		(34,466)	(55,559)	(17,834)	(82,257)	(40,376)	(209,960)
Eliminate brokered sales			Energy		(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
Eliminate ESM revenues		ESMREV			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct			R01		(132,469)	(173,673)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue		DSMREV			(14,688)	(16,281)	-	-	-	-
Year End Revenue Adjustment		YREND			-	566,077	-	147,900	-	-
Adjustment for Merger savings			R01		(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit		RATESW			-	-	-	-	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV		815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				$	13,434,580 $	18,271,695 $	5,826,237 $	32,011,772 $	14,970,276 $	73,526,990

12 CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$ 2,662,722	$ 5,655,911	$ 194,251	$ 6,854,604	$ 724,458	$ 39,113,964
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$ (6,454)	$ (15,890)	$ (464)	$ (19,577)	$ (1,786)	$ (90,792)
Mismatch in fuel cost recovery			Energy	(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Full Year of the FAC Roll-In		FACRI		1,436	(3,891)	156	(1,432)	797	23,036
Remove ECR revenues		ECRREV		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR Roll-In		ECRRI		3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			PLPPT	(6,015)	(2,183)	(187)	(2,265)	(1,374)	(94,610)
Eliminate brokered sales			Energy	(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues		ESMREV		(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct			R01	(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue		DSMREV		-	-	-	-	-	-
Year End Revenue Adjustment		YREND		-	2,999	(1,159)	17,114	5,808	-
Adjustment for Merger savings			R01	(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW		-	-	-	-	-	(90,000)
VDT Amortization and Surcredit			VDTREV	146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				$ 2,459,233	$ 5,282,911	$ 176,520	$ 6,440,820	$ 674,830	$ 35,806,523

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 508,149,420	$ 199,109,198	$ 1,147,550	$ 62,867,909	$ 5,837,225	$ 85,752,023
Depreciation and Amortization Expenses				95,827,965	42,190,941	321,814	12,609,571	889,962	15,457,337
Accretion Expense				462,519	175,933	575	60,638	5,224	89,036
Property and Other Taxes			NPT	12,603,252	5,488,447	40,188	1,657,920	119,074	2,064,448
Amortization of Investment Tax Credit				(4,010,380)	(1,746,435)	(12,788)	(527,553)	(37,890)	(656,912)
Other Expenses				(6,055,342)	(2,636,972)	(19,309)	(796,562)	(57,210)	(991,882)
State and Federal Income Taxes			TXINCPF	27,184,243	$ 2,736,402	$ (270,924)	$ 7,098,638	$ 483,843	$ 6,667,019
Specific Assignment of Interruptible Credit				(3,519,894)	-	-	-	-	-
Allocation of Interruptible Credits			SCP	3,519,894	$ 1,511,175	$ 2,563	$ 514,921	$ 41,545	$ 625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	(2,005,300)	$ (673,190)	$ (3,045)	$ (233,620)	$ (26,547)	$ (360,271)
Remove ECR expenses			ECRREV	(1,766,344)	$ (670,920)	$ (2,417)	$ (256,487)	$ (20,079)	$ (305,205)
Eliminate brokered sales expenses			Energy	(25,030,766)	$ (8,402,958)	$ (38,013)	$ (2,916,114)	$ (331,372)	$ (4,497,006)
Eliminate DSM Expenses			DSMREV	(3,280,013)	$ (2,773,781)	$ -	$ (109,057)	$ (25,643)	$ (340,540)
Year end Expense adjustment			YREND	1,458,544	$ 687,488	$ (5,575)	$ (155,950)	$ -	$ 520,439
Adjustment to annualize depreciation expense			DET	8,959,741	$ 3,944,776	$ 30,089	$ 1,178,972	$ 83,210	$ 1,445,233
Depreciation adjustment			DET	-	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	918,580	$ 423,052	$ 3,074	$ 123,560	$ 8,734	$ 140,133
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	70,492	$ 46,793	$ 694	$ 9,491	$ 283	$ 5,995
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	333,580	$ 130,707	$ 753	$ 41,270	$ 3,832	$ 56,293
Amortization of ESM audit expenses			R01	58,333	$ 22,362	$ 76	$ 8,475	$ 667	$ 10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	5,640,000	$ 2,597,500	$ 18,874	$ 758,646	$ 53,623	$ 860,403
Adjustment for merger savings			LBT	19,427,401	$ 8,947,281	$ 65,011	$ 2,613,213	$ 184,709	$ 2,963,722
Adjustment for merger amortization expenses			LBT	(2,722,005)	$ (1,253,618)	$ (9,109)	$ (366,142)	$ (25,880)	$ (415,252)
MISO Schedule 10 one time credit			PLTRT	709,577	$ 269,909	$ 882	$ 93,029	$ 8,014	$ 136,595
Adjustment cumulative effect of accounting change			DET	5,280,909	$ 2,325,068	$ 17,735	$ 694,891	$ 49,044	$ 851,826
Adjustment for IT staff reduction			LBT	(431,834)	$ (198,881)	$ (1,445)	$ (58,087)	$ (4,106)	$ (65,878)
Remove Alstom Expenses			PLPPT	(2,157,640)	$ (820,723)	$ (2,681)	$ (282,877)	$ (24,369)	$ (415,350)
Adjustment for Obsolete inventory write-off			PLT	(1,373,632)	$ (599,352)	$ (4,380)	$ (180,603)	$ (12,944)	$ (224,476)
Adjustment for corporate office lease			LBT	1,798,420	$ 828,262	$ 6,018	$ 241,909	$ 17,099	$ 274,356
Adjustment for carbide lime write-off			Energy	(1,416,711)	$ (475,597)	$ (2,152)	$ (165,048)	$ (18,755)	$ (254,525)
Adjustment for Cane Run repair refund			PLPPT	3,588,000	$ 1,364,803	$ 4,458	$ 470,405	$ 40,524	$ 690,698
VDT Amortization and Surcredit			VDTREV	(224,718)	$ (87,676)	$ (286)	$ (32,570)	$ (2,549)	$ (38,480)
Total Expense Adjustments				7,834,614	5,631,305	78,561	1,477,307	(42,506)	1,038,780
Total Operating Expenses		TOE		$ 641,996,290	$ 252,459,995	$ 1,288,231	$ 84,962,789	$ 7,239,267	$ 110,044,884
Net Operating Income -- Pro-Forma				$ 67,635,652	$ 15,053,897	$ (350,102)	$ 14,470,463	$ 998,169	$ 14,581,963
Net Cost Rate Base				$ 1,473,843,556	$ 644,527,736	$ 4,772,258	$ 193,447,680	$ 13,870,109	$ 239,280,834
Rate of Return				4.59%	2.34%	-7.34%	7.48%	1.00%	6.09%

12 CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary -- Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 9,572,410	$ 12,627,670	$ 4,384,582	$ 21,563,584	$ 12,583,514	$ 58,100,988
Depreciation and Amortization Expenses				1,397,760	2,246,628	726,267	3,475,583	1,472,921	8,341,436
Accretion Expense				8,260	13,315	4,274	19,713	9,676	50,318
Property and Other Taxes			NPT	187,137	300,872	97,197	463,522	199,323	1,119,022
Amortization of Investment Tax Credit				(59,547)	(95,738)	(30,928)	(147,494)	(63,425)	(356,075)
Other Expenses				(89,912)	(144,556)	(46,699)	(222,703)	(95,766)	(537,644)
State and Federal Income Taxes			TXINCPF	$ 803,548	$ 874,819	$ 175,256	$ 2,225,338	$ 895,341	$ 2,419,630
Specific Assignment of Interruptible Credit				-	-	-	-	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits			SCP	$ 66,076	$ 84,505	$ 29,945	$ 140,138	$ 60,511	$ 270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (44,786)	$ (54,061)	$ (19,122)	$ (96,898)	$ (63,230)	$ (273,643)
Remove ECR expenses			ECRREV	$ (32,690)	$ (43,382)	$ (14,011)	$ (79,468)	$ (35,195)	$ (177,854)
Eliminate brokered sales expenses			Energy	$ (559,033)	$ (674,807)	$ (238,687)	$ (1,209,515)	$ (789,257)	$ (3,415,692)
Eliminate DSM Expenses			DSMREV	$ (14,699)	$ (16,293)	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 315,814	$ -	$ 82,513	$ -	$ -
Adjustment to annualize depreciation expense			DET	$ 130,688	$ 210,056	$ 67,905	$ 324,961	$ 137,715	$ 779,909
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 13,628	$ 19,965	$ 6,919	$ 32,586	$ 15,832	$ 81,548
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 454	$ 719	$ 221	$ 1,509	$ -	$ 2,235
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 6,284	$ 8,290	$ 2,878	$ 14,156	$ 8,261	$ 38,141
Amortization of ESM audit expenses			R01	$ 1,081	$ 1,418	$ 461	$ 2,604	$ 1,162	$ 5,739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 83,678	$ 122,585	$ 42,484	$ 200,077	$ 97,208	$ 500,699
Adjustment for merger savings			LBT	$ 288,234	$ 422,252	$ 146,341	$ 689,180	$ 334,839	$ 1,724,695
Adjustment for merger amortization expenses			LBT	$ (40,385)	$ (59,162)	$ (20,504)	$ (96,562)	$ (46,915)	$ (241,650)
MISO Schedule 10 one time credit			PLTRT	$ 12,672	$ 20,427	$ 6,557	$ 30,243	$ 14,845	$ 77,196
Adjustment cumulative effect of accounting change			DET	$ 77,028	$ 123,808	$ 40,023	$ 191,533	$ 81,170	$ 459,682
Adjustment for IT staff reduction			LBT	$ (6,407)	$ (9,386)	$ (3,253)	$ (15,319)	$ (7,443)	$ (38,337)
Remove Alstom Expenses			PLPPT	$ (38,532)	$ (62,114)	$ (19,939)	$ (91,962)	$ (45,140)	$ (234,734)
Adjustment for Obsolete inventory write-off			PLT	$ (20,340)	$ (32,701)	$ (10,565)	$ (50,411)	$ (21,629)	$ (121,591)
Adjustment for corporate office lease			LBT	$ 26,682	$ 39,088	$ 13,547	$ 63,798	$ 30,996	$ 159,657
Adjustment for carbide lime write-off			Energy	$ (31,641)	$ (38,193)	$ (13,509)	$ (68,457)	$ (44,671)	$ (193,324)
Adjustment for Cane Run repair refund			PLPPT	$ 64,077	$ 103,292	$ 33,156	$ 152,927	$ 75,064	$ 390,346
VDT Amortization and Surcredit			VDTREV	$ (4,116)	$ (5,407)	$ (1,762)	$ (9,874)	$ (4,381)	$ (21,640)
Total Expense Adjustments				(88,125)	392,206	19,142	67,620	(260,769)	(498,618)
Total Operating Expenses		TOE		$ 11,797,606	$ 16,299,721	$ 5,359,037	$ 27,585,302	$ 13,164,265	$ 67,512,261
Net Operating Income -- Pro-Forma				$ 1,636,974	$ 1,971,975	$ 467,201	$ 4,426,470	$ 1,806,012	$ 6,014,729
Net Cost Rate Base				$ 21,825,190	$ 34,821,982	$ 11,284,222	$ 53,987,843	$ 23,320,016	$ 130,427,115
Rate of Return				**7.50%**	**5.66%**	**4.14%**	**8.20%**	**7.74%**	**4.61%**

12 CP Prod Trans Allocation
All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				$ 1,665,521	$ 2,594,348	$ 129,427	$ 2,912,979	$ 432,625	$ 26,867,866
Depreciation and Amortization Expenses				270,636	1,137,618	11,687	1,495,811	60,321	3,721,670
Accretion Expense				1,442	523	45	543	329	22,674
Property and Other Taxes			NPT	35,890	138,773	1,512	182,151	8,017	499,758
Amortization of Investment Tax Credit				(11,420)	(44,158)	(481)	(57,961)	(2,551)	(159,024)
Other Expenses				(17,243)	(66,675)	(726)	(87,516)	(3,852)	(240,113)
State and Federal Income Taxes			TXINCPF	$ 167,645	$ 433,110	$ 14,364	$ 558,681	$ 62,883	$ 1,838,648
Specific Assignment of Interruptible Credit				-	-	-	-	-	(486,000)
Allocation of Interruptible Credits			SCP	$ 12,085	$ -	$ -	$ -	$ 1,678	$ 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (7,490)	$ (8,992)	$ (698)	$ (9,342)	$ (2,007)	$ (128,357)
Remove ECR expenses			ECRREV	$ (6,339)	$ (15,470)	$ (474)	$ (19,117)	$ (1,746)	$ (85,491)
Eliminate brokered sales expenses			Energy	$ (93,494)	$ (112,246)	$ (8,719)	$ (116,606)	$ (25,054)	$ (1,602,194)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ -	$ 1,673	$ (647)	$ 9,548	$ 3,240	$ -
Adjustment to annualize depreciation expense			DET	$ 25,304	$ 106,365	$ 1,093	$ 139,856	$ 5,640	$ 347,969
Depreciation adjustment			DET	$ -	$ -	$ -	$ -	$ -	$ -
Labor adjustment			LBT	$ 2,545	$ 4,376	$ 157	$ 4,959	$ 650	$ 36,862
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment			SDALL	$ 164	$ 487	$ 15	$ 508	$ 27	$ 896
Adjustment to eliminate advertising expense (See Functional Assignment)									
Amortization of rate case expenses			OMT	$ 1,093	$ 1,703	$ 85	$ 1,912	$ 284	$ 17,638
Amortization of ESM audit expenses			R01	$ 202	$ 496	$ 15	$ 612	$ 56	$ 2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders			LBT	$ 15,623	$ 26,868	$ 962	$ 30,450	$ 3,992	$ 226,328
Adjustment for merger savings			LBT	$ 53,815	$ 92,550	$ 3,315	$ 104,889	$ 13,751	$ 779,605
Adjustment for merger amortization expenses			LBT	$ (7,540)	$ (12,967)	$ (465)	$ (14,696)	$ (1,927)	$ (109,232)
MISO Schedule 10 one time credit			PLTRT	$ 2,212	$ 803	$ 69	$ 833	$ 505	$ 34,786
Adjustment cumulative effect of accounting change			DET	$ 14,914	$ 62,692	$ 644	$ 82,431	$ 3,324	$ 205,095
Adjustment for IT staff reduction			LBT	$ (1,196)	$ (2,057)	$ (74)	$ (2,331)	$ (306)	$ (17,329)
Remove Alstom Expenses			PLPPT	$ (6,725)	$ (2,441)	$ (209)	$ (2,532)	$ (1,537)	$ (105,774)
Adjustment for Obsolete inventory write-off			PLT	$ (3,907)	$ (15,303)	$ (165)	$ (20,097)	$ (873)	$ (54,285)
Adjustment for corporate office lease			LBT	$ 4,982	$ 8,568	$ 307	$ 9,710	$ 1,273	$ 72,169
Adjustment for carbide lime write-off			Energy	$ (5,292)	$ (6,353)	$ (493)	$ (6,600)	$ (1,418)	$ (90,682)
Adjustment for Cane Run repair refund			PLPPT	$ 11,183	$ 4,059	$ 347	$ 4,211	$ 2,555	$ 175,894
VDT Amortization and Surcredit			VDTREV	$ (738)	$ (1,836)	$ (52)	$ (2,290)	$ (206)	$ (10,853)
Total Expense Adjustments				(684)	132,975	(4,987)	196,308	225	(304,127)
Total Operating Expenses		TOE		$ 2,123,871	$ 4,326,516	$ 150,840	$ 5,200,996	$ 559,676	$ 31,921,034
Net Operating Income – Pro-Forma				$ 335,362	$ 956,395	$ 25,680	$ 1,239,824	$ 115,154	$ 3,885,489
Net Cost Rate Base				$ 4,194,659	$ 16,723,512	$ 185,073	$ 21,932,886	$ 941,914	$ 58,300,526
Rate of Return				**7.99%**	**5.72%**	**13.88%**	**5.65%**	**12.23%**	**6.66%**

12 CP Prod Trans Allocation
All Other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	**CASE NO. 2003-00433**
AND	)))	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO. 2003-00434**

EXHIBIT (SJB-12)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service GS	Combined Light & Power LP,HLF,M	Large Comm/Ind TOD Primary LCI-TOD
Cost of Service Summary -- Pro-Forma						
Total Pro-Forma Operating Revenue	$ 693,449,939	$ 124,345,569	$ 135,772,513	$ 67,310,253	$ 232,654,411	$ 85,699,043
Total Operating Expenses	$ 633,180,928	$ 121,678,365	$ 133,986,084	$ 58,484,592	$ 201,628,996	$ 75,886,497
Net Operating Income (Adjusted)	$ 60,269,011	$ 2,667,204	$ 1,786,429	$ 8,825,661	$ 31,025,414	$ 9,812,546
Net Cost Rate Base	$ 1,412,033,543	$ 318,616,683	$ 371,840,037	$ 142,212,684	$ 342,893,824	$ 120,860,788
Rate of Return	**4.27%**	**0.84%**	**0.48%**	**6.21%**	**9.05%**	**8.12%**
Subsidy at Current Rates	(0)	(18,406,858)	(23,714,808)	4,639,847	27,596,286	7,835,982
KU Proposed Increases						
Proposed Base Rate Increase	58,911,660	10,917,610	13,171,979	5,663,282	18,928,419	6,910,666
Increase in Miscellaneous Charges	1,003,763	539,919	395,326	65,368	3,118	7
Decrease in Rents	(556,373)	(28,757)	(21,055)	(152,518)	(344,931)	(784)
Incremental Income Taxes	(24,104,760)	$ (4,641,041)	$ (5,500,915)	$ (2,264,378)	$ (7,547,723)	$ (2,805,995)
Net Operating Income after increase	95,523,300	$ 9,454,934	$ 9,831,763	$ 12,137,415	$ 42,064,297	$ 13,916,440
Rate of Return at KU Proposed Rates	**6.76%**	**2.97%**	**2.64%**	**8.53%**	**12.27%**	**11.51%**
Subsidy at KU Proposed Rates	(0)	(20,372,091)	(25,799,966)	4,237,644	31,768,325	9,665,126
Change in Subsidy resulting from KU Proposed Rates		10.7%	8.8%	-8.7%	15.1%	23.3%
Base Rate Increase Required for Equalized Rates of Return	58,911,660	31,289,701	38,971,945	1,425,638	(12,839,906)	(2,754,460)
Base Rate increase Required for 25% Subsidy Reduction	58,911,660	17,484,557	21,185,839	4,905,523	7,857,308	3,122,526
Incremental Income Taxes	(24,104,760)	(7,307,774)	(8,755,215)	(1,956,664)	(3,051,922)	(1,267,692)
Net Operating Income after increase	95,523,300	$ 13,355,149	$ 14,591,323	$ 11,687,370	$ 35,488,987	$ 11,666,603
Rate of Return after 25% Subsidy Reduction	**6.76%**	**4.19%**	**3.92%**	**8.22%**	**10.35%**	**9.65%**
Subsidy after 25% Subsidy Reduction	(0)	(13,805,144)	(17,786,106)	3,479,885	20,697,214	5,876,987
Change in Subsidy resulting from 25% Subsidy Reduction		-25.0%	-25.0%	-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	676,762,013	121,233,915	131,265,061	65,598,531	226,957,350	84,135,770
Percentage Increase proposed by KU	8.70%	9.01%	10.03%	8.63%	8.34%	8.21%
Percentage Increase to achieve equalized Rates of Return	8.70%	25.81%	29.69%	2.17%	-5.66%	-3.27%
Percentage Increase to achieve 25% subsidy reduction	8.70%	14.42%	16.14%	7.48%	3.46%	3.71%

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off-Peak CWH	All Elcetric School AES	Electric Space Heating Rider 33
Cost of Service Summary -- Pro-Forma							
Total Pro-Forma Operating Revenue	$ 4,900,693	$ 3,840,839	$ 1,984,106	$ 4,207,348	$ 427,775	$ 4,051,813	$ 684,657
Total Operating Expenses	$ 3,986,444	$ 3,209,576	$ 1,699,608	$ 3,553,714	$ 1,057,389	$ 3,676,265	$ 655,878
Net Operating Income (Adjusted)	$ 914,249	$ 631,263	$ 284,498	$ 653,634	$ (629,614)	$ 375,547	$ 28,779
Net Cost Rate Base	$ 6,738,314	$ 5,192,612	$ 2,812,219	$ 6,367,053	$ 4,518,731	$ 8,113,397	$ 1,490,422
Rate of Return	13.57%	12.16%	10.12%	10.27%	-13.93%	4.63%	1.93%
Subsidy at Current Rates	1,055,102	689,710	276,917	642,975	(1,384,849)	49,246	(58,654)
KU Proposed Increases							
Proposed Base Rate Increase	405,257	319,850	165,746	347,607	96,148	-	129,034
Increase in Miscellaneous Charges	9	6	1	3	-	-	-
Decrease in Rents	(3,712)	(2,603)	(356)	(1,166)	-	-	-
Incremental Income Taxes	$ (163,065)	$ (128,831)	$ (67,163)	$ (140,685)	$ (39,044)	$ -	$ (52,399)
Net Operating Income after increase	$ 1,152,739	$ 819,685	$ 382,726	$ 859,393	$ (572,510)	$ 375,547	$ 105,414
Rate of Return at KU Proposed Rates	17.11%	15.79%	13.61%	13.50%	-12.67%	4.63%	7.07%
Subsidy at KU Proposed Rates	1,173,390	788,676	324,088	721,761	(1,478,659)	(291,825)	7,725
Change in Subsidy resulting from KU Proposed Rates	11.2%	14.3%	17.0%	12.3%	6.8%	-692.6%	-113.2%
Base Rate Increase Required for Equalized Rates of Return	(768,133)	(468,826)	(158,342)	(374,154)	1,574,807	291,825	121,309
Base Rate increase Required for 25% Subsidy Reduction	23,193	48,456	49,345	108,077	536,171	328,759	77,318
Incremental Income Taxes	(7,914)	(18,623)	(19,894)	(43,416)	(217,730)	(133,504)	(31,398)
Net Operating Income after increase	$ 925,825	$ 658,500	$ 313,594	$ 717,133	$ (311,173)	$ 570,803	$ 74,699
Rate of Return after 25% Subsidy Reduction	13.74%	12.68%	11.15%	11.26%	-6.89%	7.04%	5.01%
Subsidy after 25% Subsidy Reduction	791,326	517,283	207,688	482,231	(1,038,637)	36,934	(43,991)
Change in Subsidy resulting from 25% Subsidy Reduction	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	4,793,968	3,748,239	1,944,714	4,098,693	414,203	3,955,546	668,128
Percentage increase proposed by KU	8.45%	8.53%	8.52%	8.48%	23.21%	0.00%	19.31%
Percentage increase to achieve equalized Rates of Return	-16.02%	-12.51%	-8.14%	-9.13%	380.20%	7.38%	18.16%
Percentage Increase to achieve 25% subsidy reduction	0.48%	1.29%	2.54%	2.64%	129.45%	8.31%	11.57%

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Street Lighting St Lt	Decorative Street Lighting Dec St Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary -- Pro-Forma					
Total Pro-Forma Operating Revenue	$ 5,421,077	$ 807,012	$ 6,328,527	$ 898,820	$ 14,115,482
Total Operating Expenses	$ 5,595,768	$ 685,056	$ 4,880,294	$ 722,198	$ 11,794,204
Net Operating Income (Adjusted)	$ (174,691)	$ 121,956	$ 1,448,234	$ 176,622	$ 2,321,278
Net Cost Rate Base	$ 31,905,511	$ 3,716,038	$ 15,836,075	$ 2,518,660	$ 26,400,496
Rate of Return	**-0.55%**	**3.28%**	**9.15%**	**7.01%**	**8.79%**
Subsidy at Current Rates	(2,587,059)	(61,715)	1,300,372	116,380	2,011,128
KU Proposed Increases					
Proposed Base Rate Increase	512,748	76,631	517,636	72,319	676,728
Increase in Miscellaneous Charges	3	-	3	-	-
Decrease in Rents	(219)	(17)	(220)	(36)	-
Incremental Income Taxes	$ (208,131)	$ (31,112)	$ (210,116)	$ (29,353)	$ (274,808)
Net Operating Income after increase	$ 129,710	$ 167,459	$ 1,755,537	$ 219,552	$ 2,723,198
Rate of Return at KU Proposed Rates	**0.41%**	**4.51%**	**11.09%**	**8.72%**	**10.31%**
Subsidy at KU Proposed Rates	(3,415,770)	(141,315)	1,152,074	82,784	1,578,032
Change in Subsidy resulting from KU Proposed Rates	32.0%	129.0%	-11.4%	-28.9%	-21.5%
Base Rate Increase Required for Equalized Rates of Return	3,928,518	217,946	(634,438)	(10,465)	(901,304)
Base Rate increase Required for 25% Subsidy Reduction	1,988,224	171,660	340,841	76,820	607,042
Incremental Income Taxes	(807,298)	(69,702)	(138,322)	(31,181)	(246,510)
Net Operating Income after increase	$ 1,006,019	$ 223,898	$ 1,650,535	$ 222,226	$ 2,681,810
Rate of Return after 25% Subsidy Reduction	**3.15%**	**6.03%**	**10.42%**	**8.82%**	**10.16%**
Subsidy after 25% Subsidy Reduction	(1,940,294)	(46,286)	975,279	87,285	1,508,346
Change in Subsidy resulting from 25% Subsidy Reduction	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	5,402,425	807,559	6,293,269	893,164	14,551,478
Percentage Increase proposed by KU	9.49%	9.49%	8.23%	8.10%	4.65%
Percentage Increase to achieve equalized Rates of Return	72.72%	26.99%	-10.08%	-1.17%	-6.19%
Percentage Increase to achieve 25% subsidy reduction	36.80%	21.26%	5.42%	8.60%	4.17%

BIP Prod Trans Allocation
Corrected Demand Allocators
Removes ECR Rate Base
Present Revenues Reflect CSR Incr
Allocates CSR Credits on SCP

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 2003-00433
AND	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)	CASE NO. 2003-00434

EXHIBIT (SJB-13)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC/LC-TOD	Rate LP/LP-TOD	Street Lighting Rate PSL	Street Lighting Rate SLE
Cost of Service Summary – Pro-Forma								
Total Pro-Forma Operating Revenue	$ 709,631,942	$ 269,278,378	$ 952,526	$ 98,312,757	$ 163,343,827	$ 128,897,802	$ 5,453,014	$ 189,714
Total Operating Expenses	$ 641,996,290	$ 257,792,040	$ 1,325,576	$ 81,888,738	$ 141,780,579	$ 115,774,394	$ 4,801,103	$ 187,590
Net Operating Income (Adjusted)	$ 67,635,652	$ 11,486,338	$ (373,051)	$ 16,424,019	$ 21,563,248	$ 13,123,408	$ 651,910	$ 2,124
Net Cost Rate Base	$ 1,473,843,556	$ 680,151,878	$ 5,062,926	$ 170,825,435	$ 285,031,005	$ 225,299,290	$ 20,157,813	$ 451,450
Rate of Return	**4.59%**	**1.69%**	**-7.37%**	**9.61%**	**7.57%**	**5.82%**	**3.23%**	**0.47%**
Subsidy at Current Rates	$ 0	(33,300,831)	(1,021,989)	14,492,269	14,320,517	4,700,261	(461,109)	(31,389)
LG&E Proposed Increases								
Proposed Base Rate Increase	64,260,364	26,277,410	156,774	8,974,815	13,708,637	10,638,506	586,307	17,030
Increase in Miscellaneous Charges	410,061	305,284	-	104,713	36	28	-	-
Incremental Income Taxes	(26,361,864)	$ (10,836,010)	$ (63,906)	$ (3,701,124)	$ (5,588,121)	$ (4,336,628)	$ (238,999)	$ (6,942)
Net Operating Income after increase	105,944,212	$ 27,233,022	$ (280,183)	$ 21,802,423	$ 29,683,800	$ 19,425,313	$ 999,219	$ 12,212
Rate of Return at LG&E Proposed Rates	**7.19%**	**4.00%**	**-5.53%**	**12.76%**	**10.41%**	**8.62%**	**4.96%**	**2.70%**
Subsidy at LG&E Proposed Rates	(0)	(36,562,357)	(1,087,370)	16,076,190	15,522,384	5,452,942	(759,301)	(34,168)
Change in Subsidy resulting from LG&E Proposed Rates		9.8%	6.4%	10.9%	8.4%	16.0%	64.7%	8.9%
Base Rate Increase Required for Equalized Rates of Return	64,260,364	62,839,767	1,244,144	(7,101,375)	(1,813,747)	5,185,564	1,345,608	51,198
Base Rate increase Required for 25% Subsidy Reduction	64,260,364	37,864,144	477,652	3,767,827	8,926,641	8,710,760	999,777	27,656
Incremental Income Taxes	(26,361,864)	(15,559,156)	(194,707)	(1,578,579)	(3,638,817)	(3,550,813)	(407,543)	(11,274)
Net Operating Income after increase	105,944,212	$ 34,096,609	$ (90,106)	$ 18,717,981	$ 26,851,108	$ 18,283,382	$ 1,244,144	$ 18,506
Rate of Return after 25% Subsidy Reduction	**7.19%**	**5.01%**	**-1.78%**	**10.96%**	**9.42%**	**8.12%**	**6.17%**	**4.10%**
Subsidy after 25% Subsidy Reduction	0	(24,975,623)	(766,492)	10,869,202	10,740,388	3,525,196	(345,831)	(23,542)
Change in Subsidy resulting from 25% Subsidy Reduction		-25.0%	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	561,367,938	213,814,897	722,586	81,284,688	128,727,508	98,118,565	4,777,509	138,741
Percentage Increase proposed by LG&E	11.45%	12.29%	21.70%	11.04%	10.65%	10.84%	12.27%	12.27%
Percentage Increase to achieve equalized Rates of Return	11.45%	29.39%	172.18%	-8.74%	-1.41%	5.28%	28.17%	36.90%
Percentage Increase to achieve 25% subsidy reduction	11.45%	17.71%	66.10%	4.64%	6.93%	8.88%	20.93%	19.93%

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
September 30, 2003

Description	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary -- Pro-Forma			
Total Pro-Forma Operating Revenue	$ 6,617,260	$ 677,761	$ 35,908,904
Total Operating Expenses	$ 5,693,263	$ 566,398	$ 32,186,608
Net Operating Income (Adjusted)	$ 923,997	$ 111,362	$ 3,722,296
Net Cost Rate Base	$ 25,495,128	$ 1,001,089	$ 60,367,542
Rate of Return	**3.62%**	**11.12%**	**6.17%**
Subsidy at Current Rates	(415,268)	110,441	1,607,097
LG&E Proposed Increases			
Proposed Base Rate Increase	726,051	56,796	3,118,038
Increase in Miscellaneous Charges	-	-	-
Incremental Income Taxes	$ (295,963)	$ (23,152)	$ (1,271,018)
Net Operating Income after increase	$ 1,354,085	$ 145,006	$ 5,569,315
Rate of Return at LG&E Proposed Rates	**5.31%**	**14.48%**	**9.23%**
Subsidy at LG&E Proposed Rates	(807,912)	123,311	2,076,282
Change in Subsidy resulting from LG&E Proposed Rates	94.6%	11.7%	29.2%
Base Rate Increase Required for Equalized Rates of Return	1,533,963	(66,515)	1,041,756
Base Rate increase Required for 25% Subsidy Reduction	1,222,512	16,316	2,247,079
Incremental Income Taxes	(498,337)	(6,651)	(915,986)
Net Operating Income after increase	$ 1,648,172	$ 121,028	$ 5,053,389
Rate of Return after 25% Subsidy Reduction	**6.46%**	**12.09%**	**8.37%**
Subsidy after 25% Subsidy Reduction	(311,451)	82,831	1,205,322
Change in Subsidy resulting from 25% Subsidy Reduction	-25.0%	-25.0%	-25.0%
Adjusted Revenue at Current Rates	5,908,023	543,908	27,331,513
Percentage Increase proposed by LG&E	12.29%	10.44%	11.41%
Percentage Increase to achieve equalized Rates of Return	25.96%	-12.23%	3.81%
Percentage Increase to achieve 25% subsidy reduction	20.69%	3.00%	8.22%

BIP Prod Trans Allocation
Removes ECR Rate Base
Present Revenues reflect CSR incr
CSR Credits allocated on SCP

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	**CASE NO.**
LOUISVILLE GAS AND ELECTRIC COMPANY	)	**2003-00433**
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	**CASE NO.**
KENTUCKY UTILITIES COMPANY	)	**2003-00434**

EXHIBIT (SJB-14)

KENTUCKY UTILITIES COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Proposed Rates	Calculated Revenue @ Proposed KU Rates	Proposed Rates	Calculated Revenue @ Proposed KIUC Rates
LCIP - Rate Code 563								
Number of Customers	315				$ 120.00	$ 37,800	$ 120.00	$ 37,800
On-Peak Demand	4,068,204		$ 4.14	$ 16,842,364	$ 5.52	22,456,486	$ 4.79	19,476,875
Off-Peak Demand	3,969,563		$ 0.73	$ 2,897,781	$ 0.73	2,897,781	$ 0.73	2,897,781
CSR Credits	64,834		$ (3.20)	$ (207,469)	$ (4.19)	(271,655)	$ (4.19)	(271,655)
Penalties				21,553		21,553		21,553
Energy		2,080,874,735	$ 0.02210	45,987,332	$ 0.02200	45,779,244	$ 0.02200	45,779,244
Total Calculated at Base Rates				$ 65,541,561		$ 70,921,209		$ 67,941,598
Correction Factor				0.999029		0.999029		0.999029
Total After Application of Correction Factor				$ 65,605,294		$ 70,990,174		$ 68,007,665
Fuel Clause Billings - proforma for rollin				1,698,726		1,698,726		1,698,726
Merger Surcredit				(1,573,353)		(1,573,353)		(1,573,353)
Value Delivery Surcredit				(192,241)		(192,241)		(192,241)
VDT Amortization & Surcredit Adjustment				8,140		8,140		8,140
Adjustment to Reflect Year-End Customers				-		-		-
Total Rate LCI Primary				**$ 65,546,566**		**$ 70,931,445**		**$ 67,948,937**
Proposed Increase						**5,384,879**		**2,402,371**
Percentage Increase						8.22%		3.67%
Total Rate LCI Primary (without Interruptible Credit)				**$ 65,754,035**		**$ 71,203,101**		**$ 68,220,592**
Proposed Increase (without Interruptible Credit)						5,449,065		2,466,557
Percentage Increase						8.29%		3.75%

KENTUCKY UTILITIES COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates (see Exhibit 9)	Proposed Rates	Calculated Revenue @ Proposed KU Rates	Proposed Rates	Calculated Revenue @ Proposed KIUC Rates
LCIT - Rate Code 564								
Number of Customers	48				$ 120.00	$ 5,760	$ 120.00	$ 5,760
On-Peak Demand	1,099,952		$ 3.95	$ 4,344,810	$ 5.33	5,862,744	$ 4.60	5,057,123
Off-Peak Demand	1,092,494		$ 0.73	797,521	$ 0.73	797,521	$ 0.73	797,521
CSR Credits	122,014		$ (3.10)	(378,243)	$ (4.09)	(499,036)	$ (4.09)	(499,036)
Penalties				76,807		76,807		76,807
Energy		621,047,926	$ 0.02210	13,725,159	$ 0.02200	13,663,054	$ 0.02200	13,663,054
Total Calculated at Base Rates				$ 18,566,054		$ 19,906,850		$ 19,101,229
Correction Factor				0.999990		0.999990		0.999990
Total After Application of Correction Factor				$ 18,566,238		$ 19,907,046		$ 19,101,418
Fuel Clause Billings - proforma for rollin				526,690		526,690		526,690
Merger Surcredit				(450,942)		(450,942)		(450,942)
Value Delivery Surcredit				(55,117)		(55,117)		(55,117)
VDT Amortization & Surcredit Adjustment				2,334		2,334		2,334
Adjustment to Reflect Year-End Customers				-		-		-
Total Rate LCI Transmission				**$ 18,589,204**		**$ 19,930,012**		**$ 19,124,383**
Proposed Increase						**1,340,808**		**535,180**
Percentage Increase						7.21%		2.69%
Total Rate LCI Primary (without Interruptible Credit)				**$ 18,967,446**		**$ 20,429,048**		**$ 19,623,420**
Proposed Increase (without Interruptible Credit)						1,461,602		655,974
Percentage Increase						7.71%		3.46%
Total Rate LCI (without Interruptible Credit)				**$ 84,721,482**		**$ 91,632,149**		**$ 87,844,012**
Proposed Increase (without Interruptible Credit)						6,910,667		3,122,530
Percentage Increase						8.16%		3.69%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)	CASE NO. 2003-00433
AND	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)	CASE NO. 2003-00434

EXHIBIT (SJB-15)

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates	Proposed Rates	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LP - TRANSMISSION VOLTAGE							
Customer Charges	-	$ -	$ -	$ 90.00	$ -	$ 90.00	$ -
Demand Charges	*kW-Months*						
Summer Season	-	$ 7.39	-	$ 12.01	-	$ 11.65	-
Winter Season	-	$ 4.87	-	$ 9.49	-	$ 9.13	-
	-						
	kWh's						
Energy Charges	-	$ 0.02480	-	$ 0.02000	-	$ 0.02000	-
Power Factor Provision	*kW-Months*						
Summer Season	-	$ 7.39	-	$ 12.01	-	$ 11.65	-
Winter Season	-	$ 4.87	-	$ 9.49	-	$ 9.13	-
	-						
Subtotal @ base rates before application of correction factor			$ -		$ -		$ -
Correction Factor -		-		-		-	
Subtotal @ base rates after application of correction factor			$ -		$ -		$ -
Fuel Adjustment Clause - proforma for rollin			-		-		-
Merger Surcredit			-		-		-
Value Delivery Surcredit			-		-		-
VDT Amortization & Surcredit Adjustment			-		-		-
Adjustment to Reflect Year-End Customers			-		-		-
TOTAL INDUSTRIAL POWER RATE LP PRIMARY			$ -		$ -		$ -
PROPOSED INCREASE					$ -		$ -
Percentage Increase							

Note: Currently no customers are served under this rate

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates	Proposed Rates	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LP - PRIMARY VOLTAGE							
Customer Charges	494	$ 42.64	$ 21,064	$ 90.00	$ 44,460	$ 90.00	$ 44,460
Demand Charges	*kW-Months*						
Summer Season	95,177	$ 8.55	813,763	$ 13.17	1,253,481	$ 12.81	1,218,979
Winter Season	181,277	$ 6.01	1,089,475	$ 10.63	1,926,975	$ 10.27	1,861,261
	276,454						
	kWh's						
Energy Charges	111,622,714	$ 0.02480	2,768,243	$ 0.02000	2,232,454	$ 0.02000	2,232,454
Power Factor Provision	*kW-Months*						
Summer Season	(806)	$ 8.55	(6,891)	$ 13.17	(10,615)	$ 12.81	(10,323)
Winter Season	(3,501)	$ 6.01	(21,041)	$ 10.63	(37,216)	$ 10.27	(35,947)
	(4,307)						
Subtotal @ base rates before application of correction factor			$ 4,664,613		$ 5,409,539		$ 5,310,885
Correction Factor -		0.999681		0.999681		0.999681	
Subtotal @ base rates after application of correction factor			$ 4,666,103		$ 5,411,266		$ 5,312,581
Fuel Adjustment Clause - proforma for rollin			(58,665)		(58,665)		(58,665)
Merger Surcredit			(130,757)		(130,757)		(130,757)
Value Delivery Surcredit			(29,824)		(29,824)		(29,824)
VDT Amortization & Surcredit Adjustment			349		349		349
Adjustment to Reflect Year-End Customers	-		-		-		-
TOTAL INDUSTRIAL POWER RATE LP PRIMARY			$ 4,447,206		$ 5,192,370		$ 5,093,684
PROPOSED INCREASE					$ 745,164		$ 646,478
Percentage Increase					16.76%		14.54%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants		Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates	Proposed Rates	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LP - SECONDARY VOLTAGE								
Customer Charges	4,225		$ 42.64	$ 180,154	$ 90.00	$ 380,250	$ 90.00	$ 380,250
Demand Charges		*kW-Months*						
Summer Season		495,852	$ 10.41	5,161,819	$ 14.27	7,075,808	$ 13.91	6,896,060
Winter Season		927,407	$ 7.90	7,326,515	$ 11.73	10,878,484	$ 11.37	10,542,296
		1,423,259						
		kWh's						
Energy Charges		553,836,275	$ 0.02480	13,735,140	$ 0.02000	11,076,726	$ 0.02000	11,076,726
Power Factor Provision		*kW-Months*						
Summer Season		(4,581)	$ 10.41	(47,688)	$ 14.27	(65,371)	$ 13.91	(63,710)
Winter Season		(10,121)	$ 7.90	(79,956)	$ 11.73	(118,719)	$ 11.37	(115,050)
		(14,702)						
Subtotal @ base rates before application of correction factor				**$ 26,275,984**		**$ 29,227,177**		**$ 28,716,571**
Correction Factor -			0.999681		0.999681		0.999681	
Subtotal @ base rates after application of correction factor				**$ 26,284,374**		**$ 29,236,509**		**$ 28,725,740**
Fuel Adjustment Clause - proforma for rollin				(277,626)		(277,626)		(277,626)
Merger Surcredit				(738,856)		(738,856)		(738,856)
Value Delivery Surcredit				(167,175)		(167,175)		(167,175)
VDT Amortization & Surcredit Adjustment				1,955		1,955		1,955
Adjustment to Reflect Year-End Customers		3,146,798		147,900		165,294		162,285
TOTAL INDUSTRIAL POWER RATE LP SECONDARY				**$ 25,250,571**		**$ 28,220,101**		**$ 27,706,322**
PROPOSED INCREASE						**$ 2,969,530**		**$ 2,455,752**
Percentage Increase						11.76%		9.73%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates	Proposed Rates	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LPTOD - TRANSMISSION VOLTAGE							
Customer Charges	73	$ 44.62	$ 3,257	$ 120.00	$ 8,760	$ 120.00	$ 8,760
	kW-Months						
Basic Demand Charges	696,788	$ 2.05	1,428,415	$ 2.33	1,623,516	$ 2.23	1,556,006
Peak Demand Charges	*kW-Months*						
Summer Peak	234,813	$ 5.36	1,258,598	$ 9.65	2,265,945	$ 9.38	2,203,576
Winter Peak	454,878	$ 2.84	1,291,854	$ 7.11	3,234,183	$ 6.84	3,113,360
	689,691						
	kWh's						
Energy Charges	376,359,726	$ 0.02480	9,333,721	$ 0.02000	7,527,195	$ 0.02000	7,527,195
Power Factor Provision	*kW-Months*						
Basic Demand	(25,159)	$ 2.05	(51,576)	$ 2.33	(58,620)	$ 2.23	(56,183)
Summer Peak	(7,762)	$ 5.36	(41,604)	$ 9.65	(74,903)	$ 9.38	(72,842)
Winter Peak	(17,215)	$ 2.84	(48,891)	$ 7.11	(122,399)	$ 6.84	(117,826)
	kW-Months						
Interruptible Service Rider	411,322	$ (3.30)	(1,357,363)	$ (3.98)	(1,637,062)	$ (3.98)	(1,637,062)
Subtotal @ base rates before application of correction factor			$ **11,816,412**		$ **12,766,615**		$ **12,524,984**
Correction Factor -		1.000343		1.000343		1.000343	
Subtotal @ base rates after application of correction factor			$ **11,812,356**		$ **12,762,233**		$ **12,520,685**
Fuel Adjustment Clause - proforma for rollin			(213,291)		(213,291)		(213,291)
Merger Surcredit			(328,889)		(328,889)		(328,889)
Value Delivery Surcredit			(74,173)		(74,173)		(74,173)
VDT Amortization & Surcredit Adjustment			867		867		867
Adjustment to Reflect Year-End Customers	-		-		-		-
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION			$ 11,196,870		$ 12,146,747		$ **11,905,199**
PROPOSED INCREASE					$ **949,877**		$ **708,329**
Percentage Increase					8.48%		6.33%
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION (without Interruptible Credit)			$ 12,554,232		$ 13,783,808		$ **13,542,260**
PROPOSED INCREASE (without Interruptible Credit)					$ **1,229,576**		$ **988,028**
Percentage Increase					9.79%		7.87%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates	Proposed Rates	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LPTOD - PRIMARY VOLTAGE							
Customer Charges	540	$ 44.62	$ 24,095	$ 120.00	$ 64,800	$ 120.00	$ 64,800
	kW-Months						
Basic Demand Charges	2,963,564	$ 3.20	9,483,405	$ 3.52	10,431,745	$ 3.42	10,144,612
Peak Demand Charges	*kW-Months*						
Summer Peak	996,472	$ 5.36	5,341,090	$ 9.65	9,615,955	$ 9.38	9,351,277
Winter Peak	1,952,825	$ 2.84	5,546,023	$ 7.11	13,884,586	$ 6.84	13,365,885
	2,949,297						
	kWh's						
Energy Charges	1,597,360,760	$ 0.02480	39,614,547	$ 0.02000	31,947,215	$ 0.02000	31,947,215
Power Factor Provision	*kW-Months*						
Basic Demand	(103,903)	$ 3.20	(332,489)	$ 3.52	(365,737)	$ 3.42	(355,671)
Summer Peak	(41,348)	$ 5.36	(221,623)	$ 9.65	(399,004)	$ 9.38	(388,022)
Winter Peak	(58,231)	$ 2.84	(165,376)	$ 7.11	(414,023)	$ 6.84	(398,556)
	kW-Months						
Interruptible Service Rider	344,897	$ (3.30)	(1,138,160)	$ (4.05)	(1,396,833)	$ (4.05)	(1,396,833)
Subtotal @ base rates before application of correction factor			$ 58,151,511		$ 63,368,703		$ 62,334,709
Correction Factor -		1.000342		1.000342		1.000342	
Subtotal @ base rates after application of correction factor			$ 58,131,626		$ 63,347,034		$ 62,313,393
Fuel Adjustment Clause - proforma for rollin			(864,770)		(864,770)		(864,770)
Merger Surcredit			(1,626,347)		(1,626,347)		(1,626,347)
Value Delivery Surcredit			(366,371)		(366,371)		(366,371)
VDT Amortization & Surcredit Adjustment			4,284		4,284		4,284
Adjustment to Reflect Year-End Customers	-		-		-		-
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY			**$ 55,278,422**		**$ 60,493,830**		**$ 59,460,189**
PROPOSED INCREASE					**$ 5,215,408**		**$ 4,181,767**
Percentage Increase					9.43%		7.56%
TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY (without Interruptible Credit)			**$ 56,416,582**		**$ 61,890,663**		**$ 60,857,022**
PROPOSED INCREASE (without Interruptible Credit)					**$ 5,474,081**		**$ 4,440,440**
Percentage Increase					9.70%		7.87%

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates	Proposed Rates	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LPTOD - SECONDARY VOLTAGE							
Customer Charges	151	$ 44.62	$ 6,738	$ 120.00	$ 18,120	$ 120.00	$ 18,120
	kW-Months						
Basic Demand Charges	114,966	$ 5.11	587,476	$ 4.62	531,143	$ 4.52	520,004
Peak Demand Charges	*kW-Months*						
Summer Peak	31,727	$ 5.36	170,057	$ 9.65	306,166	$ 9.38	297,738
Winter Peak	80,068	$ 2.84	227,393	$ 7.11	569,283	$ 6.84	548,016
	111,795						
	kWh's						
Energy Charges	42,810,915	$ 0.02480	1,061,711	$ 0.02000	856,218	$ 0.02000	856,218
Power Factor Provision	*kW-Months*						
Basic Demand	(1,951)	$ 5.11	(9,970)	$ 4.62	(9,014)	$ 4.52	(8,825)
Summer Peak	(533)	$ 5.36	(2,857)	$ 9.65	(5,143)	$ 9.38	(5,002)
Winter Peak	(1,404)	$ 2.84	(3,987)	$ 7.11	(9,982)	$ 6.84	(9,610)
Subtotal @ base rates before application of correction factor			$ 2,036,561		$ 2,256,791		$ 2,216,661
Correction Factor -		1.000343		1.000343		1.000343	
Subtotal @ base rates after application of correction factor			$ 2,035,862		$ 2,256,016		$ 2,215,900
Fuel Adjustment Clause - proforma for rollin			(21,506)		(21,506)		(21,506)
Merger Surcredit			(56,520)		(56,520)		(56,520)
Value Delivery Surcredit			(12,486)		(12,486)		(12,486)
VDT Amortization & Surcredit Adjustment			146		146		146
Adjustment to Reflect Year-End Customers	-		-		-		-
TOTAL INDUSTRIAL POWER RATE LPTOD SECONDARY			$ 1,945,496		$ 2,165,650		$ 2,125,534
PROPOSED INCREASE					$ 220,155		$ 180,039
Percentage Increase					11.32%		9.25%
TOTAL INDUSTRIAL POWER RATE LESS INTERRUPTIBLE CREDIT			$ 100,614,087		$ 111,252,592		$ 109,324,823
PROPOSED INCREASE					$ 10,638,505		$ 8,710,736
Percentage Increase					10.57%		8.66%

EXHIBIT (SJB-16)

ANALYSIS OF LGE/KU EXPECTED HOURLY OPERATION OF COMBUSTION TURBINES

(Test year ending September 30, 2003 and Calendar year 2004)

Unit	Mw	Test Year Hours	2004 Hours	Average Hours[1]	Mw[4]	Mw Wtd Hrs[3]	Heat Rate	Mw Wtd HR[2]
Cane Run 11	14	3	0	1.5	0	0		
Brown 5	117	76	70	73	117	6.44	12,185	451
Brown 6	154	171	370	270.5	154	31.39	10,532	1,902
Brown 7	154	221	306	263.5	154	30.58	10,544	1,855
Brown 8	106	108	45	76.5	106	6.11	12,033	423
Brown 9	106	67	40	53.5	106	4.27	11,994	295
Brown 10	106	83	43	63	106	5.03	11,920	345
Brown 11	106	36	36	36	106	2.88	11,875	196
Heafling	36	0	0	0	0	0.00		
Paddys Run 11	12	0	0	0	0	0.00		
Paddys Run 12	23	0	0	0	0	0.00		
Paddys Run 13	158	293	87	190	158	22.62	9,919	1,291
Trimble County 5	160	375	207	291	160	35.09	10,624	2,144
Trimble County 6	160	310	178	244	160	29.42	10,645	1,802
Trimble County 7	155		148	148	0	0.00		
Trimble County 8	155		104	104	0	0.00		
Trimble County 9	155		0	0	0	0.00		
Trimble County 10	155		0	0	0	0.00		
Waterside 7	11	0	0	0	0	0.00		
Waterside 8	11	0	0	0	0	0.00		
Zorn 1	14	4	0	2	0	0.00		
Weighted Average	2068	1747	1634	1817	1327	**174**		10,704

[1] If unit was not shown as available in test year, average is set at 2004 hours.
[2] Weighted by "Mw weighted hours" for non-zero capacity factor units in both test year and 2004.
[3] Weighted average hours of operation for non-zero capacity factor units in both test year and 2004.
[4] Mw for units with non-zero capacity factors in both test year and 2004.

Exhibit__(SJB-16)

EXHIBIT (SJB-17)

Kentucky Utilities Company

ELECTRIC RIDER **CSR**
Curtailable Service Rider
(KIUC REVISED)

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This rider shall be made available to any customer served under the applicable power schedules who contracts for not less than 1,000 kilowatts of their total requirements to be subject to curtailment upon notification by the Company.

CONTRACT OPTION
Customer may, at Customer's option, contract with Company to curtail service upon notification by the Company. Requests for curtailment shall not exceed one hundred seveny-five (175) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with unlimited requests for curtailment per calendar day within these parameters. Company may request or cancel a curtailment at any time during an hour, but shall give no less than one hour notice when either requesting or canceling a curtailment.

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Compliance with a request for curtailment shall be measured in one of the following two ways:

a) The customer shall contract for a given amount of firm demand, and the curtailment load shall be the Customer's monthly billing demand in excess of the firm contract. During a request for curtailment, the customer shall reduce its demand to the firm demand designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not less than the contracted firm demand, in the billing period shall be the curtailable demand on which the monthly credit is based. The demand in excess of the firm load during each requested curtailment in the billing period shall be the measure of non-compliance.

b) The customer shall contract for a given amount of curtailable load by which the customer shall agree to reduce its demand from the monthly maximum demand. During a request for curtailment, the Customer shall reduce its demand to a level equal to the maximum monthly demand less the curtailable load designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not more than the contracted curtailable load, in the billing period shall be the curtailable demand on which the monthly credit is based. The difference in contracted curtailable load and the actual curtailed load during each requested curtailment in the billing period shall be the measure of non-compliance.

c) In those months in which the Company does not request load curtailment, the customer will receive a credit based on either the difference in the monthly billing demand and the contracted firm demand, a) above, or the contracted curtailable demand, b) above.

RATE

Customer will receive a credit against the applicable power schedule for curtailable kW, as determined in the preceding paragraph, times the applicable credit. Customers will be charged for the portion of each requested curtailment not met at the applicable charge.

	Primary	Transmission
Demand Credit of:	$ 4.19 per KW	$ 4.09 per KW
Non-Compliance Charge of	$16.00 per KW	$16.00 per KW

For each kWh of actual interrupted energy, customer will receive an additional credit equal to the avoided energy cost of the Company's average combustion turbine capacity less the applicable energy charge paid by the customer under customer's applicable firm tariff. The average cost of combustion turbine capacity will be determined by multiplying the monthly average cost of natural gas per mmbtu used to supply its combustion turbine capacity times a heat rate of 10,704 btu's per kWh. Actual interrupted energy shall be determined by accumulating the kW of interrupted demand over the interruption period during any month.

Failure of Customer to curtail when requested to do so may result in termination of service under this rider.

BUY-THROUGH OPTION

Upon notification of a request for interruption, customer will be offered the option of purchasing energy at the Company's avoided cost, based on prevailing market conditions, in lieu of being interrupted. The Company shall provide customer with the cost, in dollars per mWh, associated with such buy-through energy, based on the Company's best estimate at the time. In addition, the Company shall be permitted to charge customer a transaction fee of one-half (0.5) mill per kWh to cover the costs of obtaining the buy-through energy. This buy-through provision shall only apply in the event of a Company request for an economic interruption. It shall not be applicable in the event of a request to interrupt for reliability reasons, as determined by the Company's system operators.

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TERM OF CONTRACT

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply

EXHIBIT (SJB-18)

Louisville Gas and Electric Company

ELECTRIC RIDER

CSR
Curtailable Service Rider
(KIUC REVISED)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to any customer served under the applicable power schedules who contracts for not less than 1,000 kilowatts of their total requirements to be subject to curtailment upon notification by the Company.

CONTRACT OPTION

Customer may, at Customer's option, contract with Company to curtail service upon notification by the Company. Requests for curtailment shall not exceed one hundred seventy-five (175) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with unlimited requests for curtailment per calendar day within these parameters. Company may request or cancel a curtailment at any time during an hour, but shall give no less than one hour notice when either requesting or canceling a curtailment.

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Compliance with a request for curtailment shall be measured in one of the following two ways:

a) The customer shall contract for a given amount of firm demand, and the curtailment load shall be the Customer's monthly billing demand in excess of the firm contract. During a request for curtailment, the customer shall reduce its demand to the firm demand designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not less than the contracted firm demand, in the billing period shall be the curtailable demand on which the monthly credit is based. The demand in excess of the firm load during each requested curtailment in the billing period shall be the measure of non-compliance.

b) The customer shall contract for a given amount of curtailable load by which the customer shall agree to reduce its demand from the monthly maximum demand. During a request for curtailment, the Customer shall reduce its demand to a level equal to the maximum monthly demand less the curtailable load designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not more than the contracted curtailable load, in the billing period shall be the curtailable demand on which the monthly credit is based. The difference in contracted curtailable load and the actual curtailed load during each requested curtailment in the billing period shall be the measure of non-compliance.

c) In those months in which the Company does not request load curtailment, the customer will receive a credit based on either the difference in the monthly billing demand and the contracted firm demand, a) above, or the contracted curtailable demand, b) above.

RATE

Customer will receive a credit against the applicable power schedule for curtailable kW, as determined in the preceding paragraph, times the applicable credit. Customers will be charged for the portion of each requested curtailment not met at the applicable charge.

	Primary	Transmission
Demand Credit of:	$ 4.05 per KW	$ 3.98 per KW
Non-Compliance Charge of	$16.00 per KW	$16.00 per KW

For each kWh of actual interrupted energy, customer will receive an additional credit equal to the avoided energy cost of the Company's average combustion turbine capacity less the applicable energy charge paid by the customer under customer's applicable firm tariff. The average cost of combustion turbine capacity will be determined by multiplying the monthly average cost of natural gas per mmbtu used to supply its combustion turbine capacity times a heat rate of 10,704 btu's per kWh. Actual interrupted energy shall be determined by accumulating the kW of interrupted demand over the interruption period during any month.

Failure of Customer to curtail when requested to do so may result in termination of service under this rider.

BUY-THROUGH OPTION

Upon notification of a request for interruption, customer will be offered the option of purchasing energy at the Company's avoided cost, based on prevailing market conditions, in lieu of being interrupted. The Company shall provide customer with the cost, in dollars per mWh, associated with such buy-through energy, based on the Company's best estimate at the time. In addition, the Company shall be permitted to charge customer a transaction fee of one-half (0.5) mill per kWh to cover the costs of obtaining the buy-through energy. This buy-through provision shall only apply in the event of a Company request for an economic interruption. It shall not be applicable in the event of a request to interrupt for reliability reasons, as determined by the Company's system operators.

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TERM OF CONTRACT

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply