#### **COMMONWEALTH OF KENTUCKY**

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### 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 ELECTRIC	) )	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434 i

**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

# COMMONWEALTH OF KENTUCKY

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

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V.	SPECIAL CONTRACT ISSUES

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### DIRECT TESTIMONY OF STEPHEN J. BARON

### I. QUALIFICATIONS AND SUMMARY

- 2 Q. Please state your name and business address. 3 My name is Stephen J. Baron. My business address is J. Kennedy and Associates, 4 A. Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, 5 6 Georgia 30075. 7 8
  - What is your occupation and by who are you employed? Q.

1	A.	I am the President and a Principal of Kennedy and Associates, a firm of utility rate,
2		planning, and economic consultants in Atlanta, Georgia.
3		
4	Q.	Please describe briefly the nature of the consulting services provided by
5		Kennedy and Associates.
6		
7	A.	Kennedy and Associates provides consulting services in the electric and gas utility
8		industries. Our clients include state agencies and industrial electricity consumers.
9		The firm provides expertise in system planning, load forecasting, financial analysis,
10		cost-of-service, and rate design. Current clients include the Georgia and Louisiana
11		Public Service Commissions, and industrial consumer groups throughout the United
12		States.
13		
14	Q.	Please state your educational background.
15		
16	A.	I graduated from the University of Florida in 1972 with a B.A. degree with high
17		honors in Political Science and significant coursework in Mathematics and
18		Computer Science. In 1974, I received a Master of Arts Degree in Economics, also
19		from the University of Florida. My areas of specialization were econometrics,
20		statistics, and public utility economics. My thesis concerned the development of an

My

econometric model to forecast electricity sales in the State of Florida, for which I 1 2 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 3 4 and dynamic model building. 5 6 Q. Please describe your professional experience. 7 I have more than twenty-nine years of experience in the electric utility industry in 8 A. the areas of cost and rate analysis, forecasting, planning, and economic analysis. 9 10 11 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 12 responsibilities included the analysis of rate cases for electric, telephone, and gas 13 utilities, as well as the preparation of cross-examination material and the preparation 14 15 of staff recommendations. 16 17 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 18 successive promotions, ultimately to the position of Vice President of Energy 19

Management Services of Ebasco Business Consulting Company.

responsibilities included the management of a staff of consultants engaged in 1 2 providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, 3 4 cogeneration, and load management. 5 I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of 6 the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this 7 capacity I was responsible for the operation and management of the Atlanta office. 8 My duties included the technical and administrative supervision of the staff, 9 budgeting, recruiting, and marketing as well as project management on client 10 11 At Coopers & Lybrand, I specialized in utility cost analysis, engagements. forecasting, load analysis, economic analysis, and planning. 12 13 14 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. 15 16 During the course of my career, I have provided consulting services to more than 17 thirty utility, industrial, and Public Service Commission clients, including three 18 19 international utility clients. 20

1 I have presented numerous papers and published an article entitled "How to Rate 2 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 3 4 "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research 5 6 Institute, which published the study. 7 I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, 8 Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, 9 Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North 10 Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory 11 12 Commission and in United States Bankruptcy Court. A list of my specific 13 regulatory appearances can be found in Baron Exhibit \_\_\_ (SJB-1) 14 Would you please discuss your experience in electric utility restructuring 15 Q. 16 proceedings? 17 I have been extensively involved in electric utility restructuring since 1995. This 18 A. 19 involvement includes participation in eight proceedings in Pennsylvania, seven of which involved detailed implementation analyses associated with restructuring. In 20

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 1 2 tariffs, load profiling and other issues. 3 To date, I have presented testimony in 13 electric restructuring proceedings. 4 5 6 Q. On whose behalf are you testifying in this proceeding? 7 I am testifying on behalf of the Kentucky Industrial Utility Customers ("KIUC"), a 8 A. group of large industrial customers taking service on the LG&E and KU systems. 9 10 How have you organized your testimony with regard to LG&E and KU issues? 11 Q. For many of the issues that I will discuss, I present common testimony that is 12 A. applicable to both LG&E and KU. This would include discussions of basic 13 principles associated with cost allocation and rate design as well as a number of 14 other issues, including interruptible and curtailable rates. However, since the 15 revenue requirement requests and the specific cost of service study results for 16 LG&E and KU rate classes are different, I will be presenting separate analyses and 17 18 discussions of these results. 19

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, the residential class is substantially underpaying its costs 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.

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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 buythrough 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.

1		II. COS	Γ OF SERVICE STUDY ISSUES
2			
3	Q.	Have you reviewed the	Company's proposed "base-intermediate-peak" cost
4		allocation methodology	?
5			
6	A.	Yes. The BIP method i	s the class cost allocation method used by LG&E in prior
7		cases and is being propo	osed for use by KU for the first time in this proceeding.
8		Though the Commission	has accepted the BIP method in past LG&E proceedings,
9		the Commission has not a	accepted the method for KU in prior cases.
10			
11		The basic methodology,	as discussed by Company witness Steven Seelye, first
12		functionalizes the Comp	any's production and transmission demand-related costs
13		into three periods. Unde	er the Company's BIP functionalization, which is used in
14		both the LG&E and KU	studies, total system production and transmission demand-
15		related costs are assigned	as follows:
16			Assignment of
17 18			Total P&T Costs
19		Base	22 EQD/
20		Intermediate	33.58% 39.97%
21		Peak	26.45%
22		<del>-</del>	AU-TJ /U

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?

Α.

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 implies the reverse. 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.

Would you please discuss the additional corrections that you made to the KU 2 BIP cost of service study? 3 Based on a review of the KU BIP cost of service study and the accompanying 4 A. 5 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 6 schools and Rate 33 classes, wherein the summer and winter peak demands (used to 7 allocate peak and intermediate costs) where inadvertently set to "zero" for these 8 classes. It appears that this was an error in the spreadsheet. The second error 9 concerns the failure to include any NCP kW demand for Rate Schedule HLFS 10 secondary load. NCP demand is used to assign costs associated with secondary and 11 primary distribution service. Though the Company did assign demand for HLFS 12 primary customers, no HLFS secondary demand was assigned. 13 14 15 Have you made these corrections to the Company's filed BIP class cost of Q. 16 service studies? 17 18 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 19 class cost of service study. Both of these studies reflect the aforementioned changes 20

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Q.

that I have just discussed. Though, in total, these changes do not have a significant 1 2 impact on the cost of service study results, I believe they each represent a reasonable 3 adjustment (and in the case of KU, a required correction) to the Company's studies. 4 Would you please describe the additional studies that you have developed to 5 Q. assess the contributions of each customer class to the Company's overall cost of 6 7 service 8 Yes. Baron Exhibits \_\_\_\_(SJB-3), \_\_\_\_(SJB-4). (SJB-5) and \_\_\_\_(SJB-6) contain 9 A. the results of three alternative cost of service studies for KU. Each of these studies 10 11 incorporates the corrections that I previously discussed with regard to the 12 Company's BIP cost of service study. 13 14 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 15 16 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 17 class's contribution to average demands and the class contribution to excess 18 demands, which is defined as the class peak mW in excess of the average demand 19 mW for the class. The calculation of each class's allocation factor is two-fold. 20

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 1 used for the excess portion is that if the class coincident peak demand is used, the 2 A&E method becomes identical to a single coincident peak method. 3 4 Would you please discuss the remaining cost of service studies that you have 5 Q. 6 developed for KU? 7 Baron Exhibit \_\_\_\_(SJB-4) contains the results of a summer/winter average 8 A. coincident peak cost of service study, while Exhibit \_\_\_(SJB-5) contains the results 9 of a single summer coincident peak study. Exhibit \_\_\_\_(SJB-6) contains the results 10 of a 12 CP study. Each of these studies represents additional cost of service 11 12 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 13 methodology that I referenced earlier in my testimony except that it is based on an 14 equal weighting between the summer and winter peaks instead of the 73/27% 15 weighting that the Company computed using the unserved load method. 16 17 What do the studies show with regard to the rate of return paid by the 18 Q. residential class and the all-electric residential class? 19 20

As can be seen from each of the exhibits summarizing the studies evaluated, the A. 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.

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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?

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

Table 1

Kentucky Utilities

Class Rate of Return Indices under Present Rates

		Corrected <u>BIP</u>	Average & Excess	Sum/Win <u>CP</u>	Summer <u>CP</u>	12 <u>CP</u>
Total System		1.000	1.000	1.000	1.000	1.000
Residential	Rate RS Rate	0.196	0.119	0.175	(0.025)	0.220
All Electric Residential	FERS	0.113	(0.083)	(0.058)	0.624	0.231
General Service	GS LP,HLF,	1.454	0.960	1.361	0.983	1.099
Combined Light & Power	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	COL	1.643	1.449	1.736	2.447	-
Special Contracts		2.060	2.810	1.941	1.347	<ul><li>2.142</li><li>3.719</li></ul>

This type of analysis is commonly referred to as a rate of return index presentation.

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For the total system, the rate of return index is 1.0. For the residential class, under

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the corrected BIP method, the rate of return index is 0.196. This means that

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.

1	Q.	Have you prepared similar analyses for LG&E?
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3	A.	Yes. Baron Exhibits(SJB-7),(SJB-8),(SJB-9), (SJB-10) and
4		(SJB-11) contain cost of service study results for LG&E reflecting the same
5		five study methodologies. The corrected BIP method that I previously discussed
6		presented in Exhibit (SJB-7), while Exhibits (SJB-8) through (SJB-11) contain the
7		LG&E A&E results, the summer/winter CP results, the summer CP results.
8		·
9	Q.	Do the LG&E cost of service study results, under each of the five methods, lead
10		to similar conclusions with regard to subsidies being paid to residential
11		customers?
12		
13	A.	Yes. As can be seen, the rate of return for residential customers is in the range of
14		1.7% based on the corrected BIP method, compared to an overall system rate of
15		return of 4.59%. For large customers on Rates LP and LP-TOD, the rate of return
16		under the corrected BIP method is 5.82%, while under the four alternative methods
17		the rate of return rises to between 7% and 9%. Table 2 summarizes these class
18		rates of return using the relative rate of return indices.
	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

Total System		Corrected BIP 1.000	Average & Excess 1.000	Sum/Win <u>CP</u> 1.000	<b>Summer CP</b> 1.000	12 <u>CP</u> 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.

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

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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** 

		<u>Percent</u>	<u>Increase</u>	
	KU	on Total	on Non-Fuel	ROR Index
	Proposed	Rate	Rate	at Proposed
	<u>Increase</u>	Revenues	Revenues	<u>Rates (1)</u>
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 Coal Mining Power	6,910,666	8.2%	16.6%	1.702
Primary Coal Mining Power	405,257	8.5%	14.6%	2.529
Trans ∟arge Power Mine TOD	319,850	8.5%	16.4%	2.333
Pri Large Power Mine TOD	165,746	8.5%	15.6%	2.012
Trans	347,607	8.5%	17.6%	1.995
Combination Off-Peak	96,148	23.2%	45.8%	(1.873)
All Electric School Electric Space Heating	-	0.0%	0.0%	0.684
Rider	129,034	19.3%	31.9%	1.046
Street Lighting Decorative Street	512,748	9.5%	10.8%	0.060
Lighting	76,631	9.5%	9.9%	0.666
Private Outdoor Lighting Customer Outdoor	517,636	8.2%	9.8%	1.639
_ighting	72,319	8.1%	9.8%	1.289
Special Contracts	676,728	4.7%	9.7%	1.525

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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

			Percent	Increase	
		LG&E	on Total	on Non-Fuel	ROR Index
		Proposed	Rate	Rate	at Proposed
		<u>Increase</u>	Revenues	Revenues	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	<b>1</b> 1.4%	14.9%	1.283

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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.

r	Ų.	what overall conclusions have you drawn from your analysis of the
2		Company's proposed increases in this case for both KU and LG&E?
3		
4	A.	Both LG&E and KU have failed to adequately address the subsidy problem in their
5		recommended apportionment of the overall revenue increases in this case. Even
6		under the BIP cost of service study methodology advocated by the Company as the
7		basis to measure the relationship between rates and cost of service, there is no
8		material mitigation n in the subsidy problem under the Companies' proposals.
9		
10	Q.	Have you developed an alternative methodology to apportion the Company's
11		authorized revenue requirement increase in this case?
12		
13	A.	Yes. I am recommending a methodology that would specifically provide for
14		mitigation of the subsidies under present rates paid and received by each rate class.
15		The methodology that I recommend is a "25% subsidy reduction method," wherein
16		the subsidies paid and received by each rate class at present rates are reduced by
17		25% in the apportionment of the authorized revenue requirement increase, if any.
18		
19		Though the alternative cost of service methods that I have looked at (A&E, S/W
20		average, and summer CP and 12 CP) generally produced more favorable results to
21		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).<sup>2</sup>

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%.

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

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		Allocation
		\$ Amount	<u>% Total</u> <u>Rev</u>	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	COLt	76,820	8.6%	0.130%
Special Contracts		607,042	4.2%	1.030%

<sup>(1)</sup> 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?

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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.

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## Table 6 Louisville Gas & Electric Company

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

		Proposed	Increase	Alfocation
Total System		<b>\$ Amount</b> 64,260,364	<u>% Total</u> <u>Rev</u> 11.4%	<u>of</u> <u>Increase</u> 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%

<sup>(1)</sup> Based on Corrected BIP Cost Study

1 Assuming the Company receives a lower authorized revenue increase, as 2 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 3 receive a revenue decrease in this proceeding, the decrease should be allocated to 4 reduce subsidies by 25%, subject to the caveat that no customer class or group of 5 6 classes should receive an increase. 7 KIUC is proposing that the Commission adopt a specific methodology in this 8 Q. case to address the subsidy problem that you have identified in both the KU 9 and LGE rates. Do you believe that your proposal to reduce subsidies by 10 11 25% is consistent with the economic development objectives of the State of 12 Kentucky? 13 Yes. The Kentucky Cabinet for Economic Development ("KCED") has issued a 14 A. White Paper that specifically addresses the significance of low cost electricity in 15 Kentucky as a factor in attracting and keeping industry in the State. According to 16 17 the White Paper: 18 19 "In Kentucky, we provide a wealth of information about power for 20 companies considering us in the site selection process. And we are 21 often asked about it since we have been ranked the least expensive for 22 industrial users of electricity, Strong said" [Shedding Light on Energy: 23 How Supply and Costs Affect Business Decisions, KCED White Paper, 24 http://www.thinkkentucky.com/kyedc/pdfs/Whitepaper\_energy.pdf.] 25

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

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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

1 proposal for the LG&E rider, as long as the provision regarding applicability is 2 maintained in the tariff. 3 For KU, there is no current excess facilities charge rider. Rather, current customers 4 pay a lease rate associated with contributions in aid of construction. Under the 5 excess facilities rider for KU, which is a new rider, the lease rate would be reduced. 6 7 KIUC does not object to KU's excess facilities rider. 8 Would you please discuss the Company's proposed redundant capacity tariff? 9 Q. 10 For both KU and LG&E, the redundant capacity rider is new and, according to the 11 A. Company, does not have any test year revenues associated with the rider. Based on 12 discovery responses from the Company, no existing customer facilities would be 13 charged under this redundant capacity rider. 14 15 16 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 17 18 feeders that would be paid for through the excess facilities rider. For specifically assigned distribution facilities (e.g., a separate distribution feeder), customers are 19 required to pay for this investment through a contribution in aid of construction, 20

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.

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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

#### J. Kennedy and Associates, Inc.

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.

1	Q.	Are there any additional rate design issues that you would like to address?
2		
3	A.	Yes. KIUC believes that the KU and LGE fuel roll-in procedure should be
4		modified in a manner that recognizes the differential in fuel costs among rate
5		schedules on the basis of service voltage.
6		
7		In the current case, both KU and LGE have allocated test year fuel expense on the
8		basis of class energy, adjusted for losses. This is the appropriate method to assign
9		cost responsibility for these energy related costs. However, no such loss
10		adjustments are made to rolled-in fuel costs during the roll-in of fuel costs to base
11		rates that occurs periodically for both Companies. KIUC believes that in future
12		fuel roll-in proceedings, the Company be required to roll-in fuel costs into base
13		rates on a voltage differentiated basis, following the concept used by the Company
14		in this case to allocate fuel expense to rate schedules.
15		
16	Q.	Is KIUC recommending that the fuel clause itself be voltage differentiated?
17		
18	A.	No, not at this time.
19		

#### 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.

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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?

1 A. The Company is proposing to revise its interruptible and curtailable service rates to
2 reflect a credit based on the avoided cost associated with a simple cycle combustion
3 turbine. The credit for both LG&E and KU is determined based on the cost of a
4 new CT and reflects the Company's view that interruptible load is a substitute for
5 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.

1	The third concern that I have with the Company's proposal is that it does not offer
2	curtailable service customers the option of electing to "buy-through" an interruption
3	at prevailing market rates, if such power is available. Finally, the interruptible credit
4	should include an additional component to reflect fuel savings provided during
5	actual interruptions.
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Would you please discuss the first concern that you have with the Company's Q. CSR tariff, the increase in the maximum annual hours of potential

interruption to 500 hours?

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The Company is proposing to increase the maximum annualized hours of A. 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.

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

20

Yes. Baron Exhibit \_\_\_\_(SJB-16) shows an analysis of the actual and expected A. 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.

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1	Q.	Under your proposed methodology for determining the appropriate level of
2		maximum annual hours of interruption, are the Company's larger CTs given
3		more weight in the calculation?
4		
5	A.	Yes. The Company's newer CTs tend to be larger and are weighted at a higher level
6		in the calculation than the Company's smaller combustion turbines. As shown in
7		Exhibit (SJB-16), these larger units also have the lowest heat rates, which tend to
8		drive the operation of these units to a higher level.
9		
10	Q.	What is your recommendation for modifying the Company's proposed CSR
11		tariff with regard to maximum annual hours of interruption?
12		
13	A.	Based on the analysis that I prepared, I am recommending that the maximum annual
14		hours of interruption be set at 175 hours per year, for both LG&E and KU.
15		
16	Q.	The Company's production cost analysis shows that in future years, beyond
17		2004, some of the Company's CTs will operate in the 400 to 600 hour range
18		annually. Does this information justify the Company's 500 hour maximum
19		hours of interruption?
20		

1 A. No. These projections are based on production cost simulation model that is, in turn,
2 based on assumptions regarding load on the system, natural gas prices, market
3 conditions and other factors. As such, it is reasonable to rely on the test year results
4 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

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

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.

1	Q.	Would you summarize your recommendation regarding the appropriate
2		increase for the MeadWestvaco contract?
3		
4	A.	Each contract in the special contract rate class should receive the same percentage
5		increase and that increase should be well below system average based upon the class
6		cost studies and my 25% subsidy reduction proposal. This proposal results in the
7		special contract class and the otherwise most nearly applicable tariff, LCI-TOD,
8		getting nearly the same increase,
9		
10	Q.	Does that complete your testimony?
11		
12	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	)	CASE NO.
LOUISVILLE GAS AND ELECTRIC COMPANY	)	2003-00433
	)	
AND	)	
	)	
AN ADJUSTMENT OF THE ELECTRIC )		
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKV UTILITIES COMPANY	)	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:

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	)	CASE NO.
KENTUCKY UTILITIES COMPANY	j	2003-00434

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J. KENNEDY AND ASSOCIATES, INC. ROSWELL, GEORGIA

March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	КҮ	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	МО	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	кү	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.

# J. KENNEDY AND ASSOCIATES, INC.

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.

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	КҮ	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	СТ	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.

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	СТ	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	S 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	OH Case	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	ОН	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.

<u>Date</u>	Case	Jurisdict.	Party	Utility	Subject
<b>8</b> /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 fore-
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	casting. 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	СТ	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

<u>Date</u>	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	СТ	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	ОН	Armco Steel Co., L.P.	Cincinnati Gas &	Economic analysis of
	EL-UNC			Electric Co.	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	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
	testimony led on this.		<u>ાતા</u>		
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	ОН	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.

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	СТ	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	!D	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	Armoo Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO <sub>2</sub> 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.

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	Guif 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 ER94-898-00		Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	СО	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

# J. KENNEDY AND ASSOCIATES, INC.

Date	Case	Jurisdict.	Party	Utility	Subject
4/95	R-0094327	1 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		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 <i>1</i> 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	ŁA	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.

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
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	analysis. Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocate Cost Issu	U-22092 d Stranded les)	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

# J. KENNEDY AND ASSOCIATES, INC.

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- 4 Answeri	EC-98- 40-000 ing Testimony)	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Respon Testimo		КҮ	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	СТ	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	СТ	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	ОН	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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- <b>T</b> 00-1051-E-1	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundfing.
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-28 EL95-33-002		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 I Addressing 6	LA B) Contested Issue	Louisiana Public Service Commission es	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.

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	СО	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	СО	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	ER03-753-0	00 FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-00 ER03-583-00 ER03-583-00	01, and 02 00,	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.
	ER03-681-00 ER03-682-00 ER03-682-00 ER03-682-00	00, 01, and			
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	со	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 Allucation

			Allocation	Totaf	Residential	All Electric Residential	General Service Secondary	General Service Primary
Description	Ref	Name	Vector	System	Rate RS	Rate FERS	GSS	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			Rat	675,000 \$	122,243	\$ 129,125	\$ 61,916	\$ 2,52
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728) \$	(5,723,277)	•	\$ (2,393,685)	\$ (109,346
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		1,417,623 \$	181,543	•	\$ 96,991	\$ 4,700
Remove ECR revenues		ECRREV		\$ (626,036,03)	(4,562,377)	•	\$ (2,291,842)	\$ (91,53)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813 \$	3,208,163	•	\$ 1,547,196	\$ 66.93
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)	•	(1,505,781)	\$ (68,786
Eliminate ESM revenues collected		ESMREV	;	(4,504,742) \$	(915,119)	•	\$ (428,633)	\$ (15,26)
Eliminate ESM, FAC, ECR from rate refund acct.			R01	1,630,147 \$	295,220	•	\$ 149,529	\$ 6,106
Eliminate DSM Revenue		DSMREV		(2,942,935) \$	(1,508,819)	•	\$ (222,733)	\$ (10,743
Year end adjustment		YREND		251,167 \$	(417,181)	•	\$ 815,724	
Merger savings			RO1	(2,564,269) \$	(464,390)	•	\$ (235,213)	(609'6)
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) \$	693,448,939 \$	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 fact Allocates CSR Credits on SCP

KENTUCKY UTILITIES
Cust of Service Study
Class Allucation

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Combined Light & Power LPP LPP	Large Commilind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLES	High Load Factor Primary HLFP
Control of Contribute Commons of Dec Commons										ŀ
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	5 64.896	\$ 18.376	12 117	5 22 783
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (8,518,255)	\$	(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	٠,	\$ 2,524	\$ 194,737	\$ 94.994	53,661	\$ 62.851
Remove ECR revenues		ECRREV		\$ (5,734,057)	•••	\$ (19,498)	\$ (2,401,012)	\$ (688,721)	\$ (446.972)	\$ (838 688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$ 4,133,949	•	\$ 14,085	1,735,487	\$ 492,058	316,548	\$ 606,165
Remove off-system ECR revenues			PLPPT	\$ (167,224)	••	\$ (583)	(777.97)	\$ (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)
Ciminate ESM revenues collected		ESMREV		\$ (1,152,341)	₽	\$ (3,814)	(474,129)	\$ (137,016)	(89,283)	\$ (160,868)
Eliminate ESM, FAC, ECR from rate refund acct.			<b>R</b> 04	\$ 373,990	•	1,271	156,727	\$ 44,379	\$ 29,263	\$ 55.022
Eliminate DSM Revenue		DSMREV		\$ (98,441)	•	(472)			•	
Year end adjustment		YREND		\$ (597,774)	\$ 117,795	\$ 273,166				\$ (537.561)
Merger savings			R01	\$ (588,297)	<b>57</b>	\$ (2,000)	\$ (246,535)	\$ (69,809)	\$ (46,031)	\$ (86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			\$ (42,856)		(64, 186)	\$ (120,793)		
VDI Amortization and Surcredit			VDTREV	19,479	\$ 4,382	99	8,140	\$ 2,334	1,514	\$ 2,828
Total Pro-Forma Operating Revenue			(13,497,703) \$	159,833,741	\$ 35,818,617	\$ 816,116	5 66,869,408	\$ 18,829,635	12,492,305	\$ 22,947,608

KENTUCKY UTILITIES Cost of Service Study Class Allocation

Description	Ŗ	Name	Allocation Vector	Goal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mina 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 unbilted revenue Adjustment for Mismatch in funt consequence			R01	\$ 4,976	3,978	\$ 1,924	\$ 4.748	\$ 432
Adjustment to Refer that the cost recovery			Energy	\$ (268,036)	\$ (234,296)	\$ (118,074) \$	(276 483)	
Remove FOR revenues		FACRI		\$ 12,843	\$ 13,496	\$ 2,865 \$	11.438	\$ 179
Admissage to segan Full Course By Bull 1		ECRREV		\$ (182,407)	\$ (145,445)	\$ (70,105) \$	(172,666)	•
Remove off-custom DOR removes		ECRR		\$ 132,466	\$ 105,333	5 51,614 \$	127.078	, ,,
Finitiate brokesed soles			PLPPT	\$ (5,165)	\$ (4,531)	\$ (2,123) \$	(5.583)	• •
Eliminate HSM revenues collected			Energy	\$ (168,612)	\$ (147,387)	\$ (74,276) \$	(173.926)	67
Eliminate ESM FAC FOR from rate refused and		FOMREV		(33,089)	\$ (25,314)	\$ (11,418) \$	(28,011)	. 49
Eliminate DSM Revenue			בחא	12,018	909'6	\$ 4,648 \$	11 466	•
Vent and advistment		DOMINE V		,		ν ,	,	•
Mander savinge		YREND		\$ (234,645)	\$ (275,257)		(703,778)	•
Adjustment for rate switching, increased internatible greative		0.4700141	<b>K01</b>	\$ (18,905)	\$ (15,111)	\$ (7,311) \$	(18,037)	(1,639)
VDT Amortization and Surcredit		200	VOTREV	\$ 619	\$ 493	\$ 236 \$	579	•1
Total Pro-Forma Operating Revenue			• 1507 704 647					
•			201, 184,017	. 585(008,4 e (	3,840,839	\$ 1,984,106 \$	4,207,348	\$ 427,775

KENTUCKY UTILITIES Cost of Service Study Class Altocation

Description	Ref	Name	Affocation Vector	All Elcetric School	Efectric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Private Outdoor Lighting Lighting Dec St Lt PO 1 f	Private Outdoor Lighting PO Lf	Customer Outdoor Lighting	Special
											-
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	673	•	\$ 5,345	\$ 790	5 6 178	\$ 206	16 135
Adjustment for Mismatch in their cost recovery			Energy	\$ (217,983)	(37,387)	\$ (37,004)	\$ (87,643)	(2,009)	(135,957)	\$ (21,106) \$	(1.007.994)
Demonstrate to remediate the rest of the Roll-in		FACR		\$ 9,719	49	•	(1.021)	(47)	(3.573)	\$ (2.582) \$	45.827
Adjustment to reflect End Course of DOD Don't		CCRREV		\$ (143,373)	<del>6/)</del>	•>	\$ (196,772)	\$ (29,280)	(227,715)	\$ (33,264) \$	(691,956)
Remove off-evelon FOB revenue		ECX Z		5 104,270	49	•	\$ 144,134	\$ 21,362	166,721	\$ 24.687 \$	493,730
First of the state			4	5 (4.931	en ·	s,	(1,650)	(†6) \$	(2,562)	\$ (388) \$	(22.541)
Firmingth Fight payenges anti-conduction			thergy	\$ (137,125)	so.		\$ (55,133)	\$ (3,151)	(85,526)	\$ (13,277) \$	(634,093)
Filminate FSM FAC FC0 form out and and		ESMKEV	3	\$ (21,999)	υ,	<b>~</b>	\$ (37,564)	\$ (5,964)	(43,590)	\$ (6,279) \$	(133,593)
Firmingto Down Devices.		0	9	9,445	<b>69</b>	ur.	\$ 12,909	\$ 1,908	14,921	\$ 2,192 \$	39.449
Vege and adjustment		DOMREY Control		,	·	, ••					. •
Marsa sociona		YKEND	i	, 47	·		\$ 16,889	\$ 12,240	71,430	\$ (19.194) \$	,
Adjustment for rate sustehing increased intermedials and dis		1	K01	\$ (14,857)	\$ (2,564)	\$ (2,722)	\$ (20,307)	\$ (3,001) \$	(23,470)	\$ (3,447) \$	(62.054)
VDT Amortization and Surrealit		WY HAY	Č G H	•	•						(2,777,732)
			אַבורא	481		90	\$ 667	\$ 102 \$	802	\$ 115 S	2,335
Total Pro-Forma Operating Revenue			(13,497,703)	3) \$ 4,051,813	\$ 684,657	\$ 746,024	\$ 5,421,077	\$ 807,012 \$	6,328,527	\$ 898,820 \$	14,115,482

Class Allocation 12 Months Ended September 30, 2003

		Allocation		Tota	Residential	All Electric Residential	Secondary	General Service Primary
Description	Name	Vector		System	Rate RS	Rate FERS	GSS	GSP
Operating Expenses								
Operation and Maintenance Expenses				548 721 322 \$	106 395 052	115 314 028	\$ 64 174 227	1 487 883
Depreciation and Amortization Expenses			•		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	15,984
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	69	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)	806)
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		OET		2,091,278 \$	461,982	549,582	\$ 201,269	5 4,777
Laboradustment		L84		1,002,076 \$	247,020	\$ 252,112	\$ 100,391	2,144
Medical (Expense (See Functional Assignment)		1		•			•	
Supering the period of the per		6		, , , , , , , , ,	F 70 6077	, (()		
Cionn daniage adjustment Elimicate advertings expanses /See Encotional Assisonand		SUACE		<b>♦</b> ( <b>♦</b> 1.0'€/ <b>♦</b> )	(/10/991)	(C70'001)	(0)0'60)	(100)
Adjustment for sexuality expenses (oder runnblish Assignment)		200			, V 554	11160	. F3E1	
Augustination of rate case expenses		E S		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)	(Jument)	DMT				,	,	
Adjustment for VDT net savings to shareholders		Te,		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 \$	1,853,281	\$ 2,216,596	\$ 811,765	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 comorate lease expense		<u> </u>						
Adjustment for OMIT Nov expense		10010		1 050 870	21,003	485.210	1,043	725
Adjustment for ice chom		TAC.		(F 277 23E)	(4.874.535)	(1710.617)	(774.008)	(6.178)
Adjustment for management and if he		THO C		163 982	31.798	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)
VD7 Amortization and Surcredit		VDTREV		(466.280) \$	(84.947)	\$ (88.836)	\$ (42.731)	(1981)
Total Expense Adjustments		!		(35,904,718)	(5,820,456)	(4,766,255)	(1,444,794)	(126,962)
Total Operating Expenses	TOE		49	633,180,928 \$	121,678,365	\$ 133,986,084	\$ 56,525,369	1,959,223
Net Operating Income (Adjusted)			•	60,269,011 \$	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%	%06.5	19.92%

Description	Name	Alfocation Vector	Comb	Combined Light & C Power LPS	Combined Light & C Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LGIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Operating Expenses										
Operation and Maintenance Expenses Depreciation and Americation Expenses Rentiation Create and American Expenses			49	118,555,031 \$ 15,264,780	26,795,526 \$	396,971 43,985	54,387,992 6,274,319	1,547,803	\$ 9,976,981 1,141,137	\$ 18,800,670 2,128,807
Property Original and December Lypersays Property Taxes Other Taxes		NPT		1,433,504	306,242	4,177	592,905	(230,863)	107,650	201,249
Gain Disposition of Allowances				(58,459)	(14,367)	2,931 (217)	415,043 (29,956)	103,202 (8,707)	75,545 (5,503)	141,217 (10,413)
state and Federal Income Taxes Specific Assignment of Curtailable Service Rider Credit		TXINCPF	<del>69</del>	11,964,223 \$	2,866,184 \$ (181,381)	91,969	3,804,648 (771,654)	1,463,006	\$ 772,961	\$ 1,368,681
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: Fliminate mirrnatch in fuel onet recovery		Ü	•	7 544 6687	6 (0.00	100				
Remove ECR expenses		ECRREV	, ,,	(56,898)	(12,809) \$	(193)	(23,825)	(0.834)	(4.435)	\$ (1,337,916) \$ (8,322)
Eliminate brokered sales expenses		Energy	49 4	(5,869,813) \$	(1,442,579) \$	(21,787)	(3,007,876)	(874,249)	(552,511)	\$ (1,045,554)
Year end adjustment		YREND	A 6A	(360,354)	71,010 \$	(473)	, ,	, ,	,	\$ (324.056)
Depreciation adjustment		OET	₩.	***	••			,	,	
Copression of charge in depted little Labor adjustment		LBT	A 69	361,214 S	32.574 \$	1,041	148,471 5	36,626	27,003	5 50,374
Medical Expense (See Functional Assignment) Adjustment for mention/net radii banafi / See Eurotional Accidentation		<u> </u>		•	•					
Storm damage adjustment		SDALL	n 41	(42.357) \$	(5,656) \$	, ,	(9.718)	, ,	(2.245)	(3,009)
Eliminate advertising expenses (See Functional Assignment)		REVUC	<b>\$</b>		•	,		,		
Adjustment for amortization of ESM audit expense Amortization of rate case expenses		ROT	<b>69</b> 64	13,383 \$	3,000 \$	45	5.608	1,588	1,047	1,969
Remove Amortization of one-utility costs (See Functional Assignment)		LBT	**	, es	* • • • • • • • • • • • • • • • • • • •	?	20.1	77.6	507.5	B10,21
Adjustment for injuries and damages account 925 (See Functional Assignment)	tent)	TMO	<b>69</b> (	•	, ;					
Adjustment for merger savings to snareholders Adjustment for merger savings		181	v» v	3 394 708 4	94 107 \$	1,266	182,338 \$	46,544	34,157	\$ 62,810
Adjustment for merger amortization expenses		Let		(487,943) \$	(88,630) \$	(1,192)	(171,726) \$	(43,835)	(32,169)	\$ (59,155)
Adjustment for MISO schedule 10 expenses		PLTRT	49 -	181,639 \$	42,444 \$	634	83,395 \$	22,494	14,754	\$ 28,491
Adjustment for lift staff reduction		DET	<b>.</b> ,	1,456,863 \$	309,582 \$	4,198	598,818 \$	147,722	108,910	203,172
Adjustment to remove Alstom expenses		PLPPT	• ••	(673,490) \$	(157,374) \$	(2,350)	(309,217)	(83,406) 3	(54,707)	(105,639)
Adjustment for corporate lease expense		181	₩.	\$	***					
Adjustment for OMU Nox expense		PI PPT	n v	27,620 \$	5,192 \$	94 1	11,575 \$	3,278	2,161	5 4,064
Adjustment for ice storm		SDALL	, v,	(472,573) \$	(63,098)	2	(108,425) \$	917'76	(25.051)	(33.566)
Adjustment for management audit fee		OMT	<b>59</b> 6	35,429 \$	8,008	61.	16,254 \$	4,525	2,982	5,518
VOT Amortization and Succeeding		VATPE	<b>9</b> 4	(164,991) \$	(39,950) \$	(607)	(81,996) \$	(23,318) \$	(14,958)	(28,356)
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	<b>T</b> 0E		69	138,112,005 \$	30,699,881 \$	664,784	59,648,521 \$	16,237,976	11,054,549	\$ 20,377,504
Net Operating income (Adjusted)			ø	21,721,736 \$	5,118,735 \$	151,332	7,220,887 \$	2,591,659 \$	1,437,756	\$ 2,570,104
Not 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				1760 0	40 20W	/90 E09/	7177.4	40.040/	405.4	1
				200.0	1/24/21	0/ 0/197	0/ 4-4-7	( v 1 e o r	0.1076	1.0078

Exhibit (SJB-2) Page 6 of 8

KENTUCKY UTILITIES Cost of Service Study Class Albecation

		:	Coal M	Coal Mining Power	Coal Mining Power	Large Power Mine		Combination Off-	n Off.
Description	Ref Name	Allocation Vector	•	Primary MPP	Transmission MPT	Power TOD Primary LMPP	Transmission LMPT	Peak	
Operating Expenses									
Operation and Maintenance Expenses			₽7	3 428 058	2 9 16 973	1 781 151	3 476 666		174 250
Depreciation and Amortization Expenses					Ī	•	,		274 136
Argunalofy Credits and Accretion Expenses				(57,578)	(50,518)				(7.097)
Other Taxes		NPT		41 043	32,334	17,056			24,659
Gain Disposition of Allowances				28,800	22,689				7,303
State and Federal Income Taxes		TXINGPE	64	532 175	(1,500a)		•	•	(193)
Specific Assignment of Curtailable Service Rider Credit		>	•	200	976,106	02,80	000,000	_	444,979)
Allocation of Curtailable Service Rider Credits		SCP	<b>↔</b>	26,400	\$ 23,067	\$ 10,168	\$ 29,038	<b>99</b>	4.940
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	<del>69</del>	(236,347)	(206,595)	\$ (115)	(243 795)	44	(24.816)
Remove ECR expenses		ECRREV	69	(1,810) \$	(1,443)	· <b>5</b>			(156)
Calcande Drokered sales expenses		Energy	69	(184,700) \$	(161,450)	\$ (81,363)		· 143	(19,393)
Very end adjustment		DSMREV	<b>69</b> 1			,	•	s,	•
Depreciation adjustment		YKEND	<b>.</b>	(141,450)	(165,932)	·	\$ (424,256)	*	(13,589)
Adjustment for change in depreciation rate			÷ •	10 206 01	900			<b>.</b>	, ;
Labor adjustment		197		4 273	3,325	1810	760 F	A .	704.0
Medical Expense (See Functional Assignment)				•		20.	•	•	747
Adjustment for pension/post retir benefit (See Functional Assignment)	nment)	LBT	49				,	69	,
Storm damage adjustment		SDALL	ø	(860)		\$ (395)		· ••	(3,556)
Christiate advertising expenses (See Functional Assignment) Adjustment for amortivation of Fold andit account		REVUC	<del>69</del> (	, .			<b>5</b>	₩	
Amonization of rate case expenses		5 E	n u	430 6	344	₩.	<b>ب</b>	<i>د</i> ه .	37
Remove Amortization of one-utility costs (See Functional Assignment)	nment)	IBT		70.75	70	A 6	,,	<i>/</i> ) (	40
Adjustment for injuries and damages account 925 (See Functional Assignment)	nal Assignment)	OMT.	9 69				, , ,		,
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	• •	• •	80.293
Adjustment for merger amortization expenses		LBT	••	(11,625) \$	(9,048)	•		• 69	(11,541)
Adjustment for MISO schedule 10 expenses		PLTRT	•	5,610 \$	4,922	•	•••		691
Adjustment for effect of accounting change		DET	<b>6</b>	41,526 \$	32,487	\$ 17,268	••	49	5,163
Adjustment to penove Alston expenses		181	19 1	(2,565) \$	(1,997)	(1,087)	••	<b>s</b> \$	(2,547)
Adjustment for corporate lease expense		144	<i>^</i> > 4	\$ (nna'nz)	(18,250)	\$ (8,552)	\$ (22,486)	∽ .	2,564)
Adjustment for sales tax refund		9 6	n .		, ,	, ,		۰ د	, 1
Adjustment for OMU Nox expense		PLPPT	<b>,</b> ,	13 037	11 438	243	24,004,	<b>.</b>	12
Adjustment for ice storm		SDALI	• •/:	2 (598)	2	0,000	~ <b>.</b>	÷ •	700,0
Adjustment for management audit fee		OMT	• • •	1,024 \$	872	5 443		o •o	(58,073)
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	u	(5,092) \$	(4,454)	\$ (2,206)			(571)
VDT Amortization and Surgredit Total Expense Adjustments		VDTREV	s,	(3,381) \$	(2,696)	\$ (1,291)	\$ (3,165)	•	(586)
				(07)'(544)	(400,004)	(136,629)			14,263
Total Operating Expenses	TOE		*	3,986,444 \$	3,209,576	\$ 1,699,508	\$ 3,553,714	•	1,057,389
Net Operating Income (Adjusted)			•	914,249 \$	631,263	\$ 284,498	\$ 653,634	۰	(629,614)
Net Cost Rate Base			۰,	6,738,314 \$	5,192,612	\$ 2,812,219	\$ 6,367,053	ν 4	4,518,731
Date of Cotton									
			_	13.57%	12 16%	40 424	/1100 U.F		/40.00

Description	Ref Name	Allocation	All Elcet	All Elcetric School AES	Heating Rider	Water Pumping M	Street Lighting	Lighting Lighting	Lighting	Outdoor Lighting	
Operating Expenses								10 230	2	100	Contracts
Operation and Maintenance Expenses											
Depreciation and Amortization Expenses			v9	3,150,511 \$	590,795	\$ 602,027	\$ 3,408,568	\$ 323,214	\$ 2,924,595	\$ 462.005	\$ 13.356.738
Regulatory Credits and Accretion Expenses				514,052	93,849		1,853,401	214,910	932,522	149,201	•>
Property Taxes		NPT		47 953	(8,429)		(18,394)	(1,051)	(28,558)	(4,433)	•
				33,640	2,5		165,697	19,146	84,062	13,444	••
Gain Disposition of Allowances				(1.496)	62.0		116,130	13,434	58,987	9,43	٠,
State and Federal Income Taxes		TXINCPF	v	177 480	(107)		(901)	(34)	(633)	(145)	s
Specific Assignment of Curtailable Service Rider Credit			•	e 604'771	27)'6	(1,865)	\$ (358,755)	\$ 50,715 \$	814,753	\$ 94,631	*
Allocation of Curtailable Service Rider Credits		SCP	v	28.76.2			,	•	•	•	\$ (3,630,403)
		<u> </u>	,	50,00	6,563	5 6,225	,			,	\$ 161,576
Adjustments to Operating Expenses:											
Eliminale mismatch in fuel cost recovery		Energy	u	(100 011)	100 000						
Remove ECR expenses		ECRREV	. v	(122,21)	(35,967)	(32,629)	(77,281)	(4,417) \$	(119,883)	\$ (18,611)	s
Eliminate brokered sales expenses		Energy	• •	(150,209)	(257)	(707)	(1,853)	(291)	(2,260)	\$ (330)	<b>.</b>
Curtinate DSM Expenses		DSMREV		(007,001)	(60,100)	(664,62)	(60,394)	(3,452) \$	(93'886)	\$ (14,544)	(694,595)
leaf end adjustment		YREND	69		/11 ORE)			. !		,	, •••
Depreciation adjustment		DET	• ••	,	(000:		191.02	S 875.7	43,060	\$ (11,571)	•
Adjustment for change in depreciation rate		DET	₩.	12.164 \$	2 221	3.208	73 057	, ,			,
		LBT	•	4 860 \$	1081	1254	10,037	00000	22,056	3,531	\$ 41,032
Adjustment for pension/post section 1	,						10000	e #277	10,,00	1,724	5,859
Storm damage editorations retir benefit (See Functional Assignment)	<del>c</del>	LBT	'n	,	•					•	
Eliminate advertising expenses / Cop Emptional Application		SDALL	₩	(2,563) \$	(552)	\$ (1,032)	(3.854)	(302)	(4.004)	. 000	<i>a</i> •
Adjustment for amortization of FSM and the evance		REVUC	<b>₩</b>	,		. · ·			(100,1)	600)	(7 6)
Amortization of rate case expenses		103	۰ ده	338	58	\$ 62.5	\$ 462 \$	100	534		
Remove Amortization of one-utility casts (See Functional Assignment)	=	- E	,,	2,024 \$	379	387	2,189 \$	\$ 208	1.879	297	
Adjustment for injuries and damages account 925 (See Functional Assignment)	n) Seionmooth	- t	<b>99</b> (				,				<b>+</b> 4
Adjustment for VDT net savings to shareholders	asigninicia)	<u> </u>	,,		, ;		,		,	,	
Adjustment for merger savings		6 h	<i>.</i>	14,041 \$	3,122	3,624	\$ 57,308 \$	6,482 \$	31,087	4.981	5 45.816
Adjustment for merger amortization expenses		- E	9 v	91,999	20,454	23,742	375,496 \$	42,475 \$	203,690	32,637	\$ 300,200
Adjustment for MISO schedule 10 expenses		PITRI	, <b>.</b>	( 13,224) <b>3</b>	(2,940)	(3,413)	(53,972) \$	(6,105) \$	(29,278)	(4,691)	\$ (43,150)
Adjustment for effect of accounting change		DET		490.00	2 0	7,116 5	1,792	102 \$	2,782	432	\$ 24,483
Adjustment for IT staff reduction		LBT	• •	(7.918)	106,0	1, 1,20	1/5,888	20,511	88,999	14,240	\$ 165,490
Adjustment to remove Alstorn expenses		PLPPT	• •	(19.859)	(940)	(105)	8 (LL8,LL)	(1,347) \$	(6,461)	(1,035)	\$ (9,522)
Adjustment for corporate lease expense		LBT	•	\$	(antic)	(501'+)	(c+a'a)	\$ (ORE)	(10,317) \$	(1,602)	\$ (90,781)
		R01	•	898	120	128	053			. ;	,
Adjustment for the storm		PLPPT	6/7	12,447 \$	2,135	2.594 \$	200 4	4 866	1 102	162	2,913
Adjustment for management and the		SDALL	••	(58,599) \$	(6,163)	(11,514) \$	(43,003)	\$ (836.6)	0,460	1,004	56,898
Adjustment for Retrement of Green River Units 1.8.2		CMI	۰,	942 \$	177	180 \$	\$ 610,1	97 \$	874 \$	138	(10,140)
VDT Amortization and Surcredit		CMPP	<b>19</b> 6	(4,423) \$	(759)	\$ (222)	\$ (1,569) \$	\$ (06)	(2.434) \$	(378)	3,332
Total Expense Adjustments		אַנייַ	^	(2,662) \$	(445)	\$ (490)	(3,643) \$	\$ (252)	(4,383) \$	(630)	\$ (12,760)
				(564, 103)	(177'06)	(31,273)	429,923	64,722	94,866	(1,939)	(1,111,155)
Folal Operating Expenses	10E		<b>€</b>	3,676,265 \$	655,878	720,273 \$	5,595,768 \$	685,056 \$	4.880.294 \$	727 198	11 764 204
Net Operating Income (Adjusted)			•	375.547 \$	98 778	25.751	• (100 1/1)				•
Net Cost Rate Base						2	* (:Bo'*).)	\$ 068,121	1,448,234 \$	176,622	\$ 2,321,278
			ø	8,113,397 \$	1,490,422	2,176,766 \$	31,905,511 \$	3,716,038 \$	15,836,075	2.518.660	\$ 28 400 496
Rate of Return				/61.07							
				4.53%	1.83%	1.18%	70.55%	3 280€	/8370		

Exhibit (SJB-2) Page 8 of 8

BIP Prod Trans Allocation Corrected Dramad 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	)	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	Ĵ	2003-00434

EXHIBIT (SJB-3)

	i	-	Allocation	Total	Residential	All Electric Residential	General Service Secondary	General Service Primary
Describition	ž e	Name	Vector	System	Kate KS	Kate TCKS	688	desp.
Cost of Service Summary - Pro-Forma								
Operating Revenues								
Total Operating Revenue - Actual			•	768,801,159 \$	138,098,905	5 \$ 147,748,544	\$ 69,494,810	\$ 2,833,869
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	\$ 000,579	122,243	€9	\$ 61,916	\$ 2,528
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728) \$	(5,723,27	\$	\$ (2,393,685)	\$ (109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	3	1,417,623 \$	181,543	•	\$ 96,991	
Remove ECR revenues		ECRREV		(25,039,979) \$	(4,562,37	•	\$ (2,291,842)	<b>4</b> 7
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813 \$	3,208,16	45	\$ 1,547,196	s
Remove off-system ECR revenues			PLPPT	(776,418) \$	(138,21	3) \$ (191,523)	\$ (71,748)	(3,040)
Eliminale brokered sales			Energy	(22,575,669) \$	(3,600,300	•	\$ (1,505,781)	<b>د</b>
Eliminate ESM revenues collected		ESMREV		(4,604 742) \$	(915,119	es.	\$ (428,633)	•
Eliminate ESM,FAC,ECR from rate refund acct.			RO1	1,630,147 \$	295,22(	•	\$ 149,529	•
Eliminate DSM Revenue		DSMREV		(2,942,935) \$	(1,508,819)		\$ (222,733)	•
Year and adjustment		YREND		251 167 \$	(417 181)	1,771,704	\$ 815,724	•5
Merger savings			801	(2,564,269) \$	(464,390	•	\$ (235,213)	\$ (9,603)
Adjustment for rate switching, increased interruptible credit		RATESW		(3,005,567)				
VDT Amortization and Surcredit			VDTREV	85,337 \$	15,547	7 \$ 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

KENTUCKY UTLITIES Cust of Service Study Class Allocation

Description	Ref Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Combined Light & Power LPP LPP	Large Committed TOD Primary LCIP	Large Commilnd TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
		•							
Gost of Service Summary ~ Pro-Forma									
Operating Revenues									
Total Operating Revenue - Actual			\$ 175,693,980	\$ 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)	\$ (31,617)	\$ (4,365,021)	\$ (1.2	\$ (801,803)	\$ (1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in	FACRI		\$ 365,749	••	\$ 2,524	\$ 194,737	•	\$ 53,661	\$ 62,851
Remove ECR revenues	ECRRE	2	\$ (5,734,057	u+>		\$ (2,401,012)	•	\$ (446,972)	\$ (838,688)
Adjustment to reflect Full Year of ECR Roll-in	ECRR		\$ 4,133,946	40	••	\$ 1,735,487	s	316,548	\$ 606,165
Remove off-system ECR revenues		PLPPT	\$ (156,106	<del>67</del>	•	\$ (70,555)	\$ (19,496)	\$ (12,090)	\$ (22,844)
Eliminate brokered sales		Energy	\$ (5,358,526	•	<del>1/3</del>	\$ (2,745,877)	•	\$ (504,385)	\$ (954,481)
Eliminate ESM revenues collected	ESMRE		\$ (1,152,341	<b></b>	•	\$ (474, 129)	\$ (137,016)	\$ (89,283)	\$ (160,668)
Eliminate ESM,FAC,ECR from rate refund acct.		R01	373,990	40		\$ 156,727	•	\$ 29,263	\$ 55,022
Eliminate DSM Revenue	DSMREV	≥.	\$ (98,441	دء	•		•		
Year end adjustment	YREND		\$ (597,774)	<del>67</del>	\$ 273 166		,	•	\$ (537,561)
Merger savings		R01	\$ (588,297)	۰,	₩.	\$ (246,535)	(69,803)	\$ (46,031)	\$ (86,551)
Adjustment for rate switching, increased interruptible credit	RATESW	*		\$ (42,856)		\$ (64,186)	•		
VDT Amortization and Surpredit		VDTREV	\$ 19,479	s,	66	\$ 8,140	<b>.</b>	\$ 1,514	\$ 2,828
Total Pro-Forma Operating Revenue		(13,506,972) \$	2) \$ 159,538,209	\$ 35,787,997	\$ 816,653	\$ 66,704,024	\$ 18,797,384	\$ 12,452,517	\$ 22,857,613

KENTUCKY UTILITIES
Cust of Service Study
Class Albocation

								Large Power Mine	
			Alforation	Coally	Mining Power	Coal Mining Power Coal Mining Power Primary	Large Power Mine	Power TOD Transmission	Combination Off-
Description	Ref	Name	Vector	•	МРР	MPT	LMPP	LMPT	CWH
Cost of Service Summary Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual				69	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)	•
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)	(172,566)	•
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		**	132.466	105,333	\$ 51,614	127,076	49
Remove off-system ECR revenues			PLPPŢ	₩,	(5,481)	(4,328)	\$ (2,496)	(5,692)	•
Eliminate brokered sales			Energy	49	(168,612) \$	(147,387)	\$ (74,276)	(173,926)	•
Eliminate ESM revenues collected		ESMREV		6	(33,089) \$	(25,314)	\$ (11,418)	(28,011)	•
Eliminate ESM,FAC,ECR from rate refund acct.			<b>201</b>	•>	12,018 \$	909'6	\$ 4,648	11,456	•
Eliminate DSM Revenue		DSMREV		4	•	. •		,	•
Year end adjustment		YREND		es.	(234,645)	(275,257)		(703,778)	\$ (22,542)
Merger savings			R01	<b>v</b> s	(18,905) \$	(15,111)	\$ (7,311) \$	(18,037)	\$ (1,639)
Adjustment for rate switching, increased interruptible credit		RATESW					•		
VDT Amortization and Surcredit			VDTREV	v)	619 \$	493	\$ 236	579	\$ 52
Total Pro-Forma Operating Revenue			(13,506,972)	2) \$	4,909,115	3,835,436	\$ 1,994,007	4,210,238	\$ 432,121

					10 4 10 4 10 4 10						
Description	Ref	Name	Allocation Vector	All Elcatric School	Heating Rider	Water Pumping M	Street Lighting St Lt	Lighting Lighting Dec St Lt PO Lt	Lighting POLt	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 \$	18,776,539
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	3,911	s	\$ 717	5,345	\$ 790	\$ 6.178	\$ 206 \$	16.335
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (217,983)	\$ (37,387)	\$ (37,004)	\$ (87,643)	(2,009)	\$ (135,957)	\$ (21,106) \$	(1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 9,719	sA.	1,457	\$ (1,021)	\$ (4E)	(3,573)	\$ (2,582) \$	45,827
Remove ECR revenues		ECRREV		\$ (143,373)	47	\$ (26,381)	\$ (196,772)	\$ (29,280)	\$ (227,715)	\$ (33,264) \$	(691,956)
Adjustment to reflect Full Year of ECR Rol⊬in		ECRRI		\$ 104,270	ser,	\$ 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)	'n	\$ (23,278)	\$ (55,133)	(3,151)	(85,526)	\$ (13,277) \$	(634,093)
Eliminata ESM revenues collected		ESMREV		\$ (21,999)	•••	\$ (4,856)	(37,564)	\$ (5,964)	(43,690)	\$ (6,279) \$	(133,593)
Eliminate ESM, FAC, ECR from rate refund acct.			R01	9,445	s/s	1,730	12,909	1,908	14,921	\$ 2,192 \$	39,448
Circinate DSM Revenue		DSMREV			49	•					. •
Year end adjustment		YREND		•	₩	•	16,889	\$ 12,240	71,430	\$ (19,194) \$	,
Merger savings			203	\$ (14,857)	€9	\$ (2,722)	\$ (20,307)	(3,001)	(23,470)	\$ (3,447) \$	(62,054)
Adjustment for rate switching, increased interruptible credit		RATESW								•	(2,777,732)
V.U.I. Amortization and Surcredit			VDTREV	\$ 491	81	06	299 \$	\$ 102	\$ 802	\$ 115 \$	2,335
Total Pro-Forms Operating Revenue			(13,506,972)	3) \$ 4,085,470	\$ 690,430	\$ 738,418	\$ 5,430,388	\$ 807,544 \$	6,338,611	\$ 900,385 \$	14,046,931

Description Ref				1010	Lesidential Land				
	Name	Vector		System	Rate RS	Rate FERS	RS	GSS	des.
Operating Expenses									
			•	4 500 702 073	407 522 540		470 70E e	46 005 056	1 655 418
Operation and Maintenance Expenses			4	540,121,522 a	20.245,919	,	23.172.879		
Pacifical Credits and Acception Expenses				(R 656 053)	(1540 948)		(2 135 228)	(799 894)	(33,890)
		FOX		B 211 A50	1 850 240		2 147 581	888 762	74 457
Ottoer Taxes				5 761 996	1.305.335		1,506,949	623.647	17,162
Once District of allocations				1980 380/	(770 05)		(45,228)	(16.427)	(750)
Chair Disposition of Archaelton		FOUNTAIN		26.016.696 €	(1873.728)	v	(4.042.011) \$	2 599 323 \$	287 430
Consider Applications of Control Control Dides Control				4 582 475)	24 (21 (21))	•		) i	
Special Casagninari of Cultariable Service Nice: Cledit		1000	e	4 582 475 e	080 700		771 044 8	440 467	11 972
Aidcation of Curatiable beings rider Creams		200	9	4.002.47	954.950			701.611	
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) \$	(906)
Filmingle brokened sales expenses		TI PERSON		(24 729 742) \$	(3.943.832		(4.541,167) \$	(1,649,456) \$	(75,349)
Timinate DSM Evonese		DSMREV		(2 946 471) \$	(1.510.632		(1.090.913) \$	(223,001) \$	(10,756
Vegraph adjustment		VEEND.		151 410	(251.488		1 068 029 \$	491740 \$	
					2011				•
Adjustment for about it doesnoted and		5 6		2 004 278	478 362		548 346 C	\$ 578 766	A 140
		i i		1 002 076	250 942		251816 5	106.754 \$	2.471
		é		0.00,200,1	215,027	•	20,10		í
Medical Expanse (See Functional Assignment)		10		•				,	•
Adjustment to pension/post rent penetit (See Functional Assignment)	,	9 6			(270 047)	• •	4 (302.23)	(E0 37E)	(PY4)
		7 2 2 2		(*IO,014)	/ (O'00/)	• •	6 (070,001)	• (C 15 (EQ)	20
Eliminate adventsing expenses (See Functional Assignment)		ZEVOC Des			10 564	۰.	1 1 2 2	, ער	218
Adjustment for amortization of from audit expense		105		22,22,00	10,364	•	77.007	9 0000	1061
Amortization of rate case expenses		C.W.		4 054,255	400,80	•	200,7	* 871 DC	200.
Nemove Amortization of one-utility costs (See Functional Assignment)		- i		•		<i>4</i> •	•	,	•
Adjustment for injuries and damages account 925 (See Functional Assignment)	signment)	E S				۰,			
Adjustment for VDT net savings to shareholders		9		\$ 000,088,2	2/6/42/	•	DR4",77	514,505	101
Adjustment for merger savings		[B]		18,968,825 \$	4,750,213	**	, /bb, /b2 \$	\$ 108'0Z0'7	9,0
Adjustment for merger amortization expenses		LBT		(2,726,510) \$	(682,78)	ø•	6 (/cl/cpa)	4 (580,463)	(27,10)
Adjustment for MISO schedule 10 expenses		PLIRI		843,344 \$	281,061	•	208,032	\$ 708')	1000
Adjustment for effect of accounting change		DET		8,434,618 \$	1,929,348		\$ /09/11/2/2	\$ 796'816	40,164
Adjustment for IT staff reduction		T81		(601,682) \$	(150,674	<b>1</b>	\$ (861,161)	(64,099)	(0.04)
Adjustment to remove Alstom expenses		FLPPT		(3,126,995) \$	(556,667)	•	(771,350) 5	(288,961) \$	(12,24;
Adjustment for corporate lease expense		ĽBT		•••		••	,		
Adjustment for sales tax refund		<b>203</b>		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)	<b>~</b> >	(1,710,617)	(174,008) \$	(6,178)
Adjustment for management audit fee		TMO		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)
VOT Americation and Surceedit		VOTREV		(466.280) \$	(84.947)	**	(88,836) \$	(42,731) \$	(1,66
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	w <sub>2</sub>	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 Aste Base			•	1,412,033,543 \$	328,764,003	s,	371,073,844 \$	155,533,255 \$	3,988,815
Rate of Return			ŀ	4.27%	0.51%		798.0	1.88%	12.51%

Operating Expenses  Deperation and Maintenance Expenses  Deperation and Maintenance Expenses  Regulatory Checks and Annortization Expenses  Other Taxes  Adjustment of Curtainlate Service Rider Credit  Adjustment to Curtainlate Service Rider Credit  Adjustment to Curtainlate Service Rider Credit  Adjustment to Curtainlate Service Rider Credit  Adjustment of Curtainlate Service Rider Credit  Adjustment for charge in dependation rate  DET  Adjustment for charge in dependation rate  DET  Adjustment for charge in dependation rate  DET  Adjustment for charge in dependation rate  Adjustment for medical charge and demandes section of Expenses  Adjustment for medical charge in State Check of Service Rider Charge in Service Rider and Charge and Cartainlate Service Rider and Cartainlate Service	"						
ses ses size ses size services Rider Credit service Rider Recovery Service Service Rider Recovery Service Service Recovers Serv	<b>"</b>						
strates strate	,	36 120 703 €	301342 \$	52 102 217 \$	14 674 123 \$	9.449.840	17,751,732
ter Credits  Service Rider Credit  For Credits  Service Rider Credit  For Credits  Service Rider Credit  Service Rider Credit  Soft For Credits  Soft For Cr		3,157,715	45,493	5,809,620	1,457,184	1,029,621	1,875,937
NPT  TXINGPE  THE Credits  Service Rider Gredit  Service Service Rider Service Service Rider  Titinal Assignment)  Service	,354,595 950,523 (58,459)	(422, 796)	(6,730)	(786,596)	(217,355)	(134,792)	(254,680)
fer Credits  fer C	950,523 (58 459)	298,066	4,320	548,746	138,463	97,063	177,219
ler Credits  Service Rider Credit  Service Rider Rider Rider Rider Rider Rider River Units 1 & 2  Service Rider Rider Rider Rider Rider River Units 1 & 2  Service Rider Rider Rider Rider Rider River Units 1 & 2  Service River Units 1 & 3  Service River	(58 459)	209,154	3,032	385,057	97,160	68,109	124,333
ter Credits  Service Rider Gredit  Service Service Gredit Service Functional Assignment)  Service Service Gredit Se	(	(14,367)	(217)	(29,956)	(8,707)	(5,503)	(10,413)
fer Credits ScP1	932,976 \$	3,168,662 \$	93,531	4,904,205 \$	1,705,478	\$ /L5'820'L	C05,080,1
sor recovery  Services  Se		(181,381)		(271,654)	(489,037)		• 1
osi recovery  correses  preciation rate  tional Assignment)  tenti benefit (See Functional Assignment)  perses  for ESM audit expenses  for state	\$ 650'150'	240,238 \$	4,049 \$	441,260 \$	101,228 \$	78,321 \$	145,724
Process							
askes expenses  askes expenses  askes expenses  askes expenses  and damages account 925 (See Functional Assignment)  tes and damages account 925 (See Functional Assignment)  LBT  Set and damages account 925 (See Functional Assignment)  LBT  Set and damages account 925 (See Functional Assignment)  LBT  Set and damages account 925 (See Functional Assignment)  LBT  Set and damages account 925 (See Functional Assignment)  LBT  Set and damages account 925 (See Functional Assignment)  LBT  Set and damages account 925 (See Functional Assignment)  Conduction expenses  Set and damages account 925 (See Functional Assignment)  Conduction expenses  Set and damages account 925 (See Functional Assignment)  Conduction expenses  Set and damages account 925 (See Functional Assignment)  Conduction expenses  Set and damages account 925 (See Functional Assignment)  Conduction expenses  Conduction expenses  Set and damages  Conduction expenses  Conduction	511 155) \$	71.845.959) \$	(27.879)	(3,848,951) \$	(1,118,710) \$	\$ (700,707)	(1,337,916)
### Signature ### ### ### ### ### ### ### ### ### #	۰ م	(12,809) \$	(193) \$	(23,825) \$	(6,834) \$	(4,435) \$	(8,322)
PREND  The first control of Experiment to the following that the following the followi		(1,442,579) \$	(21,787) \$	(3,007,876) \$	(874,249)	(552,511) \$	(1,045,554)
reference of the control of the cont	<b>\$</b>	(12,138) \$	(473) \$	•	•	•	. !
ment depreciation rate  DET \$  type in depreciation rate  DET \$  LBT \$  LBT \$  LBT \$  starment  LBT \$  starment clear functional Assignment)  LBT \$  RCVUC \$	(360,354) \$	71,010 \$	164,672 \$	,			(324,056)
rige in depreciation rate  The sea Functional Assignment)  LBT \$  South \$	••	•			, ,		
sier Functional Assignment)  LBT \$  sier Mopost retir benefit (See Functional Assignment)  SDALL  SD	341,564 \$	74,722 \$	1,077	137,474 \$	34,482 \$	405,42	44,59
sient post ratio benefit (See Functional Assignment)  status of expenses (See Functional Assignment)  status expenses  ge expenses (See Functional Assignment)  rest and damages account 925 (See Functional Assignment)  Construction expenses  rest and damages accounting Chapter  Set and accounting change  and factor accounting change  and factor accounting change  and factor accounting change  and factor accounting change  Alox expense  form of the factor accounting the Control of Chapter  Alox expense  form of Chapter See Functional Assignment  Control of Chapter See Functional Assignment	174,630 \$	32,087	44/	\$0,482 \$	e /80'0'	• •	500'07
stiment to be further than the signment to the further than the signment to the further than the signment to the sign of the s	•		,		,		,
REVUC   See Functional Assignment    REVUC   State	(42.357) \$	(5,656) \$		\$ (9,718)		(2,245) \$	(3,009)
Action   Companies   Compani	149				,	**	
case excenses  or of one-unity costs (See Functional Assignment)  LBT S  the savings to shareholders  LBT S  LBT S  CMT S	13,383 \$	3,000 \$	45 \$	5,608 \$	1,588 \$	1,047 \$	1,969
on of one-utifity costs (See Functional Assignment) Let and damages account 925 (See Functional Assignment) Let as and damages account 925 (See Functional Assignment) Let as a standard so shareholders Let 5 get annotization expenses Let 6 Let 7 Set 6 Let 18 Set 7 Set 7 Set 7 Set 8	73,521 \$	16,778 \$	251 \$	33,466 \$	9,393	6,070 \$	11,402
ries and danages account 925 (See Functional Assignment)  LBT 5  ger savings to shareholders  LBT 5  ger savings  ger annutization expenses  LBT 5  LBT 5  ger annutization expenses  LBT 5  LBT 5  LBT 5  Cache dult 10 expenses  LBT 5	••• •	•	•••				ŀ
Their swings to shareholders		. !		, , ,	, , ,		59 677
Purpose	504,506 5	92,699 \$	1,291	7.44.62	4 100 at	24,332	384 434
State   Control of the control of	, 303,503 8 443, 443, 8	\$ 000°, 200°	0,40°	(164 563)	(47,438) S	(30.450) \$	(55 257)
In the control of t	169.562 \$	41 197 \$	\$ 656	76,637 \$	21,177	13,133 \$	24,813
aff reduction LBT \$  PLPPT \$  PLPPT \$  Standard expenses  BT \$  Standard expense  (9	377,610 \$	301,371 \$	4,342 \$	554,467 \$	139,073 \$	\$ 39,266	179,038
ve Alstom expenses         PLPPT         \$           coals lease expense         LST         \$           coals lease expense         Rg1         \$           A Nox expense         Rg1         \$           A Nox expense         SDALL         \$           S DALL         \$         SALL           S agenent audit fee         OMT         \$           remant of Green River Units 1 & 2         OMPPT         \$           remaint of Green River Units 1 & 2         VDTREV         \$           red Surcredit         \$         134	(104,854) \$	(19,266) \$	(268) \$	(36,316) \$	(9,365)	(6,720) \$	(12,194)
LBT	(628,711) \$	(152,735) \$	(2.431) \$	(284,158) \$	(78,520) \$	(48.894) \$	(92,003)
## Star without \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	•••	. ;	, ;	. [		, ,	
J Nox expense 5 J Nox expense 5 J Nox expense 5 J Nox expenses 5 J Nox Expense 5 J Nox Expenses 5 J Nox Expenses 5 J Nox Expenses 5 J Nox Expe	27,620 \$	6,192	46	11,575	3,2/6	2,161.2	4,064
Substraint	394 051 \$	95,728 \$	1,524 \$	5 (3C) (3C)	6 517.84 6 517.84	000000	(33 566)
agement addities  CMPPT \$  VDTREV \$  TOE \$ 134	(4/2,5/3) \$	(63,098)		\$ (07*'001)	* UZE Y	S 708 C	5.305
VDTREV \$ (9	34,200	(38.919) 5	\$ (265)	\$ (78.596)	(22.541) \$	(14,176) \$	(26,816)
(9) TOE S	(106 432) \$	(23 944) \$	(363) \$	(44,478) \$	(12,752) \$	(8,271) \$	(15,454)
TOE	459,436)	(2,354,437)	127,766	(5,213,900)	(1,546,926)	(965,804)	(2,162,086)
	•	30,221,647 \$	662,586 \$	57,888,992 \$	15.851,611 \$	10,645,271 \$	19,538,175
•	4		* P00 F07	400	2 046 373	A 27.7 7.00 t	3 340 438
Net Operating Income (Adjusted)	\$ €04,47€,	5,566,35U	400,4c1	¢ 700'E10'0	9 C 1 1 C+C 7		2010,0
Net Cost Rate Base \$ 226,972,096 \$	49	48,946,899 \$	694,716 \$	90,292,938 \$	22,427,620 \$	16,112,733 \$	29,237,650
7,000 07	70 647	1,121,17	14867	0 75%	12 426	14 20%	11 35%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Moaths Ended
September 30, 2003

Description	i	Allocation	Coal	Coal Mining Power Primary	Coal Mining Power Transmission	Large Power Mine Power TOD Primary	2	Comb	tion Off-
XDenses	ı	101734		L	1.52		LMF	183	Ę
Operation and Maintenance Expenses			₩	3,484,867 \$	2.	\$ 1,550,678		3 \$	,202,960
Population Chadita and Appropria				458,769	325,215	,		ø	286,346
Property Taxes		FOI		(61,110)	(48,252)			<u> </u>	(8,920)
Other Taxes		-		252,54	289,05		40,508	2 4	610.07
Gain Disposition of Allowances				(1820)	(10,12)	(2,023)		n E	
State and Federal Income Taxes		TXINCPF	6/9	499,613 \$	388.025	(519) S 119.969	ψ1	•A	(461,502)
Specific Assignment of Curtailable Service Rider Credit			•	, ! , ! ,	,		•	•	1
Allocation of Curtaliable Service Rider Credits		SCP1	49	26,400 \$	23,067	\$ 10,158	3 \$ 29,038	<b>5</b> 7	4,940
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	64	(236.347) \$	(206 595)	3104 115	(902 272)	ų.	(24 816)
Remove ECR expenses		ECRREV	• •	(1.810) \$	(1443)	(989)	, ,	• • • • •	(156)
Eliminate brokered sales expenses		Energy	• •	(184,700) \$	(161,450)	\$ (81.363)		Э-2	(19.393)
Eliminate DSM Expenses		DSMREV	٠,	**	-		• ••	• • •	(20.0)
Year end adjustment		YREND	•	(141,450) \$	(165,932)		\$ (424,256)	\$ (9	(13,589)
Depreciation adjustment		OET.	₩3	•		•	•	••	
Adjustment for change in depreciation rate			<del>69</del>	10.856 \$	969'2	\$ 4,940	\$ 10,089	<b></b>	8,776
Labor adjustridit Medical Expense (See Frontispal Assignment)		19	•	4 407 \$	3,239	\$ 1,967	s,	<b>•</b> •	4,311
Adjustment for pension/oost refir benefit (See Functional Assignment)	Ŧ	ä	4	•		•	•	٠	
Storm damage adjustment	î	SDA	• •	(BEO)		(305)		A 4	/2 EGE)
Eliminate advertising expenses (See Functional Assignment)		REVUC	• 65	· •	•	***		•	(000'0)
Adjustment for amortization of ESM audit expense		R01	• •>	430 \$	344	\$ 166	. \$ 410	• • •	37
Amortization of rate case expenses		DMT	49	2,238	1,841	\$ 396	5 2,249	<b>₩</b>	773
Remove Amortization of one-utility costs (See Functional Assignment)	ê.	LBT	€9	,	,	•	•	49	٠
Adjustment for injuries and damages account 925 (See Functional Assignment)	(ssignment)	DMC	₩.	,		•	••	<b>6</b> 4	•
Adjustment for VD1 net savings to shareholders		i i	<b>6</b> 9 1	12,731 \$	9,359	5,683	•••	٠,	12,454
Adjustment for merger savings		5	<b>69</b> 1	83,418 \$	61,320	\$ 37,237	•••	65	81,602
Adjustment for MSO schedule 10 expenses		i de de	, n	\$ (066,11)	(8,814)	(5,352)		۰ <del>۱</del>	(11,729)
Adjustment for effect of accounting change		ב ה ה		400,0	10,4	LL/'7	, ,	ya 40	900
Adjustment for IT staff reduction		- E	, ,	(7,648)	31,038	(3223	•	n •	27.72
Adjustment to remove Alstom expenses		PLPPT	> 64	(2,040)	(17.431)	(10.62)	(4,434)		(3 2 2 2 )
Adjustment for corporate lease expense		B	• • •	()	(101,11)	7000	• •	• •	777
Adjustment for sales tax refund		203	•	888	709	343	278	, se	17
Adjustment for OMU Nox expense		PLPPT	<b>.</b>	13,836 \$	10,925	\$ 6,300		. 60	2.020
Adjustment for ice storm		SDALL	•	\$ (865'6)		(4,411)		. 63	(39,675)
Adjustment for management audit fee		OMT	и	1,041 \$	857	\$ 463	<b>~</b>	4 4	359
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	<del>i/)</del>	(5,171) \$	(4,381)	\$ (2,302)	(5,345)	2) %	(610)
VOT Amortization and Surcredit Total Expense Adjustments		VDTREV	₩>	(3,381) \$	(2,696)	\$ (1,291)	•	<del>ده</del> ن	(286)
				(440,443)	(858,859)	(130,429)	(/36/868)	er F	16,985
Total Operating Expenses	TOE		'n	4,039,922 \$	3,166,621	\$ 1,764,022	\$ 3,575,639	•	1,084,553
Net Operating Income (Adjusted)			s)	869,192 \$	668,815	\$ 229,986	\$ 634,600	₩	(652,432)
Net Cost Rate Base			₩	7.085.179 \$	4.970.085	\$ 3.220.039	5 486 007	J	4 697 715
			,				•	,	
			ŀ						

						Electric Space			Teet	100	Customer	Ī
Description	Ref	Name	Allocation Vector	All Eic	All Elcetric School AES	Heating Rider 33	Water Pumping	Street Lighting St.Lt	Dec St Lt	POLt	C O Lt	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							-	1,879,564	215,405	960,855	153,599 \$	1,541,360
Regulatory Credits and Accretion Expenses					(69,089)	(11,850)		(22,299)	(1,274)	(32,788)	\$ (060'5)	(222,545)
Property Taxes			NPT		56,940	10,271	10,490	167,983	19,288	86,755	13,862 \$	145,158
Other Taxes					39,955	7,207	7,361	117,874	13,534	9/9/09	e (7)'s	102,200
Gain Disposition of Allowances					(1,496)	(257)	(254)			(883)	* (C41)	(0,910)
State and Federal Income Taxes			TXINCPF	s	44,515 \$	(16,228)	\$ 26,438	\$ (418,832) \$	47,282 \$	/40,480	# LOL'58	(607 CCS C)
Specific Assignment of Curtailable Service Rider Credit					•	•		•			,	(3,530,403)
Allocation of Curtailable Service Rider Credits			SCP1	49	38,263	6,563	\$ 6,225		• <del>?</del>			161,576
Adjustments to Operating Expenses:												
Eliminate mismatch in fuel cost recovery			Energy	49	\$ (192,211)	(32.967)	\$ (32,629)	\$ (77,281) \$	(4,417) \$	(119,883)	\$ (18,611) \$	(688,821)
Remove ECR expenses			ECRREV	· 1/3	(1423) \$	(232)	•	\$ (1953)	\$ (281)	(2,260)	\$ (330) \$	(6,866)
Eliminate brokered sales expenses			Energy		(150,209) \$	(25,763)	\$ (25	\$ (60,394) \$	(3.452) \$	(93,686)	\$ (14,544) \$	(694,595)
Eliminate DSM Expenses			DSMREV	->		•	•∽	<i>w</i>	•	•	••	
Year and adjustment			YREND	<del>60</del>	•	(11,965)	,	\$ 10,181 \$	7,379 \$	43,060	\$ (11,571) \$	
Depreciation adjustment			DET	€>	'	,		•	•	. ;		
Adjustment for change in depreciation rate			DET	64	14,402 \$	2,605	\$ 2,702	\$ 44,477 \$	5 121	22,737	3,635 \$	35,474
Labor adjustment			LBT	<b>⇔</b>	5,396 \$	1,172	\$ 1,133	\$ 19,985 \$	2,252 \$	10,921	\$ 1,749 \$	14,/68
Medical Expense (See Functional Assignment)	;		ļ	•				•	1,			
Adjustment for pension/post retir benefit (See Functional Assignment)	ignment)		190	v9 w		· (KK2)	(1013)	(3.854) \$	\$ (302)	(4.091)	639	(912)
Civilii udilaya aujastiiidii Dimbada adaodajaa osessaa 70oo Diestiood Assassad			2000	. ·	(coc.2)	(200)	(700'L)	(Lonio)	(700)		•	
Adjustment for amordization of ESM andit expense			20,00		338	. 25	. 82	462 \$	\$ 89	534	\$ 22 \$ 28 \$ 28 \$ 28	1,412
Amortization of rate case expenses			TWO	, <b>u</b>	2.166 \$	404	356	\$ 2.269 \$	212 \$	1,980	312 \$	8,134
Remove Amortization of one-utility costs (See Functional Assignment)	signment		181	. 50					•	. •		•
Adjustment for injuries and damages account 925 (See Functional Assignment)	tional Assign	nent)	TMO			•		•	•		,	
Adjustment for VDT net savings to shareholders	•		T97	•	15,589 \$	3,387	\$ 3,274	\$ 57,736 \$	\$ 205'9	31,551	\$ 5,053 \$	42,664
Adjustment for merger savings			LBT	s	102,141	22,193	s	\$ 378,302 \$	42,635 \$	206,728	\$ 33,109 \$	279,545
Adjustment for merger amortization expenses			LBT	٠,	(14,681) \$	(3,190)	5	\$ (54,376) \$	(6,128)	(29,714)	\$ (4.759) \$	(40,181)
Adjustment for MISO schedule 10 expenses			PLTRT	s	6,731	1,155	•	2,173 \$	124 \$	3,194	496 5	289,12
Adjustment for effect of accounting change			DET	•••	58,087	10,505	<b>.</b>	179,385 \$	20,654 \$	91,703	\$ 500 to \$	147,107
Adjustment for iT staff reduction			LBT	<del>67</del> 1	(3,240) \$	(704)	<b>.</b>	(12,000) \$	(1,352) (1,352)	(200)	4 (0c0.r.)	(200'0)
Adjustment to remove Alstom expenses			P.P.P.		(24,958) \$	(4,281)	(2,985)	s (actria)	(400)	(++0,11)	e (aco'-)	(100,00)
Adjustment for corporate lease expense			9 2	<b>,</b>		. ;	•	***			167	5.00
Adjustment for sales tax retund			100	٠.	980	071	07	3 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6		7 424	4 7 7 7 4	50.388
Adjustment for CMU Nox expense			46	۰.	15,543.	2,083	, .	2 100 cm	* (892 c/	(45,641)	(7.132) &	(10.180)
Adjustment for Ice storm			SUALL	e .	(SSC'07)	(0,105)	•	* (500,04)	(000')	12,0	145 \$	3.785
Adjustment for management adont fee				<b>ጉ</b> ሀ	725)	/844	50 C)	(1753)	(100)	(2 671)	(415) \$	(19.249)
Adjustment for Retrement of Green River Chits 1 & 2			VACTOV	9 6	(0.41,4)	(445)	(49h)	(3,643)	(557)	(4.383)	(630) \$	(12.760)
Vol. Anxintation and solicing			אַנאַ	9	(203,096)	(42 604)	(36,039)	435.715	65.053	101,124	(896)	(1,153,955)
					(222,222)		(1)	-				
Total Operating Expenses		TOE		uș	3,886,664 \$	691,965	\$ 673,678	\$ 5,692,011 \$	690,556 \$	4,998,723	\$ 740,583 \$	11,219,199
Net Operating Income (Adjusted)				64	198 807	(1,535)	\$ 64,740	\$ (261,623) \$	115,988 \$	1,339,887	\$ 159,803 \$	2,827,732
									170 707 0		0 E00 40E	72 576 000
Net Cost Rate Base				19	9,499,702	1,728,194	7,853,457	\$ 32,289,010	9,757,850 B	460'107'01		000,000
Pate of Return				L	7.60 6	%60 0	3.47%	-0.81%	3.13%	8 24%	6.19%	11.99%
Mary Of Ivelian.				4	The second second							١

### 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	j	2003-00434

EXHIBIT (SJB-4)

KENTUCKY UTILITIES Cost of Service Study Close Allocation

Description	Ref Name	Allocation	Total	Residential Rate RS	All Electric Residential Rate PERS	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)	₩	\$ (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	REV	(25,039,979) \$	(4,562,377)	₩.	\$ (2,291,842)	\$ (91,531)
Adjustment to reflect Full Year of ECR Roll-in	ECR	ž	17,986,813 \$	3,208,163	•	1,647,196	\$ 66,930
Remove off-system ECR revenues		PLPPT	(776,418) \$	(136,190)	•	\$ (62,130)	(2,186)
Eliminate brokered sales		Energy	(22,575,669) \$	(3,600,306)	'n	\$ (1,505,781)	\$ (58,786)
Climinate ESM revenues collected	ESMRE		(4,604,742) \$	(915,119)	•	\$ (428,633)	\$ (15,263)
Eliminate ESM,FAC,ECR from rate refund acct.		R01	1,630,147 \$	295,220		149,529	\$ 6,105
Eliminate DSM Revenue	NSO	DSMREV	(2.942,935) \$	(1,508,819)	69	\$ (222,733)	(10,743)
Year and adjustment	YREND	QZ QZ	251 167 \$	(417 181)	•	\$ 815,724	•
Merger savings		R01	(2,564,269) \$	(464,390)	\$ (490,535)	\$ (235,213)	(6,603)
Adjustment for rate switching, increased interruptible credit	RAT	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

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Commilind TOD Primary LCIP	Large Commund TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLPP
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)	**	\$ (4,365,021)	\$ (1.2	(801,803)	\$ (1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 365,749	\$	<b>57</b>	\$ 194 737	€>	\$ 53,661	\$ 62,851
Remove ECR revenues		ECRREV		\$ (5,734,057)	\$ (1,290,905)	\$ (19,498)	\$ (2,401,012)	•	(446,972)	\$ (838,688)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$ 4,133,949	•	<b>.</b>	\$ 1,735,487	₩	316,548	\$ 606,165
Remove off-system ECR revenues			PL.PPT	\$ (163,316)	50		\$ (69,046)	\$ (17,276)	(11,956)	\$ (23,205)
Eliminate brokered sales			Energy	\$ (5,358,526)	۰	•	\$ (2,745,877)	<b>\$</b>	\$ (504,385)	\$ (954,481)
Eliminate ESM revenues collected		ESMREV		\$ (1,152,341)		•	\$ (474,129)	₩.	(89,283)	\$ (150,668)
Eliminate ESM, FAC, ECR from rate refund acct.			201	\$ 373,990	~	49	156,727	•	\$ 29,263	\$ 55,022
Eliminate DSM Revenue		DSMREV		\$ (98,441)	•	59		₩		,
Year end adjustment		YREND		\$ (597,774)	₩.	673		•	,	\$ (537,561)
Merger savings			R01	\$ (588,297)	**	ss	\$ (246,535)	•	(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	99	\$ 8,140	.,	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

							Large Power Mine	
•			Allocation	Coal Mining Power Primary	Coal Mining Power Coal Mining Power Primary Transmission	Large Power Mine Power TOD Primary	Power TOD Transmission	Combination Off-
Description	Ref	Name	Vector	МРР	MPT	LMPP	LMPT	CWH
Cost of Service Summary - Pro-Forma								
Operating Revenues								
Total Operating Revenue ~ Actual				\$ 5,638,015	\$ 4,546,102	\$ 2,199,244	5,422,765	\$ 503,555
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	\$ 4,976	\$ 3,978	**	4.748	\$ 432
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (268,036)	\$ (234,296)		(276.483)	
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 12,843	\$ 13,496		11.438	
Kemove ECX revenues		ECRREV		\$ (182,407)	\$ (145,445)	w	(172,666)	•
Adjustment to reflect full Year of ECR Roll-in		ECRR		\$ 132,466	\$ 105,333	•>>	127,076	
Remove off-system ECR revenues			PLPPT	\$ (4,780)	\$ (4,199)	\$ (1,874)	(5,302)	(983)
Chromate prokered sales			Energy	\$ (168,612)	\$ (147,387)	•	(173,926)	•
Cilinitiale EVM revenues collected		ESMREV		\$ (33,089)	\$ (25,314)	•	(28,011)	
Calculate Edw. PAC, ECK from rate refund aget.			R01	\$ 12,018	909'6	P.	11,466	٠,
Eliminate USM Kevenue		DSMREV		•		••		- 49
Year end adjustment		YREND		\$ (234,645)	\$ (275,257)	,	(703,778)	
Merger savings			R01	\$ (18,905)	\$ (15,111)	\$ (7,311) \$	(18,037)	\$ (1,639)
Adjustment to rate swhorting, increased interruptible credit  VDT Amortization and Surcredit		RATESW	VDTREV	2,019	403	920	923	
			į	;	2	9000	B 20	70
Total Pro-Forma Operating Revenue			(13,504,945)	() \$ 4,890,463	\$ 3,832,000	\$ 1,977,473 \$	4,199,870	\$ 429,005

KENTUCKY UTILITIES
Cust of Service Study
Class Allucation

						Electric Space			Decorative Street Private Outdoor	Private Outdoor	Customer		
Description	Re	Name	Allocation Vector	All Elcetric School AES		Heating Rider 33	Water Pumping M	Street Lighting St Lt	Lighting Dec St Lt	Lighting Po Lt	Outdoor Lighting C O f.t		Special Contracts
Cost of Service Summary — Pro-Forma													
Operating Revenues													
Total Operating Revenue - Actual				\$ 4,474	474,128 \$	771,749 \$	821,029	5,630,511	816,571 \$	6,574,367	\$ 967,888	s,	18,879,292
Pro-Forma Adjustments:													
Eliminate unbilled revenue			R01	·"	3,911 \$	675 \$	717	5 345 \$	\$ 062	8 178			351 21
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (21)	(217,983) \$	(37,387)	(37,004)	(87,643) \$	\$ (5,009)	(135,957)	\$ (21.106)	•	1.007.994)
Adjustment to Kettect Full Year of FAC Roll-in		FACR		<b>.</b>	9719 \$	881 \$	1,457	(1021)	(74)	(3.573)	. 67	• • •	45.827
		ECRREV		\$ (143	3,373) \$	(23,364) \$	(26,381)	(196.772) \$	(29.280) \$	(227 715)		•	(691,956)
Powers of control to reflect Full Year of ECK Rollin		ECRR		<b>*</b>	1,270 \$	17,741 \$	19,017	144,134 \$	21,362 \$	166,721	. 63	• • •	493.730
Remove on-system ECX revenues			PLPPT	٠ <u>٠</u>	5,289) \$	\$ (206)	(1.127)	(1,261) \$	(72)	(1.960)	,		(23,684)
			Energy	\$ (137	7,125) \$	(23,519) \$	(23,278)	(55,133) \$	(3,151) \$	(85,526)	**	- 40	(634,093)
Filminate Com leverines collected		ESMREV		\$ (21	(21,999) \$	1,124 \$	(4,856)	(37,564) \$	(5,964)	(43,690)	€5		(133,593)
Eliminate Compression (ate fathro acc).			R01		445 \$	1,630 \$	1,730	12,909 \$	\$ B06 L	14,921	· ~	- 2-7	39.449
		DSMREV		<b>∽</b>	·,	٠,		-	•		<b>6</b> 3	47	
House the adjustment		YREND		<b>.</b> ~	**	(19,849)		\$ 6883	12,240 \$	71,430	\$ (19.194	•	
Adjustment for rate entireties incommon intermedials			Ro1	\$ (14	(14,857) \$	(2,564) \$	(2,722)	\$ (20,307)	(3,001) \$	(23,470)	\$ (3,447)	•	(62,054)
VDT Amortivation and Contracts		RATESW									-	4	(2,777,732)
			VUTREV	•	491	87 58	6	\$ 199	102	208	\$ 115	49	2,335
Total Pro-Forma Operating Revenue			(13,504,945)	69	4,061,337 \$	686,291	748,672 \$	5,410,754 \$	806,422 \$	6,312,528	\$ 896,336	₩.	14,145,862

KENTUCKY UTILITIES
Cust of Service Study
Class Albecation

		Allocation		Total	Residential	All Electric Residential		General Service Secondary	General Service Primary
Description	Ref Name	Vector		System	Rate RS	Rate FERS		GSS	GSP
Operating Expenses									
Oneration and Maintenance Concess			•			,			
Depreciation and Americation Economes			•	548,721,322	106,362,519	<b>.</b>		44,251,501 \$	-
Regulatory Credits and Acresion Expenses				470,010,00	50'04'07'	187,108,02	- 1	0.4.019.0	7#1,081
Property Zaver		ì		(20,000,0)	(1,016,046)		ĵ,	(097,000)	24,370
Other Texas		1		8,211,450	1,845,852		<b>.</b>	820,503	18,401
Cario Discontisco of Allerman				5,761,996	1,295,239	•	<u>.</u>	575,749	12,912
Cell Disposition of Allowances				(246,288)	(39,277		(9)	(16,427)	(150)
State and haderal income Taxes		TXINCPF		26,916,596 \$	(1,152,038)	(3,910,688)	8) \$	3,953,435 \$	382,134
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	•	,		•	•
Allocation of Curtailable Service Rider Credits		SCP	67)	4.582.475 \$	934.980	\$ 771,944	*	449.462 \$	11.972
Augustraems to Operating Expenses:									
Cultimate institution in the cost recovery		Energy		(31,644,777) \$	(5,046,623)	rč.	•• ••	(2,110,684) \$	(96,419)
Kemove ECR axpenses		ECRREV		(248,468) \$	(45,272)	(46.795)	5)	(22.742) \$	(806)
Eliminate brokered sales expenses		Energy		(24,729,742) \$	(3,943,832		\$ (2	(1,649,456) \$	(75,349
Eliminate DSM Expenses		OSMREV		(2,946,471) \$	(1,510,632)	•	3	(223,001) \$	(10,756)
Year end adjustment		YREND		151,410 \$	(251,488	**	9	491,740 \$	. •
Depreciation adjustment		DET			•	•	s	•	•
Adjustment for change in depreciation rate				2,091,278 \$	474,779	\$ 567,487	\$ 1	210.851 \$	4.632
Labor adjustment		LBT		1,002,076 \$	250,084	\$ 256,399	. <b>.</b> .	102,685 \$	2,110
Medical Expense (See Functional Assignment)						•			
Adjustment for pension/post retir benefit (See Functional Assignment)	ssignment)	L81			•	S	•		•
Storm damage adjustment		SDALL		(473,014) \$	(168,017)	(153,325)	\$ (9	(69,375) \$	(224)
Eliminate advertising expenses (See Functional Assignment)	£	REVUC		67	•	•	•		. 1
Adjustment for amortization of ESM audit expense		ROI		58,333 \$	10,584	\$ 11,159	<b></b>	5,351 \$	218
Attioutzation of rate case expenses		OMT		352,456 \$	68,319	•••	<b>*</b>	28,424 \$	954
Aemove Amonization of one-utting costs (See Functional Assignment)	ssignment)	T81			•		w	•	•
Adjustment for injunes and damages account 925 (See Functional Assignment)	nctional Assignment)	_MO:		,		•	es.		•
Adjustment for VCI het savings to shareholders		E :		2,895,000 \$	722,494	\$ 740,736	65 45	296,657 \$	900'9
Adjustment for merger savings		L81		18,968,825 \$	4,733,976	\$ 4,853,506	<b>2</b>	1,943,777 \$	39,933
Adjustment for merger amortization expenses		LBT		(2,726,510) \$	(680,445)	\$ (697,625)	5) \$	(279,391) \$	(5,740)
Adjustment for MISO schedule 10 expenses		PLTRT		843,344 \$	147,930	\$ 219,796	<b>*</b>	67,485 \$	2,375
Adjustment for effect of accounting change				8,434,518 \$	1,914,897	<b>*</b>	<b>5</b>	850,411 \$	18,682
Adjustment for IT staff reduction		LBT		(601,682) \$	(150,159)	· ·	1) <b>\$</b>	(61,556) \$	(1,267)
Adjustment to remove Alstom expenses		PLP₽T		(3,126,995) \$	(548,502)	(814,972)	2) \$	(250,225) \$	(8,806)
Adjustment for corporate lease expanse		E			•	49	<b>L</b>	•	•
Adjustment for sales tax refund		RO1		120,391 \$	21,803	۰,	* 0	11,043 \$	451
Adjustment for OMU Nox expense		PLPPT		1,959,879 \$	343,780	<b>6</b> 7	3	156,831 \$	5,519
Adjustment for ice storm		SDALL		(5,277,336) \$	(1,874,536)	5	8	(774,008) \$	(6,178)
Adjustment for management audit fee		DMT		163,982 \$	31,786	v,	, co	13,224 \$	444
Adjustment for Retirement of Green River Units 1 & 2		OMPPT		(705,035) \$	(114,982)	•	S	(49,153) \$	(2,111)
VDT Amortization and Surcredit		VOTREV		(466,280) \$	(84,947)	•	\$ (9	(42.731) \$	(1,661)
Total Expense Adjustments				(35,904,718)	(5,699,021)	4)		(1,353,943)	(128,337)
Total Operating Expenses	10E		v	533 180 028 ·	400 500 501	300 880 351		\$ 5808 087	1 05.7
			,	* 070'001'000	000,000,000		•		±67'70E'
Net Operating Income (Adjusted)			₩	60,269,011 \$	2,444,140	\$ (943,126)	\$ (9	7,970,617	631,177
Net Cost Rate Base			o	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%	77	2.50%	20 86%

Description	e E e N	Allocation	COM	Combined Light & C Power LPS	Combined Light & ( Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Commind TOD Transmission LCIT	High Load Factor Secondary HLFS	High L	High Load Factor Primary HLFP
Operating Expenses				:							
Operation and Maintenance Expenses			es.	117,230,078 \$	28,376,329 \$	389,251 \$	53,278,685	14,752,145	\$ 9,739,162	•	18,395,937
Regulatory Credits and Accretion Expenses				(1,820,763)	(409,805)	(6,234)	(769,768)	(192,609)	(133,293)	-	(258,709)
Property Taxes Other Taxes		F		1,405,766	289,796	4,005	538,034	122,710	96,108		179,784
Gain Disposition of Allowances				985,450	744.367)	5,010 (717)	(959.07)	(8,707.5)	(5.503)	_	(10.413)
State and Federal Income Taxes		TXINCPF	69	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		į	,		(181,381)	. :	(271,654)	(499,037)			
Allocation of Curtaliable Service Rider Credits		SCP	v <del>3</del>	1,097,059 \$	240,238 \$	4,049 \$	441,260	101,228	\$ /8,321	v)	145,724
Adjustments to Operating Expenses;											
Eliminate mismatch in fuel cost recovery	٠	Energy	63 -	(7,511,155) \$	(1,845,959) \$	(27,879) \$	(3,848,951)	(1,118,710)	\$ (707,007)	<b>5</b>	(1,337,916)
Renove filth expenses filthings brokered kales expenses		ECRREV	en e	\$ (888.95)	(12,809) 5	(193) \$	(33,825)	(6,834)	(4,435)	n 41	(8,322)
Eliminate DSM Expenses		DSMREV	· 65	\$ (65,59)	(12,138) \$	(473) \$	( -				
Year end adjustment		YREND	٠.	(360,354) \$	71,010 \$	164,672 \$	•		•	s	(324,056)
Depreciation adjustment Adjustment for change in depreciation rate		בו פובר	<b>19</b> 4	354307	7.566.7	908	134 807	30.559	24 126	n •	45.029
Labor adjustment		rei.	• •	177,680 \$	31,594 \$	428	59,843	14,658	11,134	. 05	20,462
Medical Expense (See Functional Assignment)			,	٠		,					
Adjustment for pension/post retir benefit (See Functional Assignment) Storm damage adjustment		LBT SDATE	69 E	\$	, (939 3)		(0.718)		. 0 245		(3.000)
Eliminate advertising expenses (See Functional Assignment)		REVUC	9 69	* (100'34)	(000'e)		(0)		C	• •	(2001)
Adjustment for amortization of ESM audit expense		Rot	• •	13,383 \$	3,000 \$	45 \$	5,608	1,588	1,047	•	1,969
Amortization of rate case expenses		OMT	69	75,300 \$	16,942 \$	\$ 220 \$	34,222	9,476	\$ 6,256	o,	11,815
Remove Amortization of one-utility costs (See Functional Assignment)		181	€> (		•		•			<b>.</b>	
Adjustment for injuries and damages account 925 (See Functional Assignment)	signment)	Two.	v+ 4			, ,	100 017	, , ,	, , ,	v> o	
Adjustment for memor savings to snarghdads		9 18	, v	3 363 406 \$	50 H 053 S	8 101 5	1132 806	777.474	32,166	9 V	387,328
Adjustment for merger amortization expenses		<u> </u>		(483,444) \$	(85.962) \$	(1.164) \$	(162.825)	(39,883)	\$ (30,295)	. 50	(55.673)
Adjustment for MISO schedule 10 expenses		PLTRT	· 03	177,394 \$	39,927 \$	\$ 209	74,997	18,766	\$ 12,987	•	25,206
Adjustment for effect of accounting change		DET	<b>69</b>	1,429,005 \$	293,065 \$	4,025 \$	543,708	123,251	\$ 97,308	<b>•</b> > :	181,614
Adjustment for IT staff reduction		LBT	<b>.</b>	(106,686) \$	(18,970) \$	(257)	(35,932)	(8,801)	\$ (6,686)	<b>.</b>	(12,286)
Adjustment to remove Alstom expenses		7.	A 4	* (nc/'/co)	(140,042)	¢ (707'7)	(0/0'0/7)	(noc'sa)	(40,132	? <b>~</b>	(90,408)
Adjustment for sales tax refund		202	• • •	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	u)	58,576
Adjustment for ice storm		SDALL	63	(472,573) \$	\$ (83,098)	•••	(108,425)	•	\$ (25,051)	**	(33,566)
Adjustment for management audit fee		OMT	<b>6</b> 5 (	35,033 \$	7,882 \$	116 \$	15,922	4,409	2,910	<b>ن</b> ې د	5,498
Adjustment for Retrement of Green River Units 1 & 2 VOT Amortization and Superadit		OMPPT VITEE/	v	(163,032) \$	(39,372) \$	(585) \$	(80,530)	(22,832)	(14,643	w w	(27,829)
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		<b>ب</b>	137,073,963 \$	30,306,501	658,645 \$	58,511,391	15,795,796	\$ 10,812,561	•	18,950,386
Net Operating Income (Adjusted)			•	22,655,896 \$	5,450,523 \$	156,826 \$	8,152,513	2,942,590	\$ 1,636,481	•	2,916,834
				100 100	* ***	10000	777 070 00	40007	607 300 37		0000
Sel Cost Rate Dane	;		•	\$ 470,500,457	* *OI' ( /0' /*	6 10,040			06*'006'01	•	500,000,00
Rate of Return				9.65%	11.43%	24.28%	9.20%	14.71%	10.25%		9.84%

KENTUCKY UTILITIES Cast of Service Stady Class Allocation

12 Months Ended	September 30, 2003		

				Coal Mining Power	Coal Mining Power	ande Power wills		Power TOD	Combination Off-
Description	Ref Name	Allocation Vector			Transmission MPT	Power TOD Primary LMPP	тапу	Transmission LMPT	Peak
Operating Expenses									
Operation and Maintenance Expenses			*	3,395,813	2,890,098	\$ 1,45	\$,586.\$	3,459,123 \$	1,173,678
Depreciation and Amortization Expenses				406,362	315,559	16.	162,290	397,238	277,591
Regulatory Credits and Accretion Expenses		FOI		(53,287)	(45,811)	<u>z</u> , -	0,891) 5,286	37 740	24.987
Property Laxes		<u>.</u>		26,883	21.033	= ==	10,725	26,482	17,533
Cain Disposition of Allowances				(1.839)	(1,608)		(810)	(1,897)	(193)
State and Federal Income Taxes		TXINCPF	63	557,274 \$	382,826	171	176,255 \$	\$ 766,085	(446,205)
Specific Assignment of Curtailable Service Rider Credit					•		,	,	•
Allocation of Curtaitable Service Rider Credits		SCP	ø	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	64	(1,810)	(1,443)	<b>1</b> 73	(969)	(1,713) \$	(156)
Eliminate brokered sales expenses		Energy	₩	(184,700) \$	(161,450)	£)	(81,363) \$	(190,521)	(19,393)
Eliminate DSM Expenses		OSMREV	ω,		. !	•	,		. 44
Year end adjustment		YREND	·s	(141,450) \$	(165,932)	w •		(454,25b) \$	(890'91)
Depreciation adjustment		DEL	<b>پ</b>	, ,	1 167			* 0000	. 4
Adjustment for change in depreciation rate		DET.	· •	9,616	7,40	A 4	1704	2 288 E	4 26 1
Labor adjustment		5	•	• •	9.0	•		2001	
Medical Expense (See Functional Assignment) Adjustment for pension/host retir benefit (See Functional Assignment)	signment	TBT	•			ss.			
Storm damage adjustment		SDALL	•	(980)		•••	(385)	•	(3,556)
Eliminate advertising expenses (See Functional Assignment)	•	REVUC	•			<b>\$</b>		. :	, ;
Adjustment for amortization of ESM audit expense	•	R01	₩.	430	344	<del>69</del> 1	156	410 \$	37
Amortization of rate case expenses		OMT.	٠ <u>٠</u> ،	2,181	909'.		7 <b>4</b>	777'7	5
Remove Amortization of one-utility costs (See Functional Assignment)	signment)	E81	<b>₩</b>					. ,	
Adjustment for injuries and damages account 925 (See Pund	ctional Assignment)	<u> </u>	9 6	11 877	9 201		4 923 \$	11.224 \$	12.311
Adjustment for VD1 net savings to shareholders		9 1	9 v	77 798	60 284	eri •	32,255 \$	73,543 \$	80,664
Adjustment for merger savings		. E	•	(11 182) \$	(8,665)	. 65	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	so.	5,489 \$	37,912 \$	26,493
Adjustment for IT staff reduction		LBT	<b>~</b>	(2,468) \$	(1,912)	<b>.</b>	(1,023) \$	(2,333) \$	(2,559)
Adjustment to remove Alstom expenses		PLPPT	v	(19,250)	(16,910)	<b></b>	(7,547)	(21,353) \$	(2,750)
Adjustment for corporate lease expense		<b>LB</b> T	٠		• }	<b>Ŀ</b> > (		, ;	
Adjustment for sales tax refund		RO1	<b>6</b> 9	988	- 1dg	υ» «	245	4 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6	1 101
Adjustment for OMU Nox expense		PLPPT	<b>.</b> ,	12,065	10,599	v> e	05/4	13,563	(30.675)
Adjustment for ice stom		SDALL	<b>v</b> 3 •	(8,598)	, ;	•	A (114)		(59,613)
Adjustment for management audit fee		OMT	· ·	1,015	904	ın s	2 450	1,034	(568)
Adjustment for Retirement of Green River Units 1 & 2		CMPF1	A 4	(3,030)	(1.424)	, ,	1 2011	(3.165) 5	(286)
VDF Amortzation and surgreat Total Expense Adjustments		N N	•	(452,152)	(440,842)	•	(140,798)	(743,380)	15,039
	ii.		v	3 943 765	\$ 3 173 297	1.67	\$ 608.029	3,526,232	1,059,758
Total Operating Expenses			,		•	•			
Net Operating Income (Adjusted)			<b>₩</b>	946,698	658,703	••	306,664 \$	673,639 \$	(630,752)
Net Cost Rate Base			•	6,316,969	\$ 4,828,552	\$ 2,53	2,539,011 \$	6,059,060	4,569,377
									10000

		AHADAMA	*	A 17 (5) 4-1- (5 - 1 1	Fieding Space			Decorative Street Private Outdoor		Customer	
Description	Ref Name			AES			St Lt	Dec St Lt	Polt	COLt	Contracts
Operating Expenses											
Conception and Maintenance Conception			٠								
Decretation and American Comments			A	3,145,245	268,890	\$ 816,278 \$	3,413,013 \$	323,469 \$	2,931,658	\$ 463,102 \$	13,344,427
The contract of the state of th				510,040	204,00	143,003	1,524,395	213,252	887,566	142,222	1,819,340
Property Taxes		A. C.		(38.957)	(10,114)	(12,558)	(14,064)	(804)	(21,847)	(3,392)	(264,040)
Other Taxes		Ž		50,496	9,166	13,228	162,741	18.988	79,790	12,781 \$	172,574
Caio Disposition of Allermana				35,433	6,432	9,282	114,196	13,324	55,989	\$ 896'8	121,095
Carlo Cieposition of Attendances				(1,496)	(257)	(254)	(601)	(34)	(623)	(145)	(6,918)
Create and Tederal moone laxes		TXINCPF	s»	162,996 \$	4,093	\$ (10,583) \$	(347,969)	51,332 \$	831,402	\$ 97.215 \$	1,229,785
Specific Assignment of Curtailable Service Rider Credit				Ī	•			•		***	(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	69	(192,211) \$	(32.967)	32.629) \$	(77,281) \$	(4.417) \$	(119.883)	(18611) \$	(888.821)
Remove ECR expenses		ECRREV	₩	(1,423) \$	(232)	(262) \$	(1.953) \$	(291)	(2.260) \$	(330)	(6.866)
Eliminate brokered sales expenses		Energy	ø	(150,209) \$	(25,763)	(25,499) \$	(60,394) \$	(3.452) \$	(93.686) \$	(14.544) \$	(694.595)
Eliminate DSM Expenses		DSMREV	s,	•		449			-		,
Year end adjustment		YREND	•	•	(11.965) 5		10.181	2 878 7	43.060.5	(11.571) \$	,
Depreciation adjustment		E	49								
Adjustment for change in depreciation rate		DET	**	12 797 \$	2 300 6	3 787 2	43 171 \$	. A. A.	24 003	3 375 6	
Labor adjustment		i Bi	, vi	5.012	\$ 107 F	200.0	10,673	0,040	200,12	* 100°°	CPC 94
Medical Expense (See Functional Assignment)			•	•		2041	1000	107'7	900'0	Con'.	7 1 1
Adjustment for pension/post refir benefit (See Functional Assignment)	menti	- BT	65	,	,				•		•
Storm damage adjustment	<b>(1)</b>	SDALL	•	0 563)	, (5,5)	, , , , , ,	, (20.0)	* (202/	, , ,	- 60	. 8
Eliminate advertising expenses (See Functional Assignment)		REVIIC		(000,14)	(700)	\$ (200,1)	(*C0'c)	¢ (70c)	t (160't)	(aco)	(218)
Adjustment for amortization of ESM audit expense		200	• •	328			. 453	, ,			. :
Amortization of rate case expenses		TAIC	• •	2 030	2020	70 202	704	8 6	9 4 6 6 6 7	0 10 0	714.7
Remove Amortization of one-utility costs (See Functional Assignment)	ment	Ta .		27,4	, <del>1</del>	262	¢ 751'7	007	200	÷ 167	1,6'0
Adjustment for joinness and damages account 925. (See Functional Assistants)	miletity not Assignment)	5 5	9 4	•		,				,	•
Adjustment for VOT net souther to chareholders	idi Assigini idir.	- E	۰.	, ;	, ,	, ,					
Adjustment for menaer sovings		9 5	<b>?</b> •	W 074,4-	- DL'2	147.50 147.50	\$ 55,833	6,435	30,351	2 /98/	47,213
Adjustment for mercer amortization occasion		9 5	۰.	600'56	C 056'02	24,040	3/2,385 \$	42,297	\$ 699'96	31,889 \$	309,354
Adjustment for tell OD cotte delle 10 economic		191	۰.	(13,536)	3 (110,8)	(3.527) \$	(53,525)	(e,080) <b>\$</b>	(28 585) \$	(4,584) \$	(44,465)
Adjustment for effect of appropriate about		ארוא. פריאו		2,740	5 696	1,224 \$	1,370 \$	8/	2,129 \$	330 2	25,725
Adjustment for IT stoff and adjusting		<u> </u>	n (	51,615 \$	38.6	13,648 \$	174,119 \$	20,353 \$	84 709 \$	13,574 \$	173,637
Adjustment to remove Metors accounts		9 6	<i>a</i> (	(B00's)	(pga)	\$ (8//)	(11,812) \$	(1,342) \$	(6,308)	(1.011) \$	(9,813)
Adjustment to remove the contract of the contr			<b>,</b>	(202,12)	(3.654)	(4,540) \$	(5,081) \$	(230) \$	(7,892) \$	(1,225) \$	(95,384)
Adjustment for corporate adjust		5	in (	,		•	,	•		,	
Adjustment for Date by the contract of the con		R01	<b>,</b>	989	120 \$	128 \$	953 \$	141	1,102 \$	162 \$	2,913
Adjustment for the despense		1 dd 1	n i	13,351 \$	2,290 \$	2,846 \$	3,184 \$	182 \$	4,947 \$	768 \$	59,783
Adjustment for management for		SDALL	<b>1</b> 5 (	(28,599) \$	(6,163)	(11,514) \$	(43,003) \$	(3,368) \$	(45,641) \$	(7,132) \$	(10,180)
Adjustment for Definition (2008 fee		TMO	<b>1</b> 3 (	940	\$ 921	184 \$	1,020	<b>\$</b> 26	876 \$	138 \$	3,988
Adjustment for Administration Green River Units 1 & 2		Iddiwo	v9 ·	(4,400) \$	(755)	(794) \$	(1,591) \$	(81)	(2,469) \$	(383) \$	(20,189)
		VDTREV	v)	(2,682) \$	(445) \$	(490) \$	(3,643) \$	(221) \$	(4,383) \$	(630) \$	(12,760)
ioral 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 Operation Income (Adjusted)			•	11					!	;	
			•	300°/300°	\$ 007'17	13,773	(164,365) \$	122,546 \$	1,464,133 \$	179,090 \$	2,290,420
Net Cost Rate Base			s	\$ 505,675 \$	1,557,703 \$	2,285,839 \$	31,480,324 \$	3,691,737 \$	15,177,086 \$	2,416,359 \$	27,651,808
Kara 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	ĺ	2003-00434

EXHIBIT (SJB-5)

KENTUCKY UTILITIES Cust of Service Study Class Allocation

Description	à	į	Allocation	Total	Residential Date De	All Electric Residential	General Service Secondary	General Service Primary
Cost of Service Summary - Pro-Forma								
Operating Revenues								
Total Operating Revenue Actual			и	768,801,159 \$	138,655,960	146,073,598	\$ 69,616,315	\$ 2,805,997
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	875,000 \$	122,243	129,125	\$ 61,916	\$ 2,528
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728) \$	(5,723,27)	9	\$ (2,393,685)	\$ (109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	3	1,417,623 \$	181,543	•	166'96	•
Remove ECR revenues		ECRREV		(25,039,979) \$	(4,562,377)	•	\$ (2,291,842)	•
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813 \$	3,208,163	49	\$ 1,647,196	s
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	•	\$ (1,505,781)	49
Eliminate ESM revenues collected		ESMREV		(4,604,742) \$	(915,119	**	\$ (428,633)	•
Eliminate ESM,FAC,ECR from rate retund acct.			R01	1,630,147 \$	295,220	·»	\$ 149,529	"
Eliminate DSM Revenue		DSMREV		(2,942,935) \$	(1,508,819)	s	\$ (222,733)	59
Year end adjustment		YREND		251,167 \$	(417,181)	•	\$ 815,724	s
Merger savings			R01	(2,564,269) \$	(464,390)	•	\$ (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	5 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

			Allocation	Combined Light & Power	Combined Light & Power	Combined Light & Combined Light & Power	Large Commilled TOD Primary	Large Commilled TOD Transmission	High Load Factor Secondary	High Load Factor Primary
Description	ě	Мате	Vector	SdJ	dd)	LPT	Cib		MLF3	
Cost of Service Summary Pro-Forms										
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			203	\$ 154,859	•	\$ 526	\$ 64,896	4	\$ 12,117	<b>\$</b> >
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (8,518,255	(2,093,467)	••	\$ (4,365,021)	\$ (1,268,707)	\$ (801,803)	••
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 365,749	••	.,	\$ 194,737		\$ 53,661	<b>~</b> 3
Remove ECR revenues		ECRREV		\$ (5.734.057	•	•	\$ (2,401,012)	•	\$ (446,972)	•
Adjustment to reflect Full Year of ECR Roll-in		ECRR		\$ 4.133.949	•	•	\$ 1,735,487	•	\$ 316,548	₩.
Remove off-system ECR revenues			PLPPT	\$ (185,877	.,	•	\$ (74,764)	•	\$ (13,270)	€3
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	s	•	\$ (474,129)	\$	\$ (89,283)	•
Eliminate ESM, FAC, ECR from rate refund acct.			801	373,990	•	14	\$ 156,727	٠,	\$ 29,263	۰.
Eliminate DSM Revenue		OSMREV		\$ (98,441	**	**	•	•	•	,
Year end adjustment		YREND		\$ (597,774			,		•	\$ (537,561)
Merger savings			R01	\$ (588,297	~	••	\$ (246,535)	s,	\$ (46,031)	\$ (86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			•		\$ (64,186)	٠ •		
VOT Amortization and Surcredit			VDTREV	\$ 19,479	~	\$ 66	\$ 8,140	\$ 2,334	5 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

KENTUCKY UTILITIES
Cost of Service Study
Class Albuention
12 Munths Ended
September 30, 2003

								Large Power Mine	
Description	n e	SE SE	Aflocation Vector	Cost Minng Primary MPP	g rower ary	Coas Mining Power Coal Mining Power Primary Transmission MPP MPT	Large Power Mine Power TOD Primary LMPP	Fower IOU Transmission LMPT	Combination UT- Peak CWH
	ļ								
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue - Actual				£A	5,629,555 \$	4,538,092	\$ 2,195,076	5 5,412,231	\$ 507,806
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	69	4.976 \$	3.978	\$ 1.924	\$ 4,748	69
Adjustment for Mismatch in fuel cost recovery			Energy	•	268,036) \$	(234,296)	\$ (118,074)	\$ (276,483)	-
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	;		12,843 \$	13,496	\$ 2,865	\$ 11,438	1,179
Remove ECR revenues		ECRREV		<b>,</b>	182 407) \$	(145,445)	<b>5</b> 5	\$ (172,666)	•
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		49	132,466 \$	105,333	••	\$ 127,076	.,
Remove off-system ECR revenues			PLPPT	<b>.</b>	(4,473) \$	(3,908)	٠,	\$ (4,920)	v
Eliminate brokered sales			Energy		168 612) \$	(147,387)	۰n	\$ (173,926)	
Eliminate ESM revenues collected		ESMREV		₽9	(33,089) \$	(25,314)	<b>5</b>	\$ (28,011)	•9
Eliminate ESM,FAC,ECR from rate refund acct.			R01	₩	12,018	909'6	<b></b>	\$ 11,466	۰,
Eliminate DSM Revenue		DSMREV		<del></del>	57		٠,	•	est.
Year end adjustment		YREND		•	234,645) \$	(275,257)		\$ (703,778)	(22,542)
Merger savings			R01	₩	(18,905) \$	(15,111)	\$ (7,311)	\$ (18,037)	₩
Adjustment for rate switching, increased interruptible credit		RATESW				•			
VDT Amortization and Surcredit			VDTREV	\$>	619 \$	493	\$ 236	\$ 579	•
Total Pro-Forma Operating Revenue			(13,527,170)	•	4,882,311 \$	3,824,281	1,973,457	\$ 4,189,718	\$ 433,102

THLITIES	e Study	ation
ENTUCKY U	Cost of Service Study	Class Allucation

					Electric Space	4		å	Decorative Street Private Outdoor	rivate Outdoor	Customer	
Description	Ret	Name	Allocation Vector	All Elcetric School AES		r Water Pumping M		Street Lighting St.Lt	Lighting Dec St Lt	Lighting PO Lt	Outdoor Lighting C O Lt	Special Contracts
Cost of Service Summary - Pro-Forma												
Operating Revenues												
Total Operating Revenue – Actuai				\$ 4,507,053	53 \$ 777,396	v,	819,029 \$	5,595,719 \$	814,583 \$	6,520,320	\$ 959,498 \$	18,981,135
Pro-Forma Adjustments:												
Eliminate unbilled revenue			R01	6.6	₩2	\$2	717 \$	5,345 \$	\$ 062	6,178	\$ 206 \$	16,335
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (217.9	69	•	7,004) \$	(87,643) \$	\$ (600'5)	(135,957)	\$ (21,106) \$	(1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	3	\$ 9,719	19 \$ 881	•••	1,457 \$	(1,021) \$	(74)	(3,573)	\$ (2,582) \$	45,827
Remove ECR revanues		ECRREV		\$ (143,3	\$7	•	5,381) \$	(196,772) \$	\$ (29,280)	(227,715)	\$ (33,264) \$	(691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$ 104.2	s,	•	3,017 \$	144 134 \$	21,362 \$	166,721	\$ 24,687 \$	493,730
Remove off-system ECR revenues			PLPPT	9	•	٠,	\$ (550)		•	•	₩,	(27,376)
Eliminate brokered sales			Energy	\$ (137,125)	25) \$ (23,519)	6	3,278) \$	(55, 133) \$	(3,151) \$	(85,526)	\$ (13,277) \$	(634,093)
Eliminate ESM revenues collected		ESMREV	ì	5 (21.9)	••	€4	\$ (958)	(37,564) \$	(5.964) \$	(43,690)	~	(133,593)
Eliminate ESM,FAC,ECR from rate refund acct.			R01	40	s	w)	1,730 \$	12,909 \$	1,908	14,921	•	39,449
Eliminate DSM Revenue		DSMREV			<b>5</b> 9	₩,	•	•		•	€4	
Year end adjustment		YREND			\$ (19.6	۰,	٠	16,889 \$	12,240 \$	71,430	\$ (19,194) \$	
Merger savings			R01	\$ (14,857)	€?	(2,564) \$ (5	(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 \$	<b>\$</b>	\$ 299	102 \$	802	\$ 115 \$	2,335
Total Pro-Forma Operating Revenue			(13,527,170)	0) \$ 4,093,069	59 \$ 691,733	65	746,744 \$	5,377,223 \$	804,505 \$	6,260,441	\$ 888,250 \$	14,244,013

KENTUCKY UTILITIES Cost of Service Study Class Allocation

Operating Expenses  Operation and Maintenance Expenses Depretation and Amoritation Expenses Remising Confits and Accessing Expenses					Kate Ko	2010			
Operation and Maintenance Expenses Depreciation and Amortization Expenses Remisiator Credits and Arcetion Expenses									
Regulatory Credits and Accessor			es.	548,721,322 \$	109,776,204	٠ -	· ••	46,405,462 \$	1,460,330
specially line of the control of the				(8,556,053)	(1,766,127)	18,637,218 (1,458,160)	_	9,957,822 (849,010)	183,943
Property Taxes Other Taxes		¥P⊤		8,211,450	2,003,584			920,028	17,280
Gain Disposition of Allowapees				5,761,996	1,405,920	1,204,512		545,586	12,125
State and Federal income Taxes		TXINCPF		26,916,596 \$	(3.211.541)	.2	•••	2.653,933 \$	396.774
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	,	,	•	,	
Allocation of Curtailable Service Rider Credits		SCP	<b>€</b>	4.582.475 \$	934.980	\$ 771.944	s,	449.462 \$	11.972
Adjustments to Operating Expenses:		į			1	•	•	4	
		Energy		(31,644,777) \$	(5,046,623)	(2)	- -	(2,110,584) \$	(96,419)
Militarios de Martina		ECRREV Frame		(248,468) \$	(45,272)	(46,795)		(22,742) \$	(908)
Eliminate DSM Expenses		DSMREV		(24,729,742) \$	(3,943,032)	4 es	- -	23 001) 5	(10,549)
Year end adjustment		YREND		151,410 \$	(251,488)	1,068,029	,	491,740 \$	
Depreciation adjustment		DET		,	•	•	<b>\$</b>	,	•
Adjustment tot change in depreciation rate i abor adjustment		DET.		2,091,278 \$	514,058	\$ 441,017	so o	235,634 \$	4,353
Medical Expense (See Functional Assignment)		9		1,002,076 \$	259,488	271,077	,	\$ 819'80L	2,043
Adjustment for pension/post retir benefit (See Functional Assignment)	ment)	LBT			•		•	•9	i
Storm damage adjustment		SDALL		(473,014) \$	(168,017)	(153,325)	•	\$ (575,93)	(554)
Eliminate advertising expenses (See Functional Assignment)		REVUC		67	•	•	•	*	•
Adjustment for amortization of ESM audit expense		. BG		58,333	10,564	<b>~</b> •	<i>u</i> a (	5,351 \$	218
Remove Amortization of one-utility costs (See Functions) Assignment)	mean	E E		\$ 004,200	710'07	. +c'so	^ v	* '00'87	950
Adjustment for injuries and damages account 925 (See Functional Assignment)	nien) nal Assionment)	OMT		, ,	, ,		9 v1	, ,	, <b>.</b>
Adjustment for VDT net savings to shareholders	•	HB⊥		2.895.000	749.660	\$ 653.266	•	313.798 \$	5.901
Adjustment for merger savings		181		18,968,825 \$	4,911,976	\$ 4,280,374	2	2.056,091	38,668
Adjustment for merger amortization expenses		LBT		(2,726,510) \$	(706,030)		<u>ن</u>	(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			950,369 \$	17,555
Adjustment for II stain requestion Adjustment for II stain requestion		19.0 19.0 19.0		(601,682) \$	(155,806)			(65,218) \$	(1,227)
Adjustment for composts leads expenses		- A - H		\$ (688,921,6)	(638,013)	\$ (526,760	· ·	(306,704) \$	(8,170)
Adjustment for sales tax refund		2		120 301	21 803	24.030		11047 5	451
Adjustment for OMU Nox expense		PLPPT		1.959.879	399.882	• vi	, ,,	192 230 \$	5.120
Adjustment for ice storm		SDALL		(5,277,336) \$	(1.874,536)	. S	•	(774,008) \$	(6,173)
Adjustment for management audit fee		OMT		163,982 \$	32,806			13,868 \$	436
Adjustment for Retirement of Green River Units 1 & 2		OMPPT		(705,035) \$	(119,554)	•	ss)	52,038) \$	(2,079)
VDT Amortization and Surcredit Total Expense Adjustments		VDTREV		(466,280) \$ (35,904,718)	(84,947) (5,328,614)	••	<b>\$</b>	(42,731) \$ (1.120,224)	(1,661) (130,970)
Total Operating Expenses	TOE		υ	633,180,928 \$	125,499,010	\$ 126,021,005	67	59,046,633 \$	1,928,089
Net Operating Income (Adjusted)			49	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

Dascrivion	Pod emely	Allocation	Con	Combined Light & ( Power	Combined Light & Power I PP	Combined Light & Power	Large Comm/Ind TOD Primary LCIP	Large Committed TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP	Factor N
Xpenses	1			ı J	i						
Operation and Maintenance Expenses			•	120,695,298 \$	26,982,414	\$ 408,746	vn •>	\$ 14,732,940	\$ 9,941,001	•	18,624,035
Depreciation and Amortization Expenses				16,557,830	3,365,392	51,650	6,123,936	(191.215)	(147 943)		(275,265)
Regulatory Credits and Accietion Expenses		±GN		1 585 879	317 801	4 906			105,434		90.324
Other Taxes		-		1.098.782	223,002	3,442	405,015		73,984		33,551
Gain Disposition of Allowances				(58.459)	(14,367)	(217)	(29,956)		(5,503)		(10,413)
State and Federal Income Taxes		TXINCPF	<del>57</del>	10,520,722 \$	2 740 138	\$ 84,027	\$ 3,960,476	٠,	\$ 797,227	٠ -	87,812
Specific Assignment of Curtaitable Service Rider Credit				•	(181,381)		(271,654)	_	•		
Altocation of Curtailable Service Rider Credits		SCP	en	1,097,059	240,238	\$ 4,049	\$ 441,260	\$ 101,228	\$ 78,321	<b>.</b> .	145,724
Adjustments to Operating Expenses:											
Eliminate mismatch in the cost recovery		Energy	и	(7.511.155)	(1.845,959)	\$ (27,879)	\$ (3.848.951)	\$ (1,118,710)	\$ (707,007)	۰,	(1,337,916)
Remove ECR expenses		ECRREV	• •	\$ (56.898)	(12,809)	(193)	\$ (23,825)	٠,	•	s	(8.322)
Eliminate brokered sales expenses		Energy	•	(5 869 813) \$	(1,442,579)	\$ (21,787)	\$ (3,007,876)	\$ (874,249)	\$ (552,511)	•	45,554)
Eliminate DSM Expenses		DSMREV	₩.	\$ (655,86)	(12,138)	\$ (473)	•			•	. !
Year end adjustment		YREND	<b>.</b> .	(360,354) \$	71,010	\$ 164,672		•			(324,056)
Depreciation adjustment		DET	us :		. :					•	
Adjustment for change in depreciation rate		DET	ι» ι	394,178 \$	79,636	1,222	5 144,912	30,038	11 590	, <sub>~</sub>	71 090
Labor adjustment		9	<b>1</b> 9	\$ 977'/RL	33,2b3	794	\$ \$27,20	cho'+i	000'11	•	300
Medical Expense (See Functional Assignment)	4	H		•	,					67	
Adjustinati tot petisioniposi toti Oenem (See Turcuotta) Assignma Stom damana adinatmant	Ć II	SDALI	9 44	(42.357)	(5 558)		(9.718)		\$ (2.245)	•	(3,009)
Filminate advartision expenses (See Functional Assignment)		REVIIC	÷ ⊌1	(100/11)	(20)					•	
Adjustment for amortization of ESM audit expense		R01	- 64	13.383 \$	3,000	45	\$ 5.608	•	1,047	•	1,969
Amortization of rate case expenses		OMT	•	77,525 \$	17,331	\$ 263	\$ 34,786	\$ 9,463	\$ 6,385	<b>5</b>	11,963
Remove Amortization of one-utility costs (See Functional Assignment)	ent)	LBT	49	•	•		•			••	
Adjustment for injuries and damages account 925 (See Functional Assignment)	Assignment)	OMT	<b>4</b> 9		•		•	•		· ·	. 0
Adjustment for VDT net savings to shareholders		.BT	<del>69</del>	540,895 \$	260'96	1,392	179,877	\$ 42,195	33,774	· ·	60,929
Adjustment for merger savings			<b>6</b> 3	3,544,093	629,656	9,118	· ,	<b>,</b>	,,	, ·	27,55
Adjustment for merger amortization expenses		LeT	<b>69</b> 1	(509,415) \$	(30,505)	(1,311)	<b>5</b> 7 •	,,			24,505
Adjustment for MISO schedule 10 expenses		PLTRT	69 1	201,899 \$	44,213	45	81,208	·> •		, ·	000 200
Adjustment for effect of accounting change		<u>.</u>	۰.	4 4 18 1880, I	191,126	676'+	3 364,465	000°777	(7 0.19)		12,563)
Adjustment for HI start reduction		5 6	A 6	* (114,211)	(7/8'RI)	(507)	(701,107)	, .	, ,		99 439)
Adjustified for anyone page acceptance		- L	<b>5</b> 44	(*) p'ar	(100,001)	• • •	(in ,	• •	,		
Adjustment for sales fax refund		3 2	<b>•</b>	27.620 \$	6.192	- <del>2</del> 6	\$ 11.575	· • • •	\$ 2,161	۰,	4,064
Adjustment for CMI Nov expense		Tdd Id	, v:	469 201 \$	102 747	1 732	\$ 188,722	•	\$ 33,497	•	52,325
Adjustment for ice storm		SDALL	• •2	(472.573) \$	(63,098)		\$ (108,425)	· v	\$ (25,051)	<b>.</b>	(33,566)
Adjustment for management audit fee		OMT	67	36,069	8,064	\$ 122	\$ 16,184	<b>4</b> 3	5 2,971	×	5,566
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	••	(167,673) \$	(40,184)	\$ (622)	\$ (81,707)	₩,	\$ (14,913)	<b>.</b>	(28,135)
VDT Amortization and Surcredit		VDTREV	t/9	(106,432) \$	(23.944)	\$ (363)	\$ (44,478)	\$ (12,752)	\$ (8,271)	<b>.</b> ,	15,454)
Total Expense Adjustments				(8,974,354)	(2,308,377)	129,136	(5,144,679)	(1,586,310)	(946,348)		31,697)
Total Operating Expenses	TOE		69	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	<b>~</b>	2,728,782
											!
Net Cost Rate Base			••	259,564,825 \$	51,991,165	\$ 784,972	\$ 94,900,421	\$ 19,860,683	17,404,133	31,2	31,259,117
Bata of Batura			-	7.63%	7,425 6	17.93%	7.83%	14.90%	8,45%		8.73%

KENTUCKY UTILITIES
Cost of Service Study
Class Allucation
12 Months Ended
September 30, 2003

						ALONE TOWER MINE			
Description	Ref Name	Allocation Vector		Primary MPP	Transmission MPT	Power TOD Primary LMPP		2 S	Peak
Operating Expenses									
Operation and Maintenance Expenses			•		\$ 2,845,493	\$	ю ••	w	1,197,352
Depreciation and Amortization Expenses				383,454	293,871			0	289 103
Description of the contract of		ķ		(49,857)	(43,573)			6.0	(9,331)
Other Takes		<u>_</u>		35,135	57,913	212,41	35,029	79.5	76,08
Gain Disposition of Allowaneas				(1,839)	19,307			o 6	10,00
State and Federal Income Taxes		TXINCPE		585 607	409 736	(10)	*		(460,488)
Specific Assignment of Curtailable Service Rider Credit			,		001,004	•	, ,	•	(004,004)
Allocation of Curtailable Service Rider Credits		SCP	₩,	26,400	23,067	\$ 10,168	8 \$ 29,038	e9 80	4,940
Adiustments to Operation Expenses:									
Flightate mismatch to the local personers		Coarm		778C 3CU/	(303 301)	9 116	50 4	ě	(34 948)
Remove ECR expenses		FCRRFV	9 <b>4</b> 7	(1810)	(1443)			9 e4	(158)
Eliminate brokered sales expenses		Frem		(184 700) 3	(161.450)			, c	(19,393)
Eliminate DSM Expenses		DSMREV	• •		(22.1.2.1)		,	· ••	,
Year end adjustment		YREND	•	(141,450)	(165,932)		\$ (424,256)	8 8	(13,589)
Depreciation adjustment		DET	€9	,		•	•	•	•
Adjustment for change in depreciation rate		DET.	₩.	9,074	6,954	\$ 3,573	3 \$ 8,725	<b>₽</b>	6,841
Labor adjustment		181	e)	3,980	3,062	\$ 1,640	•	eo	4,326
Medical Expense (See Functional Assignment)	4	Ė	•	•		•	•	•	
Storm damage adjustment	signment)	100		(000)	•	, (306)			, o 5 E 6 0
Eliminate advertising expenses (See Functional Assignment)	-	SEVIN		(100)	•	360	A 44	, v	(occ'c)
Adjustment for amortization of ESM audit expense		R04	,	430	344	\$ 186	\$ 410	• • •	37
Amortization of rate case expenses		TMO	- 64	2,151	1,828	\$ 922		• • •	769
Remove Amortization of one-utility costs (See Functional Assignment)	signment)	LBT	₩.	,		•	•	•	
Adjustment for injuries and damages account 925 (See Functional Assignment)	ctional Assignment)	OMT	69	•		<b>1</b> /2	•	υ,	
Adjustment for VDT net savings to shareholders		E :	<b>4</b> 9 (	11,498	8,846	**	<b>\$</b>	<b>\$</b>	12,499
Adjustment for merger savings		<b>5</b>	<b>.</b> ,	75,341	57,959	<b>63</b>		4 :	81.898
Adjustment for INFIGER Amorazation expenses		CB I	· ·	(10,829) \$	(8,331)	\$ (4,462)	(10,131)	, e	(11,772)
Adjustment for effect of accounting change		Į,	•	36.507	747,4		• •	, . , .	27 503
Adjustment for iT staff reduction		- E	<b>9</b> 49	2 390	(1.838)		4 4	, v	756,77
Adjustment to remove Alstom expenses		PLPPT	,	(18,015)	(15,741)	9)	••	<b></b>	(3.371)
Adjustment for corporate lease expense		LBT	- 6-3				•		1
Adjustment for sales tax refund		R01	69	\$ 888	109	\$ 343	3 \$ 847		77
Adjustment for OMU Nox expense		PLPPT	49	11,291	9,866	\$ 4,349	\$ 12	<b>₽</b>	2,113
Adjustment for ice stom:		SDALL	₩	(8,598)		\$ (4,411)	<b>~</b>	<b>1</b> /9	(39,675)
Adjustment for management audit fee		DMT	↔	1,00,1	850	<b>•</b>	•	<b>4</b> 9	358
Adjustment for Retirement of Green River Units 1 & 2		TAGMO	<b>.</b> ,	(4 993)	(4,364)	(2,149)	••	9	(900)
voi Antonization and Surcredit Total Expense Adjustments		VD! KEV	,	(3,381) \$ (457,264)	(2,695) (445,682)		(3,155) (749,746)	e G (f)	(286) 17,608
Total Operating Expenses	TOE		•	3,896,772 \$	3,128,805	1,647,550	3,467,710	<b>∽</b>	,083,372
Net Operating Income (Adjusted)			49	985,539 \$	695,476	\$ 325,797	722,007	<b>57</b>	(650,270)
Net Cost Rate Base			49	5,981,173 \$	4,510,623	\$ 2,373,597	5,640,885	••	4,738,120

		Allocation	A11 615.	All Glandsin Cohool	Decision Space	Make Dame	Change 1 factoring	Control attention   Links		Outdoor 1 inhting	l aire and
Description	Ref Name	Vector		AES	33	- 1	StLt	Dec St Lt		C O Lt	Contracts
Operating Expenses											
Oneration and Maintenance Expenses			6	00000							
Depreciation and Amortization Expenses			•	5,520,012	113 731	137,585	3,219,253	2012,394	741 212	119.577 3	2,095,125
Regulatory Credits and Accretion Expenses				(72,276)	(12,396)	(11,759)		,			(305,209)
Property Taxes		ΥΡΊ		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)
Coate and redectal income laxes  Coaces as a formation of Duration in the Coaces		TXINCPF		52,369 \$	(14,881)	\$ (3,961) \$	(231,071)	\$ 58,013 \$	\$ 1,012,992 \$	125,405 \$	887,604
opening hysogenesis of cultivitation of control of Control of Curtainable Service Rider Credit		Ü			. 4	2000	,	,		v9 s	(3,630,403)
		Š	,	20,200	coc'n	. C77'D		•	•	,	0.00
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	<b></b>	(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) \$	\$ (93,685) \$	(14,544) \$	(694,595)
Climinate USW Expenses		DSMREV	<b>.</b>	,	•		•				•
Ted: end adjustment		YREND	s> s		(11,965)		10,181	7,379	43,060 \$	(11,571) \$	
Adjustment for change in decreciation rate			A 4	4 000 \$		, ,	, 000		* 1 5 2 2	, 000	40 577
Labor adjustment		18 E	s es	5,517	1,193	3,250 3	10,042 81,042	4 40cc	# 1223 #	7,020	170071
Medical Expense (See Functional Assignment)		į	•	÷		*	2		- (2')		3,
Adjustment for pension/post retir benefit (See Functional Assignment)	signment)	LBT	69	•	•		,	,	•	,	•
Storm damage adjustment		SDALL	s	(2,563) \$	(225)	\$ (1,032) \$	(3,854)	\$ (302) \$	(4,091) \$	\$ (629)	(912)
Eliminate advertising expenses (See Functional Assignment)	_	REVUC	so.	49	•				67	<b>49</b>	,
Adjustment tot amortization of ESM addit expense		203	<b>ب</b>	338	8 2	\$ 62 \$	462	2 29 3	534 \$	80 P	1,412
Remove Amortization of one-utility costs (See Functional Assistants)	ignmonth	- CM	<b>→</b> ₩	7, 13d	RAS	A .	7,000	יייי דיייי	089	107	058,0
Adjustment for injuries and damages account 925 (See Functional Assignment)	efonal Assignment)	i No	<b>,</b>	, ,		•					
Adjustment for VDT net savings to shareholders	( )	. LBT	• •	15.938 \$	3.447	3.657.5	55.291	6.367	27.956.5	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 \$		•	649	•	29,736
Adjustment for effect of accounting change			•	60,124 \$	10,854	5 13,131 \$	165,128	\$ 19,839 \$	70,741 \$	11,405 \$	199,958
Adjustment for It start reduction		LBT	•••	(3,312) \$	(716)	\$ (200)	(11,491) \$	\$ (1,323) \$	(5,810) \$	(934) \$	(10,751)
Adjustment for company 10000 commens		PLPPT	ı,	(26,110) \$	(4,478)	5 (4,248) \$		,	·	,	(110,257)
Adjustment for cales for refund			<b>^</b> 6	000	, ;				, ,	A 6	, ,
Adjustment for OMU Nov expense		- F00 10	9 v	16 265 4	120	6 621 6	20	*	c 7nl'.	701	2,2,0
Adjustment for ice stam		TEC	9 44	28 599)	(8.163)	4 2,002 3 (11,514) S	(43 003)	6 368)	(45 641)	7 125	(10,180)
Adjustment for management audit fee		OMT		\$ 666	186	181 \$	962	\$ 100.00	786 5	124 S	4 157
Adjustment for Refirement of Green River Units 1 & 2		OMPPT		(4.646) \$	(787)	\$ (6/2)	(1,332) \$	(76) s	(2.066) \$	(321) \$	(20.948)
VDT Amortization and Surcredit		VDTREV	.,	(2,682) \$	(445)	\$ (490) \$	(3,643) \$	\$ (567) \$	(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		w	3,877,516 \$	986,088	\$ 723,785 \$	5,381,845	\$ 672,829 \$	4,548,162 \$	670,638 \$	12,421,193
Net Operating Income (Adjusted)			103	215,552 \$	1,337	\$ 22,959 \$	(4,622) \$	\$ 131,676 \$	1,712,280 \$	217,613 \$	1,822,820
Net Cost Rate Base			va	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			L	2.20%	%B0.0	1.04%	-0.02%	3.64%	13.14%	10.45%	2.75%

# 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	) ) )	CASE NO.
KENTUCKY UTILITIES COMPANY	,	2003-00434

EXHIBIT (SJB-6)

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

12 Months Ended September 30, 2003

2,528 (109,346) 4,709 (91,531) 66,930 (2,574) (68,786) (15,263) 6,105 (10,743) (9,603) General Service Primary GSP 2,821,048 304 2,593,777 61,916 \$ (2.393,665) \$ \$ (2.393,665) \$ \$ (2.291,642) \$ (7.062) \$ (1.062) \$ (1.062) \$ (428,633) \$ (428, 69,475,900 \$ 65,106,127 \$ 7,821 \$ General Service Secondary GSS 129,125 \$ (6,590,128) \$ (6,590,128) \$ (4,715,9216) \$ (4,715,9216) \$ (4,145,925) \$ (4,145,926) \$ (4,1410) \$ (4, 147,101,217 \$ 16,258 \$ 135,130,054 \$ All Electric Residential Rate FERS 137,916,946 \$ 124,416,572 \$ 122,243 181,23,277 181,562,574 3,208,163 (4,562,574 3,208,163 (4,13,19) (4,17,181) (464,390) 15,547 Residential Rate RS 675,000 \$ (35,887,728) \$ (4,728) \$ (4,47,728) \$ (7,62) \$ (7,62) \$ (7,62) \$ (7,62) \$ (7,76) \$ 768,801,159 \$ 693,449,939 \$ Total System (13,500,374) \$ Allocation Vector VDTREV PLPPT Energy **2**04 89 FACRI ECRREV ECRRI ESMREV RATESW DSMREV YREND Ref Pro-Forma Adjustments:

Eliminate unbilled revenue

Adjustment for Mismatch in Keel cost recovery

Adjustment for Reflect Full Vear of FAC Roll-in

Remove ECR Revenues

Adjustment to reflect Full Vear of ECR Roll-in

Remove off-system ECR revenues

Eliminate ESM, FAC, ECR Roll-in

Eliminate ESM, FAC, ECR from rate refund acct.

Eliminate DSM, Revenue

Year end adjustment

Merger aavings

Adjustment for rate switching, increased interruptible credit

VOT Amortization and Surcredit Cost of Service Summary -- Pro-Forma Total Pro-Forma Operating Revenue Total Operating Revenue ~ Actual Operating Revenues

KENTUCKY UTILITIES
Cust of Service Study
Class Allocation
13 Manths Ended
September 30, 2003

Description	Ref Name		Affocation Vector	Combined Light & Power LPS	Combined Light & Power	Combined Light & Power LPT	Large Commilind TOD Primary LCIP	Large Commind TOD Transmission LCIT	High Lead Factor Secondary HŁFS	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	<b>\$</b> 7	\$ 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	FACR	준		\$ 365,749	•	\$ 2,524	\$ 194,737	•	\$ 53,661	62.851
Remove FLA revenues	P. P	ECRREV		\$ (5,734,057)	••	\$ (19,498)	\$ (2,401,012)	•	\$ (446,972)	\$ (838,688)
Adjustment to reflect Full Year of ECR Roll-in	ä			\$ 4,133,949	•	\$ 14,085	\$ 1,735,487	₩,	316,548	\$ 606,165
Remove of system ECR revenues		_	PLPPT	\$ (173,813)	٠,	\$ (652)	\$ (79,812)	•	(14,134)	\$ (26,648)
Chiminate brokered sales			Energy	\$ (5,358,526)	<del>65</del>	\$ (19,889)	\$ (2,745,877)	•	\$ (504,385)	\$ (954,481)
CUMINATE COM TEVENDES CONTECTED	ESV	ESMREV		\$ (1,152,341)	s	\$ (3,814)	\$ (474,129)	₩,	\$ (89,283)	\$ (160,668)
Timmoate EdwinAC, ECK from rate refund acct.			R01	\$ 373,990	•	1,271	\$ 156.727		\$ 29.263	\$ 55.022
Eliminate DSM Revenue	NSO	DSMREV		\$ (98,441)		\$ (472)		49		
Teal end adjustment	YRE	YREND		\$ (587,774)	••	\$ 273,166	•	,		\$ (537.561)
Merger savings			R01	\$ (588,297)	69	\$ (2,000)	\$ (246,535)	\$ (69,809)	(46.031)	(86.551)
Adjustment for rate switching, increased interruptible credit	RAT	RATESW			49		\$ (64,184)	\$ (120,793)		
VOI Amonization and Surcredit			VDTREV	\$ 19,479	\$ 4,382	99	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

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
September 30, 2003

Cost of Service Summary – Pro-Forma  Operating Revenues  Total Operating Revenue – Actual  Pro-Forma Adjustments:  Eliminate unbilled revenue Adjustment for Mismach in teal cost recovery Adjustment for Mismach in teal of FAC Roll-in  Remove ECR revenues  Adjustment to reflect Full Year of EAR Roll-in  Remove GRA revenues  Remove GRA revenues  Remove GRA revenues		Allocation	Mining Power Primary MPP	Coat mining Power Coat Mining Power Primary Transmission MPP MPT	Power TOD Primary	Transmission LMPT	Peak
ost recovery FAC Roll-in ECR Roll-in			:				
ue – Actual s: lifed revenue lifed revenue Reflect Fur of FAC Roll-in revenues revenues revenues sistem ECR Roverues							
Actual d revenue site man to the cost recovery site man to the cost recovery venues reputed Full Year of ECR Roll-in medical Full Year of ECR Roll-in							
flevenue fismatch in tuel cost recovery filled Full Year of FAC Roll-in venues freed Full Year of ECR Roll-in enn ECR revenues.		₩	2,660,987	\$ 4,559,871	\$ 2,216,475	\$ 5,425,560	\$ 508,911
of revenue Mismarch in tuel cost recovery filter Full Year of FAC Roll-in venues Heef Full Year of ECR Roll-in							
ery III-in Lin	801	€9	4,976	3,978	1,924	\$ 4,748	<b>5</b> 7
il-in Lin	Energy	v,	(268,036)	\$ (234,296)	\$ (118,074)	\$ (276,483)	₩
툿		<b>v</b> 9	12,843	13,496	\$ 2,865	\$ 11,438	1,179
Lin	REV	69	(182,407)	\$ (145,445)	\$ (70,105)	\$ (172,666)	₩,
Remove off-system ECR revenues	ē	673	132,466	\$ 105,333	\$ 51,614	\$ 127,076	v,
-	PLPPT	•	(5,613)	(4,698)	\$ (2,499)	\$ (5,403)	••
Eliminate brokered sales	Energy	**	(168,612)	(147,387)	\$ (74,276)	\$ (173,926)	*
Eliminate ESM revenues collected		'n	(33,089)	\$ (25,314)	\$ (11,418)	\$ (28,011)	<b>.</b> ,
acct.	R01	S	12,018	909'6	\$ 4,648	\$ 11,466	••
	REV	₩7	•	•		,	•
Year end adjustment	Q		(234,645)	(275,257)	,	\$ (703,778)	(22,542)
	R01	<b>.</b> 9	(18,905)	\$ (15,111)	\$ (7,311)	\$ (18,037)	••
Adjustment for rate switching, increased interruptible credit  VDT Amortization and Surcredit	ESW VDTREV	₩ `	619	\$ 493	\$ 236	\$ 579	\$ 52
Total Pro-Forma Operating Revenue	(13	(13,500,374) \$	4,912,603	3,845,270	\$ 1,994,079	\$ 4,202,563	\$ 434,167

KENTUCKY UTILITIES Cost of Service Study Class Alforation

			Allocation	All Elcetric School		Electric Space Heating Rider	Water Pumping	C Street Lighting	Decorative Street Private Outdoor Lighting Lighting	Private Outdoor Lighting	0.5	ing	Special
Description	Ref	Name	Vector	AES		33	Œ	StLt	Dec St Lt	P0 Lt	COL		Contracts
Cost of Service Summary Pro-Forma													
Operating Revenues													
Total Operating Revenue Actual				\$ 4,492,389	389 \$	776,874	\$ 817,460	\$ 5,609,441	\$ 815,367	\$ 6,541,571	\$ 962,798	80 80	18,686,630
Pro-Forma Adjustments:			ě	•		37.2	747	7 3.67	790	6 178	•	\$ 200	16.335
Firminate unbilled revenue			102	24.0	017 082) 4	727 387)	(37,004)	(87.643)	(5,009)	\$ (135,957)	(21,106)	90	(1,007,994)
Adjustment to maintain in the cost according		1000	ĥ		719	881	1.457	S (1021)	(74)	5 (3,573	<b>.</b> ,	182) \$	45,827
		VI B B C		. (143	373) \$	(23.364)	\$ (26,381)	\$ (196,772)	(29,280)	\$ (227,715	<b>6</b> 7	(64) \$	(691,956)
Adjustment to reflect Full Year of FOR Rollin		FCRR		20.	270,	17,741	19,017	\$ 144,134	21,362	\$ 166,721	<b>-</b> -7	87 \$	493,730
Persona off-curtery FCR revenues			Ladia	(5	951) \$	(1,093)	(866)	\$ (498)	(28)	(771)	•>	20) \$	(16,698)
Figure 4 Professed Roles			Finerov	5 (137	125 \$	(23,519)	\$ (23,278)	\$ (55,133)	(3,151)	\$ (85,526	**	\$ (77)	(634,093)
Timinate TAM sevences collected		ESMREV	n i	.5	\$ (666	1,124	(4,856)	(37,564)	(5,964)	\$ (43,690	٠,	\$ (62)	(133,593)
Eliminate ESM FAC ECR from rate retund acct.			R01		445 \$	1,630	1,730	\$ 12,909	1,908	\$ 14,921	٠,	92	38,449
Eliminate DSM Revenue		DSMREV		€9	•	•				, \$	<b>5</b> 4>	,	
Year end adjustment		YREND		•	ι·9	(19,849)	•	\$ 15,889	12,240	\$ 71,430	••	94) \$	
Mersersavings		!	202	\$ (14,	(14,857) \$	(2,564)	\$ (2,722)	\$ (20,307)	(3,001)	\$ (23,470)		(3,447) \$	(62,054)
Adjustment for rate switching, increased internotible credit		RATESW										₩.	(2.777,732)
VDT Amortization and Surcredit			VDTREV	69	491 \$	ю Т	\$	\$ 667	102	\$ 802	•	115	2,335
Total Pro-Forma Operating Revenue			(13,500,374)	4) \$ 4,078,936	\$ 986,	691,230	\$ 745,233	\$ 5,390,448	\$ 805,262	\$ 6,280,921	\$ 891,430	\$ 061	13,960,186

KENTUCKY UTILITIES
Cust of Service Study
Class Allucation
12 Months Endet
September 30, 2003

		Allocation		Total	Residential	All Electric Residential		Secondary	Primary
Description Ref	Name	Vector		System	Rate RS	Rate FERS	S	GSS	GSP
Operating Expenses									
			•			•	40.00	4 6 6 0 0 4 7 0 4	071 772 1
Operation and Maintenance Expenses			^	540,721,522	000,000,000	,	21.419.953	5 577 587	-
Depreciation and Arrivalization Expenses				(8 6 FG 0 F3)	(1 457 394)	_	(1 873 558)	(792, 250)	(28 699)
		FOR		(0,000,000)	0.7 0.70		080 080	883.896	21 153
Property laxes		2		5 761 006	1 272 480	•	1 390 064	620 232	14.843
Cond. Lakes				(880 970)	776 06/	:	(45,226)	(16.427)	(750)
Call Disposition of Alexanders		TYINCDE		25 916 506 4	(728 540)	•	732.082) \$	3.125.711 \$	346
Configuration to the contract of Contract				(4.582.475)	2 ,	•	,		. •
Allocation of Curtailable Service Rider Credits		SCP	•	4.582 475 \$	934.980	•	771,944 \$	449.462 \$	11,972
Adjustments to Operating Expenses:					1	,	í	*	007
Eliminate mismatch in fuel cost recovery		Energy		(31,644,777) \$	(5,046,623)	_ 	5,810,987) \$	(2,110,684) \$	(814,08)
Remove ECR expenses		ECRREV		(248,468) \$	(45,272)	•••	(46,795) \$	(22,742) \$	(808)
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) \$	\$ (100,622)	067,010
Year end adjustment		YREND		151,410 \$	(251,488)	,,	1.056,029	o 047.184	
Depreciation adjustment		DET				<b>,</b> .	, 000 000	. 753.300	5 2 4 7
Adjustment for change in depreciation rate		- L		2,180,2	201,004	••	200,000	* VSP SU+	777.6
(abor adjustment		Ē		1,002,016	C1 047	•	000	•	7
Medical Expense (dee Functional Assignment)		TO.			•	v	•	•	•
Adjustment to perison post rest perion (dee nortaines Assignation)		1703		473 D14) C	(158 017)	•	153.3250 \$	\$ (575.89)	(554)
Statut dathaga adjustificiti Filmbala advantision avpanses (See Functional Assignment)		REVUC		· • ·		• • •	8	\$	
Adjustment for anodization of FSM such expense		R01		58.333 \$	10,564	. 60	11,159 \$	5,351	218
Amortization of rate case expenses		TMO		352,456 \$	67,868	•	73,217 \$	29,305 \$	266
Remove Amortization of one-utility costs (See Functional Assignment)		LBT		•	•	€7	,	,	•
Adjustment for injuries and damages account 925 (See Functional Assignment)	ment)	OMT			•	₩	•	,	
Adjustment for VDT net savings to shareholders		LBT		2,895,000 \$	716,908	₩	\$ 608,869	307,575 \$	6,568
Adjustment for merger savings		LBT		18 968 825 \$	4,697,374	**	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	49	182,537 \$	77,187	2,796
Adjustment for effect of accounting change		DET		8,434,618 \$	1,882,322	<del>~</del>	2,044,309 \$	914,080 \$	21 445
Adjustment for IT staff reduction		181		(601,682) \$	(148,998)	•	(145,237) \$	(63,925) \$	CDC, L)
Adjustment to remove Alstom expenses		PLPPT		(3,126,995) \$	(530,085)		(6/6,822)	(102,200)	(10,307
Adjustment for corporate fease expense		181				., ·			757
Adjustment for sales tax refund		R01		120,391	21,803		23,030	. C.	0
Adjustment for OMU Nox expense		PLPPT		1,959,879 \$	332,243	<b>.</b>	424,206 \$	9 (000 FL)	0,480
Adjustment for ice storm		SDALL		(5,277,336) \$	(1,874,536)	۰ م	\$ (719,017,1)	4 (800,4//)	(0,1.0)
		OMT		163,982 \$	31,578		34,063	10,004	194.0
Adjustment for Retirement of Green River Units 1 & 2		OMPPT		(705,035) \$	(114,041)	, n	(134,705) 5	6 (188,0c)	(4.191
VDT Amortization and Surcredit		VOTREV		(466,280) \$	(84,847)		(00,030)	(42,731) 5	(1001)
lotal Expense Adjustments				(017,408,55)	(5,175,105	_	(ata'a	(1,0,000)	2 (1)
Total Operating Expenses	T0 <b>E</b>		**	633,180,928 \$	121,393,711		31,729,540 \$	58,266,615 \$	2,011,697
Net Operating Income (Adjusted)			49	60,269,011 \$	3,022,861	٠,	3,400,514 \$	6,839,512 \$	582,080
Net Cost Pate Base			**	1,412,033,543 \$	321,541,172	₩	345,378,280 \$	154,782,645 \$	3,479,092
Date of Determ			_	4.27%	0.94%	.9	0.95%	4.42%	16.73%

Description	SE SE	Allocation Vector	5	Power	Power	Power LPT	TOD Primary T	TOD Transmission LCIT	Secondary HLFS	Primary HLFP
xpenses										
•			٠	4+9 942 359 6	27 240 511 \$	403.589	54.932.301	15,226,217 \$	10,073,657	18,924,679
Operation and Maintenance Expenses Decreatation and Americation Expenses			9			49,142	6,500,949	1,521,924	1,182,222	2,160,026
Dept street of the American Companies				(1,937,791)	(473,184)	(7.274)	(889,795)	(227,019)	(157,572)	(29/,08/
Property Taxes		FPT		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	~ / # "LDL	(603.2)	(50.419
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(28,956)	(/П/'8)	(5,503)	1 305 431
State and Federal Income Taxes		TXINCPF	<del>67</del>	11,638,514 \$	2,578,996 \$	87,139	3,492,699 \$	1,440,754 \$	61,117	25.000
Specific Assignment of Curtaitable Service Rider Credit					(181,381)	•	(271,654)	(200'884)		ACT 201
Allocation of Curtailable Service Rider Credits		SCP	€9	1,097,059 \$	240,238 \$	4,049 \$	441,260	101,228 \$	. 128,87	20.02
Adjustments to Operating Expenses:		7	ŧ	7 811 155) \$	(1845 959) \$	\$ (27.879)	(3.848,951)	\$ (1,118,710) \$	(700,707)	(1,337,916)
Eliminate mismaich in ruel cost recovery		, Gaacu	÷ 4	(XDX 9/4)	(17.809)	(193) \$	(23,825)	(6,834) \$	(4,435)	(8,322)
Kernove ECK expenses		ביאטן ביי	9 <del>6</del>	(5,869,813)	(1.442.579) \$	(21,787)	(3,007,876)	(874,249) \$	(552,511)	(1,045,554)
Chrimate prokered sales expenses		CHAIR DAY	, ,	(98.559)	(12 138) \$	(473)		•		
		CNHRY	· en	(360.354) \$	71,010 \$	164.672			•	(324,056)
Opposition adjustment		THO	• •	***	.,		,		. !	
depreciation adjustment				372.858 \$	82,709 \$	1,163	153,834	36,014 \$	27,975	51,113
Columnia to Change III copi eciation into		- B-1	- 49	182,122 \$	33,999	467	64,398	15,964 \$	12,056	18,12
Medical Expense (See Functional Assignment)										
Adjustment for pension/bost refit benefit (See Functional Assignment)		.B.	v		,				4 6	(00000)
Storm damage adjustment		SDALL	67	(42,357) \$	(5,656)	•	(9.718)		(0,443)	20.5
Eliminate advertising expenses (See Functional Assignment)		REVUC	49		•	, !	. !		1074	1 080
Adjustment for amortization of ESM audit expense		R01	49	13,383 \$	3,000 \$	5 5 5	2,608	1,350	140'- 174'A	12.156
Amortization of rate case expenses		- DWI	va -	(6,335 3	\$ 506/1	807	7			
Remove Amortization of one-utility costs (See Functional Assignment)	_	LBT	69 (	,		•			,	
Adjustment for injuries and damages account 925 (See Functional Assignment)	signment)	WO.	99 (			1 1 1 1 1 1	186 047	46 120	34.829	5 63,32
Adjustment for VDT net savings to shareholders		<b>5</b>	<b>1</b> 9 1	\$ 001,020	\$ 77'06 \$ 77'06	000	1219 030	302.193 \$	228,212	\$ 414,89
Adjustment for merger savings		3 5	<i>a</i>	\$ 0/4'/44'C	5 (805,00)	(1272)	(175,219)	(43,436) \$	(32,802)	\$ (59,636)
Adjustment for merger amortization expenses		<u> </u>	٠.	4 907,020)	46.102	002	86.691	22.118	15,352	\$ 28,94
Adjustment for MISO schedule 10 expenses		ב ב ב	۰.	100,730	222 586	4.690	620 447	145,252	112,831	\$ 206,15
Adjustment for effect of accounting change		5 5	, ·	(100,353)	(20.414) \$	(787)	(38.667)	\$ (8,585)	(7,239)	(13,160)
Adjustment for IT staff reduction		9 6	• •	(300,000)	(170 038)	(7.628)	(321,438)	\$ (82,011) \$	(56,923)	\$ (107.32
Adjustment to remove Alstom expenses		7 10	•	(070,001)			,			,
Adjustment for corporate rease expense		ē	, .	27.620 \$	6 192 \$	76	11,575	3,278 \$	2,161	5 4,064
Adjustment for sales tex retund		T00 10	• •	2 672 827	107.137 \$	1,647	201,465	\$ 51,401 \$	35,677	\$ 67,268
Adjustment for CMC Rox expense		1905	۰.	(472.573) \$	\$ (63.098)		(106,425)		(25,051)	\$ (33,56
Adjustment for ice storm		3000	9 <del>u</del>	25.575	A 143	121	16.416	\$ 4,550 1	3,010	\$ 5,65
Adjustment for management audit ree		Tage	9 66	(165 191) \$	(40.541) \$	(615)	(82,745)	\$ (23,467)	(15,091)	\$ (28,537)
Adjustment for Retirement of Green River Units 1 & 2		VEDTO)	» v	(106,432) \$	(23.944) 5	(363)	(44,478)	\$ (12,752)	(8,271)	\$ (15,454)
VD I Amonization and surgredit		*	•	(9,175,410)	(2,279,396)	128,577	(5,060,548)	(1,532,786)	(931,953)	(2,099,076
			•		4 100 100 70		e 00 180 840	£ 16.768.675 \$	11 146 215	\$ 20,477,798
Total Operating Expenses	TOE		•	138,082,181	6 104,11,10		1000	-	:	
Net Coerating Income (Adjusted)			s	21,326,675 \$	4,730,642 \$	145,006	6,789,215	\$ 2,551,749	1,360,711	\$ 2,480,920
						040	400 406 807	22.276.610	18 349 667	\$ 33,402,015
Net Cost Rate Base				246,357,662 \$	53,894,949	740,410	100,420,031	1		
									/067 1	74107

KENTUCKY UTILITIES Cust of Service Study Class Allocation

	:	Allocation	Coal	Coal Mining Power Primary	Coat Mining Power Transmission	Large Power Mine Power TOD Primary	ine nary	Power TOD C Transmission	Combination Off- Peak CWH
Description Rel		Vector		L		j.			
			,			,		600 727	1 102 506
Operation and Maintenance Expenses			<b>6</b>	3.523,749 \$	2,956,782	,	208.952	404,804	292,095
Department of the control of the con				(62,573)	(52.377)		(27.856)	(60,238)	(9.778)
Property Taxes		FdN		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	47	480,089	336,562	•	1,18,359 \$	371,609 \$	(464,200)
Specific Assignment of Curtaliable Service Rider Credit				,	•				
Allocation of Curtailable Service Rider Credits		SCP	<b>~</b>	26,400 \$	23,067	••	10,168 \$	29,038 \$	4,940
Adjustments to Operating Expenses:									
Ellminate mismatch in fuel cost recovery		Energy	۰۰	(236,347) \$	(206,595)	•	(104,115) \$	(243,795) \$	(24,816)
Remove ECR expenses		ECRREV	<b>67</b>	(1,810) \$	(1,443)	••	(989)	(1,713) \$	(156)
Eliminate brokered sales expenses		Energy	*	(184,700) \$	(161,450	•	(81,363) \$	(190,521)	(19,393)
Eliminate DSM Expenses		DSMREV	<b>6</b>	, i		· • •		. (30.707)	
Year end adjustment		YREND	•	(141,450) \$	(165,932)	•	,	¢ (007'474)	(10,000)
Depreciation adjustment			· ·		, ,	<i>^</i>	. 64	0 570	6 917
Adjustment tot change in depreciation rate			, v	4 462	900 8		1961	3.928 \$	4 343
Marked Concess /Son Erredines   Assistants		3	•	,		•			-
Medical Expense (See Functional Assignment) Adjustment for pension/host retir benefit (See Functional Assignment)		£BT	67	,		•	<del>6/3</del>	,	•
Storm damage adjustment		SDALL	**	\$ (098)	•	•	(382) \$		(3,556)
Eliminate advertising expenses (See Functional Assignment)		REVUC	•			•	•	,	
Adjustment for amortization of ESM audit expense		R01	'n	430 \$	344	••	39 5	410 \$	37
Amortization of rate case expenses		OMT	•	2,263 \$	1,906	<b>.</b>	666	2,232 \$	2
Remove Amortization of one-utility costs (See Functional Assignment)	:	LBT	<b>د</b> ه د	,			,		
Adjustment for injuries and damages account 925 (See Functional Assignment)	nment)	L MO	<b>.</b> ,				A 6	9 076 74	12 548
Adjustment for VDT net savings to shareholders		E !	<b>,</b> ,,	12,892	118,9		27.000	040,11	82.21
Adjustment for merger savings		- E	,	204,48	207'60	•	6 (2)	100,450 100,450 100,450	(11,818)
Adjustment for merger amortization expenses		181	, e	(15,141)	(9,240)		47.5	\$ 698.5	953
Adjustment of made senecule to expenses		, Luc	•	44.720	33.675		19 947	38.634 \$	27.877
Adjustment for 17 stoff radiution		E		(2,679)	(2.039)		(1.182) \$	(2,358) \$	(2,608)
Adjustment to remove Alstom excenses		P PPT	•	(22,605) 5	(18.921)	•	(10,063) \$	(21,761) \$	(3,532)
Adjustment for commute leave expense		F	•			•	•	•	•
Adjustment for sales tax refund		R01	<i>U</i> 1	888	502	•	343	847 \$	11
Adjustment for OMU Nox expense		PL PPT	.,	14,168	11,859	٠,	6,307 \$	13,639 \$	2,214
Adjustment for ice storm		SDALL	69	\$ (8,598)		•	(4,411) \$	-	(39,675)
Adjustment for management audit fee		OMT	٠,	1,053	1887	89	465 \$	1,038 \$	360
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	₩,	(5,227)	(4,527)	۰s	308) \$	(5,313) \$	(808)
VDT Amortization and Surcredit		VOTREV	₩,	(3,381)	(2,696)	55	,291) \$	(3,165) \$	(286)
Total Expense Adjustments				(438,270)	(432,521	_	(130,386)	(741,691)	18,276
Total Operating Expenses	TOE		69	4,071,380	3,249,788	1,766,531	,531 \$	3,541,753 \$	1,089,511
Net Operating Income (Adjusted)			•	841,223	595,482	••	227,548 \$	\$ 018,099	(655,344)
Net Cost Rate Base			ø	7,228,861	5,375,126	\$ 3,223,008	\$ 800'	6,169,967 \$	4,781,983
									1000

		College A	9	All Electric Corticol	Electric Space Heating Rider	Water Pumoing	Street Lighting	Decorative Street Private Outdoor Lighting Lighting		Customer Outdoor Lighting	Special
Description	Name	Vector		İ	33	¥	StLt	Dec St Lt	POLt	COLt	Contracts
Operating Expenses											
Operation and Maintenance Expenses			69	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	7,757,338	(317)	(8,590)	(1,334) \$	(186,160)
Regulatory Credits and Accretion Expenses		TOIN		(55,348) 45,165	10.485	12 309	157,319	18,678	71,351	11,471 \$	122,997
Property Laxes		-		38.730	7,357	8,638	110,391	13,107	20,067	8,049 \$	86,307
Gaio Disnosition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(833)	(145) \$	(6,918)
State and Federal Income Taxes		TXINCPF	49	101,641 \$	(13,126)	\$ 1,309	\$ (277,175) \$	55,377 \$	941,592 \$	114,319 \$	7,877,306
Specific Assignment of Curtailable Service Rider Credit				•		•				,	(5,050,403)
Altocation of Curtailable Service Rider Credits		SCP	69	38,263 \$	6,563	\$ 6,225		v <del>3</del>		,	0
A discolator and to Open and to Discolator											
Adjustments to Operating Expenses.		Energy	•	(192,211)	(32,967)	\$ (32,629)	\$ (77,281) \$	(4,417) \$	(119,883) \$	(18,611) \$	(888,821)
ABTOVE ECR expenses		ECRREV	•	(1,423) \$	(232)	\$ (262)	\$ (1,953) \$	(291)	(2,260) \$	(330)	(0,000)
Eliminate brokered sales expenses		Energy	<b>19</b>	(150,209) \$	(25,763)	\$ (25,499)	\$ (60,394) \$	(3,452) \$	(93,686) \$	(14,544)	(084,080)
Eliminate DSM Expenses		DSMREV	'n	٠	. :				9 090 67	(11.571) \$	
Year end adjustment		YREND	<b>5</b> 7	,	(11,965)		10,181	B 10'/	000'5	• • •	,
Depreciation adjustment		DET	<b>v</b> > 0			3 155	2 16817	4 969 5	18.901	3,039	30,706
Adjustment for change in depreciation rate		DE I	n e	5,900	1,185	1 747	19.349 \$	2.216 \$	10,003	1,606 \$	13,387
Labor adjustment		9	,	767.0	1		! !!	1		•	•
Medical Expense (des numeronal Assignment) Adirection for concional retir banefit (See Functional Assignment)		181	69	67	,			,	•		, ;
Storm damage adustment		SDALL	***	(2,563) \$	(552)	\$ (1,032)	\$ (3,854) \$	(302) \$	(4,091) \$	(639)	(912)
Eliminate advertising expenses (See Functional Assignment)		REVUC	*	•				, ;		, 2	1412
Adjustment for amortization of ESM audit expense		R01	<b>69</b> 1	338 \$	85 5	\$ 62	462.5	68 62	2 450	\$ 622	7.882
Amortization of rate case expenses		LWO:	<b>69</b> 1	2,086 \$	SS	202	7	33	2		
Remove Amortization of one-utility costs (See Functional Assignment)	•	LB1	<b>1</b> 9 (	,	•			9 147			•
Adjustment for injuries and damages account 925 (See Functional Assignment)	nment)	I MO	<b>17</b> 6	, ad	3.424	3.587	55.889	6.402 \$	28,898 \$	4,641 \$	38,675
Adjustment for VD1 net savings to shareholders			, ,	100,240	22 434	23.504	\$ 356.267	41.948 \$	189,346 \$	30,410 \$	253,407
Adjustment for merger savings		- in	, 41	(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 \$	<u>ج</u>	837 \$	130 \$	18,137
Adjustment for effect of accounting change		DET	s	56.334 \$	10,719	\$ 12,726	\$ 168,674 \$	20,041 \$	(a,00e)	\$ (596)	(850.8)
Adjustment for IT staff reduction		LBT	<b>u</b> > (	(3,177) \$	(217)	(46)	(01011)	(115)	(3.103) \$	(482) \$	(67,250)
Adjustment to remove Alstom expenses		PLPPT	<b>v</b> s 6	(23,968) \$	(4,402)	(810't)	(*,004,)	9 49	<b>S</b>	•	
Adjustment for corporate lease expense		<u> </u>	÷ •:	898	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	49	(28,599) \$	(6,153)	(11,514)	\$ (43,003)	(3,368) \$	(45,641) \$	130	3.867
Adjustment for management audit fee		FMO	₩	\$ 0.26	185	\$ 178	586	ភូទ	\$ 778	245	(28, 87)
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	↔	(4,537) \$	(793)	\$ (768)	(1,434)	(82)	(2,224)	(830) 5	(12.760)
VDT Amortzation and Surcredit		VOTREV	<b>19</b>	(2,682)	(42,093)	(31,768)	410,676	63,622	64,951	(6,583)	(1,208,417)
TOTAL EXPENSE AUTHORITIES									:		107 106 07
Total Operating Expenses	TOE		<b>6</b> 7	3,796,052 \$	687,494	\$ 715,072	\$ 5,458,071	\$ 677,187 \$	4,666,211 \$	688,967 \$	10,785,185
Net Operating Income (Adjusted)			v	282,883 \$	3,735	\$ 30,161	\$ (67,623)	\$ 128,075 \$	1,614,710 \$	202,463 \$	3,175,001
•					407 700			2 543 643 6	13.875.75 C	2 214 289 \$	20 004.120
Net Cost Rate Base			••	9,230,542 \$	1,761,139	\$ 2,144,158	3 30,043,938		1	- 1	
Rate of Return			L	3.06%	0.21%	1.41%	-0.22%	3.51%	11.64%	9.14%	15.87%

# 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-7)

# LOUTSVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Clack Alteration

	Re.	Name	Allocation Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate L.C Secondary
Description										
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Total Operating Revenue Actual				63	768,525,785 \$	291,774,308 \$	1,042,105 \$	106,206,583 \$	8,933,859 \$	132,997,184
Pro-Forma Adjustments:			Rint	w	(1,867,000) \$	(715,724) \$	(2.428) \$	(271,251) \$	(21,339) \$	(322,331)
Eliminate unbilled revenue			Energy	,	(4,406,145)	(1,479,166)	(6,691)	(513,321)	11.617	139,923
		PACE			547,241	181,639	202,	60.70	(477 642)	(1 940 152)
		VERRET			(11,228,429)	(4,264,952)	(15,362)	(1,630,435)	(250, (21)	133.401
		EC.P.P.			723,260	255,297	937	/69'OL1	(Act 00)	(330,945)
To Reflect a Full Year of the TCK Koll-in			Top I		(1,929,923)	(798,593)	(2,924)	(212,071)	(20,734)	(4.064.814)
Remove off-system ECX revenues			Nuero.		(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(288,304)	(1,196,285)
Eliminate brokered sales		PSMREV	ñ		(6,974,780)	(2,763,963)	(7.154)	(1,009,115)	(80,480)	(1 234 463)
Eliminate com revenues			R01		(7,150,231)	(2,741,076)	(8,299)	(1,038,835)	(25,623)	(340,279)
Circuitate Nate Asiana Assi		DSMREV			(3,277,501)	(2,771,657)	, 00	(100,97.5)	(220,02)	932,854
Ver End Bevenie Adiistned		YREND			2,614,347	1,232,278	(8,883)	(2/8/33)	(31.532)	(476,296)
Adjustment for Memor Savings			R01		(2,758,795)	(1,057,598)	(3,300)	(10,000)		
Adjustment for Customer Rate Switching & CSR Credit		RATESW	VDTREV		(621,927) 44,485	17,356	55	6,447	505	7,617
VDI Amortization and Surpredit									9 030 000	122 516 811
Total Pro-Forma Operating Revenue				es.	709,631,942 \$	269,278,378 \$	952,526 \$	98,312,757	9 600,002,0	2

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

	And Marie	Allocation		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Description	1								
Cost of Service Summary - Pro-Forma									
Operating Revenues					:	6 0 1	9 700 600 70	16.876.390 \$	80,727,853
Total Operating Revenue Actual			υ	14,652,107 \$	19,054,006 \$	6,245,472	100,000,000		
on Como Adiustments				ė (	46.400. 6	(14 766) \$	(83,348) \$	(37.178) \$	(183,683)
Fig-rolling Adjusting to a		R01	so.	(34,589) \$	(43,400)	(42,016)	(212,910)	(138,932)	(601,251)
Mismatch in fuel cost recovery		Energy		(30,400)	24 738	5.030	28,206	10,866	280,02
To Reflect a Full Year of the FAC Roll-In	FACRI			16,117	(275.776)	(89'062)	(505,167)	(223,730)	(1,130,594)
Remove ECR revenues	ECRREV			14 884	21.249	5,484	35,195	16,754	27, 70
To Reflect a Full Year of the ECR Roll-In	ECRR	} (		(35,905)	(50.917)	(14,985)	(75,351)	(46,325)	(217,363)
Remove off-system ECR revenues		1 H H H		(504 933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(645 195)
Eliminate brokered sales	i orion			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(703.468)
Eliminate ESM revenues	A LINCU	108		(132,469)	(173,873)	(56,551)	(319,207)	(505,241)	,
Eliminate Rate Refund Acct	DSMREV			(14,688)	(16,281)		147 900		
Eliminate Down Revenue Year End Revenue Adjustment	YREND			, , ,	565,077	(21.819)	(123,161)	(54,936)	(271,421)
Adjustment for Memer savings		R01		(111, [16)	(200,10)	. "	•	(279,699)	(227,252)
Adjustment for Customer Rate Switching & CSR Credit	RATESW	V VOTEEV		815	1,070	349	1,955	867	4,284
VDT Amortization and Surcredit							\$ 600 000 70	15 123 047 \$	73,729,592
Total Pro-Forma Operating Revenue			s	13,473,965 \$	16,144,692 \$	5,748,275 \$	\$ 578,778,15		

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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				<del>59</del>	2,667,730 \$	5,832,231 \$	207,928 \$	7,037,493 \$	727,497 \$	39,220,086
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	43	(6,454) \$	(15,890) \$	(464) \$	(19,577) \$	(1,786) \$	(30,792)
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)	(121,528)	(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)	(699)	(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)
Eliminata DSM Revenue		DSMREV				•	•	•	•	•
Year End Revenue Adjustment		YREND			•	2,999	(1,159)	17,114	5,808	٠
Adjustment for Merger savings			R01		(9.537)	(23,479)	(989)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW				•	,			(000'06)
VDT Amortization and Surcredit			VDTREV		146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				so.	2,464,065 \$	5,453,014 \$	189,714 \$	6,617,260 \$	677,761 \$	35,908,904

Description	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 Expanses									
Contraction and Maintenant Contraction			٠						
Operation and American Expenses  Decreciation and Americanic Expenses			æ	95,827,965	203,882,981	340.024	60,345,199 <b>\$</b>	5,7/3,024	43 083 004
Accretion Expense				462.519	191.388	701	50 824	969	79.313
Property and Other Taxes		TdN		12,603,252	5,805,546	42.776	1,456,554	113,849	1.864,962
Amortization of Investment Tax Credit				(4,010,380)	(1,847,335)	(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 Allocation of Interruptible Credits		SCP		(3,519,894) 3,519,894, \$	1511175 \$	2.563.\$	514 921 \$	41545 \$	625 034
		<u>;</u>					*		10000
Adjustments to Operating Expenses:		i				í			
Continuate mismatch in Idel Cost recovery		Energy Energy		(2,005,300) \$	(6/3,190) \$	(3,045) \$	(233,620) \$	(26,547) \$	(360,271)
Eliminate brokered sales expenses				(75,030,768)	\$ (076,079)	(2,417)	(255,487) \$	(20,079) \$	(305,205)
Eliminate DSM Expenses		DSMREV		(3,280,013) \$	(2.773.781) \$	• (C. D.D.)	(4) 103 (57) \$	(25,643) \$	(340,540)
Year end Expense adjustment		YREND		1,458,544 \$	687,488 \$	(5.575)	(155,950) \$	÷ + + 1	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		<b>.</b>	<b>ь</b> я	,	,	un ,	•
Laboradjustment		181		918,580 \$	437,787 \$	3,194 \$	114,202 \$	8,491 \$	130,863
Adjustment for pension and post Ket Exp. (See Functional Assignment) Storm demans adjustment	<del>£</del>	- 140		607	00000		9	•	
Adjustment to eliminate advertising expense (See Functional Assignment)	lent	SUMEL		¢ 76#'n/	40,(95 &	460	9.481 9	\$ 587	cas'c
Amortization of rate case expenses	Î	OMT		333,580 \$	133,841 \$	772 \$	39,614 \$	3,790 \$	54,436
Amortization of ESM audit expenses		RO1		58,333 \$	22,362 \$	76 \$	8,475 \$	\$ 299	10,01
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)		ŧ		6 C C C C C C C C C C C C C C C C C C C		4			
Adjustment for V.C. Het savings to shareholders Adiustment for messer southers		5 5		3,640,000	2,687,975	19,612	701,192 \$	52,132 \$	803,485
Adjustment for memor smooth attour expenses		9 10		19,427,401 \$	9,258,932	\$ 455,7d	2,415,307 \$	1/9,5/3 \$	2,767,663
MISO Schedule 10 one time credit		PLTRT		208.577	293.620 \$	1075	s (c) 4,000)	7,623 \$	121,782)
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		bb1		(2,157,640) \$	(892,821) \$	(3,269) \$	(237,093) \$	(23,181) \$	(369,994)
Adjustment for Obsolate inventory write-off		PLT.		(1,373,632) \$	(633,760) \$	(4,661) \$	(158,753) \$	(12,377) \$	(202,830)
Adjustment for corporate office lease		LB.		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)
VOT Anotization and Succeedit		VOTREV		3,386,000 \$	8 /84,684,1 8 (87,678)	\$ 004.0	384,269	38,548	615,273
Total Expense Adjustments				7,834,614	6,414,712	84,946	980,157	(55,406)	546,054
Total Onerwhine Evenence	4		•						
over the and the area	2		A	641,886,280	25/,/92,040 \$	3,325,576	\$1,888,738 \$	7,160,270 \$	105,797,437
Net Operating Income Pro-Forma			49	67,635,652 \$	11,486,338 \$	(373,051) \$	16,424,019 \$	1,048,089 \$	16,719,374
Net Cost Rate Base			69	1,473,843,556 \$	680,151,878 \$	5,062,926 \$	170,825,435 \$	13,283,070 \$	216,869,731
Kate of Keturn			4	4.59%	1.69%	-7.37%	9.61%	1.00%	7.71%

# LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation

Description	Name	Vector		Primary	Secondary	Primary	Secondary	Transmission	Frimary
Cost of Service Summary – Pro-Forma									
Operating Expenses									
			ş	9 676 997 \$	12 270 238 \$	4,189,373 \$	21,079,136 \$	12,933,219 \$	58,234,595
Operation and maintering 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		LPI		194,215	278,048	83,186	429,566	6/6/977	(367,661)
Amortization of Investment Tax Credit				(61,800)	(88,475)	(26,470)	(136,689)	(72,733)	(367,601)
Other Expenses				(93,312)	(133,591)	(39.967)	_	(109,821)	033,137)
State and Federal Income Taxes		TXINCPF	49	745,236 \$	1,070.672 \$	286,102 \$	2,488,378	4 552,050	71.396.833)
Specific Assignment of Interruptible Credit					. ;	, ,		(1,037,002)	270.035
Allocation of Interruptible Credits		SCP	49	66,076 \$	84,505 \$	29,945 \$	40,138	9 110'00	200
Adjustments to Operating Expenses:									(040 040)
Eliminate mismatch in fuel cost recovery		Energy	£Α	(44,786) \$	(54,061) \$		_	6 (057'59) 6 (307'30)	(27.5,045)
Remove ECR expenses		ECRREV	ь	(32,690) \$	_		(79,468) \$	\$ (CS1,CS)	(40,771)
Eliminate brokered sales expenses		Energy	ь	(559,033) \$	(674,807) \$	(Z38,687)	_	s (103,801)	(10,10,10)
Eliminate DSM Expenses		DSMREV	es ·	(14,699) \$	(16,293) \$	, ,	, r, r, c, e,	, ,	, ,
Year end Expense adjustment		YREND	s e		315,814 8	, 62	301,511	157.916.\$	805.053
Adjustment to annualize depreciation expense		DET	ю.	135,576 \$	467,48T			9 60	,
Depreciation adjustment		- E	A 6	43057	18 905 \$	6.268 \$	31,008 \$	17,191 \$	83,240
Labor adjustment	9	3	9	מים מים	3	9			
Adjustment for pension and post Ret Exp. (See Fundional Assignment)	(Juan	LAUS	69	454 \$	719 \$	221 \$	1,509 \$	••	2,235
Storm damage adjustment Adjustment to aliminate advertision expense (See Eunctions) Assimment)	nment)		•	•					
Amortization of rate case expenses		DMT	v3	6,353 \$	8,055 \$	2,750 \$	13,838 \$	8,490 \$	38,229
Amortization of ESM audit expenses		Rot	49	1,081 \$	1,418 \$	461 \$	2,604 \$	1,162 \$	96 / 'G
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)			,		6	707 00	100 388 C	105 554 \$	511 087
Adjustment for VDT net savings to shareholders		T87	ın e	200 CO	\$ 520'01 -	137.571	555,807 \$	363.588	1,760,479
Adjustment for merger savings		E 5	<i>o</i> 5 6	295,190 \$	389,020 <b>3</b>	(18.575) \$	(91,885) \$	(50,943) \$	(246,664)
Adjustment for merger amortization expenses		5 6	9 6			5.510 \$	27.704 \$	17,032 \$	79,919
MISO Schedule 10 one time credit			9 <b>6</b>	\$ 606.62		34,320 \$	177,712 \$	83,077 \$	474,502
Adjustment cumulative enect of accounting Grange			•			(2.947) \$	(14,577) \$	(8,082) \$	(38,132)
Adjustment total state reduction		PLPPT	S	(40,142) \$	(56,925) \$	(16,753) \$		(51,791) \$	(243,013)
Adjustment for Obsolete inventory write off		- <del>a</del>	•	(21,108) \$	(30,225) \$	(9,045) \$		(24,803) \$	(125,542)
Adjustment for comorate office lease		i <b>1</b> 9	40			12,272 \$		33,658 \$	162,970
Adjustment for cachide lime write-off		Energy	w	(31,641) \$	(38,193) \$	(13,509) \$		(44,671) \$	(183,324)
Adjustment for Cane Run repair refund		PLPPT	63	66,753 \$	94,662 \$	27,859 \$		86,124 \$	404,112
VDT Amortization and Surgedit		VDTREV	623	(4,116) \$	(5,407) \$	(1,762) \$	(9.8/4)	(4.381) \$	(Z1,040)
Total Expense Adjustments				(70,639)	335,809	(15,461)	(16,253)	(188,560)	(408,937)
Total Operating Expenses	TOE		69	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			w	22,620,354 \$	32,257,851 \$	9,710,208 \$	50,173,059 \$	26,606,267 \$	134,517,544
						72000	2000	7624.3	763C F
Rate of Return			-	6.89%	6.94%	6.34%	9.5576	2.10.0	9/06:2

# LOUISVILLE GAS AND ELECTRIC COMPANY Cast of Service Study Class Allocation

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										
						6 0000	9 400 004	# 700 ccc c	427.072	27.073.40B
Operation and Majntenance Expenses				n	1,580,600	4 062,086,2			64.211	3 857 568
Depreciation and Amortzation expenses					1.484	500,408	150	880.0	355	23.571
		-	H		100	2,013	0000	213.850	8 544	518 157
Property and Office Laxes		_	Ļ		36,736	(53.885)	, 5 (8,60 £)	550,013 (68,050)	(2.719)	(164.879)
Carlot azaudil di miyasuman, tak Cradii					(47.054)	(81 363)	(1.06.5)	(102,252)	(4 105)	(248 953)
Other Experises Afore and Federal Income Taxes		-	POUNTY		159.67)	202 899 \$	(3.453) \$	319.895 \$	59.836 \$	1.712.774
Control Assistant and Internative Control		•		,	20,000	• • • • • • • • • • • • • • • • • • • •	• (22: 12)		•	(486,000)
Specific Assignment of interruptible Credit Allocation of interruptible Credits		U)	SCP	65	12,085 \$	<del>6</del> 7	<b>s</b>	<b>₩</b>	1,678 \$	159,682
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery		ĮL)	Energy	s	(7,490) \$	(8,992) \$	\$ (869)	_	(2,007) \$	(128,357)
Remove ECR expenses		, ш,	ECRREV	10	(6,339)	(15,470) \$	(474) \$	(19,117) \$	(1,746) \$	(85,491)
Eliminate brokered sales expenses		ш	nergy	49	(93,494) \$	(112,246) \$	(8,719) \$	(115,606) \$	(25,054) \$	(1,602,194)
Eliminate DSM Expenses			DSMREV	₩.	49	49	<del>ده</del>		уэ '	•
Year end Expense adjustment		>	REND	€9		1,673 \$	(647) \$	-	3,240 \$	
Adjustment to annualize depreciation expense		٥	DET	s,	25,904 \$	127,476 \$	2,730 \$	161,753 \$	6,004 \$	360,678
Depreciation adjustment		_	DET	69	••	• <del>•</del>	e9 ·		.	
Labor adjustment			Ta:	\$	2,585 \$	5,797 \$	267 \$	6,433 \$	8 529	37,717
Adjustment for pension and post Ret Exp. (See Functional Assignment)	signment)	•		,	•	•	1			Š
Storm damage adjustment	3	S	SDALL	ьэ	164 \$	48/ \$	n n	\$00c	¢ /7	080
Adjustment to eliminate advertising expense (See Functional Assignment)	Assignment)	•	1	6	6	4 053	10.	3 482 6	2 7R7 \$	17 77
Amortzeton of raid case expenses		Ju		a .	5 CUC	496 S	5 to	612 \$	9 S	2.837
Remove one-utility cost (See Functional Assignment)		•	2	,	•	2	2	•		Ī
Adjustment for injuries and damages (See Functional Assignment)	ent)									
Adjustment for VDT net savings to shareholders		_	TB.	49	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			181	<del>(</del> )	(1,660) \$	\$ (771,71)	(791) \$	(19,062) \$	(1,999) \$	(111,765)
MISO Schedule 10 one time credit		<b>a</b> .	PLTRT	€9	2,277 \$	3,089 \$	246 \$	3,204 \$	545 \$	36,161
Adjustment cumulative effect of accounting change		_	ΣΕΤ	€9	15,268 \$		1,609 \$	95,338	8 688 8 6 688 8	212,584
Adjustment for IT staff reduction			BT	69	(1,215) \$		(125) \$		% (ATS)	(17,731)
Remove Alstom Expenses			PLPPT	69	(6,923)	(8,391)	(748)		* (9c9'L)	(/ca/ant)
Adjustment for Obsolete inventory write-off		ц.,	בן.	us «	(4,001) \$	(18,620) \$	(422) \$	8 (23,238)	4 300 4	(30,291)
Adjustment for corporate office lease		, ,	<u>.</u>	<i>a</i> •	6 (a)	4 (er c. c.)	# C7C		4 125,1	(10,00)
Adjustment for carbide lime write-off		ПE	Energy	en e	(2,292) W	(0,000) 4 (200)	4933)		2 754	182.062)
Agustnent for Cane Run repair retund		1 )	/[FF] /DTDE/	<i>n</i> 6	\$ (a62)	(4836)	\$ (55)	\$ (05.0)	\$ 1900 \$ 1900	(10.853)
Total Expense Adjustments		•	ָרְי	•	1.462	208.456	867	274,601	1.524	(258,718)
					dor.	201	3		1	,
Total Operating Expenses	TOE			s	2,139,702 \$	4,801,103 \$	187,590 \$	5,693,263 \$	566,398 \$	32,186,608
Net Operating Income - Pro-Forma				69	324,363 \$	651,910 \$	2,124 \$	923,997 \$	111,362 \$	3,722,296
0 44 d				6	9 070 000	20.157.012	454 450 6	25 405 128 C	1 001 089	60.367.547
Met Cost Nate Dave				•						
Rate of Return					7.56%	3.23%	0.47%	3.62%	11.12%	6.17%

# 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	Ś	2003-00434

EXHIBIT (SJB-8)

Description	Ref Name	Allocation 9 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		ROT	69	(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	FACE			547 241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues	ECRREV	?EV		(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	ECR	≂		723,260	255,297	937	110,897	680'6	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	ŒV.		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1.196.285)
Eliminate Rate Refund Acct		204		(7,150,231)	(2,741,076)	(9,298)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue	DSMREV	ΈV		(3,277,501)	(2,771,657)	•	(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment	YREND	9		2,614,347	1,232,278	(6,993)	(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	MS.		(621,927)		•			•
VDT Amortization and Surcredit		VDTREV		44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue			49	709,631,942 \$	269,113,371 \$	1,065,289 \$	99,584,383 \$	8,254,868 \$	123,238,838

Description	Ref Name	Allocation ne Vector	tion	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			1/3	14,666,854 \$	18,848,201 \$	6,311,999 \$	34,454,413 \$	16,765,931 \$	79,766,951
Pro-Forma Adjustments:									
Eliminate unbilled revenue		ROT	€/3	(34,589) \$	(45,400) \$	(14,766) \$	(83,348) \$	(37,178) \$	(183,683)
Mismatch in fuel cost recovery		Energy		(98,406)	(118,785)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-in	FA			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	ES	ESMREV		(130.047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct		ROT		(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue	SO	MREV		(14,688)	(16,281)		٠	,	4
Year End Revenue Adjustment	Υ.	YREND		,	566,077	•	147,900	•	•
Adjustment for Merger savings		R01		(51,111)	(67,085)	(21,819)	(123,161)	(54,936)	(271.421)
Adjustment for Customer Rate Switching & CSR Credit	Σ	RATESW				•	•	(279,699)	(252,228)
VDT Amortization and Surcredit		VDTREV	.≤	815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue			673	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

Description	Ref Name		Allocation Vector	Rate LP-TOD Seco <u>ndary</u>	D Street Lighting y Rate PSL		Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
	-									
Cost of Service Summary - Pro-Forms										
Operating Revenues										
Total Operating Revenue – Actual			€9	2,756,699	9 \$ 5,846.370	\$ 02	211,367 \$	7.056,532 \$	715,799 \$	39,146,605
Pro-Forma Adjustments:		ì	•	ć r	e	÷	\$ (757)	(19.577)	\$ (88) \$	(30 792)
Eliminate unbilled revenue		ROA	KO1	(5,434) (15,458)	(19,090)	* (or	(1.535)	(20.526)	(4,410)	(282,033)
Mismatch in Tuel Cost recovery	C		e co			(16)	156	(1.432)	197	23,036
Demoke DOD revenue	7 a	TOWER TOWER		(40.29		42)	(3,010)	(121,526)	(11,097)	(543,453)
To Defect a Full Year of the FOR Roll in	I MACH			3.08		Ξ.	212	9,072	811	33,157
Semove off-evident FCB revenues	Š		Tqq lq	(9,32		(66)	(062)	(9,385)	(1,069)	(95,761)
Filminate brokered sales			Energy	(84,44		83)	(7,875)	(105,321)	(22,630)	(1,447,143)
Fliminate FSM revenues	ESM	ESMREV	3	(20,23		93)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct		ROJ	=	(24,71		54)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue	MSC	DSMREV		•				. :	, ,	ı
Year End Revenue Adjustment	YREND	Q		•		66	(1,159)	17,114	808,4	
Adjustment for Merger savings		ROT	=	(9,537)	7) (23,479)	(62:	(989)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit	RATI	RATESW		•		,	, ;	. 5	. ₹	(90,000)
VDT Amortization and Surcredit		₹	VDTREV	146		364	2	204	Ŧ	DF.1 '7
Total Pro-Forma Operating Revenue			S	2,549,898	3 \$ 5,466,655	55 55	193,033 \$	6,635,628 \$	666,475 \$	35,838,013

Description Ref	ef Name	Allocation e 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			,				_	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)	_	(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 Allocation of Interruptible Gredits		SCP1		(3,519,894)	1,511,175 \$	2,563 \$	514,921 \$	41,545 \$	625,034
Adjustments to Operation Dogwood.									
Ediminate 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) \$	\$ (620,02)	(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) \$		520,438
Adjustment to annualize depreciation expense		DET :		8,959,741 \$	4,143,283	8 L/8/3	\$ 67/'/6L'L	9 00.00 00.00 00.00	176,272,1
Depreciation adjustment		- PE		018 580 8	4 - 436 409 \$	4 136 5	124822 \$	8 879 \$	128 541
Adjustment for cension and post Ref Exp. (See Functional Assignment)	ment	ì			e control				
Storm damage adjustment	<i>'</i>	SDALL		70,492 \$	46,793 \$	694 \$	9,491 \$	283 \$	5,995
Adjustment to eliminate advertising expense (See Functional Assignment)	ignment)	!							
Amortization of rate case expenses		DMT			134,013 \$	\$ 186	41,661 \$	3,850 \$	53,814
Amortization of ESM audit expenses		202		58,333 \$	22,362 \$	¥ 92	8,475 \$	\$ 299	10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)	œ.	Fa		£ 000 000 B	2 670 614	25 30A E	766 306 €	54517 6	780 231
Adjustment for your news to snateholders		9 5		2,040,000 3	2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2	87.471	# 000'00'	187.788	7 7 18 566
Adjustment for mercer perodiation expenses		9 4		(2 722 005) \$	(1293.201) \$	(12.256) \$	(369.882)	(26.311) \$	(380,903)
MISO Schedule 10 one time credit		PLTRT		\$ 223.507	291.402 \$	2,590 \$	\$ 090'56	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) \$	\$ (089'85)	(4.174) \$	(60,429)
Remove Alstom Expenses		PLPPT		(2,157,640) \$	\$ (620'988)	\$ (2.87)	(289,053) \$	(25,081) \$	(328,636)
Adjustment for Obsolete inventory write-off		F.T		(1,373,632) \$	(630,542) \$	\$ (098'9)	(183,550) \$	(13,283) \$	(197,410)
Adjustment for corporate office lease		EH.		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) \$	\$ (9/9/8)	\$ (987)	(32.5/0)	(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			<del>s/1</del>	1,473,843,556 \$	676,820,462 \$	7,339,572 \$	196,498,955 \$	14,222,061 \$	211,257,595
Date of Deferen			-	4 5097	7 6897	7686 8-	7 15%	7-00-7	% PC 8
TARKE OF RETURN				1.55.4	100	2/ 25/2-		200	

Description	Z.	Allocation		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
rice Summary Pro-Forma									
Operating Expenses									
			6	\$ 700 070 0	11 700 441 6	3 635 645 4	24 322 155 \$	12 620 140 \$	55 734 309
Operation and American fixed and			,						7,379,861
Depreciation Processes				8 729	10 464	4.154	19.169	10,169	43,973
Donath and Other Tayer		Tan		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)	(68,639)	(314,649)
Other Expense				(94 541)	(116 447)	(45,513)	(217,335)	(100,619)	(475,095)
Cultar Lyperious State and Enders Income Taxes		TXINCPE	¥	740.596	1370270 \$	197.818 \$	2.346.968 \$	855,773 \$	3,663,837
Specific Assignment of Internatible Condit			•	9 000,000		,		(1,637,062)	(1,396,833)
Allocation of interruptible Credits		SCP1	69	\$ 920'99	84,505 \$	29,945 \$	140,138 \$	60,511 \$	270,035
Adjustments to Oneming Expanses									
Eliminate mismatch in fuel cost recovery		Energy	ы	(44,786) \$	(54,061) \$	(19,122) \$	\$ (86,88)	(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	· <del>6</del> 3	(559,033) \$	(674,807) \$	(238,687) \$	(1,209,515) \$	(789,257) \$	(3,415,692)
Eliminate DSM Expenses		DSMREV	64	(14,699) \$	(16,293) \$	₩?	<b>~</b>		•
Year end Expense adjustment		YREND	₩,	69	315,814 \$		82,513 \$		. :
Adjustment to annualize depreciation expense		0ET	s,	137,342 \$	169,653 \$	e6,200 <b>\$</b>	317,245 \$	144,691	690,004
Depreciation adjustment		OET	<del>43</del>	,	<del>.</del>			A .	1 100
Labor adjustment		EI.	<b>.</b>	14,076 \$	17,246 \$	6,805	32,Ub/ \$	\$ 105,61	pat'c
Adjustment for pension and post Ret Exp. (See Functional Assignment)	ent)		•		( )	6	000	•	2 234
Storm damage adjustment	4	SUALL	A	9 404	n n	e 77	995,	•	
Adjustment to entities advertising expense (ode numotional Assign	(Museum)	ĘĄĆ	v	\$ 350 \$	7 699 4	2 851 \$	13 997 \$	8.285 \$	36,587
Amortization of ESM audit expenses		102	ο •9	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	<del>69</del>	297,703	364,752 \$	143,915 \$	678,199 \$		1,596,745
Adjustment for merger amortization expenses		LBT	₩	(41,712) \$	(51,106) \$	(20,164) \$	(95,024) \$		(223,723)
MISO Schedule 10 ane time credit		PLTRT	\$	13,392 \$	16,053 \$	6,373 \$	29,408 \$		56,462
Adjustment cumulative effect of accounting change		DET	<b>69</b>	80,950	89.88	% (20,0)	185,985	90,201	400,031
Adjustment for iT staff reduction		E :	<del>59</del> (	(6,617) \$	(8,108)	4 (BBL'S)	(15,073)	e (coo')	(35,433)
Kemove Alstom Expenses		<u>.</u>	e (	(40,723) \$	(40,010)	6 (19,5/1)	(40,400)		(107.154)
Adjustment for Obsolete Inventory write-off		<u>.</u>	æ	# (52°LZ)	\$ (50°,35°)	4 (167'01)	(48' 188) 4 03 783 4	21 055 \$	147.813
Adjustment for corporate omice lease		9 5	e t	27,539 B	902,00	43,522	(AB 457)	(44.671) \$	(193 324)
Adjustment for carbide lime write-dif		riergy or c	*	64740	01 174	9 (600,00)	4 (202,92)	78.883	341 123
Adjustment for Cane Run repair retund		70T07	e) 6	6/1/3	61,17 3	32,223	(9.874) S		(21,640)
Total Expense Administrants		, C	*	(64.351)	247.654	13.042	39.968	(235,890)	(820,517)
						!			
Total Operating Expenses	TOE		40	11,931,987 \$	15,304,633 \$	5,314,432 \$	27,352,530 \$	13,263,334 \$	65,073,757
Net Operating Income Pro-Forma			69	1,556,204 \$	2,641,512 \$	498,073 \$	4,597,069 \$	1,763,148 \$	7,728,814
Not Could Rate Rate			4	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%

Description Ref	Name	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate P\$L	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary Pro-Forma									
Operating Expenses									
			,					4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4 4	100
Operation and maintenance expenses			n	1,914,697 8	3,073,140 \$	\$ 202.50	3,423,328	402,560	107 107 107
Depreciation and Amortization Expenses				390,982	616,186,1	33,603	1,754,384	107,84	604,007,0
Accretion Expense		-		2,236	2,133	681	2.249	256	068,22
Property and Other (axes		L A		52,183	171,794	4,4/9	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	ø	30,150 \$	163,835 \$	(10,057) \$	272,880 \$	\$ 180'12	1,856,854
Specific Assignment of Interruptible Credit						,		•	(486,000)
Altocation of Interruptible Credits		SCP1	ы	12,085 \$	₩.	<b>679</b>	,	1,678 \$	159,682
Adjustments to Onecating Expenses:									
Topical control of the barrier Experience.		Ų.	e	\$ (007.2)	\$ (CB 08)	\$ (808)	\$ (070)	\$ (2007)	(128.357)
			9 6	9 (Oct 9)	\$ (200°)	9 (900)	(40.142) 6	(1746)	(85,491)
Filtrinate trokered cales expenses		בייייייייייייייייייייייייייייייייייייי	9 6	\$ (PCC.C)	(412,246)	(4) (4) (4) (4) (4) (4)	(416 50E) \$	(04 (12)	(1 602 194)
Filminate DSM Expenses		DSMBDV	· •		* (>+-7'-1')		\$ (000°01°)		
Vegrand Expense officialment				•	1673 6	(E47) ¢	9 14 48	3 240 5	,
Adjustment to annualize depreciation expense			• •	36.556.5	129 169 \$	3 142 \$	164 033 \$	4.603 \$	351.878
Depreciation adjustment		J E	÷ 4		• • • ·	. ,		47	
Labor adjustment		BT	•	3 302 \$	5911	295 \$	6.586 \$	280 %	37 125
Adjustment for pension and post Ret Exp. (See Functional Assignment)	ent)		,						
Storm damage adjustment		SDALL	69	164 \$	487 \$	15 \$	508 \$	27 \$	968
Adjustment to eliminate advertising expense (See Functional Assignment)	ment)								
Amortization of rate case expenses		DMT	<del>69</del>	1,257 \$	2,019 \$	114 \$	2,247 \$	\$ 992	17,583
Amortization of ESM audit expenses		R01	6/3	202 \$	496 \$	±5 •>	612 \$	\$ 99	2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)		!					:		
Adjustment for VOT net savings to shareholders		LBT	s ·	20,272 \$	36,290 \$	\$ 608'L	40,439	3,554	227,943
Adjustment for merger savings		8	so ·	69,828	125,004 \$	6,232 \$	139,296	12,2/5 \$	/92,16/
Adjustment for merger amortization expenses		9 6	99 (	(9,784) \$	\$ (616,71)	(8/8) 4 (8/8)	* (7[6]81)	\$ (07/L)	(110,011)
MICO COLLEGATE ID DIRE UNITE CEDIT		֓֞֝֞֝֞֝֞֝֟֝֓֞֝֟֝֓֓֓֞֝֟֝֓֓֓֓֞֝֓֓֓֓֞֝֟֝֓֓֓֓֞֝֓֡֓֡֝	A 6	6 054.5	4 277.0	9 1 1 1 1 1 1	9 - C C C C C C C C C C C C C C C C C C	1100	20,203
Adjustment Califoliative effect of accounting change		<u> </u>	<i>^</i> •	6 04C,12	40,133	# (CD)	80'00'00'00'00'00'00'00'00'00'00'00'00'0	Z, / 13 3	(47.452)
Adjustment for II stall regulation		2 6	A 4		(2,779)	e (500)	e (0,000)	\$ (213)	(107,064)
Adjustment for Observation inventors suries of		77.	9 6	6 (00450) 6 (2553)	(0,049)	* (±00)	e (264,01)	\$ (02.1) \$ (710) \$	(200, 201)
Adjustment for concerts office leave		5 6	<b>7</b> 6		11 573 8	677	12 895 \$	1136 4	72 684
Adjustment for respice line write of		100	7 e	יי וניםניטי	A (576.0)	9 (80F)	(F.600) e	1,130	(90,682)
Adjustment for Cone Dun canair rating		660	n •	47.244 6	16 544 6	460 4	17.44B	4 087	178 034
VDT Amortization and Surredit		VOTREV	• •	1387)	\$ (98.6)	(55)	\$ (02.0)	(208)	(10.853)
Total Expense Adjustments			·	39,572	214,544	2,344	282,789	(3,487)	(290,257)
	(		•	4					200
total Operating Expenses	<u>"</u>		ø	2,400,229 \$	4,871,757	\$ 181,002	5, //8,554 &	531,788 \$	31,912,002
Net Operating Income - Pro-Forma			¢5	149,669 \$	594,897 \$	\$ (651,7)	856,064 \$	134,707 \$	3,925,351
			6	400	6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6 6	6 197 073	900 900 91	3 070 022	20 030 188
Nel Cost Ague Deve			n		20,455,213	¢ 765'910			30,300,200
Rate of Return			-	2.48%	2.91%	-1.38%	3.31%	17.42%	6.66%

### 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 HTH ITIES COMPANY	j	2003-00434

EXHIBIT (SJB-9)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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				ss	768,525,785 \$	293,491,954 \$	1,027,476 \$	106,759,166 \$	8, 907,709,8	132,960,127
Pro-Forma Artiustments:										
Filminate unbilled revenue			R01	₩	(1,867,000) \$	(715,724) \$	(2,428) \$	(271,251) \$	(21,339) \$	(322,331)
Mismatch in filel cost recovery			Energy		(4,406,145)	(1,479,166)	(6,591)	(513,321)	(58,331)	(791,604)
To Peters a Full Year of the FAC Roll in		FACR	G		547.241	181,639	1,202	87,109	11,617	139,923
Remove TOR revenues		ECRREV			(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Refer to Full Year of the FIGR Rollin		FCRR			723,260	255,297	937	110,897	680'6	133,401
Damove off-evetem FOD revenues			PI PPT		(1.929.923)	(859, 156)	(2,408)	(231,554)	(19,814)	(329,638)
Eliminate brokered cales			ALLeus		(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
Filminate Provide and		ESMREV	ŝ		(6.974.780)	(2.763.963)	(7,154)	(1,009,115)	(80,480)	(1,196,285)
Filminate Rate Refund And			R01		(7.150.231)	(2,741,076)	(8,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV	į		(3,277,501)	(2,771,657)	•	(108,973)	(25,623)	(340,279)
Vest Fod Pevenue Adjustment		YREND			2.614.347	1,232,278	(6,993)	(279,531)	•	932,854
Adjustment for Mercer savings		) i	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

Description	Ref Name	Allocation e Vector	ition	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate L.P Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary Pro-Forma									
Operating Revenues									
Total Operating Revenue - Actual			us.	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	49	(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	ECR	ZEV		(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR Rollin	ECRRI	ř		14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues		_		(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		F07		(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue	DSMREV	REV		(14,688)	(16,281)	•		•	•
Year End Revenue Adjustment	YREND	9			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	SW				•	•	(279,699)	(252,228)
VDT Amortization and Surcredit		VDTRE	≥.	815	1,070	349	1,955	298	4,284
Total Pro-Forma Operating Revenue			s)	13,411,062 \$	18,092,102 \$	5,730,245 \$	31,672,632 \$	14.878.396 \$	72,667,290

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
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	69	(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		(2,999)	(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	3		(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)	(989)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW			,	,	•	,		(900'06)
VDT Amortization and Surcredit			VDTREV		146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue				sa.	2,458,774 \$	5,372,969 \$	183,495 \$	6,534,107 \$	668,445 \$	35,578,445

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 Exnenses			e.	508 149 420 \$	208 035 041 \$	1 148 292 \$	61 335 571 \$	5 685 715 \$	82 763 009
Depreciation and Amortization Expenses			•						13,936,448
Accretion Expense				462,519	205,902	277	55,493	4,749	29,000
Property and Other Taxes		TAN		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)	_	(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 Allocation of Interruptible Credits		SCP		(3,519,894)	1,511,175 \$	2.563 \$	514,921 \$	41.545 \$	625.034
				·		•			
Adjustments to Operating Expenses.		•				( ) ( ) ( ) ( ) ( ) ( ) ( ) ( ) ( ) ( )		Í	710000
Cilminate mismatch in Tuel Cost recovery		Energy TOBBD		(2,005,300) \$	\$ (050,059)	(3,045)	(233,620) \$	(20,547)	(306,271)
		ELKKEV		(1,755,544) W	\$ (076'07'0) \$ 400'07'0'	# (2,417) # (2,417)	(256,467)	(50,073)	(505,205)
Climinate profess sales expenses		chergy		\$ (997,030,02)	(8,402,938)	¢ (510,55)	4 (400 001)		(4,487,000)
		VOMPON COMPON		1 458 544 6	4 (107,717.5)	\$ (2/2 Y)	(155,057)	_	520 439
Adjustment to annualize depreciation expense		יייייי דיייר		5 172 656 B	4 369 417 5	30 124 5	1 106 072	76.478 \$	1.303.033
Depreciation adjustment		FE					1 1	+ + + + + + + + + + + + + + + + + + + +	,
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)	il)								
Storm damage adjustment		SDALL		70,492 \$	46,793 \$	684 \$	9,491 \$	283 \$	5,995
Adjustment to eliminate advertising expense (See Functional Assignment)	ment)	!				i		į	
Amortization of rate case expenses		S S		333,580 \$	136,567 \$	754	40,264 \$	S 657'S	54,337
Amoruzadon or ESM addit expenses		50		28,333	\$ 792,32	0	6,4/3 \$	/00	1/0,01
remove one-utility cost (See Functional Assignment) Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders		ISI		5 640 000 \$	2 772 944 \$	18 888 \$	728 527 \$	50.842 \$	801 652
Adjustment for merger savings		FB.		19,427,401 \$	9,551,612	65,062 \$	2,509,465	175,128 \$	2,761,348
Adjustment for merger amortization expenses		TB.		(2,722,005) \$	(1,338,292) \$	(9,116) \$	(351,605) \$	(24,537) \$	(386,897)
MISO Schedule 10 one time credit		PLTRT		\$ 226,607	315,887 \$	885 \$	85,136 \$	7,285 \$	121,198
Adjustment comulative 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		┖		(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 lima write-off		Energy		(1,416,711) \$	(475,597) \$	(2,152) \$	(165,048) \$	(18,755) \$	(254,525)
Adjustment for Cane Run repair refund		Idd Id		3,588,000 \$	1,597,293 \$	4,478 \$	430,482 \$	36,838 \$	612,844
		אמאוסא		7 034 544	7 450 247	\$ (007)	1 24.370) 3	6 (840) 30/	520,430
diai Expense Adjustments				7,834,514	/ LZ'net' /	/8,58/	85C'9LZ'I.	(/pc'ga)	950,139
Total Operating Expenses	T0E		₩3	641,996,290 \$	262,596,495 \$	1,289,073 \$	83,222,612 \$	7,078,563 \$	106,650,455
Net Operating Income Pro-Forma			6/9	67,635,652 \$	8,338,967 \$	(350,660) \$	15,623,243 \$	1,104,627 \$	16,830,605
Net Cost Rate Rase			v	1 473 843 456 \$	713 607 594 \$	A 777 998 \$	181 588 447 S	12 774 917 \$	216 147 929
			,						0.10, 141, 323
Rate of Return			_	4.59%	1.17%	-7.34%	8.60%	1.00%	7.79%

Description	e e e	Allocation Vector		Rate L.C.TOD	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
ilce Summary - Pro-Forma									-
Operating Expenses									
			•		40 100 100	4 404 400 6	30.679.974 €	12 343 825 C	55 858 28G
Operation and Maintenance Expenses			A	A 2011 1018	2, 103, 1d3 &				7 200 293
				540°000°1	14,000,2	2 433	16.743	8 27.0	42 7RB
Accretion Expense		FOIA		480.04	247 11	70 946	402 575	182.811	964.524
Property and Other laxes		- Z		106,911	200,382	(35,430)	(128 400)	(58.171)	(306 913)
Amortization of Investment   ax Credit				(50,203)	(00,400)	(ECH'CZ)	(129, 100)	(87.833)	(463.414)
Other Expenses		1000		(67,001)	1 137 459 8	315,637	7721 700 €	1 029 708 6	3 676 863
State and Federal Income (axes		N N C L	ħ	997,840	1, 107,430	9 100'010	e 667 17 / 7	(1637,000)	(1.396.833)
Specific Assignment of Interruptions Credit		dOS		66.076 \$	84 505 \$	29 945 \$	140.138 \$	60.511 \$	270,035
		Š	,		3				
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	s	(44,785) \$	(54,061) \$	(19,122) \$	\$ (868'96)	(63,230) \$	(273,643)
Remove ECR expenses		ECRREV	υ	_	(43,382) \$	_	(79,468) \$	(35,195) \$	(177,854)
Eliminate brokered sales expenses		Energy	'n	(559,033) \$	(674,807) \$	(238,687) \$	(1,209,515) \$	(789,257) \$	(3,415,692)
Eliminate DSM Expenses		DSMREV	s,	(14,699) \$	(16,293) \$		,	*	•
Year end Expense adjustment		YREND	s		315,814 \$		82,513 \$		. 70 010
Adjustment to annualize depreciation expense		DET	so.	127,769 \$	187,767 \$	55,991	282,871 \$	126,312 \$	6/3,214
Depreciation adjustment		הי	s e	67 6	59 6 1		7 4 4 4 4	45.085.6	74 360
Labor adjustment		LBI	vs	13,432 \$	18,465 \$	Q 11:0	\$ 4C/ R7	\$ C90'C	800°t
Adjustment for pension and post Ret Exp. (See Functional Assignment)		- 7		454	240 6	22.4	1,500		2 235
Storm camage adjustment Adjustment to aliminate adjustment	4	SUALL	•	9 407	9 D	77	9	•	2
Adjustment to eliminate advertising expense (See Functional Assignment) Amortization of rate rate availables	<b>.</b>	TWO	v	6.244 \$	\$ 686.2	2 714 \$	13.575 \$	8.103 \$	36,669
Amortization of ESM audit expenses				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	s	82,472 \$	113,376 \$	37,562 \$	182,687 \$	92,496 \$	456,617
Adjustment for merger savings		LBT	63	284,080 \$	390,532 \$	129,386 \$	629,280 \$	318,611	1,572,851
Adjustment for merger amortization expenses		LBT	s	(39,803) \$	(54,718) \$	(18,128) \$	(88,169) \$	(44,641)	(520,375)
MISO Schedule 10 one time credit		PLTRT	€9 .	12,356 \$	18,014 \$	5,287	25,586 \$	4 010,51	900,044
Adjustment cumulative effect of accounting change		DET.	s,	75,308 \$	110,671 \$	33,002 \$	166,725	4 (00° F)	390,793
Adjustment for IT staff reduction		LB7	us (	(6,315) &	(8,681)	(2,8/b)	6 (10'800) 6 (10'800)	(41,002)	(34,901)
Remove Alstom Expenses		PLPPI	ı,	(37,571)	(a//'4c)	e (010,01)	(40,103)	(40,000)	(195,000)
Adjustment for Obsolete inventory write-off		ī !	99 6	\$ (2882) 26.708	36 153 6	(0,083) 4	(45,780) 4 58.252 4	\$ (05°50) \$ 70 404	145 601
Adjustment for corporate office rease		Epot 2	* tr	(31641)	(28 193) \$	4 (505 ET)	(58.457) \$	(44 671) \$	(193 324)
Adjustment to Catalog mind wind all		PI PPT		62.479.5	91,089	26.634 \$	129,883 \$	68.821 \$	331,931
VOT Amortization and Succeedit		VDTREV	• 43	(4.116) \$	(5,407) \$	(1,762) \$	(9.874) \$	(4,381)	(21,640)
Total Expense Adjustments			1	(98,565)	312,480	(23,471)	(82,931)	(301,556)	(880,258)
Total Operating Excenses	10E		s	11,727,934 \$	15,767,670 \$	5,074,656 \$	26,580,591 \$	12,892,066 \$	64,965,374
Net Operating Income – Pro-Forma			s	1,683,128 \$	2,324,432 \$	\$ 652,589	5,092,041 \$	1,986,330 \$	7,701,916
Net Cost Rate Base			60	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%

Donneitstan	N		Allocation		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Streat Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
ite Summary Pro-Forms										
Operating Expenses										
										070 070 00
Operation and Maintenance Expenses				₩	1,664,324 \$	2,829,284 \$	147,622 \$	3,156,338	W 178,014	3,418,025
Depreciation and Amortization Expenses					270,027	1,257,160	20,945	850'8'D'.	10,10	379.07
Accretion Expense					1,438	1,312	106	1,350	273	077 825
Property and Other Taxes		NPT			35,807	154,958	2,765	018/08/	0.000	(145 982)
Amortization of Investment Tax Credit					(11,394)	(49,308)	(D88)	(03,280)	(2, 198)	(140,902)
Other Expenses					(17,204)	(74,451)	(1,329)	(1/2/36)	(3,501)	(074,077)
State and Federal income Taxes		XIX.	TXINCPF	69	168,316 \$	301,407 \$	4,164 \$	422,257 \$	\$ 077.77	7,172,131
Specific Assignment of Internatible Credit								•	, 1	(460,000)
Allocation of Interruptible Credits		SCP		€9	12,085 \$	'	<del>.</del>	ν <b>,</b>	1,678 \$	790'6C
Company of the state of the sta										
Adjustments to Operating Expenses:		Fnerav	20	69	\$ (064.7)	(8,892) \$	\$ (889)	(9,342) \$	(2,007) \$	(128,357)
		808	FCRREV	• •4	(6,339) \$	(15,470) \$	(474) \$	(19,117) \$	(1,745) \$	(85,491)
Filling to the state of the sta		Ē		• <b>⊌</b> 9	(93,494) \$	(112,246) \$	(8,719) \$	(116,606) \$	(25,054) \$	(1,602,194)
Eliminate District Spice cyperiods		ASC	DSMRFV	. 69	69	•	\$	,	'	
Captage and Expense adjustment		YREND	CZ	- 69		1,673 \$	(647) \$	9,548 \$	3,240 \$	
Adjustment to appreciation expense		DET	•	62	25,247 \$	117,542 \$	1,958 \$	151,433 \$	4,848 \$	319,663
Depreciation adjustment		Tad		· 69	un.	1	به ا	•	,	. !
l abor adjustment		LBT		₩.	2,541 \$	5,128 \$	215 \$	5,738 \$	597 \$	34,957
Adjustment for pension and post Ret Exp. (See Functional Assignment)	ment)								1	5
Storm damage adjustment		SDALL	<b>+</b>	€9	164 \$	487 \$	S	208	* /7	060
Adjustment to eliminate advertising expense (See Functional Assignment)	gnment)							6	2 020	77671
Amortization of rate case expenses		OMT		<b>69</b>	1,093	1,857 \$	/9 6 	2,072	2 A A A	7837
Amortization of ESM audit expenses		R01		69	202	496 \$	20	e 710	9	3
Remove one-utility cost (See Functional Assignment)										
Adjustment for injuries and damages (See Functional Assignment)	_	-		,	6 000	24 196	1330 €	35 234 \$	3,665 \$	214.633
Adjustment for VDT net savings to shareholders		<u> </u>		e (	13,000	9 737 BOL	5 CZC.	121365 \$	12 623 \$	739 321
Adjustment for merger savings		<u> </u>		n 4	7,520	44.400	(637) \$	(17,005) \$	\$ (62.1)	(103,587)
Adjustment for merger amortization expenses			ţ	9 6	2 208	2.013	162 \$	2.086 \$	420 \$	31,721
MISO Schadule 10 one time degit		7 6	÷	9 6	26.200 26	69.280 \$	1.154 \$	89,255 \$	2,857 \$	188,411
Adjustment cumulative effect of accounting cristings		į 4		, e	(4.194) \$		(101) \$	(2,698) \$	(281) \$	(16,434)
Adjustment for it states for the control of		100 0	Į.	· 44			(494) \$	(6,344) \$	(1,276) \$	(96,454)
Admoration Expenses		ī ~	-	• ••	(3.898) \$	(17,059) \$	(301) \$	(21,916) \$	(748) \$	(49,847)
Adjustment for compate office lease		B		. 49	4.974 \$	10,040 \$	421 \$	11,235 \$	1,169 \$	68,440
Adjustment for carbide line write-off		E	AD.	• •/3	(5,292) \$		(493) \$	\$ (009'9)	(1,418) \$	(30,682)
Adjustment for Cape Bun (spained)		Lad Id	i .	· 49	11,152 \$		821 \$	10,550 \$	2,121 \$	160,397
VIII Amortization and Surrendit		TOV	/DTREV	- 4/3	(738) \$	(1,836) \$	(52) \$	(2,290) \$	(206) \$	(10,853)
Total Expense Adjustments		•	;		(888)	172,954	(1,891)	237,721	(2,609)	(405,376)
								600000000000000000000000000000000000000	540.762	21 245 346
Total Operating Expenses	ğ			69	2,122,511 \$	4,593,316	¢ coc'L/L	\$ 505'2'4'C	20/040	0.00
Net Operating Income - Pro-Forma				s	336,263 \$	779,653 \$	11,992 \$	1,056,745 \$	127,683 \$	4,333,099
				•	9 100 501	9 032 173 04	305 880	23 816 316 \$	813.020 \$	53.695.734
Net Cost Rate Base				9						
Rate of Return				L	8.03%	4.20%	3.68%	4,44%	15.70%	8.07%
in the same										

### 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	<i>,</i>	2003-00434

EXHIBIT (SJB-10)

1 1991	,	Allocation		Total	Residential Pets 0	Water Heating	General Service	Rate LC Primary	Rate LC Secondary
Describing	i			27318111	Variety V		20 200		
Cost of Service Summary Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual			€9	768,525,785 \$	292,624,282 \$	999,032 \$	108,199,109 \$	8,991,846 \$	133,330,572
Pro-Forma Adjustments:									
Eliminate unbilled revenue		<b>2</b> 04	69	(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	FACR			547.241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues	ECRREV	2		(11,228,429)	(4,264,952)	(15,362)	(1,530,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Rol⊩in	ECRR			723,260	255,297	937	110,897	680'6	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	2		(3,277,501)	(2,771,657)		(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment	YREND	٥		2,614,347	1,232,278	(6,993)	(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	3W		(621,927)	٠		,		
VDT Amortization and Surcredit		VDTREV		44,485	17,356	25	6,447	202	7,617
Total Pro-Forma Operating Revenue			s,	709,631,942 \$	270,098,382 \$	910,972 \$	100,235,028 \$	8,264,302 \$	123,838,443

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			<del>(1</del>	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-≀n		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		ECRR		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				,	1	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV	815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue			<b>69</b>	13,482,820 \$	18,019,270 \$	5,787,507 \$	31,863,456 \$	14,773,330 \$	71,833,262

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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	69	(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 Refect a Full Year of the FAC Roll-In		FACR	6		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	911	33,157
Remove off-system ECR revenues			PLPPT		(6,626)		•	,	(820)	(87,552)
Eliminate brokered sales			Finerroy		(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Firmate FSM revenues		ESMREV	ò		(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 Mercer savings		!	R01		(9.537)	(23,479)	(688)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW				,	. 1	,	•	(80,000)
VDT Amortization and Surgedit			VDTREV		146	364	10	453	4	2,148
Total Pro-Forma Operating Revenue				€9	2,475,943 \$	5,223,172 \$	171,410 \$	6,378,844 \$	662,403 \$	35,613,399

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

Description	Хапе	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									
			•	CO0 140 400 G	205 951 355 C	1 078 705	64 959 501 .5	5 907 311 \$	83.695.315
Operation and Maintenance Expenses			Ð						14,410,830
Depreciation and Amortization Expenses				462 519	198 570	337	67,681	5,459	82,130
Donoth and Other Taxes		TdN		12.603.252	5.952,910	35,308	1,802,008	123,902	1,922,763
Americation of lowestment 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)	(29,530)	(823,808)
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 Gredit Allocation of Interruptible Gredits		SCP		(3,519,894) 3,519,894 \$	1,511,175 \$	2,563 \$	514,921 \$	41,545 \$	625,034
Adjustments to Operating Expenses:		i i		\$ 606.900.0	673 100) A	\$ (3.045)	(233 620) \$	(26.547) \$	(360,271)
Eliminate mismatch in thei cost recovery		chergy		_	8 (06.3, 130) 8 (670.030)	(2,012)	(220,225) (256,487) \$		(305,205)
Remove ECR expenses		CKKE		(1,755,344) \$	\$ (076'070)		(20,407)	(331.372) \$	(4 497,006)
Eliminate prokered sales expenses					(2,723,781) \$		(109.057)	(25,643) \$	(340,540)
Year and Expense adjustment		YREND			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		<del>6</del> 9	<del>69</del> 1	ьэ (	643 d		1 200
Labor adjustment		LBT		918,580 \$	444,635 \$	2,84/ \$	130,256 \$	e 205's	B#0,00
Adjustment for pension and post Ret Exp. (See Functional Assignment)		1400		70 702 \$	46 703 \$	694	9.491	283 \$	5,995
Storm damage adjustment Adjustment to eliminate adjusticing economic (See Europhone) Assignment)	ŧ	SOME			2		•		
Augustine to commission advertisers and a properties (add ) to be a propertied of the case expenses	?	DMT		333,580 \$	135,133 \$	\$ 207	42,643 \$	3,878 \$	54,943
Amortization of ESM audit expenses		R01		58,333 \$	22,362 \$	26 \$	8,475 \$	\$ 299	10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injunes and damages (See Functional Assignment)		Ţ		5 540 000 \$	2 730 027 5	17.481 \$	2 85.758	55.001 \$	819,977
Adjustment for V.D.1 that savings to sital enoughts		- La		19 427 401	9 403 764 \$	60.215 \$	2.754.826 \$	189,454	2,824,471
Adjustment for merger savings		3 12		(2 722 005) \$	(1.317.577) \$	(8,437) \$	(385,983)	(26,545) \$	(395,741)
MiSO Schedule 10 one time gradit		PLTRT		709,577	304,638 \$	517 \$	103,803 \$	8,375 \$	126,001
Adjustment cumulative effect of accounting change		DET		5,280,909 \$			753,540 \$	\$ 600'15	794,155
Adjustment for IT staff reduction		LBT			Ė	(1,338) \$	(61,235) \$	(4,211) \$	(62,783)
Remove Alstom Expenses		PLPPT		(2,157,640) \$			(315,638) \$	(25,467) \$	(383,136)
Adjustment for Obsolete inventory write-off		PLT		_	(649,750) \$	3,850) \$	(196,237) \$	47.536	(209,102)
Adjustment for corporate office lease		Tel.			870,519 &	5,0,0 5,0,0	255,016	000')  000')	261,463
Adjustment for carbide lime write-off		Energy		_	(4/5,597)	(2,152)	(185,048) \$	e (cc/cl)	(234,343)
Adjustment for Cane Run repair refund		PLPPT		3,568,000 \$	1,540,415 %	4 CID'7	324,664	5 (549) A	(38 480)
VDT Amortization and Surcredit		VOIRE		_l	6.778.619	66.505	1,833,234	(30,580)	688,790
				1000					
Total Operating Expenses	<b>T</b> 0E		₩	641,996,290 \$	260,116,624 \$	1,207,777 \$	87,338,074 \$	7,318,859 \$	107,709,214
Net Operating Income Pro-Forma			eA	67,635,652 \$	9,981,759 \$	\$ (596,805)	12,896,954 \$	945,443 \$	16,129,229
Net Cost Rate Base			49	1,473,843,556 \$	696,707,368	4,223,971 \$	209,635,156 \$	14,412,525 \$	223,363,330
						<u> </u>		1,200	7000
Rate of Return			$\frac{1}{2}$	4.59%	1.43%	-7.03%	0.13%	W.00.	1.44.10

Cost of Service Summary – Pro-Forma  Operating Expenses  Operation and Maintenance Expenses  Operation and Amortization Expenses Accretion and Amortization Expenses Accretion Expenses Properly and Other Taxes Amortization of Investment Tax Credit Other Expenses State and Federal income Taxes Specific Assignment of Interruptible Credit Allocation of Interruptible Credits Adjustments to Operating Expenses:  Adjustments to Operating Expenses: Remove EXR expenses	NPT TXINCPF SCP SCP Energy ECREV Energy DSMREV	us us us	9,698,253 \$					
Operating Expenses  Operation and Maintenance Expenses  Depreciation and Amortization Expenses  Accretion Expense  Property and Other Taxes  Amortization of Investment Tax Credit Other Expenses  State and Federal income Taxes  Specific Assignment of Inferruptible Credit Allocation of Instruptible Credits  Adjustments to Operating Expenses:  Adjustments to Operating Expenses:  Remove FCR expenses	NPT TXINCPF SCP Energy ECRREV Energy DSMREV	us us us						
Operation and Maintenance Expenses Depreciation and Amortization Expenses Accretion Expenses Accretion Expenses Property and Other Taxes Amortization of Investment Tax Credit Other Expenses State and reder income Taxes Specific Assignment of Interruptible Credit Allocation of Interruptible Credits Adjustments to Operating Expenses: Adjustments to Operating Expenses: Remove FCR expenses:	NPT TXINCPF SCP SCP Energy ECRREV Energy DSMREV	us us us						
Operation and Mainterlance Expenses Depreciation and Amoritzation Expenses Accretion Expense Property and Other Taxes Amoritzation of Investment Tax Credit Other Expenses State and Federal income Taxes Specific Assignment of Inferruptible Credit Allocation of Inferruptible Credits Adjustments to Operating Expenses: Eliminate mismatch in fuel cost recovery Remove FCR expenses	NPT TXINCPF SCP Energy ECRREV ENERGY ENERGY ENERGY ENERGY	א אי אי				9 110 011	* ***	200 600
Deprocation and Announcement Expenses Accepted and Other Taxés Amortization of Investment Tax Credit Other Expenses State and Federal Income Taxes Specific Assignment of Inferruptible Credit Allocation of Investmptible Credits Adjustments to Operating Expenses: Remove FCR expenses: Remove FCR expenses	NPT TXINCPF SCP Energy ECRREV Energy DSMREV	v3 v3		4 044 505	4,200,007,4 070,000,0		1 211 500	200,200,00
Additional Expenses Property and Other Taxes Amortzation of Investment Tax Credit Other Expenses Specific Assignment of Interruptible Credit Allocation of Interruptible Credits Adjustments to Operating Expenses: Remove FCR expenses: Remove FCR expenses:	NPT TXINGPF SCP SCP Energy ECRREV Energy DSMREV	es es	787 1041	11,000	974,000	3,410,13	7.000	0,000,440
Amortization of luvestment Tax Credit Other Expenses State and Federal income Taxes Specific Assignment of Interruptible Credit Allocation of Interruptible Credits Adjustments to Operating Expenses: Remove FCR expenses:	TXINCPF SCP SCP Energy ECREV Energy ENERGY ENERGY	us us	100,007	201, 104	365.00	436 B68	163,930	25,463
Amenization for investing in 1 a A croun. Other Expense. State and Federal income Taxes Specific Assignment of inferruptible Credit Allocation of inferruptible Credits Adjustments to Operating Expenses: Adjustments to Operating Expenses: Remove FCR expenses.	TXINCPF SCP Energy ECRREV Energy DSMREV	<b></b>	(20,000)	200,000	000,000	(430,042)	(50,020	(259,220)
Other Lyberises Specific Assignment of Interruptible Credit Allocation of Interruptible Credit Allocation of Interruptible Credits Adjustments to Operating Expenses: Remove FCR expenses:	TXINCPF SCP SCP Energy ECRREV Energy DSMREV	s s	(04,000)	(61,303)	(43.355)	(210,501)	(78.761)	(301,401)
Specific Assignment of interruptible Credit Allocation of Interruptible Credits Adjustments to Operating Expenses: Eliminate mismatch in fuel cost recovery Remove FCR expenses	SCP Energy ECRREV Energy DSMREV	, ,,	733 001 6	1 243 968 8	334 896 6	(180°507)	1 183 356 €	4 896 552
Special Assignment or itterrupture Credits Allocation of Interruptible Credits Adjustments to Operating Expenses: Eliminate mismatch in fuel cost recovery Remove FCR expenses	SCP Energy ECRREV Energy DSMREV	<b>↔</b>	00.00	9 000 017	2 080,152	2,442,230	(163,000	(\$ 206,033)
Adjustments to Operating Expenses: Eliminate mismatch in fuel cost recovery Remove FCR expenses	Energy ECRREV Energy DSMREV		\$ 920'99	84,505 \$	29,945 \$	140,138 \$	60,511 \$	270,035
Autonomis to Operating Expenses. Reliminate mismatch in fuel cost recovery Remove FCF expenses	Energy ECREV Energy DSMREV							
Remove FCR expenses	ECRREV Energy DSMREV		\$ (387 AA)	\$ (190.64)	(10 122) &	9 (808 90)	(63.730) \$	(P73.643)
Comment of the Carlotte of the	ECANEV Energy DSMREV	9 6	(po / tr)		9 (77.101.)	(20,000)		(477,854)
Clinical brokesod rates accounts	DSMREV	ρb	(52,030)	(43,302) 4 (524,807)	* (10,41)	4 (20,450)	789.257	(3.415.602)
Filminate DSM Proposes	1	9 <del>6</del>	(14 699) \$		e (100,000)	& (215,524.)	S (103)	(300,011,0)
Year and Expense adjustment		) <i>4</i> :	600,1			82.513 \$	,	
Adjustment to annualize depreciation expense	OFT	, r.	136 675 \$	178.728 \$	63.098 \$	306,554	113.273 \$	569.708
Depreciation adjustment	<u> </u>	) 45	9 69	÷ €	9 69	• • • • • • • • • • • • • • • • • • •	)    -	3
Labor adjustment	<u> </u>	. v:	14 031 \$	17 857 \$	\$ 596.8	31.348 \$	14.187 \$	67.403
Adjustment for pension and post Ret Exp. (See Functional Assignment)	ì	,		•			•	
Storm damage adjustment	SDALL	€9	454 \$	719 \$	221 \$	1,509 \$	<b>ι</b> ,	2,235
Adjustment to eliminate advertising expense (See Functional Assignment)								
Amortization of rate case expenses	OMT	€9	6,367 \$	7,857 \$	2,812 \$	13,902 \$	7,923 \$	35,240
Amortization of ESM audit expenses	R01	₩	•	1,418 \$	461 \$	2,604 \$	1,162 \$	5,739
Remove one-utility cost (See Functional Assignment)								
Adjustment for injunes and damages (See Functional Assignment)		,		:	•		1	7 10 00 0
Adjustment for VDT net savings to shareholders	E :	us ·	86,151	109,641	40,498 \$	192,472 \$	87,109 \$	413,851
Adjustment for merger savings	E !	э	296,754	3//,668	\$ 005,851	662,984 \$	300,054	1,425,542
Adjustment for merger amontzation expenses	181	e (	4 (8/C,14)	(32,916)	4 (14,040)	e (780'76)	42,041) &	(00/881)
MISO SCHOOLING TO STATE CHOICE AND THE CONTRACT OF THE CONTRAC	Ξ L	n 6	13,320	17,035 \$	0,00,00	20,230	4 (5° 1.3°)	794,40
Adjustment for it staff reduction	<u> </u>	, v	(8,508) e	9 (400.0)	2000	44 73%		(24 887)
Remove Alston Expenses	100 10		(40,563)	(51,800)	(18.356) \$	(85,902)	-	(165,527)
Adjustment for Obsolete inventory write-off	- -	o vi				(47.519) \$		(88.563)
Adjustment for corporate office lease	<u> </u>	. 69	27.471 \$	34.961	12.914 \$	61,373 \$	27.776 \$	131,964
Adjustment for carbide lime write-off	Energy	· 69	(31,641) \$	(38,193) \$	(13,509) \$	(68,457) \$	(44,671) \$	(193,324)
Adjustment for Cane Run repair refund	PLPPT	643	67.354 \$	86.140 \$	30.525 \$	142.849 \$	61682 \$	275,260
VDT Amortization and Surcredit	VDTREV	· <del>•</del> •>	(4,116) \$	(5,407) \$		(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		•	11 940 518 \$	15.551.903	5 244 297 \$	27 145 913 S	12 580 806 \$	62 494 541
		,						
Net Operating Income Pro-Forma		63	1,542,302 \$	2,467,367 \$	543,210 \$	4,717,543 \$	2,192,524 \$	9,338,720
Net Cost Rate Base		49	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%

Exhibit (SJB-10) Page 5 of 6

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
Cost of Service Summary Pro-Forma									
Operating Expenses									
Constitution Maintenance Constitution Constitution				4 709 113 E	2 438 507 \$	116 096 \$	2 751 303 \$	400 208 \$	26 364.063
Operation and American Expenses			<b>&gt;</b>					43,826	3,465,322
Accretion Expense				1,588		•		221	20,982
Property and Other Taxes		TAN		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	69	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	49	12,085 \$	•	•	1/2	1,678 \$	159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	49	(7,490) \$	(8,992) \$	\$ (869)	(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	49	(93,494) \$	(112,246) \$	(B,719) \$	(116,606) \$	(25,054) \$	(1,602,194)
Eliminate DSM Expenses		DSMREV	47)	•	<b>43</b>	,	·•	,	•
Year end Expense adjustment		YREND	s	,	1,673 \$	(647) \$	9,548 \$	3,240 \$	
Adjustment to annualize depreciation expense		DET	ıs	27,378 \$	98,951 \$	459 \$	132,164 \$	4,098 \$	324,001
Depreciation adjustment		DET	s,	67) (	69s	<del>1</del>	<b>9</b> 7	,	•
Labor adjustment		LBT	s	2,684 \$	3,877 \$	114 \$	4,442 \$	546 \$	35,249
Adjustment for pension and post Ret Exp. (See Functional Assignment)	£				1	!			*
Storm damage adjustment		SDALL	₩.	164 \$	487 \$	45 \$	208 \$	27 \$	968
Adjustment to eliminate advertising expense (See Functional Assignment)	ent)	1	•	4	5	4	4 808	262 €	47 307
Amortization of rate case expenses		E 5	9 6	\$ 20°C	907	. f.	,000 0.00 0.00 0.00	2 50	2 837
Amount and this cont object to be a controlled to the control of t			,	707	? ? !	<b>)</b>	) !	}	
remove offe-duilty cost (See Functional Assignment) Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders		LBT	47	16.480 \$	23.805 \$	700 \$	27,273 \$	3,355 \$	216,426
Adjustment for merger savings		LBT	w	56,766 \$	81 999 \$	2,413 \$	93,942 \$	11,556 \$	745,494
Adjustment for merger amortization expenses		LBT	49	(7,954) \$	(11,489) \$	(338) \$	(13,162) \$	\$ (1,619) \$	(104,452)
MISO Schedule 10 one time credit		PLTRT	<del>(1)</del>	2,436 \$	1	,	<del>ν</del>	338 \$	32,190
Adjustment cumulative effect of accounting change		DET	<del>.,,</del>	16,137 \$	58,322 \$	270 \$	77,898 \$	2,415 \$	190,968
Adjustment for IT staff reduction		LBŢ	en	(1,262) \$	(1,823) \$	(54) \$	(2,088) \$	(257) \$	(16,571)
Remove Alstom Expenses		PLPPT	<b>65</b>	(7,408) \$	<b>6</b> 7		· ·	(1,029) \$	(97,883)
Adjustment for Obsolete inventory write-off		ΡĹΤ	45	(4,233) \$	(14,138) \$	(65)	(18,888) \$	(029)	(50,529)
Adjustment for corporate office lease		LBŢ	(A)	5,255 \$	7,591 \$	223 \$	8, 986, \$	1,070 \$	69,011
Adjustment for carbide lime write-off		Energy	49	(5,292) \$	(6,353) \$	(483) \$	\$ (009'9)	(1,418) \$	(90,682)
Adjustment for Cane Run repair refund		PLPPT	49	12,319 \$	<b>4</b> Э	•	1	1,711 \$	162,772
VDT Amortization and Surcredit		VDTREV	69	\$ (822)	(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		s	2,173,375 \$	4,149,537 \$	135,701 \$	5,017,391 \$	522,862 \$	31,348,898
Net Operating Income – Pro-Forma			w	302,568 \$	1,073,635 \$	\$ 602'58	1,361,453 \$	139,541 \$	4,264,501
Net Cost Rate Base			42	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%

### 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	Ś	2003-00434

EXHIBIT (SJB-11)

Description	že.	Name	Allocation Vector		Total Svstem	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary Pro-Forma										
Operating Ravenues										
Total Operating Revenue - Actual				<del>10</del>	768,525,785 \$	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		FACR			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	680'6	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			R04		(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	(8,993)	(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				<del>63</del>	709,631,942 \$	267,513,891 \$	938,129 \$	99,433,251 \$	8,237,436 \$	124,626,847

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				<b>59</b>	14,611,283 \$	19,185,651 \$	6,326,234 \$	34,518,858 \$	16,707,671 \$	80,517,847
Pro-Forma Adjustments:										
Eliminate unbilled revenue			Ro1	₩	(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		ECRR			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)	(173,873)	(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	298	4,284
Total Pro-Forma Operating Revenue				69	13,434,580 \$	18,271,695 \$	5,826,237 \$	32,011,772 \$	14,970,276 \$	73,526,990

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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				64	2,662,722 \$	5,655.911 \$	194,251 \$	6,854,604 \$	724,458 \$	39,113,964
Pro-Forma Adiustments:										
First patient revenue			R01	45	(6.454) \$	(15,890) \$	(464) \$	\$ (19,577)	(1,786) \$	(90,792)
Mismatch in final cost recovery			Fnerny		(16.458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Defect a Full Veer of the EAC Boilde		FACRI	S i		1 436	(3,891)	156	(1,432)	797	23,036
Remove FOR revenues		ECRREV			(40 296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the FCR Roll. in		FORR			3,088	6,611	212	5'0'6	811	33,157
Domove off-evetem FOR revenues		)	⊥dd Id		(6,015)	(2,183)	(187)	(2,265)	(1,374)	(94,610)
Fliminate brokered sales			Fnerov		(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1 447, 143)
Firminate TAM resolutes		FSMRFV	i i		(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)
Fliminate DSM Revenue		DSMREV					•	•	•	•
Vest End Revenue Adjustment		YREND			•	2,999	(1,159)	17,114	5,808	•
Adjustment for Mercer savinos			R01		(9,537)	(23,479)	(989)	(28,928)	(2.639)	(134,160)
Adjustment for Customer Rate Switching & CSB Credit		RATESW					•			(000'06)
VDT Amortization and Surcredit			VDTREV		146	364	10	453	14	2,148
Total Pro-Forma Operating Revenue				us	2,459,233 \$	5,282,911 \$	176,520 \$	6,440,820 \$	674,830 \$	35,806,523

Ref	e E	Allocation Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of vervice outfinisty - Pro-Pulled									
Operating Expenses									
Cheration and Maintenance Expenses			69	508,149,420 \$	199,109,198 \$	1,147,550 \$	62,867,909 \$	5,837,225 \$	85,752,023
Operation and Americation Expenses				95,827,965	42,190,941	321,814	12,609,571	298,988	55, 55, 5 55, 55, 55
Accretion Expense				462,519	175,933	5/5	60,638	7,224 119 074	2 064 448
Property and Other Taxes		LdN		12,603,252	5,458,447	40,100	(527,553)	(37.890)	(656,912)
Amortization of Investment Tax Credit				(4,010,380)	(1,746,435)	(12,756)	(796.562)	(57,210)	(991,882)
Other Expenses		AGCNIXI		27.184.243 \$	2,736,402 \$	(270,924) \$	7,098,638 \$	483,843 \$	6,667,019
Spacific Assignment of Internatible Credit				(3,519,894)				44 545 6	- 525 034
Aliocation of Interruptible Credits		SCP		3,519,894 \$	1,511,175 \$	2,563 \$	\$ 126,41c		100,000
Adjustments to Operating Expenses:		25000		(2,005,300)	(673,190) \$	(3,045) \$	(233,620) \$	(26,547) \$	(360,271)
Eliminate mismatch in tuel cost recovery		ECRREV		(1,766,344) \$	(670,920) \$	(2,417) \$	(256,487) \$	_	(305,205)
Remove not deviced sales expenses		Energy		(25,030,766) \$	(8,402,958) \$	(38,013) \$	(2,916,114) \$		(4,497,006)
Eliminate DSM Expenses		DSMREV		(3,280,013) \$	(2,773,781) \$	, į	(109,057) \$	(25,643)	520,340)
Year end Expense adjustment		YREND		1 458 544 \$	687,488 \$	(5,5/2) \$	\$ (05,950) \$ 670,871,	83.210 \$	1,445,233
Adjustment to annualize depreciation expense		DET		8,959,741 \$	3,844,776	s son'ne	9 69		
Depreciation adjustment		i E		918.580 \$	423,052 \$	3,074 \$	123,560 \$	8,734 \$	140,133
Lacon adjustment Adjustment for cension and post Ret Exp. (See Functional Assignment)	<del>-</del>	<u>.</u>							900
Storm damage adjustment	7	SDALL		70,492 \$	46,793 \$	694 \$	9,491 \$	783	0.88°C
Adjustment to eliminate advertising expense (See Functional Assignment)	Tent)	!		1	407.004	753 €	41270 \$	3 832	56,293
Amortization of rate case expenses		TWO		333,580 8	22.362 \$	92.	8,475 \$	\$ 299	10,071
Amortization of ESM audit expenses		2		2000					
Remove one-tulity cost (ose Functional Assignment) Adjustment for injuries and damages (See Functional Assignment)								•	000
Adjustment for VDT net savings to shareholders		ĽBŢ		5,640,000 \$	2,597,500 \$	18,874 \$	758,646 \$	53,623 \$	2 063 722
Adjustment for merger savings		LB1		19,427,401 \$	8,947,281 \$	65,011	2,613,213 <b>3</b>	(25,880)	(415,252)
Adjustment for merger amortization expenses		187		(2,722,005)	* (a1a'8c2'1)	(3,103) (882) (882)	93.029 \$	8,014	136,595
MISO Schedule 10 one time credit		7 C		# 575,807 # 900,080 A	2325,068 \$	17.735 \$	694,891 \$	49,044 \$	851,826
Adjustment cumulative effect of accounting change		- E		(431.834) \$	(198,881) \$	(1,445) \$	(58,087) \$	(4,106) \$	(65,878)
Adjustitem to its statifications.		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) \$	77/356
Adjustment for corporate office lease		Ш		1,798,420 \$	828,262 \$	5,018 \$	241,909 \$	(40 755) 6	(254 525)
Adjustment for carbide lime write-off		Energy		(1,416,711) \$	(475,597) \$	4 (51,152)	470,046) \$	40.524 \$	690 698
Adjustment for Cane Run repair refund		PLPPT		3,588,000 \$	1,364,803 \$	4,456 3	(32,570)	(2.549) \$	(38,480)
VOT Amortization and Surcredit		אוטא		7,834,614	5,631,305	78,561	1,477,307	(42,506)	1,038,780
							60000	7 720 000 7	110 044 884
Total Operating Expenses	<b>T</b> 0E		er)	641,996,290 \$	252,459,995 \$	\$ 15Z,88Z,T	94,302,708		
Net Operating Income Pro-Forma			₩	67,635,652 \$	15,053,897 \$	(350,102) \$	14,470,463 \$	998,169 \$	14,581,963
O to M			69	1,473,843,556 \$	644,527,736 \$	4,772,258 \$	193,447,680 \$	13,870,109 \$	239,280,834
						127.0	1,000	4 008/	7060 2
Rate of Return			$\frac{1}{1}$	4.59%	2.34%	-1.3470	TR/ Off'		

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									
			4	4 071		6 000 700 7	6 100 000 10	47 562 514 6	000 000
Operation and Maintenance Expenses			**	1 307 760	72,527,570 \$	4,384,382 \$	3.475.583		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)	_	(46,699)	(222,703)	(35,766)	(537,644)
State and Federal Income Taxes		TXINCPF	<del>()</del>	803,548 \$	874,819 \$	175,256 \$	2,225,338 \$	895,341	2,419,630
Specific Assignment of Interruptible Credit		1	•			, , ,		(1,637,062)	(1,396,833)
Allocation of Interruptible Credits		SCP	643	\$ 9/0/99	84,505	29,945	\$ 851,U≯1	6 116,06	270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	₩	(44,786) \$	(54,061) \$	(19,122) \$	(96,898) \$		(273,643)
Remove ECR expenses		ECRREV	ы	(32,690) \$	_	(14,011) \$	_	_	(177,854)
Eliminate brokered sales expenses		Energy	<del>(1</del>	(559,033) \$	(674,807) \$	(238,687) \$	(1,209,515) \$	(789,257) \$	(3,415,692)
Eliminate DSM Expenses		DSMREV	₩	(14,699) \$	(16,293) \$	٠,	e> 1		,
Year end Expense adjustment		YREND	₩ (	<b>.</b>	315,814 \$		82,513 \$	69 6	, 424
Adjustment to annualize depreciation expense		DET	<del>(/)</del>	130,688 \$	210,056 \$	67,905 \$	324,961 \$	137,715 \$	806'8//
Depreciation adjustment		DET	<b>₩</b>			59 6 6	67 6	×9 6	04 17 40
Labor adjustment		9	-	13,528	4 COB. B.	6 818'0	34,580	15,832	040':0
Adjustment for pension and post Net Exp. (See Functional Assignment)	_	11000	ŧ	2 F24	740 6	221 6	1 500 €		2 235
Storm damage adjustment Adjustment to eliminate advertision expense (See Functional Assidement)	ŧ	SUALL		6	P	\$ 177	9		667'7
Amortization of rate case expenses	ì	DMT	49	6,284 \$	8,290 \$	2,878 \$	14,156 \$	8,261 \$	38,141
Amortization of ESM audit expenses		R01	· 49	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	<del>69</del>	83,678 \$	122,585 \$	42,484 \$	200,077 \$	97,208 \$	500,699
Adjustment for merger savings		ĽВŢ	<del>•</del>	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	69	12,672 \$	20,427 \$	6,557 \$	30,243 \$		77,196
Adjustment cumulative effect of accounting change		DET	69 (	77,028 \$	123,808 \$	40,023 \$	191,533 \$	8 0/L'18	459,682
Adjustment for IT staff reduction		181	us e	(6,407) \$	(9,386) \$	(3,253) \$	(15,319) \$	\$ (5,443)	(38,337)
Kemave Alstom Expenses				\$ (25,950)	(62,174) \$	9 (858'BL)	€ (706,18) € (444,03)	(43,140) 6	(234,734)
Adjustment for Obsolete Inventory write-off		1	<b>→</b> 6	(20,340) \$	30,707) \$	(10,505) \$	◆ (114,05)	3 900 08	150,531)
Adjustment for Colporate Orice rease		9 6	ŋ 6	\$ 700,02	23,000 ¢	3,045	(68 /57)	30,330 ¢	(103.27)
Adjustment for Cana Run repair refund		Fad id	13 CF	64.077	103 292	33.156.8	152 927 \$	75 064 \$	390.346
VOT Amortization and Surcredit		VDTREV	, v3	(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		69	11,797,606 \$	16,299,721 \$	5,359,037 \$	27,585,302 \$	13,164,265 \$	67,512,261
Net Operating Income Pro-Forma			69	1,635,974 \$	1,971,975 \$	467,201 \$	4,426,470 \$	1,806,012 \$	6,014,729
Not Coet Base			e.	21 825 190 \$	34 821 982 \$	11.284.727 \$	53 987 843 \$	23.320.016 \$	130 427 115
			•						
Rate of Return				7.50%	%99'\$	4.14%	8.20%	7.74%	4.61%

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			e.	1665.521 \$	2 594 348 \$	129 427 \$	2 912.979 \$	432.625 \$	26,867,866
Depredation and Amortization Expenses			•	_		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	ψŋ	167,645 \$	433,110 \$	14,364 \$	558,681 \$	62,883 \$	1,838,548
Specific Assignment of Interruptible Credit Allocation of Interruptible Credits		SCP	w	12,085 \$	69	69	<b>v</b> >	1,678 \$	(486,000) 159,682
Adjustments to Operation Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	ø	(7,490) \$	(8,992) \$	\$ (869)	(9,342) \$	(2,007) \$	(128,357)
Remove ECR expenses		ECRREV	w	(6,339) \$	(15,470) \$	(474) \$	(19,117) \$	(1,746) \$	(85,491)
Eliminate brokered salas expenses		Energy	s	(93,494) \$	(112,246) \$	(8,719) \$	(116,606) \$	(25,054) \$	(1,602,194)
Eliminate DSM Expenses		DSMREV	↔	,		69	<b>₩</b>		
Year end Expense adjustment		YREND	₩.	6 <del>9</del> 1	1,673 \$	(647) \$	9,548	3,240 \$	
Adjustment to annualize depreciation expense		0E1	LP (	25,304 \$	105,365 \$	\$ 560,r	139,856 8	¥ 040,€	. 46. GO
Depreciation adjustment		<u> </u>	A 6	, c	6 376 K	147 6	4 050 4	9 65	36 862
Labor adjustment for nension and nost Ref Evn (See Frinctional Assignment)	floam		9	7		2	•		200100
Stom damage adjustment	•	SDALL	49	164 \$	487 \$	15 8	\$ 809	27 \$	898
Adjustment to eliminate advertising expense (Sea Functional Assignment)	ignment)								
Amortization of rate case expenses		OMT	sop.	1,093 \$	1,703 \$	85	1,912 \$	284 \$	17,638
Amortization of ESM audit expenses		R01	s	202 \$	496 \$	15 5	612 \$	200	2,83/
Remove one-utility cost (See Functional Assignment)	4								
Adjustment tot injunes and damages (See Functional Assignment)	£.	i i	٠	15 623 K	26.868 3	8 296	30.450 \$	3 992 \$	226 328
Adjustment for mercer covince		1	. 4	53 B15 &	92 550 \$	3315	104 889 \$	13.751	779.605
Adjustment for merger amortization expenses		9	• •	(7,540) \$	(12,967) \$	(465) \$	(14,696) \$	(1,927) \$	(109,232)
MISO Schedule 10 one time credit		PLTRI	ь	2,212 \$	803 \$	<b>69</b>	833 \$	205 \$	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	€		(2,057) \$	(74) \$	(2,331) \$	(306)	(17,329)
Remove Aistom Expenses		PLPPT	φ,		(2,441) \$	(503)	(2,532) \$	(1,537) \$	(105,774)
Adjustment for Obsolete inventory write-off		딘	<b>∞</b> 3	(3,907) \$	(15,303) \$	(165) \$	(20,097)	(8/3) \$	(54,295)
Adjustment for corporate office lease		Let	<b>69</b>	4,982 \$	8,568	302	9,710	1,273 \$	72,169
Adjustment for carbide line write-off		Energy	63 (	(5,292) \$	(6,353) \$	(493) \$	\$ (009'9)	(1,418) \$	(30,682)
Adjustment for Cane Run repair refund		PLPPT	e> (	11,183 \$	4,059 \$	34/ 5	\$ L12,4	4 (202) 4 (202)	1/5,694
		אוויי	4	(100)	127 075	6 (20)	106.200	225	(304 127)
l otal Expense Adjustments				(554)	578,751	(4,907)	000'061	677	(204,147)
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			45	335,362 \$	\$ 56,395	25,680 \$	1,239,824 \$	115,154 \$	3,885,489
Net Cost Rate Base			vs	4,194,659 \$	16,723,512 \$	185,073 \$	21,932,886 \$	941,914 \$	58,300,526
			-	1,000 %	/0u4 2	473 0007	70203	7806 67	7655 3
Nate of Aetum			-	1.00/0	4.4	E) 0000	lar sans	ar maria.	

### 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-12)

KENTUCKY UTILITIES Cost of Service Study Class Allocation

		Total	Residential	All Flectric Residential	General Service		Combined Light &	Large Commilind
Description		System	Rate RS	Rate FERS	SS		LP,HLF,M	LCI-TOD
Cost of Service Summary Pro-Forma								
Total Pro-Forma Operating Revenue	w	693,449,939 \$	124,345,569	\$ 135,772,513	\$ 67,310,253	53 \$	232,654,411	\$ 85,699,043
Total Operating Expenses	s	633,180,928 \$	121,678,365	133,986,084	\$ 58,484,592	\$ 26	201,528,995	\$ 75,886,497
Net Operating (ncome (Adjusted)	so	60,269,011 \$	2,667,204	5 1,786,429	\$ 8,825,661	\$	31,025,414	\$ 9,812,546
Net Cost Rate Base	ç	1,412,033,543 \$	318,616,683	\$ 371,840,037	\$ 142,212,684	84 45	342,893,824	\$ 120,860,788
Rate of Return		4.27%	0.84%	0.48%	6.2	6.21%	9.05%	8.12%
Subsidy at Current Rates		(0)	(18,406,858)	(23,714,808)	4,639,847	23	27,596,286	7,835,982
KU Proposed Increases Proposed Base Rate increase increase in Miscellaneous Charges Decrease in Rents		58,911,660 1,003,763 (556,373)	10,917,610 539,919 (28,757)	13,171,979 395,326 (21,055)	5,663,282 65,368 (152,518)	82 38 18)	16,928,419 3,118 (344,931)	6,910,666 7 (784)
Incremental Income Taxes		(24,104,760) \$	(4,641,041)	\$ (5,500,915) \$	(2,264,378)	\$ (8)	(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%	3%	12.27%	11.51%
Subsidy at KU Proposed Rates Change in Subsidy resulting from KU Proposed Rates		(0)	(20,372,091) 10.7%	(25,799,966) 8.8%	4,237,644 -8.7%	<b>4</b> %	31,768,325 15,1%	9,665,126 23,3%
Base Rate Increase Required for Equalized Rates of Return		58,911,660	31,289,701	38,971,945	1,425,638	82	(12,839,906)	(2,754,460)
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		58,911,660 (24,104,760)	17,484,557 (7,307,774)	21,185,839 (8,755,215)	4,905,523 (1,956,664)	8 <del>§</del>	7,857,308 (3,051,922)	3,122,526 (1,267,692)
Net Operating Income after increase		95,523,300 \$	13,355,149	\$ 14,591,323 \$	11,687,370	\$ 0.	35,488,987	\$ 11,666,603
Rate of Return after 25% Subsidy Reduction	Ц	8.76%	4.19%	3.92%	8.22%	7%2	10.35%	9.65%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		(0)	(13,805,144) -25.0%	(17,786,106) -25,0%	3,479,885 -25.0%	35	20,697,214 -25.0%	5,876,987 -25.0%
Adjusted Revenue at Current Rates		676,762,013	121,233,915	131,265,061	65,598,531	Ξ	226,957,350	84,135,770
Percentage increase proposed by KU Percentage increase to achieve equalized Rates of Return Percentage increase to achieve 25% subsidy reduction		8.70% 8.70% 8.70%	9.01% 25.81% 14.42%	10.03% 29.69% 16.14%	8.63% 2.17% 7.48%	888	8.34% -5.66% 3.46%	8.21% -3.27% 3.71%

KENTUCKY UTILITIES Cost of Service Study Class Allocation

	ć		Total Ministry		Mind of the second	Large Power Mine	Combination Off.	ŧ		Electric Space
Description	3	Primary MPP	Transmission MPT		Power TOD Primary LMPP	Transmission	Peak CWH		All Elcetric School AES	Heating Rider 33
Cost of Service Summary – Pro-Forma										
Total Pro-Forma Operating Revenue	ь	4,900,693	\$ 3,840,839	\$ 628	1,984,106 \$	4,207,348	\$ 42	427,775 \$	4,051,813	\$ 684,657
Total Operating Expenses	69	3,986,444	\$ 3,209,576	\$ 925	1,699,608 \$	3,553,714	\$ 1,05	\$ 685,730,1	3,676,265	\$ 655,878
Net Operating Income (Adjusted)	•	914,249	\$ 631	631,263 \$	284,498 \$	653,634	\$ (62	(629,614) \$	375,547	\$ 28,779
Net Cost Rate Base	w	6,738,314	\$ 5,192,512	,612 \$	2,812,219 \$	6,367,053	\$ 4,51	4,518,731 \$	8,113,397	\$ 1,490,422
Rate of Return	$\mid$	13.57%	12	12.16%	10.12%	10.27%		-13.93%	4.63%	1.93%
Subsidy at Current Rates		1,055,102	689	689,710	276,917	642,975	(1,38	(1,384,849)	49,246	(58,654)
KU Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges Decrease in Rents		405,257 9 (3,712)	319	319,850 6 (2,603)	165,746 1 (356)	347,607 3 (1,166)	σ	96,148		129,034
Incremental Income Taxes	t/s	(163,065)	\$ (128	(128,831) \$	(67,163) \$	(140,685)	£)	(39.044) \$	•	\$ (52,399)
Net Operating Income after increase	677	1,152,739	\$ 819	819,685 \$	382,726 \$	859,393	2) \$	(572,510) \$	375,547	\$ 105,414
Rate of Return at KU Proposed Rates		17.11%	15	15.79%	13.61%	13.50%		-12.67%	4.63%	7.07%
Subsidy at KU Proposed Rates Change in Subsidy resulting from KU Proposed Rates		1,173,390	788	788,676 14.3%	324,088 17.0%	721,761 12.3%		(1,478,659) 6.8%	(291,825) -692.6%	7,725 -113.2%
Base Rate Increase Required for Equalized Rates of Return		(768,133)	(468)	(468,826)	(158,342)	(374,154)	1,57	1,574,807	291,825	121,309
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		23,193 (7,914)	48 (18	48,456 (18,623)	49,345 (19,894)	108,077 (43,416)	53	536,171 (217,730)	328,759 (133,504)	77,318 (31,398)
Net Operating Income after increase	w	925,825	\$ 658	\$ 005,839	313,594 \$	717,133	\$ (31	(311,173) \$	570,803	\$ 74,699
Rate of Return after 25% Subsidy Reduction	H	13.74%	12	12.68%	11,15%	11.26%		%68°9-	7.04%	5.01%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		791,326 -25.0%	517	517,283 -25.0%	207,688 -25.0%	482,231 -25.0%	(1,0	(1,038,637) -25.0%	36,934 -25.0%	(43,991) -25.0%
Adjusted Revenue at Current Rates		4,793,968	3,748,239	539	1,944,714	4,098,693	41	414,203	3,955,546	668,128
Percentage increase proposed by KU Percentage increase to achieve equalized Rates of Return Percentage increase to achieve 25% subsidy reduction		8.45% -16.02% 0.48%	8 21-	8.53% -12.51% 1.29%	8.52% -8.14% 2.54%	8.48% -9.13% 2.64%		23.21% 380.20% 129.45%	0.00% 7.38% 8.31%	19.31% 18.16% 11.57%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation

			Decorativ	Decorative Street	Private Outdoor		Customer		
Description	ž	Street Lighting St Lt	Lighting Dec St Lt	Lighting Dec St Lt	Lighting PO Lt	ō	Outdoor Lighting C O Lt	Special	cts sta
Cost of Service Summary – Pro-Forma									
Total Pro-Forma Operating Revenue	s	5,421,077	<del>1/2</del>	807,012	\$ 6,328,527	\$ 27	898,820 \$	14,115,482	82
Total Operating Expenses	69	5,595,768	₩	685,056	\$ 4,880,294	34 \$	722,198 \$	11,794,204	4
Net Operating Income (Adjusted)	w	(174,691)	s,	121,956	\$ 1,448,234	34	176,622 \$	2,321,278	78
Net Cost Rate Base	es	31,905,511	<sub>හ</sub>	3,716,038	\$ 15,836,075	\$	2,518,660 \$	26,400,496	96
Rate of Return	H	-0.55%		3.28%	9.15%	2%	7.01%	8.7	8.79%
Subsidy at Current Rates		(2,587,059)		(61,715)	1,300,372	72	116.380	2,011,128	28
KU Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges Decrease in Rents		512,748 3 (219)		76,631 - (17)	517,636 3 (220)	,636 3 (220)	72,319	676,728 -	
incremental income Taxes	s	(208,131)	63	(31,112)	\$ (210,116)	16) \$	(29,353) \$	(274,808)	(80
Net Operating Income after increase	69	129,710	63	167,459	\$ 1,755,537	37 \$	219,552 \$	2,723,198	96
Rate of Return at KU Proposed Rates	Н	0.41%		4.51%	11.09%	%6	8.72%	10.3	10.31%
Subsidy at KU Proposed Rates Change in Subsidy resulting from KU Proposed Rates		(3,415,770) 32.0%		(141,315) 129.0%	1,152,074	4%	82,784 -28.9%	1,578,032 -21.5%	32
Base Rate Increase Required for Equalized Rates of Refurn		3,928,518		217,946	(634,438)	98	(10,465)	(901,304)	<u>\$</u>
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		1,988,224 (807,298)		171,660 (69,702)	340,841 (138,322)	# <del>(</del> 2	76,820 (31,181)	607,042 (246,510)	10,
Net Operating Income after increase	69	1,006,019	w	223,898	\$ 1,650,535	35 \$	222,226 \$	2,681,810	9
Rate of Return after 25% Subsidy Reduction	H	3.15%		6.03%	10.42%	5%	8.82%	10.16%	%9
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		(1,940,294) -25.0%		(46,286) -25.0%	975,279 -25.0%	%c	87,285	1,508,346 -25.0%	08,346 -25.0%
Adjusted Revenue at Current Rates		5,402,425		807,559	6,293,269	66	893,164	14,551,478	28
Percentage Increase proposed by KU Percentage Increase to achieve equalized Rates of Return Percentage Increase to achieve 25% subsidy reduction		9.49% 72.72% 36.80%		9,49% 26.99% 21.26%	8.23% -10.08% 5.42%	% % 8 % 8 % 8 % 8 % 8 % 8 % 8 % 8 % 8 %	8.10% -1,17% 8.60%	4. è 4.	4.65% -6.19% 4.17%

### 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	Ś	2003-00434

EXHIBIT (SJB-13)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

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									
Ťotal Pro-Forma Operating Revenue	ь	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	es.	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)	<del>69</del>	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	<b>U</b> 3	1,473,843,556 \$	680,151,878 \$	5,062,926 \$	170,825,435 \$	285,031,005 \$	\$ 25,299,290 \$	20,157,813 \$	451,450
Rate of Return	Ц	4.59%	1.69%	-7.37%	9.61%	7.57%	5.82%	3.23%	0.47%
Subsidy at Current Rates	so.	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 fincrease Increase in Miscellaneous Charges		64,260,364 410,061	26.277,410 305,284	158,774	8,974,815 104,713	13,708,637 36	10,638,506 28	586,307	17,030
Incremental Income Taxes		(26,361,864) \$	(10,836,010) \$	\$ (93,906)	(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 Change in Subsidy resulting from LG&E Proposed Rates		(0)	(36,562,357) 9.8%	(1,087,370) 6.4%	16.076,190 10.9%	15,522,384 8.4%	5,452,942 16.0%	(759.301) 64.7%	(34,168) 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 Incremental Income Taxes		64,260,364 (26,361,864)	37,864,144 (15,559,156)	477,652 (194,707)	3,767,827 (1,578,579)	8,926,641 (3,638,817)	8,710,760 (3,550,813)	999,777 (407,543)	27,656 (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	Ц	7.19%	5.01%	-1.78%	10.96%	9.42%	8,12%	6.17%	4.10%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		0	(24,975,623) -25.0%	(766,492) -25.0%	10,869,202 -25.0%	10,740,388 -25.0%	3,525,196 -25.0%	(345,831) -25.0%	(23,542) -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 Percentage increase to achieve equalized Rates of Return Percentage increase to achieve 25% subsidy reduction		11.45% 11.45% 11.45%	12.29% 29.39% 17.71%	21.70% 172.18% 66.10%	11.04% -8.74% 4.64%	1065% -141% 6.93%	10.84% 5.28% 8.88%	12.27% 28.17% 20.93%	12.27% 36.90% 19.93%

Description	5	Street Lighting Rate OL	Stre	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary Pro-Forma					
Total Pro-Forma Operating Revenue	<b>6</b> >	6,617,260	69	677,761 \$	35,908,904
Total Operating Expanses	s <sub>9</sub>	5,693,263	<del>63</del>	\$66,398 \$	32,186,608
Net Operating Income (Adjusted)	<b>↔</b>	923,997	er)	111,362 \$	3,722,296
Net Cost Rate Base	479	25,495,128	s,	1,001,089 \$	60,367,542
Rate of Return	Н	3.62%		11.12%	6.17%
Subsidy at Current Rates		(415,268)		110,441	1,607,097
LGAE Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges		726,051		- 26,796	3,118,038
incremental income Taxes	ьэ	(295,963)	s.	(23,152) \$	(1,271,018)
Net Operating Income after increase	69	1,354,085	69	145,006 \$	5,569,315
Rate of Return at LG&E Proposed Rates	Ц	5,31%		14.48%	8.23%
Subsidy at LG&E Proposed Rates Change in Subsidy resulting from LG&E Proposed Rates		(807,912) 94.6%		123,311	2,076,282 29.2%
Base Rate Increase Required for Equalized Rates of Retum		1,533,963		(66,515)	1,041,756
Base Rate increase Required for 25% Subsidy Reduction incremental Income Taxes		1,222,512 (498,337)		16,316 (6,651)	2,247,079 (915,986)
Net Operating Income after increase	s	1,648,172	b3	121,028 \$	5,053,389
Rate of Return after 25% Subsidy Reduction	Н	6.46%		12.09%	8.37%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		(311,451) -25.0%		82,831 -25.0%	1,205,322 -25.0%
Adjusted Revenue at Current Rates		5,908,023		543,908	27,331,513
Percentage increase proposed by LG&E Percentage increase to achieve equalized Rates of Return Percentage increase to achieve 25% subsidy reduction		12.29% 25.96% 20.69%		10.44% -12.23% 3.00%	11.41% 3.81% 8.22%

### 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	j	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

(6)	Calculated Revenue @ Proposed KIUC Rates	\$ 37,800 19,476,875 2,897,781 (271,655) 21,553	45,779,244	\$ 67,941,598 0.999029 \$ 68,007,665	1,698,726 (1,573,353) (192,241) 8,140	\$ 67,948,937	<b>2,402,371</b> 3.67%	\$ 68,220,592 2,466,557 3.75%
(8)	Proposed Rates	\$ 120.00 \$ 4.79 \$ 0.73 \$ (4.19)	\$ 0.02200					ı
(2)	Calculated Revenue @ Proposed KU Rates	\$ 37,800 22,456,486 2,897,781 (271,655) 21,553	45,779,244	\$ 70,921,209 0.999029 \$ 70,990,174	1,698,726 (1,573,353) (192,241) 8,140	70,931,445	<b>5,384,879</b> 8.22%	5,449,065 8.29%
(9)	Proposed Rates	\$ 120.00 \$ 5.52 \$ 0.73 \$ (4.19)	\$ 0.02200	<i></i>		1971		<i>ω</i>
(5)	Calculated Revenue @ Present Rates (see Exhibit 9)	16,842,364 2,897,781 (207,469) 21,553	45,987,332	65,541,561 0,999029 65,605,294	1,698,726 (1,573,353) (192,241) 8,140	65,546,566		65,754,035
4	Present Rates	4.14 \$ 0.73 \$ \$	\$ 0.02210	<i></i>		69		•>∥
(3)	Total KWH		2,080,874,735					ile Credit) redit)
(2)	Bills / KW	315 4,068,204 3,969,563 64,834		se Rates Correction Factor of Correction Factor	or rollin ijustment Customers			out Interruptik Interruptible C
(1)	I CIP. Rate Code 463	Number of Customers On-Peak Demand Off-Peak Demand CSR Credits Penalties	Energy	Total Calculated at Base Rates Correction Factor Total After Application of Correction Factor	Fuel Clause Billings - proforma for rollin Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	Total Rate LCI Primary	Proposed Increase Percentage Increase	Total Rate LCI Primary (without Interruptible Cre Proposed Increase (without Interruptible Credit) Percentage Increase

Exhibit (SJB-14)
Page 1 of 2

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

(2)	Calculated Revenue Proposed @ Proposed Rates KIUC Rates	120.00 \$ 5,760 4.60 5,057,123 0.73 797,521 (4.09) (499,036) 76,807	\$ 0.02200 13,663,054	\$ 19,101,229 0.999990 \$ 19,101,418	526,690 (450,942) (55,117) 2,334	\$ 19,124,383	<b>535,180</b> 2.69%	\$ 19,623,420 655,974 3.46%	\$ 87,844,012 3,122,530 3.69%
(2)	Calculated Revenue @ Proposed P	\$ 5,760 \$ 5,862,744 \$ 797,521 \$ (499,036) \$ 76,807	13,663,054 \$ (	\$ 19,906,850 0,99990 \$ 19,907,046	526,690 (450,942) (55,117) 2,334	\$ 19,930,012	<b>1,340,808</b> 7.21%	\$ 20,429,048 1,461,602 7.71%	\$ 91,632,149 6,910,667 8.16%
(9)	Proposed Rates	\$ 120.00 \$ 5.33 \$ 0.73 \$ (4.09)	\$ 0.02200			r H		"	if
(5)	Calculated Revenue @ Present Rates (see Exhibit 9)	4,344,810 797,521 (378,243) 76,807	13,725,159	18,566,054 0.999990 18,566,238	526,690 (450,942) (55,117) 2,334	18,589,204		18,967,446	84,721,482
(4)	Present Rates	\$ 3.95 \$ \$ 0.73 \$ (3.10)	\$ 0.02210	<i>↔</i>   <i>↔</i>		₩		∽∥	ν»
(3)	Total		621,047,926					e Credit) edit)	edit)
(2)	Bills /	48 1,099,952 1,092,494 122,014		se Rates Correction Factor I of Correction Factor	for rollin Sjustment Customers	c		hout Interruptible I Interruptible Cr	rruptible Credit) Interruptible Cr
(1)	LCIT - Rate Code 564	Number of Customers On-Peak Demand Off-Peak Demand CSR Credits Penalties	Energy	Total Calculated at Base Rates Correction Factor Total After Application of Correction Factor	Fuel Clause Billings - proforma for rollin Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	Total Rate LCI Transmission	Proposed increase Percentage increase	Total Rate LCI Primary (without Interruptible Credit) Proposed Increase (without Interruptible Credit) Percentage Increase	Total Rate LCI (without Interruptible Credit) Proposed Increase (without Interruptible Credit) Percentage Increase

Exhibit (SJB-14)
Page 2 of 2

# 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	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBIT (SJB-15)

	Billing Determinants		Present Rates		Calculated Revenue at Present Rates	Pro	Proposed Rates		Calculated Revenue at Proposed Rates	ď.	Proposed Rates	0 # £	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LP. TRANSMISSION VOLTAGE Customer Charges		€9		69	•	ø	90.00	€7	,	€9	90.00	₽	,
Demand Charges Summer Season Winter Season	KW-Months	69 69	7.39			wω	12.01 9.49			<i>↔</i>	11.65 9.13		• •
Energy Charges	kWn's	69	0.02480			о́ •	0.02000		•	49	0.02000		
Power Factor Provision Summer Season Winter Season	kW-Months	w w	7.39		1 1	<del>и и</del>	12.01 9.49			<i>6</i> 9 <i>6</i> 9	11.65 9.13		
Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor			ı	us us	. ,						٠	w w	
Fuel Adjustment Ciause - 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				•27			"	s s				v. v.	
Percentage increase													

Note: Currently no customers are served under this rate

Exhibit (SJB-15)
Page 2 of 6

(10,323) (35,947) (130,757) (29,824) 349 (58,665) 646,478 14.54% at Proposed KIUC Rates 44,460 1,218,979 1,861,261 Calculated Revenue 5,310,885 5,093,684 2,232,454 5,312,581 Proposed Rates 90.00 12.81 10.27 12.81 10.27 0.02000 0.999681 69 •• <del>49</del> 49 (10,615) (37,216) Calculated Revenue 5,192,370 **745,164** 16.76% Rates 44,460 1,253,481 1,926,975 (58,665) (29,824) 349 at Proposed 2,232,454 (130,757) 5,409,539 5,411,266 69 90.00 13.17 13.17 10.63 Rates Proposed 0.02000 0.999681 **69** 69 <del>(/)</del> 69 69 (6,891) (21,041) (29,824) 21,064 813,763 at Present 2,768,243 (58,665) (130,757) Calculated Revenue 4,664,613 4,666,103 4,447,206 Rates 45.64 8.55 6.01 Present 8.55 6.01 0.02480 0.999681 G (4,307) (4,307) kWh's 111,622,714 181,277 276,454 kW-Months 95.177 Billing Determinants 494 Subtotal @ base rates before application of correction factor Correction Factor -Subtotal @ base rates after application of correction factor INDUSTRIAL POWER RATE LP - PRIMARY VOLTAGE TOTAL INDUSTRIAL POWER RATE LP PRIMARY VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers Fuel Adjustment Clause - proforma for rollin PROPOSED INCREASE
Percentage Increase Value Delivery Surcredit Power Factor Provision Demand Charges Summer Season Winter Season Summer Season Winter Season Customer Charges Merger Surcredit Energy Charges

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

Exhibit (SJB-15)
Page 3 of 6

Calculated Revenue at Proposed KIUC Rates (63,710) (115,050) 6,896,060 10,542,296 9.73% (277,626) 380,250 (738,856)(167,175) 11,076,726 28,725,740 1,955 162,285 27,706,322 2,455,752 28,716,571 \* 90.00 13.91 13.91 Proposed Rates 0.02000 0.999681 69 <del>69</del> 69 <del>()</del> Calculated Revenue at Proposed Rates (738,856) (167,175) 1,955 (65,371) (118,719) 2,969,530 11.76% 380,250 7,075,808 10,878,484 11,076,726 (277,626)29,236,509 28,220,101 29,227,177 165,294 69 90.00 14.27 Rates 14.27 Proposed 0.02000 0.999681 69 w <del>и</del> и 49 49 5,161,819 7,326,515 (47,688) (79,956) (738,856) (167,175) at Present Rates 180,154 Calculated Revenue 13,735,140 (277,626) 1,955 26,275,984 26,284,374 147,900 25,250,571 <del>4)</del> Rates 42.64 10.41 7.90 0.02480 10.41 7.90 Present 0.999681 69 <del>и</del> и (4,581) (10,121) (14,702) *kW-Months* 495,852 927,407 1,423,259 kWh's 553,836,275 3,146,798 BIIIIng Determinants 4,225 Subtotal @ base rates before application of correction factor INDUSTRIAL POWER RATE LP - SECONDARY VOLTAGE Subtotal @ base rates after application of correction factor TOTAL INDUSTRIAL POWER RATE LP SECONDARY Value Delivery Surcredit
VDT Amortization & Surcredit Adjustment
Adjustment to Reflect Year-End Customers Fuel Adjustment Clause - proforma for rollin Percentage Increase PROPOSED INCREASE Power Factor Provision Customer Charges Summer Season Winter Season Summer Season Winter Season Merger Surcredit Demand Charges Energy Charges

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

Exhibit (SJB-15)
Page 4 of 6

2,203,576 3,113,360 (56,183) (72,842) (117,826) 8,760 6.33% **988,028** 7.87% Calculated (1,637,062)Revenue at Proposed (213,291) (328.889)KIUC Rates 1,556,006 7,527,195 708,329 12,524,984 12,520,685 867 11,905,199 13,542,260 47 Proposed Rates 120.00 (3.98)9.38 0.02000 2.23 9.38 6.84 2.23 1.000343 ₩ <del>()</del> (58,620) (74,903) (122,399) 2,265,945 3,234,183 949,877 8.48% 13,783,808 1,229,576 9.79% (328,889) (74,173) 8,760 (1,637,062)Calculated Revenue at Proposed 1,623,516 7,527,195 12,762,233 (213,291) Rates 12,766,615 867 12,146,747 \* Rates 120.00 (3.98)9.65 2.33 9.65 7.11 Proposed 2.33 0.02000 1,000343 ↔ 49 es es 43 1,258,598 1,291,854 (51,576) (41,604) (48,891) (213,291) Calculated Revenue Rates 3,257 1,428,415 (1,357,363)at Present 9,333,721 (328.889)(74, 173)11,816,412 11,812,356 867 12,554,232 11,196,870 w Rates 44.62 (3.30)2.05 5.36 2.84 2.05 5.36 2.84 Present 0.02480 1,000343 υs 44 69 69 4Mh's 376,359,726 kW-Months 696,788 KW-Months (25,159) 411,322 (17,215)**KW-Months** 454,878 689,691 TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION (without interruptible Credit) Billing Determinants 23 INDUSTRIAL POWER RATE LPTOD - TRANSMISSION VOLTAGE TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION Subtotal @ base rates before application of correction factor Subtotal @ base rates after application of correction factor Correction Factor -PROPOSED INCREASE (without Interruptible Credit) Fuel Adjustment Clause - proforma for rollin Adjustment to Reflect Year-End Customers VDT Amortization & Surcredit Adjustment Percentage increase Percentage Increase PROPOSED INCREASE Value Delivery Surcredit Interruptible Service Rider Basic Demand Charges Peak Demand Charges Power Factor Provision Customer Charges Merger Surcredit Summer Peak Basic Demand **Energy Charges** Summer Peak Winter Peak Winter Peak

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Exhibit (SJB-15)
Page 5 of 6

Revenue at Proposed KIUC Rates 9,351,277 (355,671) (388,022) (398,556) 64,800 (1,626,347) (366,371) 60,857,022 4,440,440 7.87% 10,144,612 (1,396,833) Calculated 31,947,215 (864,770) 4,284 7.56% 62,334,709 62,313,393 59,460,189 4,181,767 (4.05) 120.00 Proposed 3.42 9.38 6.84 0.02000 3.42 9.38 6.84 1,000342 69 6 153 49 49 Calculated Revenue 9,615,955 13,884,586 (365,737) (399,004) (414,023) (1,626,347) (366,371) 61,890,663 5,474,081 9.70% 64,800 (1,396,833) at Proposed Rates 9.43% 10,431,745 31,947,215 63,368,703 63,347,034 (864,770) 4,284 60,493,830 5,215,408 ↔ ₩ 120,00 (4.05)Rates 9.65 Proposed 3.52 3.52 9.65 7.11 0.02000 1.000342 64 49 ↔ 49 (332,489) (221,623) (165,376) (1.138,160)(1,626,347) (366,371) 24,095 5,341,090 5,546,023 Calculated Revenue at Present Rates 9,483,405 39,614,547 (864,770) 4.284 56,416,582 55,278,422 58,151,511 58,131,626 'n w ∽∥ 44.62 3.20 5.36 2.84 (3.30)Present 5.36 Rates 3.20 0.02480 1.000342 ω 49 (103,903) (41,348) (58,231) kWn's 1,597,360,760 KW-Months 2,963,564 1,952,825 996,472 KW-Months 344,897 KW-Months kW-Months Billing Determinants TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY (without interruptible Credit) PROPOSED INCREASE (without interruptible Credit) 540 Subtotal @ base rates before application of correction factor INDUSTRIAL POWER RATE LPTOD - PRIMARY VOLTAGE Subtotal @ base rates after application of correction factor Correction Factor -TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY Fuel Adjustment Clause - proforma for rollin Adjustment to Reflect Year-End Customers VDT Amortization & Surcredit Adjustment Percentage Increase Percentage increase PROPOSED INCREASE Value Delivery Surcredit Interruptible Service Rider Basic Demand Charges Peak Demand Charges Power Factor Provision Customer Charges Merger Surcredit Basic Demand Summer Peak Energy Charges Summer Peak Winter Peak Winter Peak

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

LOUISVILLE GAS AND ELECTRIC COMPANY

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	O.	Proposed Rates		Calculated Revenue at Proposed Rates	ū.	Proposed Rates	rs —	Calculated Revenue at Proposed KIUC Rates	
INDUSTRIAL POWER RATE LPTOD - SECONDARY VOLTAGE Customer Charges	151	es	44.62	σs	6,738	es.	120.00	↔	18,120	₩	120.00	₩.	18,120	
Basic Demand Charges	kW-Months 114,966	↔	5.11		587,476	69	4.62		531,143	<del>69</del>	4.52		520,004	
Peak Demand Charges Summer Peak Winter Peak	kW-Months 31,727 80,068 111,795	<i>\$</i> 3 €5	5.36		170,057 227,393	69 tA	9.65 7.11		306.166 569,283	ωн	9.38 6.84		297,738 548,016	
Energy Charges	kWh's 42,810,915	69	0.02480		1,061,711	₩	0.02000		856.218	₩	0.02000		856,218	
Power Factor Provision Basic Demand Summer Peak Winter Peak	KW-Months (1,951) (533) (1,404)	60 69 69	5,11 5,36 2,84		(9,970) (2,857) (3,987)	**	4.62 9.65 7.11		(9.014) (5.143) (9.982)	<del>69 69 69</del>	4.52 9.38 6.84		(8,825) (5,002) (9,610)	
Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor		<del>-</del>	1.000343	w w	2,036,561	Ψ-	1.000343	v> v>	2,256,791		1.000343		2,216,661	
Fuel Adjustment Clause - proforma for rollin					(21,506)				(21,506)				(21,506)	
Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	,				(56,520) (12,486) 146				(56,520) (12,486) 146				(56,520) (12,486) 146	
TOTAL INDUSTRIAL POWER RATE LPTOD SECONDARY				w	1,945,496			•	2,165,650			•	2,125,534	
PROPOSED INCREASE Percentage Increase								v)	220,155 11.32%			•	180,039 9.25%	
TOTAL INDUSTRIAL POWER RATE LESS INTERRUPTIBLE CREDIT PROPOSED INCREASE Percentage increase	EDIT			v	100,614,087				111,252,592 10,638,505 10.57%			₩ <b>₩</b>	109,324,823 8,710,736 8.66%	



ANALYSIS OF LGE/KU EXPECTED HOURLY OPERATION OF COMBUSTION TURBINES (Test year ending September 30, 2003 and Calendar year 2004)

w Witd HR <sup>2</sup>		451	1,902	1,855	423	295	345	196				1,291	2,144	1,802	•							10,704
Heat Rate Mw Wtd HR2		12.185	10,532	10,544	12,033	11,994	11,920	11,875				9,919	10,624	10,645								
Mw Wtd Hrs.	0	6.44	31.39	30.58	6.11	4.27	5.03	2.88	0.00	0.00	0.00	22.62	35.09	29.42	00.0	0.00	0.00	0.00	0.00	0.00	00.0	174
MW	0	117	154	154	106	106	106	106	o	0	0	158	160	160	0	0	0	0	0	0	a	1327
Average Hours	r.	73	270.5	263.5	76.5	53.5	63	36	0	0	0	190	291	244	148	104	0	0	0	0	7	1817
2004 Hours	0	70	370	306	45	4	43	36	0	0	0	87	207	178	148	104	0	0	0	0	α	1634
Test Year Hours	ო	9/	171	221	108	29	83	36	0	0	0	293	375	310					0	0	ধা	1747
MW	14	117	154	154	106	106	106	106	36	12	23	158	160	160	155	155	155	155	11	=	41	2068
Light	Cane Run 11	Brown 5	Brown 6	Brown 7	Brown 8	Brown 9	Brown 10	Brown 11	Heafling	Paddys Run 11	Paddys Run 12	Paddys Run 13	Trimble County 5	Trimble County 6	Trimble County 7	Trimble County 8	Trimble County 9	Trimble County 10	Waterside 7	Waterside 8	Zorn 1	Weighted Average

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

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 noncompliance.
- 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.

Transmission

#### 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.

	1 Tilliai y	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.

#### 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

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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 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:

- 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 noncompliance.
- 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.

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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 minbtu 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 (0.51 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.

#### 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

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