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October 28, 2008

Stephanie Stumbo Executive Director,
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

**Re: Case Nos. 2008-00251 and 252;
2007-00564 and 565.**

Dear Ms. Stumbo:

Please find enclosed the original and twelve (12) copies each of the DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN and the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON filed on behalf of THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. in the above-referenced matter. By copy of this letter, all parties listed on the Certificate of Service have been served.

Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by first-class postage prepaid mail, (unless otherwise noted) to all parties on the 28th of October, 2008.

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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. 2008-00252
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564
AND		
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2008-00251
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	))	CASE NO. 2007-00565

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2008

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

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

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

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

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

Q. Please state your educational background and experience.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

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

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court.

A complete copy of my resume and my testimony appearances is contained in Baron Exhibit__(SJB-1).

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

A. I am testifying on behalf of the Kentucky Industrial Utility Customers ("KIUC"), a group of large industrial customers taking service on the LG&E and KU systems. The KIUC members who take service from the Companies are: Arch Chemicals, Inc., Arvin Meritor dba Carrollton Castings, Carbide Industries LLC, Cemex, Clopay Plastics Products Co., Inc., Corning Incorporated, Dow Corning

Corporation, E.I. DuPont de Nemours & Co., Ford Motor Co., General Electric – Appliance Park, Golden Foods, Lexmark International, Inc., MeadWestvaco, NewPage Corp., North American Stainless, Occidental Chemical Corporation, Osram-Sylvania, Pilkington North America (formerly United L-N Glass), Protein Technologies, Rohm & Haas Kentucky, Inc., Square D. Company (US Schneider Electric), TI Group Automotive Systems, and Toyota Motor Engineering and Manufacturing North America, Inc.

Q. Have you previously testified in KU and LG&E rate proceedings before the Kentucky Public Service Commission?

A. Yes. I have testified in 10 KU and LG&E cases since 1981.

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

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

LG&E and KU rate classes are different, I will be presenting separate analyses and discussions of these results.

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

Q. What is the purpose of your testimony?

A. I am presenting testimony on a variety of cost of service and rate design issues raised by the Company's filings in this case. The first issue that I address concerns the Company's filed cost of service study using the base-intermediate-peak ("BIP") class cost of service methodology. I will discuss two problems that we have identified with the Companies' filed BIP studies. The first issue concerns the development of the summer and winter peak demand allocation factors that are used in each of the Company's studies to allocate "peak" and "intermediate" production demand costs to rate classes. Specifically, the Companies' analyses *did not* adjust the summer and winter class coincident peak demands for losses, which is required for a correct allocation of the peak and intermediate production demand costs under the BIP method. The second problem that we identified concerns the base, intermediate and peak functionalization factors. Upon evaluation of the Companies' models, it appears that the BIP functionalization factors have not been updated from the 2004 rate cases to reflect the test year factors developed in this case. KIUC has corrected the Companies' BIP studies for these two problems.

The next set of issues that I will address concerns the Company's proposed rate design for large commercial and industrial customers. The Companies are not proposing increases to their large industrial rates in this case. In the event that the Commission adopts KIUC's recommendation to reduce each Company's revenue requested revenue increase, KIUC recommends that the reductions be used to further reduce subsidies paid by large commercial and industrial customers for both KU and LG&E via reductions in the proposed rate schedule revenues for every rate class. However, due to the extremely large subsidies paid by KU's Large Industrial TOD Rate, I will discuss a proposal to initially reduce this rate schedule such that it only pays a relative rate of return of "2 Times" the retail average at proposed rates. Even with this reduction, the Large Industrial TOD Rate will have the highest rate of return on the KU system. Any additional decreases would then be used to reduce all rate schedules. With regard to rate design within individual rate classes, the reductions should be applied on an equal percentage basis to the demand and non-fuel energy charges of the industrial rate schedules.

The final issue that I will address concerns the Companies' interruptible rates under the curtailable service rider ("CSR"). Based on updating the Companies' prior analysis, the industrial interruptible credits should be increased substantially to reflect a more current calculation of avoided capacity cost.

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, corrections should be made to the studies submitted by LG&E and KU to incorporate losses in the summer and winter demand allocation factors and the correct BIP functionalization factors.

- Based on the BIP cost of service study, LG&E's and KU's proposed revenue increases to each rate schedule are reasonable and should be adopted by the Commission. However, in the likely event that the Commission approves a smaller overall revenue increase (or a revenue decrease) to KU, the first $3.1 million reduction from the KU's requested increase should first be applied to reduce rate schedule Large Industrial TOD such that its relative rate of return at proposed rates drops to "2 Times" the retail average rate of return. Any remaining dollar amounts available for KU should then be used to scale back the Companies "Proposed Revenues" for each class (including LI-TOD, as adjusted above) to reflect the lower overall increase (or overall revenue decrease). For LG&E, the entire amount of the reduction from the Company's revenue increase request should be used to scale back, on an equal percentage basis, LG&E's proposed revenues by rate schedule.

- KIUC generally supports the Company's proposed large commercial and industrial rate design. Any changes or reductions in the allocated revenue increase to LG&E's and KU's large commercial and industrial power rates should be applied equally to the energy and demand charges proposed by the Companies.

- LG&E's and KU's proposed curtailable service rider ("CSR") should be modified by increasing the monthly interruptible credit to $8.51 per kW month from the existing $4.09 per kW, based on an updated analysis of the avoided cost of peaking capacity. All of the Companies' CSR credits should be increased by the same percentage (108%). This is appropriate because of the significant increase in avoided capacity costs for the Companies. It is also appropriate to encourage economic demand response by setting the interruptible credits at a current avoided cost, thus providing customers correct price signals.

II. COST OF SERVICE STUDY ISSUES

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

A. Yes. The BIP method is the class cost allocation method used by LG&E in prior cases and was used for the first time by KU in Case No. 2003-00434.

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

	Assignment of Total P&T Costs
Base	**33.89%**
Intermediate	**15.32%**
Peak	**50.78%**

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 33.89% 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 15.32% of all production and transmission demand-related costs, costs are allocated to classes based on class contributions to the winter system peak demand. Finally, for peak period costs that comprise 50.78% 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.

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 does not oppose the use of this methodology in this case. As I will discuss subsequently, under both the Companies' filed BIP studies and the corrected BIP studies that I present, the results indicate that certain rate classes are 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).

Q. 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 identified two problems with the analyses.

First, a review of the Companies' cost of service models indicates that the functional allocation of costs between the base, intermediate and peak periods is incorrect; it appears that the functional allocation factors are the factors used in the Companies' cost of service model from Case Nos. 2003-00433 and 2003-00434. I have updated these functional allocation factors to the values shown in Seelye Exhibit 25.

The second correction that I made is to add losses to the winter and summer class coincident demands that are used to allocate the intermediate and peak period demand costs. The Companies' studies did not adjust these summer and winter class CP demands for losses, which is required to properly allocate costs.[1] These adjustments produce studies that more properly reflect the underlying assumptions relied upon by the Company's in these studies.

[1] The energy allocation factors for the "base" costs did include losses in the Companies' studies.

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

A. Yes. Baron Exhibit ____(SJB-2) contains the corrected KU BIP class cost of service study, while Baron Exhibit ____(SJB-3) contains the corrected LG&E BIP class cost of service study. Both of these studies reflect the aforementioned changes that I have just discussed.

Q. What do the BIP cost of service studies show with regard to the rate of return paid by the residential class on the KU system?

A. As can be seen from each of the exhibits summarizing the studies evaluated, the residential and all electric residential classes pay substantially below the average system rate of return. Table 1 below summarizes the Company's and the Corrected BIP cost of service study results for KU.

Table 1
Kentucky Utilities Company
KU BIP and Corrected BIP Cost of Service Study Results

	KU BIP		Corrected BIP	
	Rate of Return	Relative ROR Index	Rate of Return	Relative ROR Index
Residential	3.58%	0.50	3.98%	0.56
General Service	11.92%	1.67	10.85%	1.52
All Electric School	6.32%	0.88	8.35%	1.17
Combined Light & Power	11.60%	1.62	10.53%	1.47
Small Time-of-Day	6.74%	0.94	5.83%	0.82
Large Comm/Ind TOD	7.90%	1.11	7.73%	1.08
Coal Mining Power	13.04%	1.82	13.45%	1.88
Large Power Mine Power TOD	12.81%	1.79	12.66%	1.77
Large Industrial Time-of-Day	25.00%	3.50	23.64%	3.31
Lighting	8.41%	1.18	8.60%	1.20
Total	7.15%	1.00	7.15%	1.00

Table 1 summarizes the cost of service results in the form of a relative rate of return index. For the total system, the rate of return index is 1.0. For the residential class, under the corrected BIP method, the rate of return index is 0.56. This means that residential customers are paying a rate of return at approximately 56% of the system average. This is in contrast to the rate of return index for the large commercial/industrial time-of-day class that has a rate of return index of 1.08. For this class, customers are paying a return on investment equal to 108% of the system average.

Q. What conclusions do you draw from these "relative rate of return" indices?

A. Regardless of the cost of service study, residential customers are paying rates of return substantially below the system average rate of return. Based on these results, the Companies' proposal to increase residential rates, while proposing no increase to large commercial and industrial rates is reasonable and should be adopted by the Commission.

Q. Have you identified any particular subsidy problems in your evaluation of the KU BIP class cost of service results?

A. Yes. As can be seen from Table 1, KU's Large Industrial Time-of-Day rate is paying a rate of return on rate base of 23.64%, which is more than 3.3 times the average rate of return paid by all KU retail customers. This is highly unreasonable and should be mitigated in this case. This rate is providing a huge subsidy to other rate classes, which should be remedied in the event that the Commission authorizes a smaller increase in revenues than requested by the Company. This would also include a situation wherein the Commission reduces KU's revenues, as recommended by KIUC witness Lane Kollen in this case.

Q. Have you prepared similar cost of service summary for LG&E?

A. Yes. Table 2 summarizes the LG&E BIP and the corrected BIP class cost of service study results, on a relative rate of return basis.

Table 2
Louisville Gas & Electric Company
LG&E BIP and Corrected BIP Cost of Service Study Results

	LG&E BIP		Corrected BIP	
	Rate of Return	Relative ROR Index	Rate of Return	Relative ROR Index
Residential	5.28%	0.68	5.28%	0.68
General Service	13.01%	1.67	13.01%	1.67
Rate LC	10.39%	1.34	10.99%	1.41
Rate LC-TOD	8.56%	1.10	8.41%	1.08
Rate LP	10.11%	1.30	10.67%	1.37
Rate LP-TOD	7.49%	0.96	8.03%	1.03
Special Contract	5.36%	0.69	3.67%	0.47
Lighting	7.53%	0.97	7.51%	0.97
Rate LC-STOD	5.51%	0.71	5.70%	0.73
Total	7.77%	1.00	7.77%	1.00

As can be seen, the LG&E'S residential class is producing a relative rate of return substantially below 1.0 under both studies, while large commercial and industrial classes are producing relative rates of return at or substantially above 1.0 at present rates.

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

A. Yes, though there remain a very significant problem for KU's rate LI-TOD, as I just discussed. In general, the Company's proposed increases have been guided by the cost of service results, and make progress in moving rates towards full cost of service. In this regard, KU is proposing no increases on large commercial and industrial rate schedules.

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

A. Yes. As in KU, LG&E is proposing no increases for its Large Commercial and Industrial rate schedules.

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

A. Both LG&E and KU have made progress in addressing the subsidy problem in their rate schedules in this case. KIUC supports the apportionment of the revenue increase to rate classes in this case recommended by both KU and LG&E. However, as I will discuss next, if KU receives a lower increase (or a revenue decrease), the reduction in the Company's requested revenues should first be used to reduce KU's Large Industrial TOD rate so that its rate of return at proposed rates is no greater than "2 Times" the retail average rate of return. Even with this reduction the Large Industrial TOD rate would still pay the highest return on rate base on the system. All remaining revenue reductions (from the amount requested by KU) should be applied to all rate schedules in the manner that I discuss next.

Q. In the event that the Commission approves a lower increase, or a revenue decrease as recommended by KIUC witness Lane Kollen, how should the any changes to the requested increases be apportioned to rate schedules?

A. Because the Companies' have proposed no increases to large customer classes in this case, the most appropriate and reasonable methodology is to allocate the Commission approved revenue adjustment (<u>the difference between each Company's proposed revenues and the Commission authorized revenues</u>) on the basis of the share of each rate schedules proposed revenues to the total Company proposed revenues (i.e., revenues after the requested increase).[2] However, as I discussed above, for KU, the "revenue adjustment" should first be applied to reduce the relative rate of return of rate schedule LI-TOD to "2 Times" the retail average. Using the Correct BIP class cost of service study, KU's rate LI-TOD should receive

[2] If, instead, the rate schedule revenue increases themselves are scaled back, a "0%" increase to a rate schedule would not receive any of the benefit, in the event that the Company receives a lower overall

a $3,120,535 revenue decrease to bring it to a rate of return equal to "2 Times" the overall KU retail rate of return at proposed rates. This recommendation means that the first $3.12 million of any Commission approved adjustment to KU's proposed revenues would be applied to rate LI-TOD. Any additional amounts would then be applied to all rate schedules (including LI-TOD).

Effectively, the KIUC recommendation reduces the KU and LG&E proposed rate schedule revenues on an equal percentage to match the Commission approved increase (or decrease).[3] For example, KU has proposed residential revenues of $422,812,114 in this case, reflecting a requested residential increase of $17,329,356. This is based on an overall KU revenue increase of $22,109,840. For illustration purposes, if the Commission were only to approve an increase of $5,000,000 for KU (instead of the requested $22,109,840), KIUC is proposing that the Commission "adjustment" of $17,109,840 be spread to each rate schedule on the basis of each rate schedules' share of total KU proposed revenues.[4] Since the residential class comprises 37.94% of total KU proposed revenues, the residential class should receive 37.94% of the $17,109,840 "adjustment."

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increase. This would be counter-intuitive and therefore the scale back should be on total revenues at proposed rates.

[3] The only exception to this would be the adjustment to KU's LI-TOD rate to reduce its excessive rate of return.

[4] Total requested revenue increase of $22,109,840 minus "adjustment" of $17,109,840 equals $5,000,000

III. INTERRUPTIBLE CREDITS

Q. Are the Companies proposing any changes to their interruptible/curtailable credits in this case?

A. No. Both of the Companies currently have three different interruptible/curtailable riders in which they provide "credits" to large customers in exchange for the ability to interruptible customer load in the event of system emergencies. Based on the responses to KIUC data requests Q-2.13, KU currently has customers on Curtailable Service Rider 1 (CSR1) and CSR3. LG&E currently has customers on CSR1. Each of these riders provides customers a credit based on the avoided capacity cost associated with the "installed cost per kW of a combustion turbine."[5] In the Companies last base rate case Mr. Seelye developed the interruptible credits based on an installed combustion turbine ("CT") cost of $374/kW. Baron Exhibit__(SJB-4) contains a copy of Mr. Seelye's analysis in KU Case No. 2003-00434 (a similar analysis was developed in the companion LG&E case).

Q. How did the Companies develop interruptible/curtailable credits using an installed CT cost?

[5] Direct Testimony of Steven Seelye, page 45, KU Case No. 2003-00434.

A. As can be seen from Mr. Seelye's 2004 analysis, the Companies applied a levelized fixed charge rate to the installed cost of a CT, added in annual fixed O&M expenses, and then adjusted the results for a planning reserve margin of 14% and losses. The resulting interruptible credits, as shown in Exhibit__(SJB-4) are $4.09/kW/Mo for transmission voltage customers and $4.19/kW/Mo for primary customers. These are the credits for KU's CSR2 interruptible tariff. The LG&E credits are slightly different for its CSR2 tariff ($4.09/kW and $3.98/kW for transmission and primary service).[6] Each Companies' CSR1 and CSR3 credits are lower, reflecting fewer hours of annual interruption and a longer interruption notice period than the CSR2 interruptible tariff.

Q. Do you agree with the Companies methodology to calculate interruptible credits?

A. Yes. The Companies' methodology is a reasonable approach to the development of interruptible credits. The underlying rationale of the methodology is that interruptible load is comparable to combustion turbine capacity with regard to meeting peak demands on the system.

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[6] In Case No. 2003-00433, LG&E used a lower fixed charge rate for the computation of interruptible credits; LG&E also had a slightly lower primary loss factor.

Q. Has the installed cost of combustion turbine capacity increased since the Companies' 2004 rate case, when the current credits were approved?

A. Yes. In their response to KIUC Q-2.9, the Companies stated that the "current estimated cost of an installed CT in 2009 dollars is approximately $710/kW." Baron Exhibit__(SJB-5) contains a copy of KU's response to KIUC Q-2.9 (LG&E's response is identical).

Q. Should the Companies' interruptible credits be increased in these Cases, based on the significant increase in the avoided capacity costs associated with combustion turbines?

A. Yes. The Companies have provided evidence that their avoided capacity cost, which is the basis for their current interruptible credits, has increased substantially. Based on this information, the credits should be increased in this case to reasonably reflect this substantial increase in peaking costs for the Companies.

Q. Have other factors used in the credit computation changed as well?

A. Yes. While the levelized fixed charge rate and the planning reserve margins have remained constant, based on the Companies' response to KIUC Q-2.10 and Q-2.12, there has been a substantial increase in the annual fixed O&M expense associated with new combustion turbine capacity. Baron Exhibit__(SJB-6) contains the Companies' response to KIUC Q-2.11. This response indicates that the annual fixed O&M expense for a new CT in 2009 dollars is $12.20/kW/Yr.

Q. Have you updated Mr. Seelye's 2004 interruptible credit computation using the current avoided capacity costs provided by the Companies in response to KIUC data requests in this case?

A. Table 3 contains an update of Mr. Seelye's CSR credit computation using the current installed cost and fixed O&M expenses for a 2009 combustion turbine. Based on this updated computation, the Companies' CSR2 credits should be $8.51/kW/Mo and $8.72/kW/Mo for transmission and primary voltage customers. This represents a 108% increase over the current interruptible credits being proposed by the Companies in this case.

Table 3
KU and LG&E
Computation of CSR Credit

Avoided Capital Cost	$710 00 per kW	
Levelized Fixed Charge Rate	x 10.59%	
Annual Fixed Charges	$75 19 per kW	
Fixed O&M	+ $12.30 per kW	
	$87 49	
Reserve Margin Adjustment	x 1.14	
Annual Avoided Capacity Cost	$99 74 per kW	
	Transmission	Primary
Annual Avoided Capacity Cost at Source	$99.74 /kW	$99 74 /kW
Adjustment for Losses	1 0233	1 0488
Annual Loss Adjusted Avoided Cost	$102 06 /kW	$104 61 /kW
Monthly Credit	$8.51 /kW/Mo	$8 72 /kW/Mo
Current Credit	$ 4 09 /kW/Mo	$ 4 19 /kW/Mo
Pecent Increase	108%	108%

Q. Are you recommending that the Commission increase the Companies' CSR credits in this case by 108%?

A. Yes. I recommend that the CSR1, CSR2 and CSR3 credits each be increased by 108% in this case, based on the updated analysis reflecting the Commission approved methodology.

Q. Does that complete your testimony?

A. Yes.

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EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

Professional Qualifications

Of

Stephen J. Baron

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

Mr. Baron has more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

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

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

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

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

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

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

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2008

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

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

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

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

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

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

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

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

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

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

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

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Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co American Electric Co	Electric utility restructuring rate unbundling
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Electric utility restructuring rate unbundling
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc	Electric utility restructuring rate unbundling
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc	Nuclear decommissioning, revenue requirements
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc	Inter-Company System Agreement: Modifications for retail competition, interruptible load
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc	*Jurisdictional Business Separation* - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co	Test year revenue forecast
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc	*Nuclear decommissioning requirements* transmission revenues
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco") RTO rate design
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	*RTO Issues*
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan

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

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Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc. and The Trane Co	Aquila, Inc	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service. rate design. tariff issues and transmission service charge
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates
03/05	Case No 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers. Inc	Kentucky Utilities Louisville Gas & Electric Co	Environmental cost recovery
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc Entergy Gulf States, Inc	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co Potomac Edison Co	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Power Company	Cost of service, rate design, transmission expenses Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana. Inc	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design. Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Separation of EGSI into Texas and Louisiana Companies

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2008

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Revenue Incr, Off-System Sales margin rate treatment
11/06	Doc No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop	Distribution Line Cost Allocation
09/07	Doc No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc	Wisconsin Electric Power Co	Cost of Service, rate design, tariff issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues
1/08	Doc No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues

**Expert Testimony Appearances
of
Stephen J. Baron
As of October 2008**

Date	Case	Jurisdict.	Party	Utility	Subject
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc No. 6690-UR-119	WI	Wisconsin Industrial Energy Group. Inc	Wisconsin Public Service Co	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan

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. 2008-00252**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00564**
AND		
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO. 2008-00251**
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	))	**CASE NO. 2007-00565**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector		Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT
Cost of Service Summary -- Pro-Forma												
Operating Revenues												
Total Operating Revenue -- Actual				$	1 154 166,041 $	434 291 785 $	141 164 130 $	3 110,803 $	7,044,060 $	226,030,378 $	66,940,071 $	1 370,500
Pro-Forma Adjustments:												
Eliminate unbilled revenue			R01		(6,878,000) $	(2,504,013) $	(848,150) $	(18,081) $	(47,381) $	(1,343,022) $	(515,139) $	(8,119)
Adjustment for Mismatch in fuel cost recovery			Energy		(110,253,033) $	(40,731,777) $	(11,400,305) $	(265,407) $	(827,021) $	(23,801,704) $	(9,603,831) $	(164,207)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	Energy		98,767 $	34,430 $	9,042 $	224 $	600 $	20,118 $	8,338 $	130
Remove ECR revenues			ECRREV		(54,342,557) $	(20,020,185) $	(6,055,772) $	(150,005) $	(375,784) $	(10,481,203) $	(4,017,782) $	(63,714)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV		21,035,653 $	8,326,800 $	2,080,637 $	60,550 $	151,070 $	4,230,818 $	1,021,700 $	25,716
Remove off-system ECR revenues			OSSALL		(371,205) $	(112,827) $	(35,368) $	(156) $	(2,450) $	(70,003) $	(34,084) $	(504)
Eliminate brokered sales			Energy		90,746 $	31,705 $	8,904 $	207 $	646 $	18,580 $	7,700 $	120
Eliminate ESM,FAC,ECR from rate refund acct.			R01		17,082,129 $	6,870,295 $	2,175,319 $	46,026 $	121,800 $	3,452,874 $	1 324,332 $	20,872
Eliminate DSM Revenue		DSMREV			(4,420,150)	(3,093,509)	(123,092)	(2,670)	-	(240,135)	(45,915)	(2,128)
Year end adjustment		YREND			(4,243,045) $	843,080 $	1,130,882 $	(40,127) $	- $	(6,373,054) $	- $	-
Merger Surcredit Revenues			MSCREV		18,568,431 $	7,355,680 $	2,306,449 $	53,508 $	132,776 $	3,760,072 $	1,337,070 $	22,850
Weather Normalized electric operating revenues			Energy		(8,721,220) $	(3,055,858) $	(855,680) $	(19,011) $	(62,042) $	(1,785,580) $	(739,976) $	(11,508)
VDT Surcredit Revenues			VDTREV		3,405,550	1,281,117	418,427	9,403	23,304	660,103	253,206	3,988
Total Pro-Forma Operating Revenue				(40,578,204) $	1,020,697,01C $	387 713,522 $	130,005 787 $	2 785,854 $	7,001,297 $	194,073,481 $	76,276 137 $	1 203,944
					(126,580,131)	(43,083,651)						
Operating Expenses					06207							
Operation and Maintenance Expenses				$	789,501,236 $	312,951,320 $	83,203,529 $	1,021,440 $	5,230,409 $	149,573,269 $	50,045,721 $	922,785
Depreciation and Amortization Expenses					109,730,123	52,821,720	13,079,030	402,072	717,433	17,013,339	5,600,600	98,034
Regulatory Credits and Accretion Expenses					(255,373)	(105,706)	(20,053)	(1,224)	(1,904)	(46,580)	(18,708)	(328)
Property Taxes			PPT		10,473,065	4,058,330	1,225,018	30,050	70,188	1,671,337	505,246	9,888
Other Taxes					6,763,065	3,207,307	701,171	25,801	40,331	1,070,423	354,430	6,385
Gain Disposition of Allowances					(104,602)	(176,797)	(40,509)	(1,152)	(3,500)	(103,312)	(42,814)	(609)
State and Federal Income Taxes			TXINCPF		56,064,882 $	9,610,643 $	12,101,040 $	150,470 $	409,474 $	14,201,039 $	5,330,265 $	80,873
Specific Assignment of Curtailable Service Rider Credit					(2,640,210)	-	-			-	430,293	-
Allocation of Curtailable Service Rider Credits			INTCRE	$	2,640,210 $	910,407 $	212,000 $	12,411 $	10,003 $	373,165 $	137,470 $	2,581
Adjustments to Operating Expenses:												
Eliminate mismatch in fuel cost recovery			Energy		(90,155,050) $	(33,080,840) $	(9,434,310) $	(210,522) $	(664,041) $	(19,088,733) $	(8,158,517) $	(127,547)
Remove ECR expenses			ECRREV		(10,487,050) $	(6,250,440) $	(2,010,027) $	(45,457) $	(113,660) $	(3,178,182) $	(1,217,601) $	(19,307)
Adjust base expenses for full year of ECR roll-in			ECRREV		8,500,654 $	3,228,730 $	1,041,885 $	23,401 $	58,621 $	1,640,003 $	678,914 $	9,073
Eliminate brokered sales expenses			Energy		(8,127) $	(2,847) $	(787) $	(19) $	(58) $	(1,664) $	(690) $	(11)
Eliminate DSM Expenses			DSMREV		(4,437,148) $	(4,000,781) $	(123,314) $	(2,674) $	- $	(240,569) $	(45,997) $	(2 132)
Year end adjustment			YREND		(2,747,550) $	645,930 $	732,151 $	(25,984) $	- $	(4,127,209) $	- $	-
Adjustment for change in depreciation rate			DET		230,246 $	113,934 $	28,157 $	887 $	1 545 $	38,028 $	12,852 $	211
Labor adjustment			LBT		1,549,060 $	783,589 $	191,221 $	4,092 $	8,287 $	238,931 $	73,888 $	1,137
Weather Normalized electric operating expenses			Energy		(4,355,140) $	(1 525,912) $	(427,308) $	(9,943) $	(30,982) $	(891,670) $	(369,523) $	(5,777)
Adjustment for pension/post rate benefit (See Functional Assignment)					- $	- $	- $	- $	- $	- $	- $	-
Storm damage adjustment			SDALL		(2,731,370) $	(1,871,899) $	(443,220) $	(3 387) $	(11,043) $	(219,272) $	(35,450) $	(4)
Eliminate advertising expenses (See Functional Assignment)			REVUC		- $	- $	- $	- $	- $	- $	- $	-
Adjustment for amortization of ESM and mgmt audit expense			R01		(37,080) $	(14,330) $	(4,073) $	(103) $	(202) $	(7,417) $	(2,845) $	(45)
Amortization of rate case expenses			OMT		324,004 $	178,789 $	34,241 $	701 $	2,152 $	81,554 $	24,299 $	380
Adjustment for injuries and damages account 925 (See Functional Assignment)					$	- $	- $	- $	- $	- $	- $	-
Adjustment for FERC assessment fee (See Functional Assignment)			LBT		- $	- $	- $	- $	- $	- $	- $	-
Adjustment for EKPC settlement charges			Energy		(1 338 790) $	(469,072) $	(131 350) $	(3,050) $	(9,524) $	(274 103) $	(113,593) $	(1 776)
Adjustment for merger amortization expenses			LBT		- $	- $	- $	- $	- $	- $	- $	-
Adjustment for MISO schedule 10 expenses			PLTRT		1,061,070 $	611,805 $	200,077 $	9,408 $	15,324 $	373 388 $	143,814 $	2,523
Adjustment for effect of accounting change			DET		- $	- $	- $	- $	- $	- $	- $	-
Adjustment for IT prepaid amortization (See Functional Assignment)					$	- $	- $	- $	- $	- $	- $	-
Adjustment for postage rate increase (See Functional Assignment)					$	- $	- $	- $	- $	- $	- $	-
Adjustment for property tax expense (See Functional Assignment)					$	- $	- $	- $	- $	- $	- $	-
Adjustment to reflect reallocation of OVEC demand charges			BDEM		2,721,657 $	953,657 $	267,057 $	6,214 $	10,303 $	557,271 $	230,943 $	3,610
Adjustment for reserve margin demand purchases			PPSDA		1,109,403 $	504,210 $	134,091 $	7,160 $	8,253 $	231,843 $	85,012 $	1,521
Adjustment to reflect annualized vehicle fuel costs			R01		198,008 $	74,922 $	24,433 $	530 $	1,388 $	38,781 $	14,875 $	234
Adjustment for Retirement of Tyrone Units 1 & 2			OMPPT		(9,585) $	(3,420) $	(944) $	(24) $	(00) $	(1,948) $	(602) $	(13)
Adjustment for new credit facilities bank fees			RB1		2,005,078 $	938,890 $	232 155 $	7,077 $	13,557 $	325,050 $	110,809 $	1,043
Total Expense Adjustments					(109,583,264)	(30,751,878)	(9,097,416)	(249,910)	(721,170)	(25,124,830)	(8,813,539)	(135,078)
Total Operating Expenses		TOE		$	882,100,011 $	344,520,643 $	100,029,507 $	2 300,458 $	5,822 737 $	158 725,991 $	63,224,065 $	990,469
Net Operating Income (Adjusted)				$	158,501,809 $	43,102,878 $	29 136,281 $	485,396 $	1 238 560 $	35 347 490 $	13,052,072 $	213 475

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue -- Actual				8,533,669	768,004	135,164,478	35,811,049	6,897,405	3,993,105	4,917,147	13,000,073
Pro-Forma Adjustments:											
Eliminate unbilled revenue			R01	(68,155)	(4,508)	(801,074)	(210,813)	(41,101)	(23,657)	(29,204)	(82,773)
Adjustment for Mismatch in fuel cost recovery			Energy	(1,166,601)	(96,213)	(16,677,277)	(4,074,499)	(667,404)	(408,130)	(520,004)	(1,584,082)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	Energy	1,003	81	14,037	4,205	564	345	447	1,340
Remove ECR revenues			ECRREV	(430,530)	(35,409)	(6,234,270)	(1,899,607)	(322,310)	(165,614)	(220,700)	(653,519)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV	177,422	14,329	2,518,405	768,887	130,102	74,074	91,543	283,700
Remove off-system ECR revenues			OSSALL	(4,001)	(340)	(59,713)	(18,412)	(1,990)	(1,200)	(1,604)	(5,558)
Eliminate brokered sales			Energy	926	75	13,016	3,883	521	310	413	1,237
Eliminate ESM,FAC,ECR from rate refund acct			R01	144,364	11,588	2,061,735	541,449	105,663	61,332	75,310	212,705
Eliminate DSM Revenue		DSMREV		(15,427)	(215)	-	-	-	-	-	-
Year end adjustment		YREND		-	-	-	-	216,149	-	-	-
Merger Surcredit Revenues			MSCREV	159,833	12,665	1,620,002	488,042	115,118	67,810	82,160	232,263
Weather Normalized electric operating revenues			Energy	(69,022)	(7,218)	(1,251,112)	(373,187)	(50,075)	(30,617)	(39,690)	(118,004)
VDT Surcredit Revenues			VDTREV	27,621	2,222	394,420	120,177	20,228	11,701	14,302	40,604
Total Pro-Forma Operating Revenue			(48 578 264)	8 253,034	667,063	116,769,608	30,260,059	6,401,605	3,560,066	4 354,783	12 297 403
Operating Expenses											
Operation and Maintenance Expenses				7,200,541	571 108	99,054,742	29,041,323	4 143,647	2 466,447	3,103,523	9,357,381
Depreciation and Amortization Expenses				783,537	54,413	9,709,632	2,561,750	518,464	270,744	344,124	991,765
Regulatory Credits and Accretion Expenses				(2,410)	(172)	(30,630)	(8,581)	(1,501)	(938)	(1,055)	(3,020)
Property Taxes			NPT	77,887	5,434	969,277	258,367	51,521	28,208	34,191	99,045
Other Taxes				50,303	3,510	626,002	166,664	33,274	18,218	22,082	58,737
Gain Disposition of Allowances				(5,151)	(418)	(72,388)	(21,502)	(2,807)	(1,772)	(2,290)	(6,880)
State and Federal Income Taxes			TXINCPF	208,043	29,092	5,712,275	833,635	634,120	336,772	302,371	966,270
Specific Assignment of Curtailable Service Rider Credit				-	-	(644,684)	(1 102,266)	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	18,465	1,218	220,434	59,018	13,238	7,646	8,000	22,264
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery			Energy	(981,505)	(79,670)	(13 704,017)	(4,114,480)	(552,094)	(337,570)	(437,507)	(1,310,967)
Remove ECR expenses			ECRREV	(133,105)	(10,757)	(1,889,197)	(575,707)	(97,671)	(50,247)	(66,724)	(196,039)
Adjust base expenses for full year of ECR roll-in			ECRREV	68,804	5,557	975,680	297,368	50,453	20,055	35,500	102,290
Eliminate brokered sales expenses			Energy	(83)	(7)	(1,169)	(348)	(47)	(29)	(37)	(111)
Eliminate DSM Expenses			DSMREV	(15,455)	(215)	-	-	-	-	-	-
Year end adjustment			YREND	-	-	-	-	139,318	-	-	-
Adjustment for change in depreciation rate			DET	1,687	117	20,904	5 615	1,116	602	741	1,941
Labor adjustment			LBT	9,081	691	119,717	32,278	5,933	3,171	4 134	10,020
Weather Normalized electric operating expenses			Energy	(44,455)	(3,604)	(624,772)	(186,357)	(25,006)	(15,290)	(19,820)	(59,377)
Adjustment for pension/post retu benefit (See Functional Assignment)				-	-	-	-	-	-	-	-
Storm damage adjustment			SDALL	(5,057)	(784)	(52,734)	(12)	(4,012)	(21)	(2 719)	(11)
Eliminate advertising expenses (See Functional Assignment)			REVUC	-	-	-	-	-	-	-	-
Adjustment for amortization of ESM and mgmt audit expense			R01	(310)	(25)	(4,420)	(1 103)	(227)	(132)	(162)	(457)
Amortization of rate case expenses			OMT	2,063	235	40,764	11,051	1 705	1,016	1,314	3 651
Adjustment for injuries and damages account 925 (See Functional Assignment)				-	-	-	-	-	-	-	-
Adjustment for FERC assessment fee (See Functional Assignment)			LBT	-	-	-	-	-	-	-	-
Adjustment for EKPC settlement charges			Energy	(13,066)	(1 108)	(192,057)	(57,287)	(7,687)	(4 700)	(6,093)	(18,253)
Adjustment for merger amortization expenses			LBT	-	-	-	-	-	-	-	-
Adjustment for MISO schedule 10 expenses			PLTRT	18,520	1 323	235,520	65,074	12,234	7 195	8 112	23,220
Adjustment for effect of accounting change			DET	-	-	-	-	-	-	-	-
Adjustment for IT prepaid amortization (See Functional Assignment)				-	-	-	-	-	-	-	-
Adjustment for postage rate increase (See Functional Assignment)				-	-	-	-	-	-	-	-
Adjustment for property tax expense (See Functional Assignment)				-	-	-	-	-	-	-	-
Adjustment to reflect reallocation of OVEC demand charges			RDEM	27,783	2,253	390,487	110,468	15,026	9,556	12,387	37 109
Adjustment for reserve margin demand purchases			PPSDA	11,555	685	134,050	34,097	7,700	4,831	4,548	13 819
Adjustment to reflect annualized vehicle fuel costs			R01	1 022	130	23,158	6,082	1,167	680	840	2,300
Adjustment for Retirement of Tyrone Units 1 & 2			OMPPT	(97)	(8)	(1,352)	(401)	(50)	(34)	(43)	(129)
Adjustment for new credit facilities bank fees			RBT	15 230	1,070	190 491	51,148	10,028	5,533	6,667	17,041
Total Expense Adjustments				(1,038,871)	(83,576)	(14,476,758)	(4,212,957)	(441,490)	(352,575)	(480,025)	(1,373,846)
Total Operating Expenses	TOE			7 354 344	580,717	101 115,693	27 384 442	4,948,186	2 783,753	3,500,014	10,015,814
Net Operating Income (Adjusted)				898,690	82,246	15,653,915	2,876,517	1 453,679	776,313	854 709	2,281,879

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector		Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting PDL	Customer Outdoor Lighting OL
Cost of Service Summary -- Pro-Forma									
Operating Revenues									
Total Operating Revenue -- Actual				$	23,245,204 $	7,372,333 $	1,378,826 $	4,131,546 $	6,101,577
Pro-Forma Adjustments:									
Eliminate unbilled revenue			R01	$	(136,400) $	(45,208) $	(8,521) $	(25,204) $	(37,100)
Adjustment for Mismatch in fuel cost recovery			Energy	$	(2,290,740) $	(262,670) $	(22,072) $	(100,001) $	(300,660)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	Energy	$	1,041 $	222 $	10 $	160 $	254
Remove ECR revenues			ECRREV	$	(1,074,407) $	(351,667) $	(92,047) $	(100,402) $	(280,270)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV	$	433,690 $	141,000 $	25,400 $	79,315 $	110,768
Remove off-system ECR revenues			OSSALL	$	(8,776) $	(1,224) $	(103) $	(917) $	(1,403)
Eliminate brokered sales			Energy	$	1,703 $	205 $	17 $	154 $	735
Eliminate ESM,FAC,ECR from rate refund acct.			R01	$	356,034 $	110,222 $	21,000 $	64,704 $	95,600
Eliminate DSM Revenue		DSMREV			-	-	-	-	-
Year end adjustment		YREND		$	- $	5,438 $	(87,075) $	65,957 $	(2,475)
Merger Surcredit Revenues			MSCREV	$	388,337 $	127,480 $	24,681 $	70,052 $	105,042
Weather Normalized electric operating revenues			Energy	$	(172,300) $	(10,705) $	(1,050) $	(14,760) $	(72,572)
VDT Surcredit Revenues			VDTREV		88,105	22,103	4,250	12,408	10,315
Total Pro-Forma Operating Revenue				(40,578,204) $	20,804,473 $	7,105,583 $	1,270,043 $	3,001,235 $	5,785,000
Operating Expenses									
Operation and Maintenance Expenses				$	13,817,108 $	3,345,052 $	420,958 $	1,063,980 $	2,574,878
Depreciation and Amortization Expenses					1,270,745	1,775,002	310,041	401,304	915,884
Regulatory Credits and Accretion Expenses					(3,708)	(229)	(20)	(108)	(254)
Property Taxes			NPT		126,258	140,806	20,448	34,233	52,533
Other Taxes					80,890	90,100	17,081	22,100	33,028
Gain Disposition of Allowances					(9,060)	(1,140)	(90)	(854)	(1,300)
State and Federal Income Taxes			TXINCPF	$	2,684,671 $	423,832 $	149,050 $	843,055 $	880,553
Specific Assignment of Curtailable Service Rider Credit					(633,530)	-	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$	24,108 $	290 $	24 $	217 $	332
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$	(1,800,074) $	(217,258) $	(18,250) $	(162,080) $	(248,882)
Remove ECR expenses			ECRREV	$	(325,582) $	(100,573) $	(10,075) $	(50,544) $	(87,600)
Adjust base expenses for full year of ECR roll-in			ECRREV	$	108,183 $	55,052 $	9,853 $	30,758 $	45,282
Eliminate brokered sales expenses			Energy	$	(101) $	(18) $	(2) $	(14) $	(21)
Eliminate DSM Expenses			DSMREV	$	- $	- $	- $	- $	-
Year end adjustment			YREND	$	- $	3,521 $	(50,385) $	42,710 $	(1,003)
Adjustment for change in depreciation rate			DET	$	2,730 $	3,823 $	682 $	864 $	1,320
Labor adjustment			LBT	$	10,531 $	20,257 $	4,537 $	8,546 $	10,448
Weather Normalized electric operating expenses			Energy	$	(68,042) $	(9,840) $	(877) $	(7,309) $	(11,272)
Adjustment for pension/post retr benefit (See Functional Assignment)				$	- $	- $	- $	- $	-
Storm damage adjustment			SDALL	$	(15,337) $	(22,045) $	(2,015) $	(22,543) $	(18,410)
Eliminate advertising expenses (See Functional Assignment)			REVUC	$	- $	- $	- $	- $	-
Adjustment for amortization of ESM and mgmt audit expense			R01	$	(789) $	(250) $	(47) $	(130) $	(205)
Amortization of rate case expenses			OMT	$	5,004 $	1,377 $	173 $	665 $	1,000
Adjustment for injuries and damages account 925 (See Functional Assignment)				$	- $	- $	- $	- $	-
Adjustment for FERC assessment fee (See Functional Assignment)			LBT	$	- $	- $	- $	- $	-
Adjustment for EKPC settlement charges			Energy	$	(20,450) $	(3,025) $	(254) $	(2,205) $	(3,465)
Adjustment for merger amortization expenses			LBT	$	- $	- $	- $	- $	-
Adjustment for MISO schedule 10 expenses			PLTRT	$	28,502 $	1,087 $	142 $	1,203 $	1,832
Adjustment for effect of accounting change			DET	$	- $	- $	- $	- $	-
Adjustment for IT prepaid amortization (See Functional Assignment)				$	- $	- $	- $	- $	-
Adjustment for postage rate increase (See Functional Assignment)				$	- $	- $	- $	- $	-
Adjustment for property tax expense (See Functional Assignment)				$	- $	- $	- $	- $	-
Adjustment to reflect reallocation of OVEC demand charges			BDEM	$	53,774 $	8,150 $	517 $	4,005 $	7,045
Adjustment for reserve margin demand purchases			PPSDA	$	15,317 $	- $	- $	- $	-
Adjustment to reflect annualized vehicle fuel costs			R01	$	3,099 $	1,305 $	246 $	728 $	1,074
Adjustment for Retirement of Tyrone Units 1 & 2			OMPPT	$	(184) $	(20) $	(2) $	(15) $	(23)
Adjustment for new credit facilities bank fees			RBT	$	24,567 $	26,449 $	4,838 $	8,203 $	9,409
Total Expense Adjustments					(2,034,082)	(234,000)	(76,073)	(158,150)	(203,864)
Total Operating Expenses		TOE		$	16,120,635 $	5,554,612 $	854,020 $	2,006,027 $	3,802,665
Net Operating Income (Adjusted)				$	5,083,838 $	1,550,050 $	416,024 $	1,384,608 $	1,022,321

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
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April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Secondary GSS	General Service Primary GSP	All Electric School AES	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT
Net Cost Rate Base				$ 2,034,073,711	$ 1,230,884,984	$ 305,002,203	$ 10,068,705	$ 17,810,828	$ 427,047,292	$ 153,400,887	$ 2,553,110
Less: ECR Rate Base			RBPPOB	$ 415,880,486	$ 145,714,118	$ 40,804,069	$ 940,486	$ 2,958,588	$ 85,148,369	$ 35,260,031	$ 551,860
Adjustment to Reflect Depreciation Reserve			DET	$ (236,240)	$ (113,034)	$ (28,157)	$ (807)	$ (1,545)	$ (38,828)	$ (12,852)	$ (211)
Cash Working Capital			OMLF	$ (1,942,732)	$ (1,071,039)	$ (252,308)	$ (5,718)	$ (9,866)	$ (267,890)	$ (70,383)	$ (1,238)
Adjusted Net Cost Rate Base				$ 2,216,908,245	$ 1,083,985,294	$ 263,918,758	$ 9,130,155	$ 14,840,827	$ 341,504,375	$ 118,061,721	$ 2,000,001
Rate of Return				7.15%	3.96%	11.04%	6.32%	8.36%	10.35%	11.65%	10.67%
Taxable Income Pro-Forma											
Total Operating Revenue				$ 1,020,697,010	$ 387,713,522	$ 130,065,787	$ 2,785,854	$ 7,061,207	$ 104,073,481	$ 78,278,137	$ 1,203,944
Operating Expenses				$ 806,131,149	$ 334,900,801	$ 88,737,807	$ 2,140,070	$ 5,353,763	$ 144,434,052	$ 57,887,800	$ 903,505
Interest Expense		INTEXP		$ 50,236,895	$ 28,024,591	$ 6,577,043	$ 214,510	$ 378,866	$ 8,074,529	$ 3,106,787	$ 53,085
Interest Syncronization Adjustment			INTEXP	$ (3,186,481)	$ (1,600,587)	$ (372,715)	$ (12,155)	$ (21,355)	$ (508,500)	$ (181,100)	$ (3,006)
Taxable Income		TXINCPF		$ 161,516,328	$ 27,087,717	$ 35,122,094	$ 433,614	$ 1,352,501	$ 41,173,410	$ 15,373,150	$ 250,271
Net Operating Income -- Adjusted for Increase											
Operating Revenue											
Total Operating Revenue				$ 1,020,697,010	$ 387,713,522	$ 130,065,787	$ 2,785,854	$ 7,061,207	$ 104,073,481	$ 78,278,137	$ 1,203,944
Proposed Increase				$ 10,573,831	$ 17,320,356	$ -	$ 448,784	$ 321,038	$ -	$ -	$ (70,021)
Increase in Miscellaneous Charges			MISCA	$ 2,530,000	$ 1,221,813	$ 552,142	$ 12,190	$ 7,070	$ 490,095	$ 188,330	$ 2,908
			RENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Total Pro-Forma Operating Revenue				$ 1,042,807,749	$ 406,264,690	$ 130,617,929	$ 3,244,828	$ 7,390,314	$ 104,564,476	$ 78,464,466	$ 1,136,201
Operating Expenses											
Total Operating Expenses				$ 871,770,275	$ 384,272,521	$ 110,620,922	$ 2,550,377	$ 6,543,915	$ 183,850,821	$ 71,837,003	$ 1,125,546
Pro-Forma Adjustments				$ (109,583,204)	$ (39,751,878)	$ (9,897,415)	$ (249,910)	$ (721,178)	$ (25,124,830)	$ (8,613,539)	$ (135,878)
Incremental Income Taxes				$ 8,313,919	$ 6,975,759	$ 707,021	$ 172,587	$ 123,720	$ 184,928	$ 70,817	$ (25,439)
Total Pro-Forma Operating Expenses				$ 870,509,930	$ 351,496,402	$ 101,137,120	$ 2,473,045	$ 5,946,457	$ 158,910,919	$ 63,294,882	$ 965,029
Net Operating Income				$ 172,297,819	$ 54,768,768	$ 29,480,607	$ 771,783	$ 1,443,857	$ 35,653,557	$ 15,169,585	$ 171,202
Net Cost Rate Base				$ 2,216,908,245	$ 1,083,985,294	$ 263,918,758	$ 9,130,155	$ 14,840,827	$ 341,504,375	$ 118,061,721	$ 2,000,001
Rate of Return				7.77%	5.05%	11.17%	8.45%	9.73%	10.44%	11.15%	8.56%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Small Time-of-Day Secondary STODS	Small Time-of-Day Primary STODP	Large Comm/Ind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT
Net Cost Rate Base				$ 20,009,413	$ 1,405,200	$ 750,264,510	$ 67,107,365	$ 13,174,753	$ 7,200,602	$ 8,704,773	$ 23,570,102
Less: ECR Rate Base			RBPPDB	$ 4,245,170	$ 344,101	$ 50,001,309	$ 17,705,607	$ 2,387,806	$ 1,400,040	$ 1,002,078	$ 5,070,126
Adjustment to Reflect Depreciation Reserve			DET	$ (1,087)	$ (117)	$ (20,004)	$ (5,515)	$ (1,110)	$ (802)	$ (741)	$ (1,041)
Cash Working Capital			CWLF	$ (10,595)	$ (723)	$ (125,858)	$ (32,110)	$ (8,063)	$ (3,557)	$ (4,543)	$ (11,352)
Adjusted Net Cost Rate Base				$ 15,751,001	$ 1,060,204	$ 100,456,349	$ 40,363,053	$ 10,778,778	$ 5,805,300	$ 8,080,811	$ 17,680,742
Rate of Return				5.71%	7.76%	8.22%	5.43%	13.49%	13.37%	12.41%	12.76%
Taxable Income Pro-Forma											
Total Operating Revenue				$ 8,253,034	$ 682,003	$ 118,789,808	$ 30,200,959	$ 6,401,885	$ 3,500,060	$ 4,354,783	$ 12,207,403
Operating Expenses				$ 7,068,301	$ 651,025	$ 95,403,818	$ 26,550,007	$ 4,314,066	$ 2,440,081	$ 3,137,043	$ 9,047,344
Interest Expense		INTEXP		$ 418,220	$ 29,180	$ 5,204,097	$ 1,387,343	$ 278,040	$ 151,408	$ 183,504	$ 480,347
Interest Synchronization Adjustment			INTEXP	$ (23,007)	$ (1,053)	$ (204,905)	$ (78,000)	$ (15,675)	$ (8,582)	$ (10,403)	$ (27,870)
Taxable Income		TXINCPF		$ 772,201	$ 83,011	$ 18,450,390	$ 2,401,310	$ 1,820,825	$ 970,201	$ 1,043,940	$ 2,780,473
Net Operating Income -- Adjusted for Increase											
Operating Revenue											
Total Operating Revenue				$ 8,253,034	$ 682,003	$ 118,789,808	$ 30,200,959	$ 6,401,885	$ 3,500,060	$ 4,354,783	$ 12,207,403
Proposed Increase				$ 82,070	$ 6,037	$ -	$ (38,022)	$ 575,403	$ 100,123	$ 29,106	$ 5,099
Increase in Miscellaneous Charges			MISCA	$ 31,534	$ 2,531	$ 19,601	$ 5,163	$ 322	$ 0	$ 0	$ 645
			RENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
Total Pro-Forma Operating Revenue				$ 8,366,637	$ 672,131	$ 118,769,409	$ 30,226,100	$ 6,977,650	$ 3,600,180	$ 4,383,070	$ 12,303,137
Operating Expenses											
Total Operating Expenses				$ 8,391,215	$ 664,243	$ 115,544,052	$ 31,008,309	$ 5,389,676	$ 3,136,326	$ 3,960,039	$ 11,389,462
Pro-Forma Adjustments				$ (1,030,871)	$ (83,520)	$ (14,420,758)	$ (4,313,057)	$ (441,490)	$ (352,575)	$ (460,025)	$ (1,373,848)
Incremental Income Taxes				$ 47,718	$ 3,440	$ 7,393	$ (12,350)	$ 216,611	$ 37,640	$ 10,070	$ 2,122
Total Pro-Forma Operating Expenses				$ 7,397,062	$ 584,165	$ 101,173,286	$ 27,372,068	$ 5,164,697	$ 2,821,402	$ 3,510,003	$ 10,017,736
Net Operating Income				$ 969,575	$ 87,966	$ 15,660,162	$ 2,856,014	$ 1,812,953	$ 838,787	$ 872,066	$ 2,285,401
Net Cost Rate Base				$ 15,751,001	$ 1,060,204	$ 100,456,349	$ 40,363,953	$ 10,778,778	$ 5,805,300	$ 8,080,811	$ 17,680,742
Rate of Return				6.16%	8.30%	8.23%	6.79%	16.82%	14.45%	12.03%	12.78%

KENTUCKY UTILITIES
Cost of Service Study
Class Allocation
12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Large Industrial Time-of-Day LITOD	Street Lighting SL	Decorative Street Lighting SLDEC	Private Outdoor Lighting POL	Customer Outdoor Lighting OL
Net Cost Rate Base				$ 32,275,824	$ 34,740,107	$ 8,092,066	$ 10,855,054	$ 12,470,508
Less: ECR Rate Base			RBPFDB	$ 8,216,403	$ 930,677	$ 78,900	$ 703,842	$ 1,078,388
Adjustment to Reflect Depreciation Reserve			DET	$ (2,736)	$ (3,823)	$ (882)	$ (884)	$ (1,328)
Cash Working Capital			OMLF	$ (17,071)	$ (21,160)	$ (3,288)	$ (6,818)	$ (10,748)
Adjusted Net Cost Rate Base				$ 24,039,614	$ 33,783,507	$ 8,010,039	$ 10,144,830	$ 11,391,067
Rate of Return				23.64%	4.59%	6.92%	13.65%	10.86%
Taxable Income Pro-Forma								
Total Operating Revenue				$ 20,604,473	$ 7,105,503	$ 1,270,643	$ 3,901,235	$ 5,785,006
Operating Expenses				$ 12,430,004	$ 5,130,781	$ 704,061	$ 1,802,072	$ 2,062,132
Interest Expense		INTEXP		$ 672,582	$ 700,047	$ 142,016	$ 183,620	$ 282,087
Interest Syncronization Adjustment			INTEXP	$ (38,100)	$ (45,275)	$ (8,047)	$ (10,415)	$ (15,863)
Taxable Income		TXINCPF		$ 7,733,036	$ 1,221,010	$ 432,014	$ 1,855,150	$ 2,538,771
Net Operating Income -- Adjusted for Increase								
Operating Revenue								
Total Operating Revenue				$ 20,604,473	$ 7,105,503	$ 1,270,643	$ 3,901,235	$ 5,785,006
Proposed Increase				$ -	$ 304,845	$ 61,720	$ 195,070	$ 224,423
Increase in Miscellaneous Charges			MISCA	$ 735	$ 0	$ -	$ 0	$ -
			RENT	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 20,605,208	$ 7,410,208	$ 1,332,363	$ 4,186,255	$ 6,009,429
Operating Expenses								
Total Operating Expenses				$ 17,165,617	$ 5,786,621	$ 931,293	$ 2,764,777	$ 4,150,548
Pro-Forma Adjustments				$ (2,034,982)	$ (234,000)	$ (76,673)	$ (158,150)	$ (203,604)
Incremental Income Taxes				$ 277	$ 114,556	$ 23,208	$ 73,333	$ 84,369
Total Pro-Forma Operating Expenses				$ 15,120,912	$ 5,669,107	$ 877,828	$ 2,679,960	$ 3,047,074
Net Operating Income				$ 5,684,297	$ 1,741,040	$ 454,535	$ 1,506,295	$ 2,062,355
Net Cost Rate Base				$ 24,039,614	$ 33,783,507	$ 8,010,039	$ 10,144,830	$ 11,391,067
Rate of Return				23.65%	5.15%	7.56%	14.85%	18.11%

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. 2008-00252**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00564**

AND

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO. 2008-00251**
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	))	**CASE NO. 2007-00565**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	General Service Rate GS	Rate LC Primary	Rate LC Secondary	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				$ 932,384,516 $	374,820,954 $	132,300,351 $	10,109,423 $	152,183,750 $	19,897,037 $	21,870,310 $	7,874,767 $	38,670,770 $	20,528,278 $	100,060,460
Pro-Forma Adjustments:														
Eliminate unbilled revenue			R01	$ (785,000) $	(315,816) $	(114,601) $	(8,371) $	(127,979) $	(16,281) $	(18,148) $	(6,010) $	(32,300) $	(23,192) $	(81,748)
Mismatch in fuel cost recovery			Energy	(50,810,166)	(18,101,081)	(8,065,084)	(920,822)	(8,574,118)	(1,204,837)	(1,338,072)	(433,053)	(2,744,537)	(2,133,068)	(7,080,040)
To Reflect a Full Year of the FAC Roll-in FACRI			Energy	31,805	11,413	3,812	390	5,357	814	840	273	1,411	1,341	4,443
Remove ECR revenues			ECRREV	(10,158,132) $	(4,121,346) $	(1,483,109) $	(109,483) $	(1,055,315) $	(207,017) $	(230,442) $	(77,318) $	(418,481) $	(292,061) $	(1,041,065)
To Reflect a Full Year of the ECR Roll-in ECRRI			ECRREV	1,215,475 $	493,141 $	177,462 $	12,730 $	108,007 $	24,878 $	28,292 $	9,252 $	49,832 $	34,947 $	124,641
Remove off-system ECR revenues			OSSALL	(748,947)	(303,032)	(93,833)	(8,505)	(123,177)	(17,578)	(18,331)	(5,740)	(31,300)	(25,825)	(87,121)
Eliminate brokered sales			Energy	2,000,584	717,918	239,783	24,541	336,957	51,164	52,850	17,142	88,725	84,355	279,478
Eliminate Rate Refund Acct			R01	9,783,357	3,929,179	1,424,100	104,115	1,591,721	202,499	225,717	74,745	402,489	288,444	1,016,728
Eliminate DSM Revenue			DSMREV	(4,381,817)	(3,773,223)	(207,092)	(14,001)	(188,340)	(40,730)	(49,326)	-	-	-	-
Year End Revenue Adjustment		YREND		(764,511)	748,004	(682,583)	352,824	(337,723)	-	-	446,017	(897,363)	-	-
Weather normalized electric operating revenues			Energy	(14,374,348)	(5,158,298)	(1,722,861)	(176,327)	(2,421,026)	(367,761)	(379,728)	(123,167)	(637,490)	(606,100)	(2,008,011)
Adjustment for Merger Surcredit			MSCREV	10,478,242	8,545,841	3,000,502	223,071	3,453,144	437,142	491,183	161,193	872,420	113,772	1,173,092
VDT Surcredit Revenues			VDTREV	7,375,580	2,900,727	1,075,671	77,877	1,203,482	152,100	171,103	56,169	304,075	216,031	768,018
Total Pro-Forma Operating Revenue				$ 890,474,838 $	359,009,781 $	127,961,818 $	9,971,378 $	145,504,770 $	18,811,042 $	20,810,307 $	7,195,881 $	36,339,186 $	20,165,900 $	93,149,170
Cost of Service Summary -- Pro-Forma														
Operating Expenses														
Operation and Maintenance Expenses				$ 617,803,122 $	251,220,003 $	75,729,105 $	6,649,215 $	90,280,335 $	14,100,130 $	14,738,000 $	4,745,000 $	25,001,109 $	22,250,710 $	75,390,243
Depreciation and Amortization Expenses				108,203,300	52,478,719	13,482,450	973,385	14,771,700	1,974,400	2,110,377	644,045	3,580,700	2,408,248	9,202,708
Regulatory Credits				(1,556,535)	(608,738)	(108,730)	(17,093)	(251,037)	(34,750)	(38,484)	(11,231)	(62,855)	(47,078)	(103,104)
Accretion Expense				1,389,410	507,200	177,377	15,248	224,403	31,007	32,520	10,019	56,074	42,520	145,490
Property and Other Taxes			NPT	17,703,450	8,517,200	2,208,339	101,488	2,444,880	327,030	349,076	106,791	609,329	412,736	1,537,070
Amortization of Investment Tax Credit				3,910,848	1,681,537	487,841	35,674	540,095	72,378	77,248	23,501	134,605	91,177	330,652
Other Expenses				(416,255)	(219,569)	(56,913)	(4,182)	(63,010)	(8,444)	(9,012)	(2,752)	(15,704)	(10,637)	(39,013)
State and Federal Income Taxes			TXINCFF	42,700,070 $	10,534,058 $	10,721,331 $	557,200 $	8,743,801 $	730,147 $	1,128,501 $	457,083 $	2,209,602 $	1,254,340 $	3,757,792
Specific Assignment of Interruptible Credit				(6,268,703)	-	-	-	-	-	-	-	-	(2,391,305)	(3,875,488)
Allocation of Interruptible Credits			INTCRE	6,268,703 $	2,609,605 $	820,350 $	65,414 $	1,000,611 $	130,968 $	138,636 $	41,331 $	242,044 $	167,767 $	551,542
Adjustments to Operating Expenses:														
Eliminate mismatch in fuel cost recovery			Energy	(50,702,200) $	(18,227,007) $	(6,087,782) $	(623,056) $	(8,554,770) $	(1,299,495) $	(1,341,781) $	(435,213) $	(2,252,610) $	(2,141,674) $	(7,095,369)
Remove ECR expenses			ECRREV	(10,042,070) $	(4,439,404) $	(1,597,565) $	(114,670) $	(1,783,061) $	(223,063) $	(254,000) $	(83,285) $	(448,601) $	(314,000) $	(1,122,054)
Reflect full year of ECR roll-in			ECRREV	8,811,442 $	3,574,968 $	1,286,489 $	92,340 $	1,435,805 $	180,353 $	205,097 $	67,068 $	361,250 $	253,342 $	903,500
Eliminate brokered sales expenses			Energy	(78,166) $	(28,051) $	(9,369) $	(959) $	(13,166) $	(2,000) $	(2,065) $	(670) $	(3,467) $	(3,296) $	(10,920)
Eliminate DSM Expenses			DSMREV	(3,600,848) $	(3,324,783) $	(201,782) $	(12,337) $	(105,061) $	(43,620) $	(43,403) $	- $	- $	- $	-
Year end Expense adjustment			YREND	(427,034) $	137,701 $	(370,885) $	107,402 $	(180,040) $	- $	- $	250,777 $	(350,348) $	- $	-
Adjustment to annualize depreciation expense			DET	10,722,048 $	6,199,006 $	2,082,538 $	150,352 $	2,281,879 $	304,981 $	325,876 $	99,481 $	568,546 $	381,252 $	1,430,757
Depreciation adjustment			DET	- $	- $	- $	- $	- $	- $	- $	- $	- $	- $	-
Labor adjustment			LBT	2,701,011 $	1,343,645 $	350,756 $	25,041 $	372,845 $	51,206 $	53,605 $	17,042 $	93,810 $	70,330 $	253,023
Adjustment for pension and post Ret Exp. (See Functional Assignment)				-										
Storm damage adjustment			SDALL	(1,213,074) $	(650,719) $	(144,101) $	(4,447) $	(88,703) $	(8,701) $	(11,200) $	(3,000) $	(21,076) $	(5) $	(41,193)
Adjustment to eliminate advertising expense (See Functional Assignme				-										
Amortization of rate case expenses			OMT	167,642 $	70,374 $	23,022 $	2,082 $	29,272 $	4,316 $	4,480 $	1,443 $	7,600 $	6,764 $	22,071
Amortization of ESM audit expenses			R01	(10,056) $	(4,205) $	(1,554) $	(114) $	(1,737) $	(221) $	(246) $	(82) $	(439) $	(315) $	(1,110)
Adjustment for FERC assessment fee (See Functional Assignment)				-										
Adjustment for injuries and damages (See Functional Assignment)				-										
Adjustment for postage rate increase (See Functional Assignment)				-										
Adjustment to property tax expense (See Functional Assignment)				-										
Adjustment to sales and use tax (See Functional Assignment)				-										
Adjustment railcar property tax expense (See Functional Assignment)				-										
Adjustment for EKPC settlement charges			Energy	(678,260) $	(243,407) $	(81,297) $	(8,320) $	(114,242) $	(17,354) $	(17,918) $	(5,812) $	(30,082) $	(28,600) $	(94,753)
Adjustment to reflect reallocation of OVEC demand charges			BDEM	(3,145,310) $	(1,128,706) $	(378,080) $	(38,583) $	(529,755) $	(80,471) $	(83,000) $	(26,951) $	(139,403) $	(132,623) $	(439,381)
Adjustment for MISO schedule 10 expenses			PLTRT	1,360,429 $	581,504 $	173,857 $	15,044 $	221,250 $	30,505 $	32,070 $	9,882 $	55,271 $	42,082 $	143,563
Reflect weather normalized electric sales margins			Energy	(4,751,178) $	(1,704,081) $	(569,400) $	(58,282) $	(800,220) $	(121,557) $	(125,512) $	(40,710) $	(210,713) $	(200,335) $	(663,711)
Adjustment for IT prepaid amortization (See Functional Ass			LBT	- $	- $	- $	- $	- $	- $	- $	- $	- $	- $	-
Adjustment to remove IMEA/IMPA reactive power cost			Energy	(330,012) $	(118,426) $	(39,554) $	(4,048) $	(55,583) $	(8,443) $	(8,718) $	(2,828) $	(14,636) $	(13,915) $	(46,101)
Adjustment to remove reclassified capital lease			R01	1,757,207 $	707,107 $	250,318 $	18,739 $	298,487 $	38,447 $	40,020 $	13,463 $	72,430 $	51,918 $	182,097
Adjustment for new credit facilities bank fees			R01	5,304,078 $	2,171,162 $	780,021 $	57,531 $	870,544 $	111,890 $	124,725 $	41,302 $	222,304 $	150,387 $	591,817
Adjustment to reflect annualized vehicle fuel costs			R01	158,347 $	63,725 $	23,007 $	1,689 $	25,816 $	3,284 $	3,681 $	1,212 $	6,527 $	4,676 $	16,400
Total Expense Adjustments				(39,078,060)	(13,316,161)	(4,548,342)	(304,505)	(6,781,578)	(1,062,948)	(1,098,244)	(96,969)	(2,123,817)	(1,865,007)	(5,109,454)
Total Operating Expenses		TOE		$ 750,807,345 $	313,032,316 $	98,827,808 $	8,331,904 $	117,937,700 $	16,344,003 $	17,431,340 $	5,017,947 $	29,701,981 $	22,362,208 $	80,012,834

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	General Service Rate GS	Rate LC Primary	Rate LC Secondary	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Net Operating Income -- Pro-Forma				$ 139,557,403	$ 45,167,405	$ 20,133,020	$ 1,039,303	$ 27,057,071	$ 2,467,030	$ 3,370,057	$ 1,278,134	$ 8,547,206	$ 3,823,724	$ 12,230,342
Net Cost Rate Base				$ 1,828,018,110	$ 870,361,007	$ 227,805,805	$ 10,865,031	$ 254,444,804	$ 34,251,980	$ 36,409,008	$ 11,173,097	$ 63,521,460	$ 43,724,707	$ 161,608,576
Less: ECR Rate Base			RBPPT	$ 13,265,453	$ 5,645,541	$ 1,093,883	$ 147,511	$ 2,103,585	$ 300,314	$ 314,654	$ 97,154	$ 541,001	$ 410,533	$ 1,418,654
Adjustment to Reflect Depreciation Reserve			DET	$ (10,722,048)	$ (8,100,008)	$ (2,082,100)	$ (150,352)	$ (2,281,870)	$ (304,981)	$ (325,075)	$ (90,481)	$ (508,540)	$ (381,252)	$ (1,430,757)
Cash Working Capital			OMLF	$ (789,378)	$ (471,513)	$ (102,338)	$ (8,239)	$ (98,215)	$ (12,002)	$ (13,378)	$ (4,174)	$ (23,075)	$ (15,370)	$ (58,815)
Adjusted Net Cost Rate Base				$ 1,795,221,833	$ 856,167,946	$ 223,027,047	$ 10,560,030	$ 249,003,320	$ 33,634,083	$ 35,845,691	$ 10,072,880	$ 82,387,836	$ 42,911,841	$ 158,700,050
Rate of Return				7.77%	5.28%	13.01%	9.90%	11.07%	7.33%	9.43%	11.65%	10.49%	8.91%	7.71%

Taxable Income Pro-Forma

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	General Service Rate GS	Rate LC Primary	Rate LC Secondary	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Total Operating Revenue				$ 890,424,835	$ 350,000,781	$ 127,001,818	$ 9,071,328	$ 145,594,770	$ 18,811,042	$ 20,810,307	$ 7,105,081	$ 38,330,186	$ 20,185,000	$ 93,140,178
Operating Expenses				$ 709,827,201	$ 304,000,390	$ 88,305,297	$ 7,701,758	$ 108,445,530	$ 15,643,215	$ 16,330,213	$ 5,471,005	$ 27,585,234	$ 21,155,500	$ 77,318,148
Interest Expense		INTEXP		$ 45,716,737	$ 21,994,171	$ 5,702,005	$ 417,012	$ 6,313,426	$ 846,056	$ 902,007	$ 275,780	$ 1,573,466	$ 1,005,810	$ 3,960,183
Interest Synchronization Adjustment			INTEXP	$ (992,327)	$ (434,118)	$ (112,557)	$ (8,231)	$ (124,613)	$ (16,690)	$ (17,823)	$ (5,443)	$ (31,057)	$ (21,037)	$ (78,343)
Taxable Income		TXINCPF		$ 135,964,227	$ 33,473,331	$ 34,000,472	$ 1,770,788	$ 30,000,421	$ 2,330,070	$ 3,590,030	$ 1,454,202	$ 7,211,543	$ 3,065,619	$ 11,940,190

Cost of Service Summary -- Proposed Rate

Operating Revenues

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	General Service Rate GS	Rate LC Primary	Rate LC Secondary	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Total Operating Revenue -- Pro-Forma Actual				$ 890,424,835	$ 350,000,781	$ 127,061,818	$ 9,071,328	$ 145,594,770	$ 18,811,042	$ 20,810,307	$ 7,105,881	$ 38,330,186	$ 20,185,000	$ 93,140,178
Pro-Forma Adjustments:														
To Reflect Proposed Increase to Ultimate Consumers				$ 14,751,854	$ 13,673,270	$ 228,601	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,401)	$ -
To Reflect Proposed Increase in Miscellaneous Charges			MISCR	374,113	$ 321,300	$ 52,804	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 905,550,805	$ 373,994,300	$ 128,243,222	$ 9,071,328	$ 145,594,770	$ 18,811,042	$ 20,810,307	$ 7,105,081	$ 38,330,186	$ 20,177,520	$ 93,140,178

Operating Expenses

Description	Ref	Name	Allocation Vector	Total System	Residential Rate R	General Service Rate GS	Rate LC Primary	Rate LC Secondary	Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Total Operating Expenses				$ 789,044,025	$ 327,247,407	$ 103,370,230	$ 8,636,460	$ 124,699,275	$ 17,427,549	$ 18,529,584	$ 6,014,536	$ 31,915,508	$ 24,227,873	$ 80,912,288
Total Pro-Forma Adjustments				(39,070,080)	(13,315,161)	(4,946,342)	(304,505)	(6,701,575)	(1,082,946)	(1,098,244)	(96,989)	(2,123,617)	(1,865,607)	(5,090,454)
Incremental Income Taxes				5,604,379	5,268,624	105,040	-	-	-	-	-	-	(3,185)	-
Total Pro-Forma Operating Expenses				$ 756,581,724	$ 319,200,840	$ 98,930,838	$ 8,331,964	$ 117,937,700	$ 16,344,603	$ 17,431,340	$ 5,917,547	$ 29,791,081	$ 22,359,081	$ 80,912,834
Net Operating Income -- Pro-Forma				$ 148,968,861	$ 53,803,529	$ 29,309,385	$ 1,039,363	$ 27,657,071	$ 2,467,030	$ 3,379,057	$ 1,278,134	$ 8,547,705	$ 3,818,448	$ 12,230,342
Net Cost Rate Base				$ 1,795,221,833	$ 856,187,946	$ 223,027,047	$ 10,560,030	$ 249,903,320	$ 33,634,083	$ 35,845,691	$ 10,972,880	$ 82,387,838	$ 42,911,841	$ 158,700,050
Rate of Return				8.30%	6.29%	13.09%	9.90%	11.07%	7.33%	9.43%	11.65%	10.49%	8.90%	7.71%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Special Contract Cust	Special Contract Cust	Special Contract Cust	Public Street Lighting Rate PSL	Street Lighting Rate SLE	Outdoor Lighting Rate OL	Traffic Street Lighting Rate TLE	Rate LC-STOD Primary	Rate LC-STOD Secondary
Cost of Service Summary -- Pro-Forma													
Operating Revenues													
Total Operating Revenue -- Actual				2,828,358	7,874,805	11,046,700	3,130,050	6,223,443	207,241	8,020,346	270,092	801,418	5,930,348
Pro-Forma Adjustments:													
Eliminate unbilled revenue			R01	(2,364)	(6,533)	(9,268)	(2,488)	(5,782)	(173)	(8,143)	(247)	(645)	(4,838)
Mismatch in fuel cost recovery			Energy	(171,322)	(580,778)	(833,078)	(228,054)	(203,634)	(14,026)	(228,655)	(14,038)	(55,850)	(391,012)
To Reflect a Full Year of the FAC Roll-In FACRI			Energy	106	305	524	144	128	9	144	9	35	248
Remove ECR revenues			ECRREV	(30,811)	(83,494)	(122,024)	(32,095)	(72,651)	(2,182)	(103,404)	(3,076)	(8,170)	(62,030)
To Reflect a Full Year of the ECR Roll-In ECRRI			ECRREV	3,687	9,991	14,601	3,840	8,693	261	12,384	368	978	7,423
Remove off-system ECR revenues			OSSALL	(2,222)	(8,750)	(11,519)	(3,088)	(1,051)	(121)	(1,853)	(174)	(759)	(5,382)
Eliminate brokered sales			Energy	8,772	22,058	32,087	9,050	8,050	590	9,035	570	2,208	15,450
Eliminate Rate Refund Accl			R01	29,309	81,251	115,408	30,945	71,912	2,152	101,281	3,013	8,019	60,171
Eliminate DSM Revenue			DSMREV	-	-	-	-	-	-	-	-	(1,280)	(8,840)
Year End Revenue Adjustment		YREND		-	-	-	-	(315,830)	(1,478)	395,738	(43,432)	-	(148,874)
Weather Normalized electric operating revenues			Energy	(48,050)	(184,953)	(230,867)	(65,828)	(57,836)	(4,239)	(64,914)	(4,167)	(15,862)	(111,058)
Adjustment for Merger Surcredit			MSCREV	63,068	-	250,635	66,905	155,464	4,654	219,227	6,505	17,030	128,914
VDT Surcredit Revenues			VDTREV	22,775	61,408	87,255	23,300	54,248	1,628	76,416	2,275	5,938	44,922
Total Pro-Forma Operating Revenue				2,690,300	7,208,321	10,938,595	2,933,242	5,864,551	193,414	8,027,608	227,023	753,085	5,461,830
Cost of Service Summary -- Pro-Forma													
Operating Expenses													
Operation and Maintenance Expenses				1,670,316	6,000,157	9,163,160	2,513,160	2,002,073	158,221	3,548,025	217,145	611,611	4,307,461
Depreciation and Amortization Expenses				251,033	692,840	1,309,942	352,238	1,305,881	12,817	1,750,303	27,850	65,209	610,412
Regulatory Credits				(4,290)	(12,197)	(22,989)	(6,090)	(2,741)	(157)	(3,233)	(322)	(1,503)	(10,720)
Accretion Expense				3,827	10,881	20,507	5,433	2,498	140	2,050	286	1,340	9,560
Property and Other Taxes			NPT	41,559	114,000	217,314	58,308	201,600	2,076	271,177	4,400	14,150	102,050
Amortization of Investment Tax Credit				9,181	25,398	48,007	12,694	44,513	458	59,005	993	3,120	22,078
Other Expenses				(1,071)	(2,903)	(5,601)	(1,504)	(5,193)	(53)	(6,960)	(110)	(365)	(2,640)
State and Federal Income Taxes			TXINCPF	170,588	140,258	61,892	2,030	318,183	9,218	781,215	(580)	13,392	158,527
Specific Assignment of Interruptible Credit				-	-	-	-	-	-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	15,400	37,930	88,938	22,794	-	-	-	1,015	5,071	40,920
Adjustments to Operating Expenses:													
Eliminate mismatch in fuel cost recovery			Energy	(171,938)	(582,887)	(836,078)	(229,777)	(204,360)	(14,080)	(229,377)	(14,090)	(56,051)	(392,410)
Remove ECR expenses			ECRREV	(33,180)	(89,938)	(131,441)	(34,572)	(78,258)	(2,350)	(111,481)	(3,313)	(8,801)	(66,826)
Reflect full year of ECR roll-in			ECRREV	26,727	72,425	105,847	27,840	63,010	1,892	89,773	2,668	7,087	53,814
Eliminate brokered sales expenses			Energy	(265)	(897)	(1,288)	(354)	(315)	(23)	(353)	(23)	(86)	(604)
Eliminate DSM Expenses			DSMREV	-	-	-	-	-	-	-	-	(1,110)	(7,613)
Year end Expense adjustment			YREND	-	-	-	-	(178,785)	(827)	221,513	(24,311)	-	(83,220)
Adjustment to annualize depreciation expense			DET	*38,775*	*107,010*	*202,337*	*54,408*	*201,687*	*1,900*	*271,747*	4,302	13,171	95,078
Depreciation adjustment			DET	-	-	-	-	-	-	-	-	-	-
Labor adjustment			LBT	6,700	19,014	33,384	9,008	13,000	541	17,608	1,309	2,190	15,002
Adjustment for pension and post Ret Exp (See Functional Assignment)													
Storm damage adjustment			SDALL	(1,413)	(3,009)	(6,040)	(1,607)	(6,065)	(184)	(10,120)	(230)	(370)	(3,222)
Adjustment to eliminate advertising expense (See Functional Assignme													
Amortization of rate case expenses			OMT	560	1,654	2,702	704	901	48	1,079	60	166	1,309
Amortization of ESM audit expenses			R01	(32)	(89)	(126)	(34)	(78)	(2)	(111)	(3)	(9)	(66)
Adjustment for FERC assessment fee (See Functional Assignment)													
Adjustment for injuries and damages (See Functional Assignment)													
Adjustment for postage rate increase (See Functional Assignment)													
Adjustment to property tax expense (See Functional Assignment)													
Adjustment to sales and use tax (See Functional Assignment)													
Adjustment railcar property tax expense (See Functional Assignment)													
Adjustment for EKPC settlement charges			Energy	(2,200)	(7,784)	(11,177)	(3,008)	(2,729)	(200)	(3,003)	(196)	(740)	(5,240)
Adjustment to reflect reallocation of OVEC demand charges			BDEM	*(10,647)*	*(30,004)*	*(51,630)*	*(14,220)*	*(12,055)*	*(828)*	*(14,204)*	*(910)*	*(3,471)*	*(24,303)*
Adjustment for MISO schedule 10 expenses			PLTRT	3,772	10,736	20,232	5,357	1,855	130	2,002	270	1,323	9,438
Reflect weather normalized electric sales margins			Energy	(16,083)	(54,522)	(78,292)	(21,404)	(10,117)	(1,401)	(21,458)	(1,374)	(5,243)	(36,707)
Adjustment for IT prepaid amortization (See Functional Assi			LBT	-	-	-	-	-	-	-	-	-	-
Adjustment to remove IMEA/IMPA reactive power cred			Energy	(1,117)	(3,787)	(5,438)	(1,493)	(1,328)	(97)	(1,490)	(95)	(364)	(2,650)
Adjustment to remove reclassified capital lease			R01	5,291	14,024	20,788	5,570	12,943	387	18,229	542	1,443	10,830
Adjustment for new credit facilities bank fees			R01	16,245	44,807	63,821	17,090	39,730	1,189	55,905	1,665	4,431	33,240
Adjustment to reflect annualized vehicle fuel costs			R01	477	1,310	1,873	502	1,166	35	1,643	49	130	976
Total Expense Adjustments				(135,418)	(500,589)	(671,543)	(180,277)	(166,413)	(14,784)	258,007	(34,186)	(48,291)	(401,786)
Total Operating Expenses	TOE			2,218,238	6,509,609	10,229,740	2,773,881	4,058,920	167,034	8,660,427	216,584	668,002	4,848,087

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
April 30, 2008
CORRECTED BIP

Description	Ref	Name	Allocation Vector	Rate LP-TOD Secondary	Special Contract Cust	Special Contract Cust	Special Contract Cust	Public Street Lighting Rate PSL	Street Lighting Rate SLE	Outdoor Lighting Rate OL	Traffic Street Lighting Rate TLE	Rate LC-STOD Primary	Rate LC-STOD Secondary
Net Operating Income – Pro-Forma				$ 481 164	$ 608,022	$ 707 840	$ 150,561	$ 1,205,631	$ 25,480	$ 2,347 181	$ 10,430	$ 66,483	$ 815,763
Net Cost Rate Base				$ 4,350,011	$ 12 130,050	$ 22,600,953	$ 8,096,730	$ 20,300,510	$ 222,750	$ 27,200,420	$ 470,473	$ 1 470,330	$ 10,715,002
Less: ECR Rate Base			RBPF1	$ 37,142	$ 106,023	$ 198,370	$ 52,007	$ 10,430	$ 1,425	$ 21,818	$ 2,767	$ 12,062	$ 92,542
Adjustment to Reflect Depreciation Reserve			DET	$ (38,776)	$ (107,019)	$ (202,337)	$ (54,408)	$ (201,087)	$ (1,080)	$ (271,747)	$ (4,302)	$ (13,171)	$ (95,070)
Cash Working Capital			OMLF	$ (1,020)	$ (4,308)	$ (8,208)	$ (2,241)	$ (5,413)	$ (120)	$ (7,121)	$ (400)	$ (541)	$ (3 600)
Adjusted Net Cost Rate Base				$ 4,272,405	$ 11,018,020	$ 22,281,040	$ 5,987,484	$ 20,082,091	$ 210,220	$ 26,980,735	$ 402,006	$ 1 452,045	$ 10,522,885
Rate of Return				11.26%	5.11%	3.18%	2.67%	6.00%	11.62%	8.70%	2.25%	4.58%	6.85%
						Special Contract ROR	3 07%			Lighting ROR	7 51%		
Taxable Income Pro-Forma													
Total Operating Revenue				$ 2,699,390	$ 7,208 321	$ 10,938,595	$ 2 033,242	$ 5 884 551	$ 183,414	$ 9,027,800	$ 227,023	$ 753,085	$ 5,481,830
Operating Expenses				$ 2,051,838	$ 6,471,640	$ 10,180,843	$ 2,777 111	$ 4,343,478	$ 158,873	$ 5,922,440	$ 217,480	$ 674 712	$ 4,898 280
Interest Expense		INTEXP		$ 107 318	$ 298,686	$ 561 171	$ 150,710	$ 520 334	$ 5,350	$ 700,263	$ 11,000	$ 38,541	$ 265,074
Interest Syncronization Adjustment			INTEXP	$ (2,118)	$ (5,800)	$ (11,028)	$ (2,975)	$ (10,270)	$ (100)	$ (13,827)	$ (229)	$ (721)	$ (5,232)
Taxable Income		TXINCPF		$ 542,353	$ 445,655	$ 190,657	$ 8,388	$ 1,011,010	$ 79,288	$ 2,418,721	$ (1,844)	$ 42,553	$ 503,712
Cost of Service Summary – Proposed Rate													
Operating Revenues													
Total Operating Revenue – Pro-Forma Actual				$ 2,699,390	$ 7,208,321	$ 10,938,595	$ 2,033 242	$ 5,884,551	$ 183,414	$ 9,027,808	$ 227,023	$ 753,085	$ 5,481,830
Pro-Forma Adjustments:													
To Reflect Proposed Increase to Ultimate Consumers				$ -	$ (145,782)	$ -	$ -	$ 199,009	$ -	$ 402,434	$ 9,370	$ 45,334	$ 267,867
To Reflect Proposed Increase in Miscellaneous Charges			MISCR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 2,699,390	$ 7,062,539	$ 10,938,595	$ 2 033,242	$ 6,083,560	$ 183,414	$ 9,480,042	$ 236,300	$ 798,419	$ 5,749,708
Operating Expenses													
Total Operating Expenses				$ 2,356,655	$ 7 109,287	$ 10,800,290	$ 2,950,938	$ 4,827,333	$ 182,718	$ 6,392 381	$ 250,700	$ 732,803	$ 5 247,873
Total Pro-Forma Adjustments				(138,416)	(508,580)	(071,543)	(168,277)	(168,413)	(14 784)	288,067	(34 185)	(46,291)	(401 780)
Incremental Income Taxes				-	(54 882)	-	-	74,921	-	174,092	3,530	17,067	108,373
Total Pro-forma Operating Expenses				$ 2 218,238	$ 6,544 818	$ 10,728 748	$ 2 773,681	$ 4 733,841	$ 167,934	$ 6 854 510	$ 220 113	$ 703,669	$ 4,954,460
Net Operating Income – Pro-Forma				$ 481 154	$ 517 723	$ 707,840	$ 150,581	$ 1,329,720	$ 25,480	$ 2,835,523	$ 16,285	$ 94,750	$ 795,247
Net Cost Rate Base				$ 4 272,405	$ 11,918,070	$ 22,281,940	$ 5,987,484	$ 20,082,091	$ 210,220	$ 20,989,735	$ 402,096	$ 1,452,045	$ 10,522,885
Rate of Return				11.26%	4.34%	3.18%	2.67%	6.62%	11.62%	9.76%	3.57%	6.57%	7.56%

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. 2008-00252
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)	CASE NO. 2007-00564
AND		
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)	CASE NO. 2008-00251
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	)	CASE NO. 2007-00565

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

Kentucky Utilities Company
Computation of CSR Credit

Avoided Capital Cost		$374 00 per kW
Levelized Fixed Charge Rate	x	10.60%
Annual Fixed Charges		$39 66 per kW
Fixed O&M	+	$2.43 per kW
		$42 09
Reserve Margin Adjustment	x	1.14
Annual Avoided Capacity Cost		$47 98 per kW

	Transmission	Primary
Annual Avoided Capacity Cost at Source	$47 98 /kW	$47 98 /kW
Adjustment for Losses	1 0233	1 0488
Annual Loss Adjusted Avoided Cost	$49 10 /kW	$50 33 /kW
Monthly Credit	$4.09 /kW/Mo	$4.19 /kW/Mo

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. 2008-00252
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564
AND		
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2008-00251
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	))	CASE NO. 2007-00565

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Second Set of Data Requests of the Kentucky Industrial Utility Customers, Inc. Dated September 24, 2008

Question No. 2.9

Responding Witness: Paul W. Thompson / William Steven Seelye

Q-2.9. Please provide the Company's current estimated cost of an installed CT in 2009 dollars. Provide all supporting workpapers.

A-2.9. The Companies' current estimated cost of an installed CT in 2009 dollars is approximately $710/kW. For supporting documentation, please refer to the Companies' 2008 Integrated Resource Plan (Case No. 2008-00148) in the Supply-Side Analysis contained in Volume III.

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. 2008-00252
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564
AND		
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2008-00251
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	))	CASE NO. 2007-00565

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Second Set of Data Requests of the Kentucky Industrial Utility Customers, Inc. Dated September 24, 2008

Question No. 2.11

Responding Witness: Paul W. Thompson / William Steven Seelye

Q-2.11. Please provide the estimated fixed O&M for a new CT in 2009 dollars. Provide all supporting workpapers.

A-2.11. The estimated fixed O&M for a new CT in 2009 dollars is approximately $12.30/kW-Yr. For supporting documentation, please refer to the Companies' 2008 Integrated Resource Plan (Case No. 2008-00148) in the Supply-Side Analysis contained in Volume III.

RECEIVED

OCT 28 2008

PUBLIC SERVICE
COMMISSION

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE:	**APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES**	**) CASE NO. 2008-00251**
	APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	**) CASE NO. 2007-00565**
	APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	**) CASE NO. 2008-00252**
	APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	**) CASE NO. 2007-00564**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2008

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2008-00251**
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00565**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	**CASE NO. 2008-00252**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	**CASE NO. 2007-00564**

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BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN RE:	**APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES**	**) CASE NO. 2008-00251**
	APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	**) CASE NO. 2007-00565**
	APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	**) CASE NO. 2008-00252**
	APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	**) CASE NO. 2007-00564**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

Q. Please state your occupation and employer.

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, and a Certified Management Accountant ("CMA").

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including proceedings before the Public Utilities Commission of Ohio. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. Please state the purpose of your testimony.

A. I address the Companies' proposed electric base rate increases, including the Companies' proposed operating revenues and expenses, capitalization and rate of return, and make recommendations to adjust these proposed amounts so that the resulting rates will be just and reasonable.

I am testifying for Kentucky Industrial Utility Customers, Inc., (KIUC). The members of KIUC who take service from the Companies are: Arch Chemicals, Inc., Arvin Meritor dba Carrollton Castings, Carbide Industries LLC, Cemex, Clopay Plastics Products Co., Inc., Corning Incorporated, Dow Corning Corporation, E.I. DuPont de Nemours & Co., Ford Motor Co., General Electric – Appliance Park, Golden Foods, Lexmark International, Inc., MeadWestvaco, NewPage Corp., North American Stainless, Occidental Chemical Corporation, Osram-Sylvania, Pilkington North America (formerly United L-N Glass), Protein Technologies, Rohm & Haas Kentucky, Inc., Square D. Company (US Schneider Electric), TI Group Automotive Systems, and Toyota Motor Engineering and Manufacturing North America, Inc.

Q. Please summarize your testimony.

A. The Companies' present electric base revenues are excessive and should be reduced, not increased. KU's electric base revenues should be reduced by at least $68.641 million and LG&E's base revenues should be reduced by at least $50.880 million compared to their revised requested increases of $25.000 million for KU and $14.190 million for LG&E. The following table summarizes the KIUC recommendations separated into operating income, capitalization and rate of return issues.

Kentucky Utilities Company and Louisville Gas and Electric Company
Summary of Revenue Requirement Adjustments-Jurisdictional Electric Operations
Recommended by KIUC
For the Test Year Ended April 30, 2008
($000)

	KU	LG&E
Increases Requested by Companies - Initial Filing	22.742	15.141
Corrections Filed by Companies on October 10, 2008	2,259	(951)
Increases Requested by Companies as Corrected	25,001	14,190
KIUC Adjustments:		
Operating Income Issues		
Incorporate EEI Earnings as Expense Reduction	(40.130)	0
Reduce Depreciation Expense to Use ALG Depreciation Rates	(15.145)	(14,530)
Reduce Depreciation Expense to Remove Excessive Net Negative Salvage	(11.663)	(16,311)
Eliminate Weather Normalization Adjustment (Net)	(4,382)	(9.656)
Reflect Consolidated Income Tax Savings in Income Tax Expense	(5,278)	(3.941)
Reflect Kentucky Coal Tax Credit in Income Tax Expense	(2,395)	(1.666)
Capitalization Issues		
Eliminate EEI Reductions to Capitalization	2,217	0
Correct Net ECR Reduction to Capitalization	(3,263)	(50)
Reflect Reduction in Collection Cycle	0	(810)
Rate of Return Issues		
Adjust Cost of ST and LT Debt to Actual at 8/31/08	(544)	(6,955)
Reduce Return on Equity to 10 5%	(13,059)	(11,151)
Total KIUC Adjustments to Companies' Corrected Requests	(93,642)	(65,070)
KIUC Recommended Reductions from Present Base Rates	(68,641)	(50,880)

My recommendations are as follows:

1. The Commission should include all EEI earnings and all EEI investment in KU's revenue requirement. These are utility earnings and investment. In prior proceedings, it was necessary to exclude these earnings and capitalization to avoid double counting the costs for ratemaking purposes because they were recovered as purchased power expense incurred through a cost-based contract for capacity and energy between KU and EEI. That contract expired on December 31, 2005 and KU has incurred increased costs since that date while earnings extraordinary amounts from the sale of its share of the capacity and energy in the market at market prices substantially more than cost.

2. The Commission should reject the Companies' request to increase depreciation rates due to the use of a new depreciation procedure, the ELG procedure. This proposed procedure improperly accelerates depreciation expense and results in intergenerational inequities.

3. The Commission should remove an excessive inflation component from the Companies proposed cost of removal component of depreciation rates. The Companies' methodology results in unnecessarily accelerated depreciation and intergenerational inequities.

4. The Commission should reject the Companies' proposed adjustment to weather normalize electric revenues. The Commission has rejected all prior proposals by the Companies to do so. The Companies proposal suffers from conceptual and methodological infirmities and should not be implemented in the absence of similar adjustments to normalize abnormal expense levels, which the Commission historically has been reluctant to do.

5. The Commission should reflect a consolidated tax savings adjustment that provides the Companies' ratepayers a carrying charge on amounts loaned to their parent company and other loss subsidiaries. This loan occurs when rates are set for the Companies under the assumption that they file separate standalone tax returns rather than the reality that the Companies' positive taxable income is used to offset the taxable losses of other E.ON subsidiaries. A consolidated tax savings adjustment compensates the Companies and their ratepayers for their loans to these other companies and removes the subsidies that exist under the separate standalone tax return approach.

6. The Commission should reject the Companies' adjustment to eliminate the Kentucky coal tax credit, which increases the Companies' Kentucky state income tax expense. The Companies will continue to accrue this tax credit into 2011. In the event that the Commission adopts the Companies' selective post-test year adjustment, then it should offset the effect of eliminating this credit with the scheduled increase in the § 199 deduction that will occur on January 1, 2010.

7. The Commission should reject the Companies' latest proposal to change the methodology for excluding the ECR rate base from the Companies' capitalization. The Commission historically has removed the ECR rate base investment from the Companies' capitalization at the test year end. The Companies' proposed methodology would allocate capitalization between ECR and non-ECR using rate base and thereby introduce a mismatch between the rate base actually included in the ECR.

8. The Commission should reduce LG&E's capitalization due to the acceleration of cash flow resulting from its proposal to reduce the collection cycle from 15 days to 10 days. The LG&E ratepayers should receive the revenue requirement benefit of the accelerated cash flow.

9. The Commission should update the cost of debt to more recent levels in accordance with its historic practice.

10. The Commission should reject the Companies' request for an 11.25% return on common equity. I have quantified the effect of a 10.50% return on common equity. This was the midpoint of the range found reasonable by the Commission in Case Nos. 2003-00433 and 2003-00434 and slightly more than the average awards to date this year by state commissions for electric utilities.

I have structured my testimony into three additional sections consistent with the categories of issues on the preceding table.

II. OPERATING INCOME ISSUES

EEI Earnings Should be Incorporated in KU Revenue Requirement

Q. Please describe the KU investment in Electric Energy, Inc. ("EEI").

A. KU and several other utilities invested in EEI in the early 1950s. EEI was formed to own, build and operate an electric generating facility in Joppa, Illinois to supply power to the United States Atomic Energy Commission. Excess power was sold to the sponsoring utilities, including KU, pursuant to cost-based contracts, through 2005. The gross capacity of the plant currently is 1,162 mW, consisting of a 1,086 mW coal-fired plant and 76 mW in combustion turbine capacity.

KU owns 20% of EEI. Other utilities, all of which are now owned by Ameren, own the other 80% of EEI. KU is entitled to 20% of the EEI earnings and 20% of the EEI dividends. Prior to January 1, 2006, KU was entitled to 20% of the EEI capacity and energy pursuant to cost-based contracts.

KU recognizes its share of the EEI earnings using the equity method of accounting. It recognizes its share of the EEI earnings below the line in account 418.1, Equity in Earnings of Subsidiary Companies, although EEI is not a KU subsidiary. The KU share of EEI earnings each year is added to KU's account 216.1, Unappropriated Undistributed Subsidiary Earnings. The KU share of EEI dividends is then used to reduce the amount in account 216.1 and to increase

KU's account 216, Unappropriated Retained Earnings. The EEI dividends have no effect on KU's common equity capitalization; the dividends only affect which common equity account the cumulative EEI earnings are reported.

Prior to 2006, KU's share of EEI earnings was relatively minor, primarily due to the fact that most of EEI's power was sold pursuant to cost-based contracts to its owners. However, in 2006, 2007 and 2008, EEI's earnings, and therefore, KU's share of EEI earnings shot up dramatically. In the test year, KU's share of EEI earnings was $28.622 million.

The preceding information, except for the detail regarding KU's use of account 216.1 and 216, was provided by KU in response to KIUC-2-18, a copy of which I have attached as my Exhibit___(LK-2) and in response to PSC-1-34, a copy of which have attached as my Exhibit___(LK-3). The detail regarding KU's use of account 216.1 and 216 is found on pages 117, 118, and 119 of KU's FERC Form 1 filings. I have attached a copy of these pages from KU's 2007 FERC Form 1 as my Exhibit___(LK-4).

Q. Please describe how the Commission historically reflected the purchased power expense and EEI investment in KU's revenue requirement.

A. The Commission historically provided the Company recovery of the purchased power expense pursuant to its cost-based contract with EEI through base rates and the fuel adjustment clause. The Commission historically did not include the KU share of EEI earnings as a reduction to the revenue requirement. In addition, the Commission historically reduced KU's common equity capitalization in account 216.1 for the EEI earnings that had not been transferred to account 216 due to KU's share of EEI dividends. Finally, the Commission also reduced KU's capitalization for its investment in EEI.

Q. Has the Commission's methodology used for the reduction in capitalization due to KU's investment in EEI changed over the last several decades?

A. Yes. The Commission's methodology has varied primarily due to the fact that KU's filing methodology has varied. In Case Nos. 7804 (01/31/80), 8177 (12/31/80), and 8624 (06/30/82), the Commission reduced capitalization by the total amount of KU's investment in EEI, which included the original investment as well as all of KU's cumulative EEI earnings regardless of whether those earnings were recognized in account 216.1 or 216. In Case No. 98-474 (12/31/98), the Commission reduced capitalization across all components only by the original investment of $1.295 million, and account 216.1 by $0.861 million, based on KU's filing. In Case No. 2003-434, the Commission adopted a settlement, but the Company's filing reflected a reduction in capitalization across all components of $10.239 million and a reduction to account 216.1 of $8.943 million. This information was provided by the Company in response to AG-1-34, a copy of which I have attached as my Exhibit___(LK-5).

Q. What adjustments to capitalization does KU propose in this proceeding for its EEI investment?

A. KU originally proposed a reduction of $24.880 million to capitalization across all components and a reduction to account 216.1 of $23.585 million. However, in response to AG-1-34, the Company asserted that it had erroneously deducted the amount in account 216.1 twice and further, that it failed to reduce the deduction by an offsetting accumulated deferred income tax amount. Consequently, KU has proposed yet another methodology compared to the methodologies that it proposed in prior cases.

Q. Is KU's investment in EEI a "non-utility" investment that should be excluded by the Commission from capitalization for that reason?

A. No. KU's investment in EEI is not a non-utility investment. KU's investment in EEI is recorded in account 123, Investment in Associated Companies. Thus, the KU's investment in EEI should be included in capitalization unless it is necessary to exclude the investment to avoid double counting the related cost for ratemaking purposes.

Q. Then why has the Commission historically excluded the investment in EEI from KU's capitalization and the EEI earnings from operating income for ratemaking purposes?

A. Historically, it was necessary to exclude KU's investment in EEI from its capitalization to avoid providing KU a return on its EEI investment twice, once through the recovery of its cost-based purchased power expense, which included a return on EEI's capitalization, and then again through a return on KU's capitalization, which includes KU's investment in EEI.

In addition, any earnings or losses on KU's EEI investment were due to the timing of EEI's incurrence of costs compared to its recovery of those costs from KU and its other owners pursuant to cost-based purchase and sale contracts, not due to intentionally overcharging or undercharging its owners. Thus, it would not have been reasonable to incorporate those EEI earnings or losses in the Company's revenue requirement as long as the cost-based purchased power contracts remained in effect through the end of 2005.

Q. Please describe the change in circumstances that occurred on January 1, 2006.

A. KU discontinued purchasing cost-based power from EEI on January 1, 2006. Companies witness Mr. Thompson describes this change at page 6 of his Direct Testimony in this proceeding as follows:

> **As LG&E and KU notified the Commission by letter dated December 22, 2005, the Companies long-standing Power Supply Agreement ("PSA") with Electric Energy, Inc. ("EEI") ended as of January 1, 2006. Until that time, EEI had provided the Companies with approximately 200 mW of relatively low cost-based capacity and energy. EEI elected to pursue market-based pricing beginning in 2006, however, which caused it to no longer be a cost-effective source of capacity or energy for the Companies. The loss of EEI as a source of low-cost supply has increased the Companies need for TC2 and**

> **other cost-effective means of meeting the demand and energy needs of our customers.** (footnote reference to docket 2005-00162 deleted).

I have attached a copy of the letter referenced by Mr. Thompson as my Exhibit___(LK-6).

Q. What were the results of this change on KU's costs and its earnings?

A. Since January 1, 2006, KU's fuel and purchased power costs have increased compared to the "relatively low cost-based capacity and energy" obtained through the cost-based contract with EEI because KU now must generate or purchase at higher cost or sell less energy off-system than if the cost-based capacity and energy remained available. The increased fuel and energy component of purchased power expense, together with the reductions in off-system sales revenues, resulted and continues to result in increased recoveries by KU through the fuel adjustment clause. At the same time, the Company has continued to recover the capacity portion of the contract cost through base rates, despite the fact that it no longer incurs that cost. Although that has been a problem since January 1, 2006, it will be remedied going forward when new base rates are set in this proceeding.

Also at the same time that ratepayers were and will continue to be charged more for fuel and purchased power costs and base rates will be increased now or in the future due to capacity costs for new generating units or purchased power and lower off-system sales revenues, KU began recognizing huge earnings on its EEI investment, which it recognized below the line. In 2005, KU's share of EEI earnings was \$2.256 million. In 2006, KU's share of EEI earnings skyrocketed to \$29.405 million, in 2007, to \$26.359 million, and in the test year, to \$28.623 million. These amounts were provided by the Company in response to KIUC-2-18 and the test year trial balance provided in response to PSC 1-13.

Q. Now that the cost-based contract has terminated, should the Commission continue to make the adjustments that were necessary to avoid double counting the cost of the contract when it was in effect?

A. No. This is the Commission's first opportunity to revisit its historic practice and to reassess the adjustments that now are necessary given the change in circumstances on January 1, 2006. I recommend that the Commission now incorporate KU's share of EEI earnings as a reduction to the Company's revenue requirement for several reasons. First, KU, not a subsidiary or any other entity, owns the 20% share of EEI. The investment also is not a "non-utility" investment. Thus, the KU share of EEI earnings should be included in the revenue requirement unless there is some compelling reason to consider these earnings as "non-utility" even though the investment itself is not. In the past, that compelling reason was the existence of the cost-based purchased power contract. However, now that there is no cost-based purchased power contract, there no longer exists a need to avoid the double counting of the earnings or the capitalization investment in EEI.

Second, the effects of losing the "relatively low cost-based capacity and energy" obtained through the cost-based contract with EEI already are being recovered and will continue to be recovered by KU through the fuel adjustment clause. Similarly, KU's capacity costs recovered through base rates will be greater due to the loss of the EEI capacity. KU's share of the EEI earnings should be used to defray these increased costs in the base revenue requirement going forward.

Third, KU itself believes that KU's ratepayers should continue to receive the benefit of the low cost-based capacity and energy. This is evidenced by the fact that it negotiated for a continuation of the contract on a cost-basis rather than repricing the contract at market. KU provided the Commission a copy of the letter it wrote to EEI declining the contract offer repricing at market and stated in that letter the following:

> **As you know, KU had hoped to negotiate a cost-based agreement to replace the present Power Supply Agreement that expires on December 31, 2005, and we had been working toward that goal for much of the past year.**

As I previously noted, I have attached a copy of KU's letter to the Commission dated December 22, 2005 in Case No. 2005-00162 and KU's letter to EEI as my Exhibit___(LK-6).

In short, the Commission's historic practice of excluding the EEI earnings and capitalization from the Company's revenue requirement no longer is appropriate.

These amounts now should be included due to the change in circumstances since the Company's last base rate case.

Q. How should the Commission incorporate the EEI earnings and capitalization in the revenue requirement?

A. First, the Commission should compute the grossed-up revenue equivalent of KU's share of the EEI earnings and use that to reduce the revenue requirement. Second, the Commission should eliminate all adjustments to reduce the KU capitalization for the EEI investment. In this manner, the Company's operating income will be increased to include the EEI earnings and KU's capitalization no longer will be reduced to exclude the EEI investment for ratemaking purposes.

Q. Have you quantified the effect on KU's revenue requirement of incorporating the EEI earnings and capitalization?

A. Yes. The effect is to reduce KU's revenue requirement by $37.913 million in accordance with the two steps previously identified. In the first step, I computed the grossed-up revenue equivalent of the EEI earnings. In this step, I computed the after tax effect of the earnings by subtracting the Company's income tax expense on the EEI earnings. I computed the income tax expense by summing the two components of the income tax expense computation. The first component was the portion of the test year earnings that KU recognized in excess of the EEI dividend multiplied times the Company's combined federal and state income tax rate. The EEI earnings in excess of the dividends are taxed at the Company's corporate income tax rate. The second component was the portion of the earnings represented by the EEI dividend, which I multiplied times one minus the 80% dividends received exclusion and then multiplied the taxable remaining 20% times the federal income tax rate.[1] Finally, I grossed-up the after tax effect of the EEI earnings by one minus the combined federal and state income tax rate.

In the second step, I simply eliminated all of the Company's adjustments to capitalization for the EEI investment reflected on the Company's revised Exhibit 2. I then recomputed the weighted average cost of capital and multiplied this change in the weighted cost of capital times the increase in capitalization. This step had the effect of offsetting, or reducing, the effect of the first step.

These computations are detailed on my Exhibit___(LK-7).

Weather Normalization of Revenues Should be Rejected

Q. Please describe the Company's proposal to change the Commission's historic methodology for quantifying test year revenues.

A. The Companies propose that the Commission change its long-standing policy for quantifying test year revenues to reflect the effects of weather ("temperature") normalization. The Companies' proposal reduces actual test year revenues by

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[1] There is a 100% dividends received exclusion for state income tax purposes, according to the test year computation of income tax expense detailed in KU's response to AG-1-25.

$14.374 million for LG&E and by $8.721 million for KU. The Companies' proposal increases the revenue requirement by $9.656 million for LG&E and by $4.382 million for KU. These amounts are less than the reductions in test year revenue due to offsetting expense reductions.

Q. What are the premises underlying any proposal for weather normalization of revenues?

A. There are at least four. The first premise is that the use of weather normalized revenues is superior to the use of actual revenues for quantifying the revenue requirement and setting rates on a going forward basis. The second premise is that actual revenues were more or less than "normal" based on actual temperatures compared to "normal" temperatures during the test year. The third premise is that such deviations in revenues can be properly measured through a statistical analysis. The fourth premise is that the deviations in revenues can be properly correlated with the related deviations in expenses or other costs.

Q. Do you agree with the first premise that the use of weather normalized revenues is superior to the use of actual revenues for quantifying the Companies' revenue requirement in this proceeding?

A. No. First, the Commission and the Companies historically have not favored normalization of revenues or O&M expenses, with limited exceptions, such as the annualization of payroll and benefits expenses. The Commission has rejected all prior attempts of the Companies to normalize electric revenues for temperature at least since 1972. The Commission also rejected the recommendation of KIUC in LG&E Case No. 8924 to reduce the revenue requirement to remove the effects of a test year carefully selected by LG&E to include abnormally low revenues.

Second, even if the Commission were to determine that it is appropriate to weather normalize revenues, it should not do so in isolation and without consideration of abnormal and unusually high levels of operation and maintenance ("O&M") expenses, such as are included in the Companies' test year expenses in this proceeding. The Commission has been reluctant in prior proceedings to adjust such O&M expenses without evidence of changes that are "*known and measurable*."

Q. Please describe the abnormal and unusually high levels of O&M expenses sought by the Companies in this proceeding.

A. The Companies' non-fuel test year actual O&M expenses are significantly greater than their actual O&M expenses for the twelve months ending April 30, 2007, reflecting increases of 12.5% for KU and 5.8% for LG&E. The Companies provided a comparison of their actual test year O&M expenses compared to their actual calendar O&M expenses for each account for the twelve months ending April 30, 2007 in response to PSC 1-23. I have summarized the information provided in those responses for each Company and computed the percentage increase in the test year over the preceding twelve months on my Exhibit___(LK-8) for KU and my Exhibit___(LK-9) for LG&E.

In addition, the Companies' non-fuel test year actual O&M expenses are significantly greater than their actual non-fuel O&M expenses for the calendar year 2007, exhibiting increases of 5.2% for KU and 7.4% for LG&E, despite the fact that there is an overlap between the test year and calendar year 2007 of eight months. In other words, if these percentage increases were annualized, they would be three times greater yet. This total O&M data was also supplied by the Companies in the response to PSC 1-23. I have removed the non-fuel test year O&M expenses by account and compared them to the actual non-fuel calendar year amounts for each Company and computed the percentage increases on my Exhibit___(LK-10) for KU and my Exhibit___(LK-11) for LG&E.

Further, the Companies provided additional information regarding certain large increases identified by KIUC in response to KIUC 2-23 (KU) and KIUC 2-21 (LG&E), in which the Companies described the reasons for some of the largest increases. I have replicated these responses as my Exhibit__(LK-12) for KU and Exhibit___(LK-13) for LG&E.

Q. The second and third premises underlying the Companies' request for temperature normalization of revenues are that actual revenues were more or less than "normal" based on actual temperatures compared to "normal" temperatures during the test year and that such deviations in revenues can

be properly measured through a statistical analysis. Please respond to these arguments.

A. The measurement of such deviations is directly dependent upon the statistical methodology as well as the data employed. There are no real-world tests to verify the results of the statistical analyses. The Companies have used 30 years of NOAA data to determine their norms for application to the test year. Yet, evidence that my firm has developed in another proceeding indicates that there has been a warming cycle in temperatures in recent years. The Companies use 20 years of temperature data when developing their load forecasts, according to KU's response to PSC 2-61. In other words, to the extent there is a warming trend, then the use of 30 years of temperature data will tend to overstate statistical deviations from the norm and result in excessive temperature normalization adjustments, all else equal. The Companies have offered no evidence as to the relevance or reliability of a 30 year period for the determination of an adjustment for the normalization of electric revenues. The Companies have offered no evidence that the 30 years does not have an inherent bias masking the effects of any recent warming trends that may exist. In fact, the Companies' use of 20 years of data for budget and forecasting purposes suggests that 30 years of data is neither relevant nor reliable.

Q. Has KIUC previously proposed weather normalization of revenues for LG&E as claimed by Companies' witness Mr. Seelye?

A. No. Mr. Seelye's testimony on this point is in error. I have reviewed the testimony of Airco Carbide witness Mr. Stephen Baron in Case No. 8924. In that proceeding, Mr. Baron used temperature data to demonstrate that LG&E had inappropriately selected its test year to minimize its actual test year revenues and thereby increase its revenue requirement by $13 million. KIUC did not recommend a temperature normalization adjustment to revenues in that or any other KU or LG&E proceeding.

Q. The fourth premise underlying the Companies' proposed weather normalization adjustment to revenues is that the deviations in revenues can be properly correlated with the related deviations in expenses or other costs. Please respond.

A. Generally, I agree with the premise that deviations in revenues and costs can be properly correlated; however, I do not agree that the Companies' proposal achieves that goal. More specifically, there are at least two problems in the Companies' computations of the reductions in expenses correlated with their computations of the reductions in revenues.

The first problem is that the Companies assert that the Commission should use a different methodology to compute the reductions in expenses for the normalization of revenues than it uses to compute the offset for expenses due to the annualization of revenues for year end customers. The methodology proposed by the Companies results in less expense offset than if the Commission's methodology is used. More specifically, the expense offset to the revenue adjustment for year end customers is 64.8% for KU and 54.7% for LG&E (see Exhibit 1 Reference Schedule 1.12 attached to Mr. Rives Direct Testimony). Yet, the KU expense offset to the proposed revenue adjustment for weather normalization is only 49.9% for KU and only 33.1% for LG&E (see Exhibit 1 Reference Schedule 1.11 attached to Mr. Rives Direct Testimony).

If the Commission adjusts revenues for year-end customers and for weather normalization, then the expense offsets for both revenue adjustments should be computed in the same manner and with similar results as a percentage of the revenue adjustment.

The second problem with the Companies' computation of the expense offset is that they used an average FAC factor for the entire test year to compute the expense offsets to revenues that occurred only in certain months during that test year. More specifically, the Companies claim that August 2007 was abnormally warm and that a portion of these actual revenues should be removed from the test year revenues through the temperature normalization adjustment. However, the Companies propose that the fuel expenses related to those revenues be computed based on an average for the year rather than for the higher cost month of August. The Companies' proposal results in a clear mismatch between the revenue adjustments and the proposed expense adjustments.

Q. Should the Commission adopt the Companies' proposal for weather normalization of revenues?

A. No. First, the Commission has not previously adopted a weather normalization methodology for a jurisdictional electric utility in a proceeding where it was a contested issue. Second, the Commission has not previously adopted methodologies to normalize aberrations in O&M expense. Third, the Companies have not demonstrated that their use of 30 years of NOAA data does not result in an inherent temperature bias compared to using more recent temperature data indicating a warming trend. Fourth, the Companies have failed to follow the Commission's methodology for the related expense offsets to revenue annualization or normalization adjustments and thereby understated the expense offsets.

Equal Life Group Depreciation Procedure Should be Rejected and Average Life Group Procedure Maintained

Q. Please describe the Companies' proposal to use the equal life group ("ELG") procedure to determine depreciation rates.

A. The Companies propose to use the ELG procedure in lieu of the average life group procedure ("ALG") historically used by the Commission. The ELG procedure is based on the use of vintaged plant data stratified into life groups to determine the depreciation expense for each vintage year of plant data over each of the life group's service lives. The ALG or broad group procedure does not stratify plant data in this manner, but rather assumes an average retirement dispersion and an average life for the entirety of the plant data.

Q. What is the essential problem with the ELG procedure compared to the ALG procedure historically used by the Commission?

A. The ELG procedure mathematically results in an accelerated depreciation expense compared to the ALG procedure, which naturally smoothes or averages the depreciation expense over the average life of the plant data. Consider the following example. Assume the Company acquires $50,000 in plant in year 1. This plant consists of five equal life groups. The first life group consists of $10,000 with a 1 year life. The second life group consists of $10,000 with a 2 year life. The third life group consists of $10,000 with a 3 year life. The fourth life group consists of $10,000 with a 4 year life. The fifth life group consists of $10,000 with a 5 year life.

The depreciation expense in the first year would be $10,000 for the first life group, $5,000 for the second life group, $3,333 for the third life group, $2,500 for the fourth life group, and $2,000 for the fifth life group, for a total of $22,833. The depreciation expense for the second year would be $0 for the first life group, $5,000 for the second life group, $3,333 for the third life group, $2,500 for the fourth life group, and $2,000 for the fifth life group, for a total of $12,833. The depreciation expense for the third year would be $0 for the first life group, $0 for the second life group, $3,333 for the third life group, $2,500 for the fourth life group, and $2,000 for the fifth life group, for a total of $7,833. The depreciation expense for the fourth year would be $0 for the first group, $0 for the second group, $0 for the third group, $2,500 for the fourth group and $2,000 for the fifth group, for a total of $4,500. Finally, the depreciation expense for the fifth year would be $0 for groups one through four and $2,000 for the fifth group, for a total of $2,000. The total depreciation expense would be $50,000 over the 5 year period. However, the ELG depreciation rates in each year as a percentage of the total surviving plant at the beginning of each year would be 45.7%, 32.1%, 26.1%, 22.5%, and 20.0% for years 1 through 5, respectively.

By contrast, the ALG procedure would use an average life of 2.5 years and would result in depreciation expense of $18,000 in the first year, $14,000 in the second year, $10,000 the third year, $6,000 the fourth year and $2,000 the fifth year. The total depreciation expense would be $50,000 over the 5 year period, the same in total as under the ELG procedure.

The difference between the two procedures is that the ELG procedure accelerates the depreciation expense compared to the ALG procedure, although there is a crossover in the third year where the ELG and ALG procedures result in nearly equivalent depreciation and the ELG procedure results in less depreciation in years 4 and 5. However, in the normal situation where a utility continually adds to plant each year, the result of the ELG procedure will be higher depreciation expense in perpetuity compared to the ALG procedure.

Q. In addition to the essential problem of accelerated depreciation using the ELG procedure, is there another problem related to the regulatory process itself?

A. Yes. The Commission does not reset depreciation rates or the utility's base rates each year. Consequently, once the depreciation rates and the resulting depreciation expense are established, the rates remain in effect and are applied to a continually growing plant balance. Thus, the accelerated depreciation rates resulting from the ELG procedure are not reduced each year as the preceding example would suggest and the utility continues to collect excessive amounts for depreciation expense.

Q. Have you reviewed the Virginia Commission Staff's reasons for rejecting KU's request for ELG in its recent review of KU's depreciation *methodologies and rates?*

A. Yes. The Virginia Commission Staff opposed KU's request for ELG and recommended maintaining the use of the average life group procedure. The Virginia Commission Staff stated the "ALG is more appropriate for ratemaking in Virginia, since it tends to produce more stables rates, all other variables (i.e. service lives and net salvage rates) being equal. Further, Staff believes a switch to the ELG procedures would be imprudent for Virginia ratemaking since it can compound any inaccuracies in estimation of retirement dispersion, can introduce inter-generational inequities, and can be more costly and time-consuming to maintain."

Q. Do you agree with the Virginia Commission Staff's conclusions and reasons cited for its conclusions in rejecting the ELG procedure and maintaining the ALG procedure?

A. Yes. I agree with its conclusions and the reasons. These reasons are applicable to KU and LG&E in the present proceedings.

Q. Have you quantified the effect on depreciation expense of using the ALG procedure in lieu of the Company's proposed ELG procedure?

A. Yes. The effect is to reduce depreciation expense by $15.091 million[2] (KU Kentucky retail jurisdiction) and $14.482 million (LG&E electric). The Companies provided these quantifications in response to PSC-3-20 (KU) and PSC-3-21 (LG&E), copies of which I have attached as my Exhibit___(LK-14). The Companies' quantifications are net of the amounts allocated to the environmental surcharge.

<u>**Excessive Net Negative Salvage Should be Removed from Depreciation Rates**</u>

Q. Have you reviewed Attorney General witness Mr. Majoros' Direct Testimony in Case Nos. 2007-00565 and 2007-00564 wherein he proposed a reduction in

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[2] *Total Company amount of $17.255 million times 87.457% jurisdictional* allocation factor from KU Exhibit 1 Reference Schedule 1.14.

the Companies' net negative salvage rates to remove future inflation from the cost of removal component?

A. Yes. The Companies' methodology incorporates future inflation on the current cost of removal, which has the effect of accelerating the recovery of those costs from present ratepayers. This results in excessive depreciation rates and intergenerational inequities between present ratepayers and future ratepayers.

Q. Do you agree with Mr. Majoros' recommendation and methodology used to remove the effects of future inflation from the net negative salvage rates component of the Companies' depreciation rates?

A. Yes.

Q. What is the effect of this recommendation?

A. The effect is to further reduce the Companies' proposed depreciation expense by $11.621 million for KU and $16.256 million for LG&E. The quantifications are detailed on my Exhibit___(LK-15). These quantifications are based on Mr. Majoros' proposed depreciation rates less the effects of the ELG procedure issue previously discussed. For KU, the depreciation rates used to compute the overall reduction were taken directly from Mr. Majoros' Exhibit MJM-3 from Case No. 2007-00565. For LG&E, the Company provided the quantification in response to PSC 2-30. Mr. Majoros' recommendations reflected only these two issues, so the difference between the Companies' quantifications using Mr. Majoros' proposed depreciation rates and the quantifications of the effects of using the ALG procedure in lieu of the ELG procedure that I previously addressed provides the quantification of the cost of removal issue.

Kentucky Coal Tax Credit Should be Reflected in Income Tax Expense

Q. Please describe the Companies' proposal to remove the Kentucky coal tax credit from property tax and income tax expenses.

A. The Companies propose to remove this tax credit from their property tax expense for ratemaking purposes, although the Companies will continue to be eligible for these credits through 2010. KU proposes to remove $0.447 million and LG&E $1.136 million from property tax expense and neither Company has reflected the coal tax credit as a reduction to its proforma test year income tax expense. However, these amounts are based on the Companies' 2007 coal tax credit against property tax expense and do not reflect the amount of the credit for 2008 that will be applied against its state income tax expense. The amounts that will be applied against state income tax in 2008 are $2.395 million for KU, according to its response to AG1-25 ($0.599 for first quarter 2008 times 4), and $1.666 million for LG&E, according to its response to PSC-2-79.

Q. Why have the Companies proposed to remove these amounts from their test year revenue requirement?

A. The Companies claim that the credit applies only to coal purchases through 2009 and that the credit is a contingent credit based on coal purchases above a 1999 baseline, according to Ms. Scott's Direct at 6-7 and LG&E's response to PSC 2-

26 and PSC 2-81.

Q. How do the Companies record the Kentucky coal tax credits?

A. The Companies record these credits in the year after the coal purchases are made. The credit applicable to the coal purchases in 2009 will not be recorded on the Companies' accounting books until 2010. Thus, the credit will continue to reduce the Companies' income tax expense through 2010.

Q. Please address the contingent nature of the coal tax credit.

A. LG&E has been eligible for the tax credit each year based on its 2001 coal purchases, according to its response to PSC 2-79. In some years, the credit was applied to LG&E's income tax expense and in other years, it was applied to its property tax expense, according to its response to PSC 2-79. Thus, it does not appear that the credit itself is in serious dispute, rather, it appears only that the amount varies.

Q. Should the Commission reflect the Kentucky coal tax credit in the Companies' revenue requirement?

A. Yes. The Companies will continue to be eligible for the credit for purchases through 2009 and the credit will be recorded on their accounting books through 2010. The credit will not disappear until 2011. Consequently, the Companies' proposal constitutes a selective post-test year adjustment reaching into 2011, three years after the end of the test year. In addition, if the variability of the credit is an issue, then the Commission could simply move the credit from base rates, where it is now, to the fuel adjustment clause, where it would be used dollar for dollar to reduce fuel costs until such time as the credit expired. Finally, if the Commission decides that this post-test year adjustment effective in 2011 should be reflected in this proceeding, then it also should reflect the increase in the § 199 deduction from 6% of taxable income to 9% of taxable income that will become effective on January 1, 2010 a year earlier than the expiration of the coal tax credit.

Q. Have you quantified the effect of your recommendation to include the Kentucky coal tax credit as a reduction to the Companies' income tax expense?

A. Yes. The effect is to reduce KU's revenue requirement by $2.395 million and LG&E's by $1.666 million. These quantifications are based on an annualization of the first quarter 2008 effect of this credit as a reduction to the Companies' Kentucky state income tax expense.

<u>Section 199 Deduction Should be Increased if Kentucky Coal Tax Credit is Not Reflected in Income Tax Expense</u>

Q. Should the Commission reflect the § 199 increase to 9% from the present 6% rate applied to taxable income that will be effective on January 1, 2010 in the event that it adopts the Companies' proposed post test year adjustment to remove the Kentucky coal tax credit that will not be eliminated until January 1, 2011?

A. Yes. The Commission should consider both tax issues together because they both will become effective subsequent to the test year.

Q. Have you quantified the effect of increasing the §199 deduction to 9% if the Commission adopts these post-test year tax adjustments?

A. Yes. The effect is to reduce KU's revenue requirement by $2.755 million and LG&E's by $2.272 million. The computations are detailed on my Exhibit___(LK-16) and are based on the change in income tax expense after all other KIUC adjustments have been made. I have not included the effect of this adjustment in the KIUC revenue requirement recommendations because it is applicable only if the Commission does not reject the Companies' post-test year adjustment to eliminate the Kentucky coal tax credit.

Consolidated Income Tax Benefits Should be Reflected in Income Tax Expense

Q. Please describe the Companies' computation of income tax expense included in their revenue requirements.

A. The Companies' computations of income tax expense for the test year are based on the *assumption* that each Company files separate standalone federal and state income tax returns for all income and deductions as if it were not a subsidiary of E.ON US Investments Corp. ("E.ON") and did not participate along with the other E.ON affiliates in filing consolidated federal and state income tax returns.

Q. How do the Companies' computations of income tax expense using the separate standalone tax return approach compare to their domestic parent company's computation of income tax expense on a consolidated tax return basis?

A. E.ON files a consolidated income tax return, which nets the positive and negative (losses) taxable income of its subsidiaries together with its own income or loss. Thus, both the E.ON consolidated taxable income and consolidated income tax payments are less than the sum of the positive taxable income and consolidated income tax payments computed on a standalone basis for each of the E.ON subsidiaries. Pursuant to the E.ON Tax Allocation Agreement, a copy of which the Companies provided in response to KIUC 1-4, each subsidiary's taxable income is computed on a separate standalone tax return basis. Also pursuant to the E.ON Tax Allocation Agreement, the positive taxable income subsidiaries, including the Companies, remit the income tax on their positive taxable income to E.ON without regard to the savings E.ON achieves from losses incurred by other subsidiaries used by E.ON to reduce its actual tax payments to the federal and state governments. In other words, the Companies compute their share of the E.ON federal and state income tax payments at the maximum possible amount under the assumption that they are not members of the E.ON affiliate group included in the consolidated tax return.

Q. Does the fact that E.ON uses the tax payments provided by the Companies to actually reduce its tax payments by netting the tax losses of its loss

subsidiaries provide a consolidated income tax benefit to E.ON?

A. Yes. The Companies tax payments to E.ON provide loans or grants to E.ON that E.ON uses to monetize on a current basis the tax benefits resulting from the losses of its loss affiliates that otherwise would have to be carried forward or possibly lost forever. In the absence of these tax payments by the Companies and other subsidiaries with positive taxable income to E.ON, E.ON would have no ability to extract a current tax benefit from its loss companies unless those losses could be carried back to prior years. Instead, E.ON would have to wait until future years when it could apply the loss carryforwards generated by the loss affiliates against their positive taxable income, assuming that ever would transpire.

To the extent that the loss subsidiaries actually use their loss carryforwards in the future, the positive taxable income subsidiaries, including the Companies, effectively have loaned E.ON and its loss subsidiaries the cash the Companies have collected from their ratepayers to pay income taxes currently but that will not be paid by E.ON until some year or years in the future. To the extent that the loss subsidiaries never actually use their loss carryforwards in the future, the positive taxable income subsidiaries, including the Companies, effectively have provided grants to E.ON and its loss subsidiaries using the cash they have collected from their ratepayers to pay income taxes currently but that will never be paid in any year in the future.

Q. **Are the Companies compensated in any manner for their loans and/or grants**

to E.ON and its loss subsidiaries?

A. No. There is no provision in the E.ON Tax Allocation Agreement whereby E.ON or the loss subsidiaries pay a carrying charge to the Companies or repay the Companies for their grants for the tax expense the Companies have remitted to E.ON, but which E.ON has not actually used to pay the federal government.

Q. Should the Commission reflect these consolidated tax savings in some manner to reduce the Companies' revenue requirements?

A. Yes. Ratepayers should be compensated for the capital the Companies loan or invest in E.ON and its loss subsidiaries. The Companies collect these amounts from their ratepayers, remit the amounts to E.ON and then E.ON obtains and retains the current tax benefit from monetizing the losses of its loss subsidiaries. It is the positive taxable income of the Companies, collected from the ratepayers under the assumption that there are no consolidated tax savings, that makes it possible for E.ON to obtain these current tax benefits. Unless the E.ON loss subsidiaries had positive taxable income in prior years and could carry back the losses to those prior years in order to obtain a refund on a separate standalone tax return basis, E.ON would not otherwise have been able to obtain this tax benefit in the absence of the Companies' positive taxable income.

Q. Should the Commission be bound for ratemaking purposes by the requirement of the E.ON Tax Allocation Agreement to compute the Companies' income tax expense on a separate standalone tax return basis?

A. No. The Commission is not bound by the terms of the Tax Allocation Agreement for ratemaking purposes. Instead, the Commission should determine whether it is reasonable for the Companies' ratepayers to subsidize the E.ON loss subsidiaries through cash loans and grants without any compensation. The Commission should determine the amount of the subsidies provided by the Companies due to the amounts provided by the ratepayers and then compensate the ratepayers for these subsidies through the ratemaking process.

This is a ratemaking matter involving subsidization of affiliates; it is not a matter dispute regarding the application of the Tax Allocation Agreement for accounting or cash flow purposes. The Commission's statutory mandate is to set rates at just and reasonable levels; its mandate is not to allow the Companies to use ratepayer funds to subsidize their non-regulated affiliates.

Q. Do other state commissions recognize consolidated tax savings in the *computation of income tax expense for ratemaking purposes?*

A. Yes. The commissions in at least six states explicitly recognize consolidated tax savings in the computation of income tax expense for ratemaking purposes. The states include Pennsylvania, New Jersey, Texas, West Virginia, Connecticut, and Oregon. In addition, other states implicitly recognize consolidated tax savings (or costs) through various means. The former states employ a variety of methodologies to quantify the consolidated tax savings. The Pennsylvania commission uses a five year average effective income tax rate for income tax expense. The New Jersey commission uses a rate base reduction for the savings. The Texas commission computes an interest credit reduction to income tax expense by applying a debt rate of return to 15 years of cumulative savings. West Virginia computes a multi-year average of the parent company's loss to reduce the utility's income tax expense. Finally, the Oregon commission uses a "tax tracker" to ensure that only taxes actually paid are recovered in rates.

As an example of the various states that explicitly recognize consolidated tax savings in setting the utility's revenue requirement, the New Jersey commission stated its policy in BPU Docket NO. ER911218201 as follows:

> **The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. Income from utility operations provide the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment.**
>
> **The issue, in this case, is not whether such an adjustment should be made, but, rather, what methodology should be used to make such an adjustment. In this area, the courts have held that the Board has the power and discretion to choose any approach which rationally determines a subsidiary utility's effective tax rate. <u>Toms River Water Company v. New Jersey Public Utilities Commissioners</u>, 158 <u>NJ Super</u> 57 (1978). Based on our review of the record in this case, the Board <u>REJECTS</u> the ALJ's recommendation to accept the income tax expense adjustment proposed by Petitioner and, instead, <u>ADOPTS</u> the position of Staff that the rate base adjustment is a more appropriate methodology for the reflection of consolidated tax savings. The rate**

> **base approach property compensates ratepayers for the time value of money that is essentially lent cost-free to the holding companies in the form of tax advantages used currently and is consistent with our recent Atlantic Electric decision (Docket No. ER90091090J). Moreover, in order to maintain consistency with the methodology applied in the Atlantic decisions, we modify the Staff calculation and find that a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case.**

Q. How should the Commission compensate ratepayers for their funds that are not actually used to pay taxes, but rather are used to obtain immediate tax reductions not otherwise available due to the losses of non-regulated affiliates?

A. I recommend that the Commission provide ratepayers interest on their loans to E.ON and its loss subsidiaries at the Companies' grossed-up rate of return. The loans are the cumulative amount of consolidated tax savings achieved by E.ON by using the positive taxable income and tax payments from the Companies to monetize the loss subsidiaries' taxable losses. In effect, the Companies' capitalization is overstated, and therefore, their capitalization is overstated, by the amount of the loans provided by the Companies to E.ON and its unregulated subsidiaries.

The computation of these consolidated tax savings should start with the present test year and should be cumulative from this test year forward. In this manner, the funds provided by ratepayers for tax payments that are not actually paid by E.ON to the federal and state governments will be treated as loans subject to interest at the Company's grossed-up rate of return. This is the methodology employed by the New Jersey commission that I described earlier.

Q. Could the Commission consider at least a portion of the funds provided by the Company's ratepayers as a grant that never will be repaid rather than only as a loan?

A. Yes. That is a refinement of the methodology that the Commission could consider in future proceedings if it is able to establish in those proceedings that certain of the loans effectively were converted into grants. This conversion would occur when the loss affiliate never is able to use the losses that it incurred in prior years, e.g., if the loss affiliate is dissolved. To the extent that any amount of the consolidated tax savings is considered a grant, the Commission should flow through the principal amount of these savings in addition to providing a return on the unamortized grant and loan amounts.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect of my recommendation is to reduce KU's income tax expense and revenue requirement by $5.278 million and LG&E's by $3.941 million. I computed this amount for the test year in several steps. First, I computed the amount of the loans granted by each of the Companies to E.ON and its other subsidiaries to determine the reduction in each Company's capitalization for the test year. I quantified the capitalization amounts by computing the ratio of each Company's taxable income to the sum of the positive taxable income for all the

E.ON subsidiaries, including the Companies and then multiplied this times the sum of the taxable losses for all the E.ON loss subsidiaries. This is the amount each Company loaned E.ON. The assumption underlying this computation is that all the E.ON positive taxable income subsidiaries proportionately subsidize all the E.ON taxable loss subsidiaries. I used the actual E.ON subsidiaries' federal taxable income and losses for 2007 to develop the federal ratios for each Company. Since the 2007 state return quantifications were not yet available, I used the state taxable income and losses for 2006 to develop the state ratios for each Company. I obtained these actual amounts from LG&E's response to PSC 2-104 and PSC 2-105, which provided the amounts for both Companies. These responses are subject to the terms of the Confidentiality Agreement in this proceeding.

Second, I multiplied the amounts loaned by each Company to E.ON by the grossed-up weighted average cost of capital for each Company. This is the return that the ratepayers should be provided on their loans to the Companies, which then were loaned to E.ON. This is the revenue requirement effect that I have reflected on the table in the Summary section of my testimony. The effect on income tax expense for operating income purposes is the revenue requirement effect times the combined federal and state income tax rate. When this effect on income tax expense is grossed-up, it results in the same revenue requirement.

The computations are detailed on my Exhibit___(LK-17). The public version of my Exhibit___(LK-17) has the confidential amounts redacted. KIUC has filed a separate confidential version of my Exhibit___(LK-17) in accordance with the terms of the Confidentiality Agreement in this proceeding.

III. CAPITALIZATION ISSUES

<u>Methodology for Removal of ECR Rate Base Amounts from Capitalization Should Not Be Changed</u>

Q. Please describe the Commission's historic methodology for the removal of ECR rate base amounts from capitalization.

A. The Commission's historic methodology has been to remove 100% of the ECR rate base amounts from Electric operations capitalization after all rate base allocations and other capitalization adjustments have been performed. The Commission's methodology excludes from the Company's capitalization the *exact same amount* that is reflected in the ECR rate base.

Q. Please describe the Companies' proposal to modify the Commission's historic methodology by employing a rate base allocation to total capitalization.

A. Instead of the direct reduction for the rate base amounts actually used in the ECR, the Companies proposed a reduction from capitalization based on a ratio of ECR rate base to non-ECR rate base. Thus, any differences between rate base and capitalization are allocated between the ECR and base rates rather than assigning the total difference to base rates.

Q. Should the Commission adopt the Companies' proposal to change its historic methodology?

A. No. First, the Commission has previously rejected the Companies' proposed methodology. The Companies have offered no new arguments in this proceeding why the Commission should overturn its prior determination. Second, the Commission historic methodology specifically reflects the fact that the ECR is based on a rate base computation, not a capitalization computation. The only way to properly synchronize the base revenue requirement and the ECR revenue requirement is to remove the ECR rate base amounts from the total Company capitalization amounts. This methodology ensures that any differences between total Company rate base and capitalization are captured somewhere. If the Companies' methodology is adopted, part of that difference will be allocated to the ECR for base rate purposes, but will never be reconciled in actuality in the ECR.

Q. Have you computed the effect of removing the ECR rate base amounts from capitalization using the Commission's historic methodology rather than the Companies' proposed methodology?

A. Yes. The effect is to reduce KU's revenue requirement by $3.263 million and LG&E's by $0.050 million. The computations are detailed on my Exhibit___(LK-18).

<u>KU Capitalization Should Be Reduced for EEI Investment If Commission Does Not Include EEI Earnings in KU Revenue Requirement</u>

Q. If the Commission does not adopt your recommendation to incorporate the EEI earnings in KU's revenue requirement, should it reduce KU's capitalization for the EEI investment?

A. Yes.

<u>LG&E Capitalization Should Be Reduced to Reflect Reduction in Collection Cycle</u>

Q. LG&E proposes to reduce the collection cycle from 15 days to 10 days. Will this have an impact on LG&E's capitalization?

A. Yes. If the Commission grants this request, it will reduce the capitalization requirements of LG&E by the 5 days of average monthly revenues. The proposal will accelerate the Company's cash flow, thus reducing its financing requirements.

Q. If the Commission grants LG&E's request, should it also reflect a reduction in the Company's capitalization in this proceeding?

A. Yes. If the Company's request is granted, the reduction in the Company's capitalization will be a known and measurable change and should be reflected in the revenue requirement.

Q. How should the Commission reflect this reduction in the LG&E capitalization?

A. It should be reflected as an across the board reduction to LG&E's capitalization. The effect on the Company's capitalization will be the 5 days of average daily cash collections taken after tax and net of the increases in uncollectible accounts and PSC assessments.

Q. Have you quantified the effect of this recommendation on LG&E's revenue requirement?

A. Yes. The effect is to reduce LG&E's revenue requirement by $0.810 million. The computations are detailed on my Exhibit____(LK-19).

IV. RATE OF RETURN ISSUES

Cost of Long-Term Debt Should be Updated

Q. The Commission's historic practice in base rate proceedings is to update the utility's cost of debt prior to the record being closed. Have the Companies updated their cost of debt in response to Staff discovery?

A. Yes. The Companies updated their cost of debt as of August 31, 2008 in updated responses to PSC 1-43 filed on September 26, 2008. KU's cost of short term debt was reduced to 2.44% from 2.63% in KU's filing and its cost of long-term debt was reduced to 5.20% from 5.21% in its filing. LG&E's cost of short term debt was reduced to 2.4% from 2.63% in LG&E filing and its cost of long-term debt was reduced to 4.42% from 5.30% in its filing.

Q. Have you quantified the effect of these reductions in the costs of short-term debt and long-term debt on the Companies' revenue requirements?

A. Yes. The effect is to reduce KU's revenue requirement by $0.544 million and LG&E's revenue requirement by $6.955 million. The computations are detailed on my Exhibit___(LK-20).

Cost of Common Equity Should Reflect Reasonable Level

Q. How does the Companies' requested return on common equity of 11.25% compare to the Commission's authorized return on common equity set forth in Case Nos. 2003-00433 and 2003-00434?

A. The Companies' requested return on common equity is in excess of the upper end of the 10.0% to 11.0% range found reasonable by the Commission in the Companies' last base rate cases.

Q. How does the Companies requested return on common equity compare to the return on common equity granted by other state commissions for electric utilities in 2008?

A. The Companies' requested rate of return is excessive compared to returns granted by other state commissions. These authorized rates of return for electric utilities average 10.30%, according to Regulatory Research Associates' ("RRA") Regulatory Focus dated October 3, 2008 for the first three quarters of the year. I have removed the rates of return included by RRA in their averages that were set for new generating assets rather than for the electric utility as a whole and recomputed the averages for each quarter and year-to-date. I have replicated the RRA data and computations as my Exhibit___(LK-21). My computations reflecting the removal of the returns allowed specifically for new generating units are detailed on my Exhibit___(LK-22).

Q. Have you quantified the effect of using the Companies' present 10.50% midpoint return on equity in lieu of their requested 11.25%?

A. Yes. The effect is to reduce KU's jurisdictional revenue requirement by $13.059 million and LG&E's electric revenue requirement by $11.151 million. Each 10 basis points affects KU's jurisdictional revenue requirement by $1.741 million and LG&E's revenue requirement by $1.487 million. The computations are detailed on my Exhibit___(LK-20).

Q. Does this complete your testimony?

A. Yes.

EXHIBIT___(LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than thirty years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of September 2008

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency
12/86	9613	KY	Attorney General Div of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986

Expert Testimony Appearances
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As of September 2008

Date	Case	Jurisdict.	Party	Utility	Subject
8/87	9885	KY	Attorney General Div of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery
6/88	U-17282	LA 19th Judicial District Ct	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery. SFAS No. 92

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Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No 87)
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43). Part 32
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery. tax expense, revenue requirements
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements. sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements , detailed investigation
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
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.	Recovery of CAAA costs, least cost financing
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations

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Date	Case	Jurisdict.	Party	Utility	Subject
5/92	910890-EI	FL	Occidental Chemical Corp	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense. fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co	OPEB expense
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger

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Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery

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Date	Case	Jurisdict.	Party	Utility	Subject
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning

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As of September 2008

Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M. River Bend phase-in plan, base/fuel realignment. NOL and AltMin asset deferred taxes, other revenue requirement issues
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues

Expert Testimony Appearances
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As of September 2008

Date	Case	Jurisdict.	Party	Utility	Subject
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements. allowance inventory, jurisdictional allocation
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements. rate of return

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8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.

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12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring. deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning. revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Restructuring, stranded costs. regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring. unbundling, stranded costs, T&D revenue requirements
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

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11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc	Louisville Gas and Electric Co	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery mechanisms.

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5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring. unbundling, stranded cost, T&D revenue requirements
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison. Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc	Louisville Gas and Electric Co.	Revenue requirements

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8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Power Co	ECR surcharge roll-in to base rates
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Affiliate expense proforma adjustments
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom

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07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT. EDIT, ITC
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles. subsidization of nonregulated affiliates, ratemaking adjustments
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues

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01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co	Recovery of environmental costs, surcharge mechanism
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc FirstEnergy Corp/	Merger, savings, reliability
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc	Business separation plan: settlement agreement on overall plan structure
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc	Business separation plan: agreements, hold harmless conditions, separations methodology
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc	Business separation plan: agreements, hold harmless conditions, Separations methodology

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07/01	U-21453, U-20925, U-22092 Subdocket B Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm Staff	Entergy Gulf States, Inc	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of *Independent Colleges & Universities*	TXU Electric	Stipulation. Regulatory assets, securitization financing
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Revenue requirements, corporate franchise tax, conversion to LLC. River Bend uprate
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast. O&M expense, depreciation, plant additions, cash working capital
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc	Florida Power & Light Co.	Revenue requirements Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense
04/02	U-25687 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC. River Bend uprate.
04/02	U-21453, U-20925 and U-22092		Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet. separations methodologies, hold harmless

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Date	Case	Jurisdict.	Party	Utility	Subject
	(Subdocket C)		Staff		conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc and Entergy Louisiana, Inc	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc	Kentucky Utilities Co Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc	Kentucky Power Co.	Environmental compliance costs and surcharge recovery
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc and the Entergy Operating Companies	System Agreement. production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement

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11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year adjustments
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co.	Revenue requirements, depreciation rates. O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit
03/04	SOAH Docket 473-04-2459, PUC Docket	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings

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05/04	29206 04-169- EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan. deferrals, T&D rate increases. earnings
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand
09/04	Docket No U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	Docket No U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery. qualified costs, TIER requirements, cost allocation
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT. capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Energy conservation, economic development, and tariff issues.

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03/05	Case No. 2004-00426 Case No 2004-00421	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction. margins on allowances used for AEP system sales
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction. proceeds, excess mitigation credits, retrospective and prospective ADIT
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp	Revenue requirements, roll-in of surcharges, cost recovery through surcharge. reporting requirements
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp	Affiliate transactions, cost allocations. capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program. depreciation, off-system sales, maintenance normalization, pension and OPEB
03/06 05/06	31994 31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change. Retrospective ADFIT. prospective ADFIT

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03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan
3/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPioint Energy Houston Electric	Proposed Regulations affecting flow-through to ratepayers of excess deferred income taxes and investment Tax credits on generation plant that Is sold or deregulated.
4/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions
07/06	R-00061366, Et al	PA	Met-Ed Ind Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925 U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts
03/07	33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including fractionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including fractionalization of transmission and distribution costs.

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03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery
04/07	U-29764 Supplemental And Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC Entergy Gulf States, Inc	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc	East Kentucky Power Cooperative	Revenue requirements, post test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts

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10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses
01/08	ER07-682-000 Cross Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuctionalization and allocation of intangible and general plant and A&G expenses
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue Requirements
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning

Expert Testimony Appearances
of
Lane Kollen
As of September 2008

Date	Case	Jurisdict.	Party	Utility	Subject
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228 1, 182 3, 254 and 407 3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562 And 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc	Rule Nisi complaint
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc	East Kentucky Power Cooperative, Inc	Environmental surcharge recoveries. incl costs recovered in existing rates, TIER
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp	Revenue requirements, incl projected test year rate base and expenses
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters

Expert Testimony Appearances
of
Lane Kollen
As of September 2008

Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc	Wisconsin Power and Light Company	Capital structure
09/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement. capital structure
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.

EXHIBIT___(LK-2)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Second Set of Data Requests of the
Kentucky Industrial Utility Customers, Inc.
Dated September 24, 2008

Question No. 2.18

Responding Witness: S. Bradford Rives / Paul W. Thompson / Lonnie E. Bellar

Q-2.18 Refer to the KU's response to PSC 1-34.

a. Please provide a detailed description of EEI.

b. Please provide a history by year of KU's investment in EEI.

c. Please provide a history by year of KU's earnings from EEI.

d. Please explain why KU records the income from EEI in "Other Income Less Deductions."

A-2.18. a. EEI was formed in the early 1950's by several independent sponsoring companies, including:

Union Electric Company (UE)
Central Illinois Public Service Company (CIPS)
Illinois Power Company (IP)
Kentucky Utilities Company (KU)
Middle South Utilities, Inc.

Each company purchased stock in the newly formed company. EEI was formed for constructing, owning and operating the electric generating plant in Joppa, Illinois to provide power to a gaseous diffusion uranium plant owned and operated by the United States Atomic Energy Commission (AEC) near Paducah, Kentucky. Construction began on the 1,000 MW plant in 1951. Plant start-up occurred in 1954 and the plant reached full operation in the summer of 1955. At that time the sponsoring companies purchased any excess power produced by the plant beyond the energy required by the AEC pursuant to a purchase power agreement with a definite term. EEI generated 1,000 MW of electric capacity at its coal-fired power plant in Joppa, Illinois, and 55 MW at it natural gas fired facility at the same location. Today, Missouri-based utility holding company Ameren Energy holds an 80% stake in EEI and Kentucky Utilities (a subsidiary of E.ON U.S.) owns the remaining 20% of the company.

The gross capacity of the plant is currently 1,162 MW. Of that total, 1,086 MW is from the coal fired Joppa facility and 76 MW is combustion turbine capacity from Midwest Electric Power Inc. By contract, EEI sold its energy to AEC and the sponsoring companies at cost based rates until the expiration under its terms at the end of 2005. In late 2005, as a majority shareholder, Ameren Energy voted to sell this power into the market rather than to sponsoring companies beginning in 2006. KU receives equity in earnings from 20% of the net income of EEI. KU also receives 20% of the cash dividends that are declared and paid by EEI.

b. In 1951, the Company's original investment was $350,000. In 1953 and 1958 the Company invested $270,000 and $675,800, respectively. Since then, the investment has been $1,295,800.

c.

Kentucky Utilities Company
Earnings from EEI*

Year	Earnings
1998	$2,167,436
1999	2,333,723
2000	2,242,280
2001	1,802,856
2002	6,967,101
2003	3,644,247
2004	2,559,212
2005	2,256,843
2006	29,405,773
2007	26,358,781
April 30, 2008 – Year to Date	9,877,611

* Data provided is for the test year and the ten years previous that was readily available.

d. The investment in EEI has never been included in utility capitalization at KU. Correspondingly, the earnings from EEI are recorded below the line in "Other Income Less Deductions." KU records the earnings on its investments in EEI on the equity method of accounting. KU records its share of EEI's net income each period in proportion to KU's ownership percentage (20%). These amounts have been reported as "Other Income

Less Deductions" in KU's reports filed with the Commission based on the Commission's Uniform System of Accounts (USofA). The Code of Federal Regulations indicates account 418 1 "shall include the utility's equity in the earning or losses of subsidiary companies for the year", which is included in "Other Income" in the FERC Statement of Income for the Year.

EXHIBIT___(LK-3)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251

Response to First Data Request of Commission Staff
Dated July 16, 2008

Question No. 34

Responding Witness: Shannon L. Charnas

Q-34. Provide a schedule showing for the test year and the year preceding the test year, with each year shown separately, the following information regarding KU's investments in subsidiaries and joint ventures:

a. Name of subsidiary or joint venture.

b. Date of initial investment.

c. Amount and type of investment made for each of the 2 years included in this response.

d. Balance sheet and income statement. Where only internal statements are prepared, furnish copies of these.

e. A separate schedule of all dividends or income of any type received by KU from its subsidiaries or joint ventures showing how this income is reflected in the reports filed with the Commission and stockholder reports.

f. Name of each officer of each of the subsidiaries or joint ventures, each officer's annual compensation, the portion of that compensation that is charged to the subsidiary or joint venture, the position each officer holds with KU, and the compensation received from KU.

A-34. Investment 1 of 2

a. Electric Energy, Inc. (EEI)

b. KU invested in the formation of EEI when it received its charter from the State of Illinois in December 1950.

c. No investments were made in EEI by KU during the 2 years included in this response.

d. See Attachment 1 containing financial statements for EEI including Statements of Income for the twelve months ended April 30, 2008 and 2007 and Balance Sheets as of April 30, 2008 and 2007.

e. KU records its earnings on its investments in EEI on the equity method of accounting. KU records a share of EEI's net income each period in proportion to KU's ownership percentage (20%). KU has recorded $28,622,539 and $27,727,348 in income for the 12-months ended April 30, 2008 and 2007, respectively. These amounts have been reported as "Other Income Less Deductions" in KU's reports filed with the Commission and as "Equity Earnings in EEI" in stockholders reports.

f. *Officers:*

Officers:	R. Alan Kelly	Chairman of the Board
	Robert L. Powers	President
	Williams H. Sheppard	Vice President
	James M. Helm	Secretary-Treasurer

None of the officers of EEI are officers or employees of KU.

None of EEI's officers receive compensation from KU nor is any portion of their salaries charged to KU. EEI's officers' salaries are charged internally by EEI as expenses against EEI's revenues to arrive at net income. The compensation paid to these officers by EEI is not available to KU.

A-34. Investment 2 of 2

a. Ohio Valley Electric Corporation (OVEC)

b. KU's original investment in OVEC was made in 1952.

c. No investments were made in OVEC by KU during the 2 years included in this response.

d. See Attachment 2 containing financial statements for OVEC including Statements of Income for the twelve months ended April 30, 2008 and 2007 and Balance Sheets as of April 30, 2008 and 2007.

e. KU records its dividend income from OVEC on the cost method of accounting. KU has recorded $117,500 and $97,500 in dividends for the 12-months ended April 30, 2008 and 2007, respectively. These amounts have been reported as "Other Income Less Deductions" in KU's reports filed with the Commission and as "Other Income (Expense) – Net" in stockholders reports.

f. Officers:

Officers:	Michael G. Morris	President
	David L. Hart	Vice President & Asst. to President
	David E. Jones	Vice President - Operations
	John D. Brodt	Secretary and Treasurer
	Ronald D. Cook	Asst. Secretary and Asst. Treasurer
	Susan Tomasky	Asst Secretary and Asst. Treasurer

None of the officers of OVEC are officers or employees of KU.

None of OVEC's officers receive compensation from KU nor is any portion of their salaries charged to KU. OVEC's officers' salaries are charged internally by OVEC as expenses against OVEC's revenues to arrive at net income. The compensation paid to these officers by OVEC is not available to KU.

Electric Energy, Inc.

Statements of Income

For The Twelve Months Ended April 30, 2007 and 2008

	2007	2008
Operating Revenues		
Sales To Department Of Energy:		
Permanent Power	$ 315,649	$ 0
Additional Power	0	35,046,000
Excess Power	0	0
Released Power	0	0
Total Sales To Department Of Energy	**$ 315,649**	**$ 35,046,000**
Sales To Other Electric Utilities:		
Permanent Power	$ 366,395,852	$ 398,803,072
Released Power	0	0
Excess Power	0	0
Interchange Power	0	0
Total Sales To Other Electric Utilities	**$ 366,395,852**	**$ 398,803,072**
Other Electric Revenues	36,240,802	5,992,386
Total Operating Revenues	**$ 402,952,303**	**$ 439,841,458**
Operating Expenses		
Purchased Power	$ 7,936,973	$ 42,264,114
Fuel	113,250,011	114,607,063
Operation	27,427,534	27,801,657
Maintenance	22,110,099	19,669,970
Depreciation	5,474,380	6,260,900
Taxes, Other Than Income Taxes	2,158,048	2,303,918
Income Taxes	85,757,594	85,083,058
Total Operating Expenses	**$ 264,114,639**	**$ 297,990,680**
Income From Operations	**$ 138,837,664**	**$ 141,850,778**
Other (Income) And Expense		
Interest Income	$ (113,681)	$ (67,521)
Interest Expense	1,077,347	816,201
Other, Net	(947,026)	(3,514,854)
Total Other (Income) and Expense	$ 16,640	$ (2,766,174)
Net Income	**$ 138,821,024**	**$ 144,616,952**

Electric Energy, Inc.
Balance Sheets
As of April 30, 2007 and 2008

	2007	2008
Assets		
Utility Plant		
Utility Plant In Service	$ 398,031,379	$ 404,952,330
Construction Work In Progress	8,021,259	33,435,618
	$ 406,052,638	$ 438,387,948
Less: Accumulated Depreciation of Utility Plant	337,404,117	342,637,861
Total Utility Plant, Net	$ 68,648,521	$ 95,750,087
Current Assets		
Cash	$ 67,719	$ 51,316
Working Funds	57,557	66,528
Temporary Cash Investments	0	0
Accounts Receivable -		
Department of Energy	246,082	246,082
Sponsoring Companies	29,528,029	32,133,631
Subsidiaries - Short Term	316,830	269,492
Other	83,725	80,784
Fuel Inventory	19,438,340	22,128,188
Plant Material and Supplies Inventory	7,931,801	7,723,127
Prepayments	1,637,417	2,096,833
Total Current Assets	$ 59,307,500	$ 64,795,981
Other Assets		
Unamortized Debt Expense	$ 0	$ 0
Prepaid Postretirement Cost	490,777	0
Prepaid Pension Cost	0	0
Deferred Charges and Other Assets	9,462,301	9,538,061
Deferred Taxes	14,770,367	10,998,957
Long Term Receivable - Subsidiary	0	0
Investment in Subsidiaries	36,077,571	36,077,571
Total Other Assets	$ 60,801,016	$ 56,614,589
Total Assets	$ 188,757,037	$ 217,160,657

Electric Energy, Inc.
Balance Sheets
As of April 30, 2007 and 2008

	2007	2008
Stockholders' Equity And Liabilities		
Stockholders' Equity		
Common Stock	$ 6,200,000	$ 6,200,000
Retained Earnings	94,542,922	83,909,874
	$ 100,742,922	$ 90,109,874
Other Comprehensive Income	(967,498)	3,864,205
Total Stockholders' Equity	$ 99,775,424	$ 93,974,079
Long-Term Debt	$ 0	$ 0
Current Liabilities		
Notes Payable, Bank	$ 0	$ 0
Notes Payable. Sponsoring Companies	15,300,000	36,400,000
Accounts Payable	11,404,924	14,027,719
Accounts Payable to Sponsoring Companies	12,072,627	15,061,947
Accrued Interest	0	0
Dividends Payable	0	37,500,000
Accrued Taxes Other Than Income	62,651	74,343
Accrued Income Taxes	27,874,846	4,422,237
Total Current Liabilities	$ 66,715,048	$ 107,486,246
Other Liabilities		
Provision for Injuries & Damages	$ 871,479	$ 773,600
Asset Retirement Obligations	6,294,496	6,645,943
Postretirement Benefit Liability	1,422,729	716,033
Pension Liability	10,121,208	3,343,001
Deferred Taxes	3,556,653	3,824,422
Other Deferred Credits	0	397,333
Total Other Liabilities	$ 22,266,565	$ 15,700,332
Total Stockholders' Equity And Liabilities	$ 188,757,037	$ 217,160,657

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

INCOME AND RETAINED EARNINGS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2008 AND 2007

	April 30, 2008 Ohio Valley Electric Corporation	April 30, 2007 Ohio Valley Electric Corporation
OPERATING REVENUES:	$ 62,915,985	$ 46,622,847
OPERATING EXPENSES:		
FUEL CONSUMED	14,739,565	9,302,633
PURCHASED POWER	35,310,716	23,502,107
OTHER POWER EXPENSES		
LABOR-SCHED 4	548,564	2,603,525
OTHER CHARGES-SCHED 4	6,699,394	5,592,665
SO2 ALLOWANCES	838,308	(147,113)
DEPRECIATION	1,161,897	6,335,536
TAXES - STATE, LOCAL, & MISC	764,965	572,854
TAXES - FEDERAL INCOME	73,115	(1,420,131)
TOTAL OPERATING EXPENSES	60,136,524	46,342,076
NET OPERATING INCOME	2,779,461	280,771
INTEREST AND OTHER:		
INT EXP-REVOLVING CR AGR	(577,754)	788,570
INT EXP-2006A NOTES	1,998,052	2,008,682
INT EXP-2007 A, B & C NOTES	3,044,022	
INT EXP-2008A	124,704	
INT EXP-SCR		
INTEREST INCOME	(381,421)	(257,834)
AMORT OF DEBT EXPENSE	49,076	27,417
OTHER	(295,423)	(323,159)
TOTAL INTEREST AND OTHER	3,961,256	2,243,676
NET INCOME	(1,181,795)	(1,962,905)
RETAINED EARNINGS — BEGINNING	7,396,687	7,241,493
CASH DIVIDENDS	3,000,000	2,600,000
RETAINED EARNINGS — END	$ 3,214,892	$ 2,678,588

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

BALANCE SHEETS
AS OF April 30, 2008 AND 2007

	2008 Ohio Valley Electric Corporation	2007 Ohio Valley Electric Corporation
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 581,116,307	$ 577,048,301
Less — accumulated provisions for depreciation	375,760,529	366,497,435
	205,355,778	210,550,866
Construction in progress	273,639,829	83,343,616
Total electric plant	478,995,607	293,894,482
INVESTMENTS AND OTHER:		
Investment in subsidiary company	3,400,000	3,400,000
Advances to subsidiary — construction	145,365,277	153,478,688
Total investments and other	148,765,277	156,878,688
CURRENT ASSETS:		
Cash and cash equivalents	95,654,187	60,571,254
Accounts receivable	30,573,383	24,058,281
Intercompany receivable		
Fuel in storage — at average cost	17,786,100	31,882,006
Materials and supplies — at average cost	8,253,356	8,535,718
Property taxes applicable to future years	1,485,280	1,315,200
Emission allowances	8,402,547	26,858,406
Refundable federal income taxes		
Refundable state income taxes		
Prepaid expenses and other	394,286	294,717
Total current assets	162,549,139	153,515,582
REGULATORY ASSETS:		
Asset retirement costs	2,340,015	2,934,082
Unrecognized postemployment benefits	889,553	1,869,278
Deferred depreciation	23,030,032	24,444,605
Total regulatory assets	26,259,600	29,247,965
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	6,722,153	4,362,260
Deferred tax assets	39,418,189	39,099,938
Pension asset		
Other	87,507	8,151
Total deferred charges and other	46,227,849	43,470,349
TOTAL	$ 862,797,472	$ 677,007,066

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

BALANCE SHEETS
AS OF April 30, 2008 AND 2007

	2008 Ohio Valley Electric Corporation	2007 Ohio Valley Electric Corporation
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value — authorized 300,000 shares; outstanding, 100,000 shares in 2007 and 2006	$ 10,000,000	$ 10,000,000
Common stock, without par value, stated at $200 per share — authorized, 100,000 shares; outstanding, 17,000 shares in 2007 and 2006		
Senior notes	741 594 816	419 781 717
Line of credit borrowings — long term	40,000,000	120,000,000
Retained earnings	4,151,883	3,852,633
Total capitalization	795,746,699	553,634,350
CURRENT LIABILITIES:		
Current portion of long-term debt	24 789,219	12,969,638
Accounts payable	13,806,726	11 754 341
Intercompany payable	(101 750 904)	(38 149,229)
Deferred revenue — advances for construction	17 287 308	6 595 739
Accrued other taxes	10,050,461	1,585 665
Accrued interest and other	17,629,972	9,589,846
Total current liabilities	(18,187,218)	14,346,000
COMMITMENTS AND CONTINGENCIES (Note 10)		
REGULATORY LIABILITIES:		
Postretirement benefits	19,072,922	34,040,880
Pension benefits		
Investment tax credits	3,393,146	3 393,146
Net antitrust settlement	673 070	673 070
Income taxes refundable to customers	31,755,122	38,393 088
EPA emission allowance proceeds	426,959	65 000
Advance collection of interest		1 045 816
Fuel related settlement		
Total regulatory liabilities	55,321,219	77,611,000
OTHER LIABILITIES:		
Asset retirement obligations	9,790,888	9 236,687
Postretirement benefits obligation	19 236,332	20 309 751
Postemployment benefits obligation	889 553	1,869 278
Parent advances for construction		
Total other liabilities	29,916,773	31,415,716
TOTAL	$ 862,797,473	$ 677,007,066

EXHIBIT___(LK-4)

Name of Respondent Kentucky Utilities Company	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo. Da. Yr) / /	Year/Period of Report End of 2007/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No	Title of Account (a)	(Ref) Page No (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		191,103,431	162,029,272		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		1,542,843	609,912		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		6,560	-385		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	26,358,781	29,405,773		
37	Interest and Dividend Income (419)		2,954,429	1,457,963		
38	Allowance for Other Funds Used During Construction (419.1)		3,327,705	384,044		
39	Miscellaneous Nonoperating Income (421)		3,121,445	1,966,683		
40	Gain on Disposition of Property (421.1)		1,156,882			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		38,468,645	33,823,990		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		480,236	82,656		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	478,457	616,224		
46	Life Insurance (426.2)		707,185	707,185		
47	Penalties (426.3)		2,004,094	62		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		965,125	1,005,100		
49	Other Deductions (426.5)		1,208,224	1,601,891		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,843,321	4,013,118		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	11,004	22,452		
53	Income Taxes-Federal (409.2)	262-263	88,667	2,172,669		
54	Income Taxes-Other (409.2)	262-263	-183,585	51,595		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,026,463	834,249		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	504,303	376,384		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		591,310	1,081,872		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		846,936	1,622,709		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		31,778,388	28,188,163		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		13,677,837	12,994,886		
63	Amort. of Debt Disc. and Expense (428)		334,935	247,830		
64	Amortization of Loss on Reaquired Debt (428.1)		518,566	689,205		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	41,244,367	23,619,164		
68	Other Interest Expense (431)	340	1,099,347	1,108,319		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		955,807	262,752		
70	Net Interest Charges (Total of lines 62 thru 69)		55,919,245	38,396,652		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		166,962,574	151,820,783		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		166,962,574	151,820,783		

Name of Respondent Kentucky Utilities Company	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		854,131,028	704,216,017
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	FIN 48 Adjustment		355,161	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		355,161	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		140,603,793	122,415,011
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		21,400,000	27,500,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,016,489,982	854,131,028
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2007/Q4

STATEMENT OF RETAINED EARNINGS

1 Do not report Lines 49-53 on the quarterly version.
2 Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated *undistributed subsidiary earnings* for the year.
3 Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4 State the purpose and amount of each reservation or appropriation of retained earnings.
5 List first account 439, Adjustments to Retained Earnings, *reflecting adjustments to the opening balance of retained earnings*. Follow by credit, then debit items in that order.
6 Show dividends for each class and series of capital stock.
7 Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings
8 Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9 If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, *Federal (Account 215.1)*			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL *Retained Earnings* (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,016,489,982	854,131,028
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		16,248,287	14,342,514
50	Equity in Earnings for Year (Credit) (Account 418.1)		26,358,781	29,405,773
51	(Less) Dividends Received (Debit)		21,400,000	27,500,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		21,207,068	16,248,287

EXHIBIT___(LK-5)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Initial Requests for Information of the Attorney General
Dated August 27, 2008

Question No. 34

Responding Witness: S. Bradford Rives / Lonnie E. Bellar

Q-34. Please identify and quantify any changes to the filing results that should be made based on additional information that became available after the Company prepared its base rate filings.

A-34. Other than items noted in response to the various requests for information due September 11, 2008 in this proceeding, the Company is not aware of any changes to its filing results, with the following exceptions:

Upon further analysis and investigation, KU has discovered that its filed adjustments to capitalization in this proceeding are overstated due to three items: (1) double-counting KU's equity in subsidiary earnings; (2) not adjusting equity in subsidiary earnings by the related deferred taxes associated with those earnings; and (3) not reducing capital by non-utility property.[1] Each of these adjustments is explained below.

As page 1 of the attachment to this response shows, in the three rate cases (Case Nos. 7804, 8177, and 8624) and the Performance-Based Ratemaking ("PBR") proceeding (Case No. 98-474) prior to KU's most recent rate case, Case No. 2003-00434, KU correctly deducted "Investments in Subsidiary Companies" from capitalization (page 1, line 1), but removed from that deduction KU's "Equity in Subsidiary Earnings" (page 1, line 2).[2] "Equity in Subsidiary Earnings" is then deducted separately on page 1 at line 4. This ensures that KU's equity in its subsidiary earnings is deducted from its capitalization only once. KU's analysis and investigation has revealed that KU erroneously deducted its equity in

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[1] *See In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2008-00251, Testimony of S. Bradford Rives Exh. 2, Cols. 4-6 (July 29, 2008).

[2] *See In the Matter of: General Adjustment of Rates of Kentucky Utilities Company*, Case No. 7804, Newton Exh. 2 and Davis Exh. 1; *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8177, Newton Exh 2 and Davis Exh. 1; *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Newton Exh. 2 and Davis Exh. 1; *In the Matter of: Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Services*, Case No. 1998-00474, Order Appx. C (January 7, 2000); *In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order Appx. E (June 30, 2004).

subsidiary earnings twice in its most recent base rate proceeding, and that it erred in the same way in this base rate proceeding.

KU further seeks to revise Rives Exhibit 2 to reflect that the deferred taxes associated with the equity in subsidiary earnings need to be properly reflected in the capitalization adjustment. The deferred taxes (page 1, line 5) need to be deducted from equity in subsidiary earnings to arrive at the net earnings impact within the equity component of capital. This adjustment appears on page 1 at line 6 in the attachment to this response.

Finally, KU seeks to add a deduction from capitalization for non-utility property. As shown on page 1 at line 8 in the attachment and the supporting exhibits from KU's past rate cases, until the PBR case KU consistently deducted non-utility property from its capitalization.[3] In its final order in the PBR proceeding, the Commission required KU not to make such a deduction,[4] which precedent KU followed in its most recent rate case.[5] That notwithstanding, KU does not believe it is appropriate to include in its capitalization assets that are not used for utility operations, and therefore seeks to include this adjustment as shown on page 1 at line 9 in the attachment to this response.

KU therefore submits this update to adjust Exhibit 2 to the Testimony of S. Bradford Rives, filed in this proceeding on July 29, 2008 ("Rives Exhibit 2") as shown on page 2 of the attachment to this response. KU also includes the supporting exhibits from KU's past rate cases in the attachment to this response.

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[3] *Id.*
[4] *In the Matter of: Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Services*, Case No. 1998-00474, Order at 62 (January 7, 2000).
[5] *In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order Appx. E (June 30, 2004).

KENTUCKY UTILITIES

ANALYSIS OF CAPITALIZATION ADJUSTMENTS FOR 1980-2008

Line No.	Adjustments to Capitalization	Case No. 7804 as of 01/31/80	Case No. 8177 as of 12/31/80	Case No. 8624 as of 6/30/82	Case No. 98-474 as of 12/31/98	Case No. 2003-434 as of 09/30/03	Case No. 2008-251 as of 04/30/08	Adjusted Case No. 2008-251 as of 04/30/08
1.	Investments in Subsidiary Companies	$ (25,524,615)	$ (29,517,638)	$ (39,505,579)	$ (2,156,438)	$ (10,239,079)	$ (24,880,479)	$ (24,880,479)
2.	Less: Equity in Subsidiary Earnings (1)	(6,536,780)	(6,529,803)	(6,117,745)	(860,638)	-	-	(23,584,679)
3.	Subtotal (2)	(18,987,835)	(22,987,835)	(33,387,834)	(1,295,800)	(10,239,079)	(24,880,479)	(1,295,800)
4.	Equity in Subsidiary Earnings (1)	(6,536,780)	(6,529,803)	(6,117,745)	(860,638)	(8,943,279)	(23,584,679)	(23,584,679)
5.	Deferred Taxes	-	-	-	-	-	-	8,915,810
6.	Subtotal	(6,536,780)	(6,529,803)	(6,117,745)	(860,638)	(8,943,279)	(23,584,679)	(14,668,869)
7.	Investments in OVEC and Other	(385,105)	(381,969)	(373,233)	(806,485)	(798,053)	(661,140)	(661,140)
8.	Nonutility Property-Less Reserve	(388,569)	(385,913)	(306,958)	-	-	-	(179,121)
9.	Subtotal	(773,674)	(767,882)	(680,191)	(806,485)	(798,053)	(661,140)	(840,261)
10.	Total Adjustments to Capitalization (Line 3+6+9)	$ (26,298,289)	$ (30,285,520)	$ (40,165,770)	$ (2,962,923)	$ (19,980,411)	$ (49,126,298)	$ (16,804,930)

(1) Unappropriated Undistributed Subsidiary Earnings.

(2) Net investment in subsidiary companies included investment in KU's Virginia operations (Old Dominion Power Company), which was a separate subsidiary prior to 1991, when it was merged into Kentucky Utilities Company.

KENTUCKY UTILITIES

Capitalization at April 30, 2008
Revised Undistributed Subsidiary Earnings (Col 4), Investment in EEI (Col 5) and Investments in OVEC and Other (Col 6)

		Per Books 04-30-08 (1)	Capital Structure (2)	Reacquired Bonds (not retired) (3)	Undistributed Subsidiary Earnings (4)	Investment in EEI (Col 2 x Col 5 Line 4) (5)	Investments in OVEC and Other (Col 2 x Col 6 Line 4) (6)	Adjustments to Total Company Capitalization (Sum of Col 3 - Col 6) (7)	Adjusted Total Company Capitalization (Col 1 + Col 7) (8)
1.	Short Term Debt	$ 93,302,454	3.27%	$ (16,693,620)	$ -	$ (42,373)	$ (27,477)	$ (16,763,470)	$ 76,538,984
2.	Long Term Debt	1,247,059,520	43.70%	16,693,620	-	(566,265)	(367,194)	15,760,161	1,262,819,681
3.	Common Equity	1,513,015,410	53.03%	-	(14,668,869)	(687,162)	(445,590)	(15,801,621)	1,497,213,789
4.	Total Capitalization	$ 2,853,377,384	100.00%	$ -	$ (14,668,869)	$ (1,295,800)	$ (840,261)	$ (16,804,930)	$ 2,836,572,454

		Adjusted Total Company Capitalization (8)	Jurisdictional Rate Base Percentage (Exhibit 3 Line 23) (9)	Adjusted Kentucky Jurisdictional Capitalization (Col 8 x Col 9) (10)	Adjusted Jurisdictional Capital Structure (11)	Annual Cost Rate (12)	Cost of Capital (Col 11 x Col 12) (13)
1.	Short Term Debt	$ 76,538,984	73.94%	$ 56,592,925	2.70%	2.63%	0.07%
2.	Long Term Debt	1,262,819,681	73.94%	933,728,872	44.52%	5.21%	2.32%
3.	Common Equity	1,497,213,789	73.94%	1,107,039,876	52.78%	11.25%	5.94%
4.	Total Capitalization	$ 2,836,572,454		$ 2,097,361,673	100.00%		8.33%

Kentucky Utilities Company
Rollforward of Investment in EEI

(a) Year	(b) Capital Stock Ownership (Initial Investment) (Form 1 p 224)	(c) Beginning Balance Equity in Earnings (Form 1 p 224)	(d) Earnings (Form 1 p 225)	(e) Dividends (Form 1 p 225)	(f) Net Activity +(d)-(e)	(g) Ending Balance Equity in Earnings (c)+(f)	(h) Ending Balance Total Investment +(g)+(b)	(i) Deferred Taxes	(j) Cash Flow Form 1 p 120	(k) Check S/B 0 +(f)-(j)
1996	1,295,800	848,998	2,436,136	2,460,420	(24,284)	824,714	2,120,514		(24,284)	-
1997	1,295,800	824,714	2,480,168	2,443,622	36,546	861,260	2,157,060		36,546	-
1998	1,295,800	861,260	2,167,436	2,168,058	(622)	860,638	2,156,438	(73,148)	(622)	-
1999	1,295,800	860,638	2,333,723	2,366,775	(33,052)	827,586	2,123,386	(57,931)	(33,052)	-
2000	1,295,800	827,586	2,242,280	2,312,037	(69,757)	757,829	2,053,629	(53,048)	(69,757)	-
2001	1,295,800	757,829	1,802,856	2,060,553	(257,697)	500,132	1,795,932	(53,048)	(257,697)	-
2002	1,295,800	500,132	6,967,101	1,585,021	5,382,080	5,882,212	7,178,012	(411,754)	5,382,080	-
2003	1,295,800	5,882,212	3,644,247		3,644,247	9,526,459	10,822,259	(666,851)	3,644,247	-
2004	1,295,800	9,526,459	2,559,212		2,559,212	12,085,671	13,381,471	(845,996)	2,559,212	-
2005	1,295,800	12,085,671	2,256,843		2,256,843	14,342,514	15,638,314	(5,672,466)	2,256,843	-
2006	1,295,800	14,342,514	29,405,773	27,500,000	1,905,773	16,248,287	17,544,087	(6,320,585)	1,905,773	-
2007	1,295,800	16,248,287	26,358,781	21,400,000	4,958,781	21,207,068	22,502,868	(8,249,551)	4,958,781	-
4/30/08 - YTD	1,295,800	21,207,068	9,877,611	7,500,000	2,377,611	23,584,679	24,880,479	(8,915,810)	2,377,612	(1)

Case 7804

KENTUCKY UTILITIES COMPANY
CAPITALIZATION
JANUARY 31, 1980

		(1)	(2)	(3)	(4)
		Total Per Books	Adjustments (Page 2)	Adjusted Balance	Kentucky Jurisdiction
1.	Common Stock Equity	$255 170 424	$(13 003 333)	$242 167 091	$204 558 541
2.	Preferred Stock	90 000 000	(2 340 752)	87 659 248	74 045 767
3.	First Mortgage Bonds	342 465 074	(8 906 956)	333 558 118	281 756 542
4.	Bank Notes	25 000 000	(650 209)	24 349 791	20 568 268
5.	Short Term Debt	53 715 000	(1 397 039)	52 317 961	44 192 982
6.	Total	$766 350 498	$(26 298 289)	$740 052 209	$625 122 100

(1) Davis Exhibit 1, Page 14.

(4) Bradley Exhibit 1.

Case 7804

KENTUCKY UTILITIES COMPANY
ADJUSTMENTS TO CAPITALIZATION

1.	Common Stock Equity	$(6 536 780)	Subsidiary Earnings
		(6 466 553)	Portion of Other Investments
2.	Total	$(13 003 333)	
3.	Preferred Stock	$(2 340 752)	Portion of Other Investments
4.	First Mortgage	$(8 906 956)	Portion of Other Investments
5.	Bank Notes	$(650 209)	Portion of Other Investments
6.	Short Term Debt	$(1 397 049)	Portion of Other Investments
7.	Total Adjustments to Capital	$(26 298 289)	

Note: Subsidiary Earnings per Davis Exhibit 1, Page 14.
Other investments of $19 761 509 per Davis Exhibit 1, Page 13, apportioned to each capital component by ratio of that component to total capital.

Case 7804

KENTUCKY UTILITIES COMPANY

BALANCE SHEET
JANUARY 31, 1980
807 KAR 50:005
Section 6(9)
And
Section 9(1)(a)

Assets	
Utility Plant:	
Original Cost-Plant in Service	$ 876 362 669
Construction Work in Progress	185 365 887
Total	$1 061 728 556
Accumulated Provision for Depreciation and Amortization	$ 256 287 090
Net Utility Plant	$ 805 441 466
Investments and Funds:	
Non Utility Plant less reserve of $13 895	$ 388 569
Investments in Subsidiary Companies	25 524 615
Other Investments	385 105
Special Funds	7 018 172
Net Investments and Funds	$ 33 316 461
Cash	
Cash	$ 6 693 678
Special Deposits	2 594 988
Working Funds	44 984
Total Cash	$ 9 333 650
Receivables:	
Customer Receivables	$ 16 878 278
Miscellaneous Receivables	10 628 516
Accumulated Provision for Uncollectible Accounts	(268 400)
Total	$ 27 238 394
Receivables from Associated Companies	1 873 416
Net Receivables	$ 29 111 810
Inventories:	
Fuel	$ 59 567 378
Materials and Supplies	6 093 062
Stores Expense Undistributed	1 075 116
Total Inventories	$ 66 735 556
Other Current Assets:	
Prepayments	$ 697 590
Interest and Dividends Receivable	55 800
Accrued Utility Revenues	3 682 991
Total Other Current Assets	$ 4 436 381
Deferred Debits:	
Unamortized Debt Expense	$ 1 497 427
Preliminary Survey	2 295 608
Job Work	72 523
Other Deferred Debits	554 760
Total Deferred Debits	$ 4 420 318
Total Assets	$ 952 795 642

Case 804

KENTUCKY UTILITIES COMPANY

BALANCE SHEET
JANUARY 31, 1980
807 KAR 50:005
Section 6(9)
And
Section 9(1)(a)

Liabilities

Common Stock Equity:	
Common Stock	$107 963 270
Premium on Capital Stock	55 637 001
Unappropriated Retained Earnings	84 982 958
Appropriated Retained Earnings-Amortization Reserve Federal	49 815
Unappropriated Undistributed Subsidiary Earnings	6 536 780
Total Common Stock Equity	$255 170 424
Preferred Stock	$ 90 000 000
First Mortgage Bonds, including unamortized premium	342 465 074
Bank Notes	25 000 000
Commercial Paper Due Currently	53 715 000
Total Capitalization and Commercial Paper Due Currently	$766 350 498
Current Liabilities:	
Accounts Payable	$ 15 323 970
Payable to Associated Companies	15 364
Customers' Deposits	3 865 253
Taxes Accrued	3 958 215
Interest Accrued on Long-Term Debt	8 902 885
Other Interest Accrued	542 153
Tax Co[illegible]ons Payable	997 302
Dividends declared	7 501 553
Revenue subject to possible refund with interest	8 749 165
Other Current and Accrued Liabilities	6 060 417
Total Current Liabilities	$ 55 916 277
Deferred Credits:	
Customers' Advances for Construction	$ 1 072 883
Accumulated Deferred Income Taxes	83 033 105
Accumulated Deferred Investment Tax Credits	46 362 565
Other Deferred Credits	2 200
Total Deferred Credits	$130 470 753
Reserves:	
Insurance Reserve	$ 58 114
Total Reserves	$ 58 114
Total Liabilities	$952 795 642

Case 8177

KENTUCKY UTILITIES COMPANY
CAPITALIZATION

	December 31, 1980				September 30, 1982			
	Total	Adjustments	Adjusted Balance	Kentucky Jurisdiction	Total	Adjustments	Adjusted Balance	Kentucky Jurisdiction
Common Stock Equity	$283,934,773	$(13,979,964)	$269,954,809	$228,030,827	$ 346,624	$(20,639)	$325,985	$275,360
Preferred Stock	110,000,000	(2,954,229)	107,045,771	90,421,563	134,000	(5,539)	128,461	108,511
Long Term Debt	455,398,497	(12,230,466)	443,168,031	374,344,036	516,898	(21,366)	495,532	418,576
Short Term Debt	41,735,000	(1,120,861)	40,[illegible]14,139	34,306,763	17,500	(723)	16,777	14,171
Total	$891,068,270	$(30,285,520)	$860,782,750	$727,103,189	$ 1,015,022	$(48,267)	$966,755	$816,618

Davis Exhibits 1 and 4

Hewett Exhibit 1

Newton Exhibit 2
Page 1

Case 8177

KENTUCKY UTILITIES COMPANY
ADJUSTMENTS TO CAPITALIZATION

		December 31, 1980	September 30, 1982 (In Thousands)	
1.	Common Stock Equity	$ (6,529,803)	$ (6,311)	Subsidiary Earnings
2.		(7,450,161)	(14,328)	Portion of Other Investments
3.	Total	$(13,979,964)	$ (20,639)	
4.	Preferred Stock	(2,954,229)	(5,539)	Portion of Other Investments
5.	Long Term Debt	$(12,230,466)	$ (21,366)	Portion of Other Investments
6.	Short Term Debt	(1,120,861)	(723)	Portion of Other Investments
7.	Total	$(30,285,520)	$ (48,267)	

Case 8177

KENTUCKY UTILITIES COMPANY

BALANCE SHEET
DECEMBER 31, 1980
807 KAR 50:005
Section 6(9)
And
Section 9(1)(a)

Assets	
Utility Plant:	
Original Cost-Plant in Service	$ 911 680 809
Construction Work in Progress	301 927 539
Total	$1 213 608 348
Accumulated Provision for Depreciation and Amortization	281 126 940
Net Utility Plant	$ 932 481 408
Investments and Funds:	
Non Utility Plant less reserve of $20 770	$ 385 913
Investments in Subsidiary Companies	29 517 638
Other Investments	381 969
Special Funds	7 664 444
Net Investments and Funds	$ 37 949 964
Cash	
Cash	$ 6 755 330
Special Deposits	686 750
Working Funds	46 919
Total Cash	$ 7 488 999
Receivables:	
Customer Receivables	$ 19 877 650
Miscellaneous Receivables	9 227 586
Accumulated Provision for Uncollectible Accounts	(380 200)
Total	$
Receivables from Associated Companies	1 450 986
Net Receivables	$ 30 176 022
Inventories:	
Fuel	$ 60 668 499
Materials and Supplies	6 824 705
Stores Expense Undistributed	1 168 824
Total Inventories	$ 68 662 028
Other Current Assets:	
Prepayments	$ 412 916
Interest and Dividends Receivable	8 255
Accrued Utility Revenues	4 598 421
Total Other Current Assets	$ 5 019 592
Deferred Debits:	
Unamortized Debt Expense	$ 2 064 512
Preliminary Survey	80 114
Clearing accounts	334 434
Job Work	45 626
Other Deferred Debits	446 416
Total Deferred Debits	$ 2 971 102
Total Assets	$1 084 749 115

Case 8177

KENTUCKY UTILITIES COMPANY

BALANCE SHEET
DECEMBER 31, 1980
807 KAR 50:005
Section 6 (9)
And
Section 9(1)(a)

Liabilities

Common Stock Equity:	
Common Stock	$ 126 148 800
Premium on Capital Stock	67 873 410
Unappropriated Retained Earnings	83 332 072
Appropriated Retained Earnings-Amortization Reserve Federal	50 688
Unappropriated Undistributed Subsidiary Earnings	6 529 803
Total Common Stock Equity	$ 283 934 773
Preferred Stock	$ 110 000 000
First Mortgage Bonds, including unamortized premium	370 398 497
Bank Notes	85 000 000
Commercial Paper Due Currently	41 735 000
Total Capitalization and Commercial Paper Due Currently	$ 891 068 270
Current Liabilities:	
Accounts Payable	$ 16 871 763
Payable to Associated Companies	12 510
Customers' Deposits	4 088 407
Taxes Accrued	2 163 479
Interest Accrued on Long-Term Debt	9 168 302
Other Interest Accrued	562 685
Tax Collections Payable	1 878 275
Other Current and Accrued Liabilities	14 923 995
Total Current Liabilities	$ 49 669 416
Deferred Credits:	
Customers' Advances for Construction	$ 1 236 196
Accumulated Deferred Income Taxes	90 913 377
Accumulated Deferred Investment Tax Credits	51 805 354
Other Deferred Credits	2 200
Total Deferred Credits	$ 143 957 127
Reserves:	
Insurance Reserve	$ 54 302
Total Reserves	$ 54 302
Total Liabilities	$1 084 749 115

Case 8624

KENTUCKY UTILITIES COMPANY
CAPITALIZATION

	June 30, 1982				Target Capitalization		
	Total(a)	Adjustments(b)	Adjusted Balance	Kentucky(c) Jurisdiction	Adjustments(d)	Kentucky Jurisdiction	Ratio
Common Stock Equity	$340,731,541	$(18,044,960)	$322,686,881	$271,357,079	$38,701,565	$310,058,644	40.0%
Preferred Stock	108,817,000	(3,876,941)	104,940,059	88,247,244	8,646,082	96,893,326	12.5%
Long Term Debt	490,389,976	(17,480,304)	472,909,672	397,683,931	(29,489,292)	368,194,639	47.5%
Short Term Debt	22,020,000	(783,565)	21,236,435	17,858,355	(17,858,355)	-	
Total	$961,958,817	$(40,185,770)	$921,773,047	$775,146,609	-	$775,146,609	100.0%

(a) Total per Davis Exhibit 1, page 15
(b) Less subsidiary earnings and other investments, Newton Exhibit 2, page 2
(c) Kentucky jurisdiction allocated same as Rate Base per Willhite Exhibit 1, page 1.
(d) Test year ratios, Newton Exhibit 2, page 3, adjusted to target ratios

Case 8624

KENTUCKY UTILITIES COMPANY
ADJUSTMENTS TO CAPITALIZATION

June 30, 1982

1.	Common Stock Equity	$ (6,117,745)	Subsidiary Earnings
2.		(11,927,216)	Portion of Other Investments
3.	Total	$ (18,044,960)	
4.	Preferred Stock	(3,876,941)	Portion of Other Investments
5.	Long Term Debt	$ (17,480,304)	Portion of Other Investments
6.	Short Term Debt	(783,565)	Portion of Other Investments
7.	Total	$ (40,185,770)	

Davis Exhibit 1, page 14, lines 8-10

Case 8624

KENTUCKY UTILITIES COMPANY
ADJUSTMENTS TO CAPITALIZATION

June 30, 1982

1.	Common Stock Equity	$ (6,117,745)	Subsidiary Earnings
2.		(11,927,216)	Portion of Other Investments
3.	Total	$ (18,044,9ED)	
4.	Preferred Stock	(3,876,941)	Portion of Other Investments
5.	Long Term Debt	$ (17,480,304)	Portion of Other Investments
6.	Short Term Debt	(783,565)	Portion of Other Investments
7.	Total	$ (40,185,770)	

Davis Exhibit 1, page 14, lines 8-10

Case 8624

KENTUCKY UTILITIES CO

Financial Exhibit

Balance Sheet

807 KAR 50:005
Section 6(a)
and
Section 9(1)(a)

Line No.	Title of Account Col. A	No. Col. B	As of June 30, 1982 Col. C
1.	Utility Plant		
2.	Utility Plant	101-106	$1,177,936,544
3.	Construction Work in Progress	107	190,707,627
4.	Total Utility Plant		1,368,644,172
5.	Less Accumulated Provision for Depreciation	108	335,955,334
6.	Net Utility Plant		1,032,688,837
7.	Other Property & Investments		
8.	Nonutility property (less Accum.Prov.for Depreciation)	121,122	306,958
9.	Investment in Subsidiary Companies	123.1	39,505,579
10.	Other Investments	124	373,233
11.	Special Funds	125-128	8,464,086
12.	Total Other Property & Investments		48,649,856
13.	Current and Accrued Assets		
14.	Cash	131	4,344,478
15.	Special Deposits	132-134	44,556
16.	Working Funds	135	49,869
17.	Temporary Cash Investments	136	-
18.	Notes and Accounts Receivable (less Accum. Prov. for Uncoll. Accts.)	141-144	25,424,789
19.	Receivables from Associated Companies	145-146	2,239,101
20.	Fuel	151	64,662,481
21.	Materials and Supplies	154-163	7,823,988
22.	Prepayments	165	604,865
23.	Interest & Dividends Receivable	171	267,784
24.	Accrued Utility Revenues	173	4,857,732
25.	Total Current & Accrued Assets		110,319,643
26.	Deferred Debits		
27.	Unamortized Debt Expense	181	1,952,129
28.	Preliminary Survey & Investigation Charges	183	130,988
29.	Clearing Accounts	184	397,648
30.	Miscellaneous Deferred Debits	186	1,435,102
31.	Total Deferred Debits		3,915,867
	Total Assets and Other Debits		$1,195,574,203

KENTUCKY UTILITIES COMPANY

Financial Exhibit

Balance Sheet

807 KAR 50:005
Section 6(a)
and
Section 9(1)(a)

Line No.	Title of Account Col. A	No. Col. B	As of June 30, 1982 Col. C
1.	Proprietary Capital		
2.	Common Stock Issued	201	$ 159,419,770
3.	Preferred Stock Issued	204	108,817,000
4.	Premium on Capital Stock	207	85,415,082
5.	Gain on Resale or Cancellation of Reacquired		
6.	Stock	210	119,262
7.	Capital Stock Expense	214	(46,842)
8.	Retained Earnings	215-216	89,706,824
9.	Unapprop.Undistr.Subsidiary Earnings	216.1	6,117,745
10.	Total Proprietary Capital		449,548,841
11.	Long-Term Debt		
12.	Bonds	221	374,100,000
13.	Other Long-Term Debt	224	115,000,000
14.	Unamortized Premium on Long-Term Debt	225	1,289,976
15.	Total Long-Term Debt		490,389,976
16.	Current & Accrued Liabilities		
17.	Notes Payable	231	22,020,000
18.	Accounts Payable	232	21,638,820
19.	Payables to Associated Companies	233-234	108,106
20.	Customer Deposits	235	4,983,385
21.	Taxes Accrued	236	3,618,320
22.	Interest Accrued	237	12,188,030
23.	Dividends Declared	238	-
24.	Tax Collections Payable	241	1,479,179
25.	Misc. Current & Accrued Liabilities	242	7,323,740
26.	Total Current & Accrued Liabilities		73,359,580
27.	Deferred Credits		
28.	Customer Advances for Construction	252	1,863,446
29.	Accumulated Deferred Investment Tax Cr.	255	70,565,125
30.	Other Deferred Credits	253	131,481
31.	Accumulated Deferred Income Taxes	281-283	109,661,452
32.	Total Deferred Credits		182,221,504
33.	Operating Reserves		
34.	Operating Reserves	261-265	54,302
35.	Total Liabilities & Other Credits		$1,195,574,203

Case 98-474

Case 98-474

APPENDIX C (continued)

Allocation of Total Company Capitalization to Kentucky Jurisdictional Capitalization

Component of Capitalization	Total Company Balances at 12/31/98	Adjustments to Total Co. Capitalization	Adjusted Total Company Capitalization	Capital Structure	KY Juris. Capitalization	Adjustments to KY Juris. Capitalization	Adjusted KY Jurisdictional Capitalization
Long-Term Debt	546,330,000	(962,636)	545,367,364	45.83%	473,051,652	(126,445,340)	346,606,312
Preferred Stock	40,000,000	(70,427)	39,929,573	3.35%	34,634,912	(0)	34,634,912
Common Equity	606,712,973	(1,929,860)	604,783,113	50.82%	524,588,872	(0)	524,588,872
Total Capitalization	1,193,042,973	(2,962,923)	1,190,080,050	100.00%	1,032,275,436	(126,445,340)	905,830,096

Long-Term Debt, Preferred Stock, and Common Equity were allocated to Kentucky Jurisdictional Capitalization by applying the Kentucky Jurisdictional Rate Base percentage of 86.74% to the *Adjusted Total Company Capitalization* Balances.

Adjustments to Total Company Capitalization:

	Investment in EEI	Equity in EEI Earnings	Other Investments	Total Adjustments
Long-Term Debt	593,347	0	369,289	962,636
Preferred Stock	43,409	0	27,018	70,427
Common Equity	659,044	860,638	410,178	1,929,860
Totals	1,295,800	860,638	806,485	2,962,923

The allocation of the Investment in EEI and Other Investments was based on the test period actual capital structure. This capital structure was composed of 45.79% *Long-Term Debt*, 3.35% *Preferred Stock*, and 50.86% Common Equity. The assignment of the Equity in EEI Earnings totally to Common Equity results in the adjusted Capital Structure shown in the schedule above. The Other Investments *reflect* KU's *investment in the Ohio Valley Electric Corporation and various county industrial development programs.*

Adjustments to Kentucky Jurisdictional Capitalization:

This adjustment reflects the removal of the Kentucky Jurisdictional balances for KU's environmental surcharge. The jurisdictional balances are presented in Appendix B to this Order. The net adjustment of $126,445,340 *represents the sum of the Pollution Control Utility Plant* and Pollution Control CWIP plus Spare Parts, Limestone, and Emission Allowances, less Accumulated Depreciation on Pollution Control Plant. The allocation was to *Long-Term Debt, as described in* the Order. The resulting capital structure is 38.20% Long-Term Debt, 3.83% Preferred Stock, and 57.91% Common Equity.

KENTUCKY UTILITIES COMPANY
COMPARATIVE BALANCE SHEETS AS OF DECEMBER 31, 1999 AND 1998

ASSETS AND OTHER DEBITS	THIS YEAR	LAST YEAR
Utility Plant		
Utility Plant at Original Cost	2,851,066,582.49	2,685,527,353.49
Less Reserves for Depreciation & Amortization	(1,288,819,320.35)	(1,208,182,682.15)
Total	1,562,247,262.14	1,477,344,671.34
Investments - At Cost		
Nonutility Property-Less Reserve	3,820,555.23	3,888,741.48
Investments In Subsidiary Companies	2,123,386.21	2,156,438.13
Other	910,355.17	806,485.15
Special Funds	7,495,076.53	7,385,880.28
Total	14,349,373.14	14,237,545.04
Current and Accrued Assets		
Cash	6,231,656.71	25,145,576.77
Special Deposits	388,091.14	72,944.34
Temporary Cash Investments	173,060.25	33,730,684.79
Accounts Receivable-Less Reserve	88,549,457.96	93,376,185.20
Notes Receivable from Assoc. Companies	-	-
Accounts Receivable from Assoc Companies	-	12,748,358.74
Materials & Supplies-At Average Cost		
Fuel	30,224,921.42	23,927,315.45
Plant Materials & Operating Supplies	21,964,929.21	19,969,836.52
Stores Expense	4,248,048.18	4,278,632.66
Prepayments	3,059,884.83	2,426,630.17
Allowance Inventory	494,239.00	628,655.00
Miscellaneous Current & Accrued Assets	189,225.17	-
Total	155,523,513.87	216,304,819.64
Deferred Debits and Other		
Unamortized Debt Expense	4,826,738.87	5,227,390.19
Unamortized Loss on Bonds	7,594,380.12	8,675,439.96
Accumulated Deferred Income Taxes	79,354,405.45	78,280,266.57
Deferred Regulatory Assets	40,474,380.32	45,979,872.01
Other Deferred Debits	25,111,041.28	19,858,473.26
Total	157,360,946.04	158,021,441.99
Total Assets and Other Debits	1,889,481,095.19	1,865,908,478.01

LIABILITIES AND OTHER CREDITS	THIS YEAR	LAST YEAR
Capitalization		
Common Stock	308,139,977.56	308,139,977.56
Common Stock Expense	(594,394.29)	(594,394.29)
Retained Earnings	328,642,126.18	298,306,751.48
Unappropriated Undistributed Subsidiary Earnings	827,586.21	860,638.13
Total Common Equity	637,015,295.66	606,712,972.88
Preferred Stock	40,000,000.00	40,000,000.00
First Mortgage Bonds	484,830,000.00	546,330,000.00
Other Long-Term Debt	-	-
Total Long-Term Debt	484,830,000.00	546,330,000.00
Total Capitalization	1,161,845,295.66	1,193,042,972.88
Current and Accrued Liabilities		
Advances from Associated Companies	-	-
Long-Term Debt Due in 1 Year	61,500,000.00	-
Notes Payable to Associated Companies	-	-
Accounts Payable	91,061,060.67	115,501,582.53
Accounts Payable to Associated Companies	46,288,488.25	16,266,833.40
Customer Deposits	10,428,558.04	10,354,544.86
Taxes Accrued	10,502,005.90	16,733,088.30
Interest Accrued	7,329,294.60	8,110,134.51
Dividends Declared	19,149,774.24	18,188,000.00
Misc. Current & Accrued Liabilities	8,188,624.34	10,616,213.22
Total	254,447,806.04	195,770,396.82
Deferred Credits and Other		
Accumulated Deferred Income Taxes	322,974,864.00	322,773,531.00
Investment Tax Credit	18,574,553.00	22,301,583.00
Deferred Tax Liability	68,027,458.00	72,309,488.00
Customer Advances for Construction	1,173,743.27	1,263,850.33
Other Deferred Credits	5,804,408.38	6,159,582.96
Misc. Long-Term Liabilities	23,626,833.02	17,670,783.02
Misc. Long-Term Liab. Due to Assoc. Co	2,242,913.00	2,242,913.00
Accum Provision for Post-Retirement Benefits	30,763,220.82	32,373,377.00
Total	473,187,993.49	477,095,108.31
Total Liabilities and Other Credits	1,889,481,095.19	1,865,908,478.01

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00434 DATED

Determination of KU's Jurisdictional Capitalization

KU's Total Company Capitalization

	Test Year Actual Balances	Updated Capital Structure	Revised TY Actual Balances	Adjustments to Total Company Capitalization	Adjusted Total Company Capitalization
Long-Term Debt	613,712,167	43.69%	729,956,465	(4,822,123)	725,134,342
Short-Term Debt	98,730,542	2.41%	40,265,394	(265,995)	39,999,399
Accounts Receivable Securitization	49,300,000	0.00%	0	0	0
Preferred Stock	40,000,000	2.36%	39,430,013	(260,476)	39,169,537
Common Equity	869,020,543	51.54%	861,111,380	(4,169,442)	856,941,938
Totals	1,670,763,252	100.00%	1,670,763,252	(9,518,036)	1,661,245,216

Adjustments to Total Company Capitalization

	Undistributed Subsidiary Earnings	Investment in Electric Energy, Inc	Other Investments	Minimum Pension Liability	Adjustments to Total Company Capitalization
Long-Term Debt	0	(4,473,454)	(348,669)	0	(4,822,123)
Short-Term Debt	0	(246,762)	(19,233)	0	(265,995)
Preferred Stock	0	(241,642)	(18,834)	0	(260,476)
Common Equity	(8,943,279)	(5,277,221)	(411,317)	10,462,375	(4,169,442)
Totals	(8,943,279)	(10,239,079)	(798,053)	10,462,375	(9,518,036)

KENTUCKY UTILITIES COMPANY
COMPARATIVE BALANCE SHEETS AS OF SEPTEMBER 30, 2003 AND 2002

ASSETS AND OTHER DEBITS	THIS YEAR	LAST YEAR
Utility Plant		
Utility Plant at Original Cost	3,527,901,229.10	3,224,033,705.02
Less Reserves for Depreciation & Amortization	1,600,258,254.68	1,528,492,305.16
Total	1,927,642,974.42	1,695,541,399.86
Investments - At Cost		
Nonutility Property-Less Reserve	896,680.16	897,090.58
Investments in Subsidiary Companies	10,239,079.00	6,607,927.68
Investments in KU-R	3,000,000.00	3,000,000.00
Ohio Valley Electric Corporation	250,000.00	250,000.00
Other	548,053.13	837,899.66
Special Funds	5,242,439.10	5,173,190.58
Total	20,176,251.39	16,766,108.50
Current and Accrued Assets		
Cash	9,085,680.49	6,687,347.37
Special Deposits	246,616.37	102,929.26
Temporary Cash Investments	-	-
Accounts Receivable-Less Reserve	1,173,057.35	7,083,490.70
Notes Receivable from Assoc. Companies	-	-
Notes Receivable from KU-R	36,538,156.00	33,457,130.00
Accounts Receivable from Assoc Companies	10,325,288.89	11,019,706.29
Materials & Supplies-At Average Cost		
Fuel	33,559,694.22	33,980,866.20
Plant Materials & Operating Supplies	22,073,546.17	22,039,199.66
Stores Expense	5,156,409.00	4,756,697.43
Allowance Inventory	69,415.36	89,371.12
Prepayments	2,901,731.05	2,722,583.49
Miscellaneous Current & Accrued Assets	461,045.82	1,692,981.37
Total	121,590,640.72	123,632,302.89
Deferred Debits and Other		
Unamortized Debt Expense	4,832,022.42	3,976,968.29
Unamortized Loss on Bonds	8,835,282.07	6,693,194.30
Accumulated Deferred Income Taxes	64,893,528.76	75,669,056.13
Deferred Regulatory Assets	73,823,744.07	69,429,300.30
Other Deferred Debits	43,368,248.28	28,432,279.83
Total	195,752,825.60	184,200,798.85
Total Assets and Other Debits	2,265,162,692.13	2,020,140,610.10

LIABILITIES AND OTHER CREDITS	THIS YEAR	LAST YEAR
Capitalization		
Common Stock	308,139,977.56	308,139,977.56
Common Stock Expense	(594,394.29)	(594,394.29)
Paid-In Capital	15,000,000.00	15,000,000.00
Other Comprehensive Income	(10,158,966.50)	4,363,814.60
Retained Earnings	547,690,647.47	472,059,012.33
Unappropriated Undistributed Subsidiary Earnings	8,943,279.00	5,312,127.68
Total Common Equity	869,020,543.24	804,280,537.88
Preferred Stock	40,000,000.00	40,000,000.00
First Mortgage Bonds	422,830,000.00	484,830,000.00
Other Long-Term Debt	-	-
LT Notes Payable to Associated Companies	175,000,000.00	-
Long-Term Debt Marked to Market	15,882,167.00	9,665,600.00
Total Long-Term Debt	613,712,167.00	494,495,600.00
Total Capitalization	1,522,732,710.24	1,338,776,137.88
Current and Accrued Liabilities		
Advances from Associated Companies	-	-
Long-Term Debt Due in 1 Year	-	-
Notes Payable	-	-
Notes Payable to Associated Companies	98,730,541.95	87,689,649.91
Accounts Payable	43,280,523.27	33,673,751.07
Accounts Payable to Associated Companies	24,912,999.77	39,653,939.41
Customer Deposits	12,940,956.22	11,650,791.74
Taxes Accrued	10,539,547.13	12,637,032.95
Interest Accrued	5,458,770.83	4,767,068.77
Dividends Declared	188,001.65	188,000.00
Misc. Current & Accrued Liabilities	6,177,048.80	6,582,975.13
Total	202,228,389.62	196,843,208.98
Deferred Credits and Other		
Accumulated Deferred Income Taxes	325,260,086.79	318,579,479.13
Investment Tax Credit	6,519,139.00	9,238,543.00
Regulatory Liabilities	52,934,445.00	54,943,455.00
Customer Advances for Construction	1,504,616.25	1,492,333.42
Asset Retirement Obligations	19,392,583.50	-
Other Deferred Credits	28,999,862.03	14,605,191.26
Misc. Long-Term Liabilities	50,115,629.00	31,583,087.61
Misc. Long-Term Liab. Due to Assoc. Co.	-	-
Accum Provision for Post-Retirement Benefits	55,475,230.70	54,079,173.82
Total	540,201,592.27	484,521,263.24
Total Liabilities and Other Credits	2,265,162,692.13	2,020,140,610.10

Kentucky Utilities Company
Comparative Balance Sheets as of April 30, 2008 and 2007

Assets and Other Debits	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	5,151,234,451.43	4,380,737,063.36
Less Reserves for Depreciation and Amortization	1,972,362,644.75	1,876,367,654.84
Total	3,178,871,806.68	2,504,369,408.52
Investments - at Cost		
Ohio Valley Electric Corporation	250,000.00	250,000.00
Nonutility Property-Less Reserve	179,120.94	969,025.81
Investments in Subsidiary Companies	24,880,478.80	19,807,940.00
Special Funds	6,046,655.99	8,140,713.10
Other	411,140.00	426,140.00
Total	31,767,395.73	29,593,818.91
Current and Accrued Assets		
Cash	2,125,603.26	6,086,367.97
Special Deposits	4,334,948.68	20,304,946.92
Temporary Cash Investments	17,681.67	16,924.95
Accounts Receivable-Less Reserve	142,596,743.77	122,698,210.48
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	49,694.17	6,252,255.78
Materials and Supplies-At Average Cost		
Fuel	46,647,686.54	62,663,137.35
Plant Materials and Operating Supplies	28,045,637.93	25,633,096.13
Stores Expense	6,524,614.19	6,079,526.76
Allowance Inventory	223,085.27	1,134,949.48
Prepayments	3,405,611.11	3,563,125.42
Miscellaneous Current and Accrued Assets	-	1,992,267.65
Total	233,971,306.59	256,424,808.89
Deferred Debits and Other		
Unamortized Debt Expense	6,790,525.03	6,494,563.75
Unamortized Loss on Bonds	10,611,577.64	10,473,928.85
Accumulated Deferred Income Taxes	50,537,997.37	45,723,507.74
Deferred Regulatory Assets	82,545,197.75	115,638,664.82
Other Deferred Debits	58,995,218.47	78,979,983.83
Total	209,480,516.26	257,310,648.99
Total Assets and Other Debits	3,654,091,025.26	3,047,698,685.31

Liabilities and Other Credits	This Year	Last Year
Capitalization		
Common Stock	308,139,977.56	308,139,977.56
Common Stock Expense	(321,288.87)	(321,288.87)
Paid-In Capital	115,000,000.00	15,000,000.00
Other Comprehensive Income	-	-
Retained Earnings	1,066,612,042.33	910,723,554.25
Unappropriated Undistributed Subsidiary Earnings	23,584,678.80	18,512,140.00
Total Common Equity	1,513,015,409.82	1,252,054,382.94
Preferred Stock	-	-
Pollution Control Bonds - Net of Reacquired Bonds	316,059,520.00	305,951,140.00
LT Notes Payable to Associated Companies	931,000,000.00	611,000,000.00
Total Long-term Debt	1,247,059,520.00	916,951,140.00
Total Capitalization	2,760,074,929.82	2,169,005,522.94
Current and Accrued Liabilities		
Long-term Debt Due in 1 Year	-	-
ST Notes Payable to Associated Companies	93,302,454.00	62,745,054.00
Notes Payable	-	-
Notes Payable to Associated Companies	-	-
Accounts Payable	134,916,555.69	125,790,911.56
Accounts Payable to Associated Companies	36,181,072.10	102,807,708.17
Customer Deposits	19,792,751.88	18,841,017.05
Taxes Accrued	12,576,638.88	245,947.81
Interest Accrued	11,397,765.18	7,366,575.04
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	13,363,943.14	11,213,750.34
Total	321,531,180.87	329,010,963.97
Deferred Credits and Other		
Accumulated Deferred Income Taxes	331,434,967.30	328,775,200.23
Investment Tax Credit	58,094,343.32	22,701,671.32
Regulatory Liabilities	38,152,787.49	36,654,293.96
Customer Advances for Construction	2,420,052.26	1,984,291.81
Asset Retirement Obligations	30,975,691.02	29,101,856.78
Other Deferred Credits	21,296,038.92	8,355,655.58
Miscellaneous Long-term Liabilities	3,256,903.03	46,913,039.58
Accum Provision for Postretirement Benefits	86,854,131.23	75,196,189.14
Total	572,484,914.57	549,682,198.40
Total Liabilities and Other Credits	3,654,091,025.26	3,047,698,685.31

EXHIBIT___(LK-6)

Kent W. Blake
Director
State Regulation and Rates

LG&E ENERGY

LG&E Energy LLC
220 West Main Street
Louisville, Kentucky 40202
502-627-2573
502-217-2442 FAX
kent.blake@lgeenergy.com

December 22, 2005

RECEIVED
DEC 2 2 2005
PUBLIC SERVICE COMMISSION

Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RE: **<u>The 2005 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company</u>**
Case No: 2005-00162

Dear Ms. O'Donnell:

As John Malloy and I discussed with Commission Staff on September 23, 2005, Kentucky Utilities Company's ("KU") Power Supply Agreement ("PSA") with Electric Energy Inc. ("EEI") is scheduled to expire at the end of 2005. EEI's position on renewing the PSA continues to be one based on market indices (defined generally as the applicable locational marginal pricing ("MISO LMP")) with a capacity payment, as opposed to the cost-based rate structure under which the contract has historically operated and which KU requested during the contract negotiations.

After extensive negotiations, we have received and reviewed EEI's final proposed new PSA for this 200 MWs from EEI's Joppa plant located in Joppa, Illinois. KU has evaluated EEI's proposed renewal of the PSA in the context of its Integrated Resource Plan ("IRP") based upon a least-cost reasonable resource analysis.

Based on the proposed PSA by EEI, KU has determined that continuation of the PSA would not be a least-cost option for KU's customers. The results from the evaluation of the proposed EEI contract were presented to the Company's Operating Committee established pursuant to the Power Supply System Agreement on December 16, 2005. After consideration of the supporting analysis, the Operating Committee approved the recommendation not to renew the PSA with EEI. We notified EEI of KU's decision on December 22, 2005. Enclosed is a copy of our notification letter to EEI.

Elizabeth O'Donnell
Page 2
December 22, 2005

As such, the PSA will expire December 31, 2005, and KU will no longer purchase the 200 MW of capacity and energy from EEI. There is no near term (2006-2007) impact on KU's capacity plans. KU and Louisville Gas and Electric Company ("LG&E") will continue to review their capacity and energy needs in the context of their on-going IRP process.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Kent W. Blake /bgc

Kent W. Blake

Enclosure

cc: Elizabeth E. Blackford
Michael L. Kurtz

In December 2005, LG&E Energy LLC was renamed E.ON U.S. LLC

Kentucky Utilities Company One Quality Street Lexington, KY 40507-1462 Tel 606 255-2100

Kentucky
Utilities
Company

Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202

December 22, 2005

SENT by email and overnight mail

Mr. Robert L. Powers
President
Electric Energy Incorporated
One Ameren Plaza
1901 Chouteau Avenue
MC-600
St. Louis, Missouri 63103
314-554-6101

Re: Draft Power Purchase Agreement (the "Draft PPA") between Electric Energy, Inc. ("EEI") and Kentucky Utilities Company ("KU")

Dear Bob:

I send this letter in response to the draft PPA Jim Helm circulated to me on December 6, 2005. KU has understood that the Draft PPA, including the pricing provisions therein, constitutes EEI's best and final offer to KU of power from the Joppa plant after the end of calendar year 2005.

As you know, KU had hoped to negotiate a cost-based agreement to replace the present Power Supply Agreement that expires on December 31, 2005, and we had been working toward that goal for much of the past year. While the PPA draft that you forwarded may achieve EEI's goal of pursing market-based sales, it unfortunately, as confirmed through KU's generation planning analysis, is not be a least cost resource for KU and its customers. Accordingly, KU is confirming by this letter that it must decline EEI's offer of power on these terms. If EEI should have power available on better terms in the future or at a later time, KU certainly remains interested in considering such availability, and does not intend by this letter to waive any right or claim that it may otherwise have to be notified and have an opportunity to acquire that power.

Please feel free to call me with any questions or concerns.

Sincerely,

KENTUCKY UTILITIES COMPANY

By: Charles A. Freibert, Jr.

Charles A. Freibert, Jr.
Director Energy Marketing
502-627-3673

cc: Ameren – Alan Kelly, Andy Serri
EEI – Jim Helm
LGEE – Paul Thompson, John Voyles, Kent Blake, Bob Brunner, Steve Phillips, Beth Cocanougher

EXHIBIT___(LK-7)

Kentucky Utilities Company
EEI Operating Income and Total Revenue Requirement Adjustment
Recommended by KIUC
For the Test Year Ended April 30, 2008

			Amounts
EEI Earnings Recognized by KU During Test Year			28,622,539
Less: Income Taxes on Earnings as Computed Below			(4,190,601)
EEI Earnings Net of Income Taxes Recognized by KU			24,431,938
Operating Income Effect of Changes Related to EEI Earnings			39,986,805
Revenue Requirement Gross-Up Factor (B/D and PSC Assessment)			0.357017%
Rev Req Effect of Operating Income Changes Related to EEI Earnings			40,129,565
Rev Req Effect of Changes to Capitalization Related to Elimination of EEI Reductions		(1)	(2,216,886)
Total Revenue Requirement Reduction by Reflecting EEI as Utility Income			37,912,679
Income Tax Expense Computation			
Earnings Recognized In Excess of Dividend	6,855,872		
Composite Federal and State Tax Rate	38.9%		
Income Tax Expense on Non-Dividend Earnings			2,666,934
Earnings Recognized as Dividends to KU	21,766,667		
Less: 80% Dividends Received Exclusion	(17,413,333)		
Taxable Dividends	4,353,333		
Federal Tax Rate	35.0%		
Federal Income Tax Expense on Dividend Earnings			1,523,667
Income Taxes Computed on EEI Earnings		(2)	4,190,601
Computation of Earnings Recognized as Dividends to KU			
Source: AG 1-34 Page 3 of 20			
2007 Calendar Year Dividends	21,400,000		
Dividends Computed Eight Months (5/1/2007 - 12/31/07)	14,266,667		
Dividends Declared (1/1/08 - 4/30/08)	7,500,000		
Dividends Computed for Test Year Ended 4/30/08	21,766,667		

(1) See Calculation of Capitalization Effects on Pages 2 and 3 of this Exhibit
(2) See AG-1-25 - 100% of EEI Dividend Earnings excluded for State Income Tax Computation

Kentucky Utilities Company
EEI Capitalization Adjustments-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

	Total Company As Filed and Corrected	As Filed Per Books Capitalization Percentage Applications	KIUC Adjustment 1	KIUC Adjustment 2	KIUC Recommended Total Company Capitalization
Short-Term Debt	76,538,984	3.27%		42,373	76,581,357
Long Term Debt	1,262,819,681	43.70%		566,265	1,263,385,946
Common Equity	1,497,213,789	53.03%	14,668,869	687,162	1,512,569,820
Total Capitalization	2,836,572,454		14,668,869	1,295,800	2,852,537,123

KIUC Adjustment Descriptions	Total Company Amounts
Adjustment 1 - Remove Company Adjustment 4 Related to EEI	14,668,869
Adjustment 2 - Remove Company Adjustment 5 Related to EEI	1,295,800
Total KIUC Adjustments to Capitalization	15,964,669

I. Cost of Capital as Filed and Corrected by the Company

	Company's Adjusted Total Company Capitalization	Jurisdictional Rate Base Percentage	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 76,538,984	73.94%	$ 56,592,925	2.70%	2.63%	0.07%
Long Term Debt	1,262,819,681	73.94%	933,728,872	44.52%	5.21%	2.32%
Common Equity	1,497,213,789	73.94%	1,107,039,876	52.78%	11.25%	5.94%
	$ 2,836,572,454		$ 2,097,361,673	100.00%		8.33%

Kentucky Utilities Company
EEI Capitalization Adjustments-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

II. Cost of Capital With KIUC EEI Adjustment

	KIUC Adjusted Total Company Capitalization	Jurisdictional Rate Base Percentage	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 76,581,357	73.94%	$ 56,624,255	2.68%	2.63%	0.07%
Long Term Debt	1,263,385,946	73.94%	934,147,568	44.29%	5.21%	2.31%
Common Equity	1,512,569,820	73.94%	1,118,394,125	53.03%	11.25%	5.97%
	$ 2,852,537,123		$ 2,109,165,948	100.00%		8.35%

Revenue Requirement Effect Computation

Capitalization Difference			$ 11,804,275	
COC Computed by Company			8.33%	
Return on Additional Capitalization				983,296
Total Capitalization			2,109,165,948	
Additional COC			0.02%	
Additional Return on Capitalization				421,833
Capitalization Difference	$ 2,097,361,673	$ 2,109,165,948		
Total Debt Rate	2.39%	2.38%		
Additional Interest	50,126,944	50,198,150	71,206	
Composite Income Tax Rate			37.603%	
Reduced Income Tax Due to Higher Interest				(26,775)
Total Rate of Return Effect Before Gross-Up				1,378,354
Gross Up Revenue Factor				0.621752
Revenue Requirement Effect				2,216,886

EXHIBIT___(LK-8)

Kentucky Utilities Company
Comparison of O&M Expenses
Test Year vs Twelve Months Ended April 30, 2007
For the Test Year Ended April 30, 2008
($ Thousands)

Account	Twelve Months Ended 4/30/2007	Twelve Months Ended 4/30/2008	Variance	Variance Percentage
500	3,094	3,349	255	8.2%
502	7,781	9,025	1,244	16.0%
505	4,704	4,887	183	3.9%
506	6,505	6,424	(81)	-1.2%
510	3,918	4,677	759	19.4%
511	4,008	4,478	470	11.7%
512	18,724	24,647	5,923	31.6%
513	5,107	9,390	4,283	83.9%
514	891	991	100	11.2%
535	9	7	(2)	-22.2%
539	28	36	8	28.6%
541	81	104	23	28.4%
542	85	136	51	60.0%
544	77	136	59	76.6%
545	10	5	(5)	-50.0%
546	109	99	(10)	-9.2%
548	600	1,460	860	143.3%
549	117	114	(3)	-2.6%
551	34	34	-	0.0%
552	126	144	18	14.3%
553	2,094	2,314	220	10.5%
554	251	247	(4)	-1.6%
556	1,348	1,342	(6)	-0.4%
560	699	888	189	27.0%
561	2,549	843	(1,706)	-66.9%
562	409	361	(48)	-11.7%
563	278	336	58	20.9%
566	(674)	4,624	5,298	-786.1%
567	45	89	44	97.8%
570	1,083	915	(168)	-15.5%
571	2,636	3,300	664	25.2%
573	336	175	(161)	-47.9%
575	996	10	(986)	-99.0%
580	1,288	1,284	(4)	-0.3%
581	572	611	39	6.8%
582	981	1,001	20	2.0%
583	2,913	3,030	117	4.0%
584	97	73	(24)	-24.7%
585	6	11	5	83.3%
586	5,780	6,097	317	5.5%
587	(90)	(73)	17	-18.9%
588	4,457	4,379	(78)	-1.8%
589	10	12	2	20.0%

Kentucky Utilities Company
Comparison of O&M Expenses
Test Year vs Twelve Months Ended April 30, 2007
For the Test Year Ended April 30, 2008
($ Thousands)

Account	Twelve Months Ended 4/30/2007	Twelve Months Ended 4/30/2008	Variance	Variance Percentage
590	7	7	-	0.0%
591	-	1	1	0.0%
592	1,007	856	(151)	-15.0%
593	16,861	20,707	3,846	22.8%
594	654	591	(63)	-9.6%
595	68	111	43	63.2%
596	165	56	(109)	-66.1%
598	10	8	(2)	-20.0%
901	1,994	1,853	(141)	-7.1%
902	4,167	4,127	(40)	-1.0%
903	10,796	11,301	505	4.7%
904	1,844	3,133	1,289	69.9%
905	83	228	145	174.7%
907	215	218	3	1.4%
908	4,185	4,734	549	13.1%
909	192	449	257	133.9%
910	241	786	545	226.1%
913	-	66	66	0.0%
920	13,186	14,199	1,013	7.7%
921	5,895	6,742	847	14.4%
922	(1,111)	(1,409)	(298)	26.8%
923	6,002	9,557	3,555	59.2%
924	2,784	2,805	21	0.8%
925	1,488	1,059	(429)	-28.8%
926	24,887	19,877	(5,010)	-20.1%
927	-	-	-	0.0%
928	-	1,027	1,027	0.0%
929	(3)	(3)	-	0.0%
930 1	524	370	(154)	-29.4%
930 2	2,099	1,308	(791)	-37.7%
931	1,287	1,396	109	8.5%
935	6,458	5,618	(840)	-13.0%
Total Non-Fuel O&M	190,057	213,790	23,733	12.5%

EXHIBIT___(LK-9)

Louisville Gas & Electric Company
Comparison of O&M Expenses
Test Year vs Twelve Months Ended April 30, 2007
For the Test Year Ended April 30, 2008
(*$ Thousands*)

Account	Twelve Months Ended 4/30/2007	Twelve Months Ended 4/30/2008	Variance	Variance Percentage
500	1,934	2,090	156	8.1%
502	30,601	27,326	(3,275)	-10.7%
505	606	754	148	24.4%
506	16,902	16,989	87	0.5%
507	51	51	-	0.0%
510	1,900	2,347	447	23.5%
511	2,187	2,279	92	4.2%
512	30,839	39,886	9,047	29.3%
513	6,010	7,544	1,534	25.5%
514	1,577	1,335	(242)	-15.3%
535	59	53	(6)	-10.2%
538	176	161	(15)	-8.5%
539	116	130	14	12.1%
540	431	239	(192)	-44.5%
541	4	5	1	25.0%
542	72	190	118	163.9%
543	85	87	2	2.4%
544	103	283	180	174.8%
546	25	29	4	16.0%
548	333	925	592	177.8%
549	44	38	(6)	-13.6%
550	29	23	(6)	-20.7%
551	28	16	(12)	-42.9%
552	100	92	(8)	-8.0%
553	686	1,861	1,175	171.3%
554	104	110	6	5.8%
556	1,005	1,014	9	0.9%
558	(2,335)	(2,771)	(436)	18.7%
560	537	707	170	31.7%
561	1,935	712	(1,223)	-63.2%
562	1,222	1,234	12	1.0%
563	18	87	69	383.3%
566	(6)	3,725	3,731	-62183.3%
567	19	22	3	15.8%
569	12	30	18	150.0%
570	956	996	40	4.2%
571	495	777	282	57.0%
573	116	2	(114)	-98.3%
575	964	8	(956)	-99.2%
580	1,206	1,236	30	2.5%
581	365	333	(32)	-8.8%
582	863	937	74	8.6%
583	4,123	4,516	393	9.5%
584	385	441	56	14.5%

Louisville Gas & Electric Company
Comparison of O&M Expenses
Test Year vs Twelve Months Ended April 30, 2007
For the Test Year Ended April 30, 2008
($ Thousands)

Account	Twelve Months Ended 4/30/2007	Twelve Months Ended 4/30/2008	Variance	Variance Percentage
585	-	18	18	0.0%
586	5,718	5,621	(97)	-1.7%
587	(239)	(222)	17	-7.1%
588	2,684	2,960	276	10.3%
589	16	14	(2)	-12.5%
590	24	10	(14)	-58.3%
591	669	796	127	19.0%
592	907	729	(178)	-19.6%
593	11,477	12,569	1,092	9.5%
594	1,732	1,541	(191)	-11.0%
595	184	224	40	21.7%
596	347	793	446	128.5%
598	474	263	(211)	-44.5%
901	713	659	(54)	-7.6%
902	1,898	2,117	219	11.5%
903	4,425	4,763	338	7.6%
904	1,738	849	(889)	-51.2%
905	212	259	47	22.2%
907	151	140	(11)	-7.3%
908	3,820	4,202	382	10.0%
909	299	332	33	11.0%
910	162	649	487	300.6%
913	1	57	56	5600.0%
920	12,619	13,327	708	5.6%
921	5,701	6,558	857	15.0%
922	(1,483)	(1,912)	(429)	28.9%
923	4,121	4,481	360	8.7%
924	3,131	3,127	(4)	-0.1%
925	1,749	2,235	486	27.8%
926	24,022	20,434	(3,588)	-14.9%
927	22	26	4	18.2%
928	11	1,132	1,121	10190.9%
929	(30)	(33)	(3)	10.0%
930.1	301	224	(77)	-25.6%
930.2	1,416	979	(437)	-30.9%
931	1,269	1,250	(19)	-1.5%
935	6,111	4,923	(1,188)	-19.4%
Total Non-Fuel O&M	203,254	214,943	11,689	5.8%

EXHIBIT___(LK-10)

Kentucky Utilities Company
Comparison of O&M Expenses
Test Year vs Calendar Year 2007
For the Test Year Ended April 30, 2008
($ Thousands)

Account	Twelve Months Ended 12/31/2007	Twelve Months Ended 4/30/2008	Variance	Variance Percentage
Total O&M	755,872	788,745	32,873	4.3%
Less: Fuel Accounts				
501	349,272	359,944	10,672	3.1%
509	2,229	1,912	(317)	-14.2%
547	49,972	50,197	225	0.5%
555	146,097	157,243	11,146	7.6%
557	1,424	1,041	(383)	-26.9%
565	3,585	4,618	1,033	28.8%
Total Fuel Accounts	552,579	574,955	22,376	4.0%
Total Non-Fuel O&M	203,293	213,790	10,497	5.2%

EXHIBIT___(LK-11)

Louisville Gas & Electric Company
Comparison of O&M Expenses
Test Year vs Calendar Year 2007
For the Test Year Ended April 30, 2008
($ Thousands)

Account	Twelve Months Ended 12/31/2007	Twelve Months Ended 4/30/2008	Variance	Variance Percentage
Total O&M	603,075	616,937	13,862	2.3%
Less: Fuel Accounts				
501	286,061	287,349	1,288	0.5%
509	4	3	(1)	-25.0%
536	39	39	-	0.0%
547	31,203	30,157	(1,046)	-3.4%
555	82,337	81,802	(535)	-0.6%
557	(572)	(570)	2	-0.3%
565	3,791	3,214	(577)	-15.2%
Total Fuel Accounts	402,863	401,994	(869)	-0.2%
Total Non-Fuel O&M	200,212	214,943	14,731	7.4%

EXHIBIT___(LK-12)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Second Set of Data Requests of the
Kentucky Industrial Utility Customers, Inc.
Dated September 24, 2008

Question No. 2.23

Responding Witness: Paul W. Thompson / Chris Hermann / Shannon L. Charnas

Q-2.23 Please refer to the variances comparing test year vs. 2007 actual costs for each of the O&M accounts found in KU'S response to PSC-1 Question 23 (b) for the Kentucky jurisdiction. For each of the FERC accounts listed below, please describe all reasons for the increases in expenses in the test year compared to those incurred in 2007 Please quantify the effects of each reason cited

a. Acct 502 Steam Expenses - +6.05%.

b. Acct 510 Maintenance Supervision and Engineering - +10 79%.

c. Acct 512 Maintenance of Boiler Plant - +18.40%

d. Acct 514 Maintenance of Misc Steam Plant - +9.21%.

e. Acct 548 Generation Expenses - +137.90%.

f. Acct 560 Operation Supervision and Engineering - +21 33.

g. Acct 571 Maintenance of Overhead Lines - +17.45%.

h. Acct 583 Overhead Line Expenses - +16.55%.

i. Acct 593 Maintenance of Overhead Lines - +15.86%.

j. Acct 904 Uncollectible Accounts - +43.33%

k. Acct 905 Misc. Customer Accounts Expenses - +39.29%.

l. Acct 923 Outside Services - +19 57%

A-2.23. From KU's response to PSC-1 Question No. 23(b), Total Electric Operation and Maintenance Expense increased 4.35% from 2007 to the test year

a. Account 502, Steam Expenses, had a 6.05% ($515,000) increase due to scrubber operating costs, primarily limestone purchases of $316,000, for the FGD at Ghent Unit 3 that went online in June 2007. Another $199,000 was due to limestone and other operating costs, such as boiler plant operation labor and water treatment costs, for the Brown and Tyrone stations. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating KU's system.

b. Account 510, Maintenance Supervision and Engineering, had a 10.79% ($456,000) increase due to planned inspection and repairs for high energy piping at Ghent station in Spring 2008 This accounted for 9% ($391,000) of the variance. 1% ($56,000) is for labor costs. The remaining $9,000 variance is the net of all other variances. (All dollar amounts are rounded) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining KU's system.

c. Account 512, Maintenance of Boiler Plant, increased 3.67% ($872,000), based on a 2007 balance of $23,776,000 and a test year balance of $24,648,000 not the 18.40% posed in the question above. Brown Station had storm damage of $251,000 and an auxiliary outage of $232,000. Pulverizer maintenance ($225,000) and service and feed water costs ($207,000) are also major contributors across the KU fleet The remaining $16,000 variance is the net of all other variances. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining KU's system.

d. Account 514, Maintenance of Miscellaneous Steam Plant, had a 9.21% ($84,000) increase due to costs at Tyrone ($39,000) and Ghent ($11,000) for miscellaneous plant equipment charges including pump repairs, motor repairs, costs to open/clean/close auxiliary boiler, electrician fees, etc. Brown incurred $30,000 for 2008 storm damage repairs and clean up. The remaining $4,000 variance is the net of all other variances (All dollar amounts are rounded) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining KU's system.

e. Account 548, Generation Expenses, had a 137.9% ($846,000) increase due to outages for the Trimble County 10 combustion turbine in spring 2008. These expenses were incorrectly recorded to the 548 account but were later reclassified to the 553 account (Maintenance of Generating and Electric Equipment) in June 2008. (All dollar amounts are rounded) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating KU's system

f. Account 560, Operation Supervision and Engineering, had a 21.33% ($156,000) increase primarily due to compliance consulting and a new department developed for reliability compliance in January – April 2008 that were not incurred in 2007 for the same period. The compliance consulting cost accounted for 15.14% ($111,000) of the variance and the new department accounted for 4.92% ($36,000) of the variance. The remaining $9,000 variance is the net of all other variances. (All amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating KU's system.

g. Account 571, Maintenance of Overhead Lines, had a 17.45% ($490,000) increase due to NERC regulation, FAC-003. The regulation FAC-003, addresses vegetation management around transmission lines. Compliance required increased spending on vegetation management of 17.28% ($486,000). The remaining $4,000 variance is the net of all other variances. (All amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining KU's system.

h. Account 583, Overhead Lines Expense, had a 16.55% ($430,000) increase due to the January and February storms of 2008. The expense attributed to the storms accounts for a 15.25% ($412,000) variance. Additionally $4,000 can be attributed to jurisdictional rate changes from January – April 2008 compared to January – April 2007. The remaining $14,000 variance is the net of all variances. (All amounts are rounded.) Storm expense is addressed in Exhibit 1, Schedule 1.18 to the testimony of S. Bradford Rives.

i. Account 593, Maintenance of Overhead Lines, had a 15.86% ($2,780,000) increase due primarily to storm restoration expense in the 1st quarter of 2008, which accounts for a 15% ($2,712,000) variance. Additionally $20,000 can be attributed to jurisdictional rate changes from January – April 2008 compared to January – April 2007. The remaining $48,000 variance is the net of all other variances. (All dollar amounts are rounded.) Storm expense is addressed in Exhibit 1, Schedule 1.18 to the testimony of S. Bradford Rives.

j. Account 904, Uncollectible Accounts, increased 43.33% ($1,007,000). The Wholesale Uncollectible Account makes up about half of the total variance and is attributed to the billing dispute with Owensboro Municipal Utilities related to backup power supplied by Kentucky Utilities. This accounts for $555,000 or 55% of the total variance between the time periods. The remaining variance of $452,000 or 45% is due to higher net customer charge-offs during the 12 months of the test year as compared to 2007 actual costs. (See response to PSC 2-132(n).) (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses.

k. Account 905, Miscellaneous Customer Account Expenses, increased 39.29% ($64,000), due largely to the creation of a new department (Retail Strategy and Operational Analysis). This department supports the Retail Business by developing process improvements and cost analyses. This accounts for 90% or $58,000 of the variance. Also, 10% or $6,000 of the variance is due to temporary housing for employees from other parts of the state temporarily working in Lexington. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses.

l. Account 923, Outside Services, increased 19.57% ($1,564,000) due largely to increased legal expenses on environmental, contract, and regulatory issues ($1,183,000). (See response to AG 2-26(c).) Additionally, there was an increase in expenses for outside IT consultants ($149,000). Furthermore, there were additional expenses for a carbon study ($102,000), audit fees ($39,000), and environmental consulting ($28,000, due to increased regulations). The remaining $63,000 variance is the net of all other Outside Services variances. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses.

EXHIBIT___(LK-13)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Set of Data Requests of the Kentucky Industrial Utility Customers, Inc. Dated September 24, 2008

Question No. 2.21

Responding Witness: *Paul W. Thompson / Chris Hermann / Shannon L. Charnas*

Q-2.21. Please refer to the variances comparing test year vs. 2007 actual costs for each of the O&M accounts found in LG&E's response to PSC-1 Question 23 (b) for the electric operations. For each of the FERC accounts listed below, please describe all reasons for the increases in expense in the test year compared to those incurred in 2007. Please quantify the effects of each reason cited.

a. Acct 506 Miscellaneous Steam Power Expenses - +21.22%

b. Acct 510 Maintenance Supervision and Engineering - +14.59%.

c. Acct 512 Maintenance of Boiler Plant - +18.40%.

d. Acct 513 Maintenance of Electric Plant - +36.15%.

e. Acct 548 Generation Expenses - +175.45%.

f. Acct 560 Operation Supervision and Engineering - +14.88%

g. Acct 571 Maintenance of Overhead Lines - +11.72%

h. Acct 583 Overhead Line Expenses - +20.77%.

i. Acct 584 Underground Line Expenses - +15.90%.

j. Acct 593 Maintenance of Overhead Lines - +22.18%.

A-2.21. From LG&E's response to PSC-1 Question No. 23(b), Total Electric Operation and Maintenance Expense increased 2.30% from 2007 to the test year.

a. Account 506, Miscellaneous Steam Power Expenses, had a 21.22% ($2,974,000) increase; however, of this amount, $2,771,000 should be netted with account 558, *Duplicate Charges Credit*, leaving a 1.44% ($203,000) increase. Charges for auxiliary station power are recorded to account 506 in order to account for the cost of running the stations for management reporting purposes. These charges are normally offset by credits in Account 558 for FERC reporting; however, in the balances provided in the test year in the response to PSC 1-23(b) this netting was not reflected. The $203,000 variance is attributed to increased labor costs. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating LG&E's system.

b. Account 510, Maintenance Supervision and Engineering, had a 14.59% ($299,000) increase due to planned inspections and repairs for high energy piping at Cane Run in the first quarter of 2008. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining LG&E's system.

c. Account 512, Maintenance of Boiler Plant, had an 18.40% ($6,198,000) increase. Of this amount, $3,502,000 is due to higher outage cost primarily from Cane Run Unit 5's major turbine overhaul during the spring of 2008 which contributed $2,157,000 of the variance. Major turbine overhauls generally occur every 5-7 years for all LG&E steam generating units. In addition, Mill Creek 4 contributed $1,046,000 because it had a four week outage in 2008 versus a one week outage in 2007 and other outages contributed $299,000. The remaining $2,696,000 is attributed to costs for non-outage maintenance items such as: mills/feeders ($587,000), scrubbers ($374,000), sludge processing plant/thickeners ($349,000), limestone processing related maintenance ($340,000), primary fuel combustion ($298,000), ash handling ($171,000), boiler maintenance ($137,000), service water systems ($126,000), general maintenance ($105,000), barge unloader ($85,000), and sumps ($38,000). The remaining $86,000 variance is the net of all remaining variances. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining LG&E's system.

d. Account 513, Maintenance of Electric Plant, had a 36.15% ($2,003,000) increase due to Cane Run Unit 5's major turbine overhaul during the spring of 2008. The outages related this overhaul were $1,632,000. Major turbine overhauls generally occur every 5-7 years for all LG&E steam generating units. In addition, $310,000 is attributed to non-outage maintenance costs for generators at various units. The remaining $61,000 variance is the net of all other variances. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining LG&E's system.

e. Account 548, Generation Expenses, had a 175.45% ($589,000) increase. This was due to outages $(594,000) for Trimble County 10 Combustion

Turbine in spring 2008. These expenses were incorrectly recorded to the 548 account but were later reclassified by moving them to the 553 account (Maintenance of Generating and Electric Equipment) in June 2008. The remaining $5,000 variance is the net of all other variances. (All dollar amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating LG&E's system.

f. Account 560, Operation Supervision and Engineering, had a 14.88% ($92,000) increase primarily due to compliance consulting and a new department developed for reliability compliance in January – April 2008 that were not incurred in 2007 for the same period. The compliance consulting cost accounted for 82% ($75,000) of the variance and the new department costs were $27,000. The remaining $10,000 variance is the net of all other variances. (All amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating LG&E's system.

g. Account 571, Maintenance of Overhead Lines, had an 11.72% ($83,000) increase due to NERC regulation, FAC-003. The regulation FAC-003 addresses vegetation management around transmission lines. Compliance required increased spending on vegetation management of 11% ($81,000). The remaining $2,000 variance is the net of all other variances. (All amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with maintaining LG&E's system.

h. Account 583, Overhead Line Expense, had a 20.77% ($777,000) due to the January and February storms of 2008. The expense attributed to the storms accounts for a 20.71% ($732,000) variance. The remaining 6% ($46,000) variance is the net of all variances. (All amounts are rounded.) Storm expense is addressed in Exhibit 1, Schedule 1.18 to the testimony of S. Bradford Rives.

i. Account 584, Underground Line Expenses had a 15.90% ($60,000) increase due to inspection work performed January – April 2008 of $63,000. The remaining negative $3,000 variance is the net of all variances. (All amounts are rounded.) The amounts reflected in the test year for this account are normal and recurring expenses associated with operating LG&E's system.

j. Account 593, Maintenance of Overhead Lines, had a 22.18% ($2,281,000) variance due primarily to storm restoration expense in the first quarter of 2008. The storm restoration expense accounts for a 20% ($1,992,000) variance. The remaining 2% ($289,000) can be attributed to increased tree trimming expense. (All amounts are rounded.) Storm expense is addressed in Exhibit 1, Schedule 1.18 to the testimony of S. Bradford Rives.

EXHIBIT___(LK-14)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 20

Responding Witness: Shannon L. Charnas / John J. Spanos

Q-20. In Case No, 2007-00565, KU requests approval of a depreciation study based on the equal life group ("ELG") method for all plant placed into service as of December 31, 2006. The results of the study were summarized in KU's application at *Exhibit JJS-KU, III-4 through III-10*. As shown on page III-10, the equal life group method resulted in an annual depreciation expense for KU of $111,765,099.

a. Refer to KU's response to Staff's Second Request, Item 84(c). It is stated that, during the formulation of the depreciation study, the average life group method was applied to calculate depreciable lives at the same time that the equal life group was used. Provide the results of the depreciation study using the average life group method when applied to plant in service as of December 31, 2006. Provide this response in the same format as Exhibit JJS-KU, III-4 through III-10.

b. Provide the workpapers that clearly demonstrate the core/root differences in the equal life group method used to calculate the depreciation shown in KU's application at Exhibit JJS-KU, III-4 through III-10 and the depreciation calculated in (a) using the average life group.

c. Using the composite depreciation rates provided in (a), recalculate depreciation for plant in service as of April 30, 2008. The response to this request should be presented in the same format used in KU's response to Staffs Second Request, Item 90, pages 2 – 10.

A-20. a. See attached, as was provided in Case No. 2007-00565, Response to the Attorney General's Initial Requests for Information dated February 4, 2008, Question No. 27.

b. Other than the testimony referenced in KU's response to PSC-2 Question No. 84, there are no workpapers that demonstrate the core/root differences in the ELG method. The root differences between the average service life and equal life group procedures deal with the recovery rates of plant in service. The average service life procedure is based on direct weighting of all plant assets regardless of their age. The equal life group procedure more appropriately matches the level of recovery to the usefulness of the asset Therefore, using the equal life group procedure is designed to recover each vintage based on its attained age.

c. See attached.

Attachment to Response to PSC-3 Question No. 20(a)
Responding Witness – Charnas / Spanos

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2008

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DEPRECIABLE PLANT								
	STEAM PRODUCTION PLANT								
311.00	STRUCTURES AND IMPROVEMENTS								
	TYRONE UNIT 3	100-S1.5	(5)	5,447,348.04	5,719,715	0	0		
	TYRONE UNITS 1 & 2	100-S1.5	(5)	594,089.12	623,794	0	0		
	GREEN RIVER UNIT 3	100-S1.5	(5)	2,818,747.44	2,959,685	0	0		
	GREEN RIVER UNIT 4	100-S1.5	(5)	4,475,383.64	4,699,153	0	0		
	GREEN RIVER UNITS 1 & 2	100-S1.5	(5)	2,596,569.06	2,726,419	0	0		
	E W BROWN STEAM UNIT 1	100-S1.5	(5)	4,294,488.60	4,007,844	501,368	25,845	0.60	19.4
	E W BROWN STEAM UNIT 2	100-S1.5	(5)	1,542,703.85	1,595,211	24,629	1,266	0.08	19.5
	E W BROWN STEAM UNIT 3	100-S1.5	(5)	12,466,774.95	11,779,068	1,311,046	67,803	0.54	19.3
	GHENT UNIT 1 SCRUBBER	100-S1.5	(5)	24,298,756.00	13,016,631	12,497,063	644,511	2.65	19.4
	GHENT UNIT 1	100-S1.5	(5)	17,160,534.10	16,736,391	1,282,170	66,702	0.39	19.2
	GHENT UNIT 2	100-S1.5	(5)	16,175,819.55	15,355,831	1,628,781	81,369	0.50	20.0
	GHENT UNIT 3	100-S1.5	(5)	43,264,065.36	30,770,444	14,656,826	512,840	1.19	28.6
	GHENT UNIT 4	100-S1.5	(5)	22,674,760.92	14,633,236	9,175,272	319,236	1.41	28.7
	SYSTEM LABORATORY	100-S1.5	(5)	805,717.00	488,697	357,306	12,400	1.54	28.8
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS			158,615,785.63	125,112,119	41,434,461	1,731,972	1.09	23.9
312.00	BOILER PLANT EQUIPMENT								
	TYRONE UNIT 3	65-R2	(20)	12,078,002.67	9,052,070	5,441,534	480,468	3.98	11.3
	TYRONE UNITS 1 & 2	65-R2	(20)	3,531,623.26	4,193,561	44,386	3,995	0.11	11.1
	GREEN RIVER UNIT 3	65-R2	(20)	11,195,261.77	9,565,842	3,868,472	342,647	3.05	11.3
	GREEN RIVER UNIT 4	65-R2	(20)	23,652,944.82	17,191,268	11,192,270	989,652	4.18	11.3
	GREEN RIVER UNITS 1 & 2	65-R2	(20)	399,431.39	382,655	96,664	8,633	2.16	11.2
	E W BROWN STEAM UNIT 1	65-R2	(20)	35,546,187.28	22,971,136	19,684,289	1,055,029	2.97	18.7
	E W BROWN STEAM UNIT 2	65-R2	(20)	29,161,949.77	18,640,534	16,353,806	876,626	3.01	18.7
	E W BROWN STEAM UNIT 3	65-R2	(20)	79,655,480.64	54,260,794	41,325,781	2,224,398	2.79	18.6
	PINEVILL UNIT 3	65-R2	(20)	279,751.37	335,702	0	0		
	GHENT UNIT 1 SCRUBBER	65-R2	(20)	86,520,258.20	40,651,742	63,172,568	3,343,532	3.86	18.9
	GHENT UNIT 1	65-R2	(20)	162,626,761.08	77,653,906	117,498,208	6,234,675	3.83	18.8
	GHENT UNIT 2	65-R2	(20)	89,742,087.02	67,526,984	40,163,521	2,086,217	2.32	19.3
	GHENT UNIT 3	65-R2	(20)	244,747,430.08	118,161,545	175,535,370	6,428,604	2.63	27.3
	GHENT UNIT 4	65-R2	(20)	247,916,189.17	107,189,341	190,310,084	6,912,298	2.79	27.5
	GHENT LOCOMOTIVES - RAIL CARS	25-R2	20	7,647,232.00	3,735,435	2,382,351	191,047	2.50	12.5
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT			1,034,700,590.52	551,512,513	687,069,304	31,177,821	3.01	22.0

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2008

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
314.00	TURBOGENERATOR UNITS								
	TYRONE UNIT 3	55-R2.5	(15)	4,154,426.75	3,150,207	1,627,384	142,875	3.44	11.4
	TYRONE UNITS 1 & 2	55-R2.5	(15)	1,592,029.00	1,830,833	0	0		
	GREEN RIVER UNIT 3	55-R2.5	(15)	4,214,807.78	3,456,160	1,390,868	122,123	2.90	11.4
	GREEN RIVER UNIT 4	55-R2.5	(15)	10,005,416.72	7,204,057	4,302,172	379,045	3.79	11.4
	E W BROWN STEAM UNIT 1	55-R2.5	(15)	4,997,832.45	4,768,464	979,022	56,161	1.12	17.4
	E W BROWN STEAM UNIT 2	55-R2.5	(15)	10,874,093.96	6,624,591	5,880,817	318,738	2.91	18.6
	E W BROWN STEAM UNIT 3	55-R2.5	(15)	27,652,379.12	15,467,528	16,332,708	875,203	3.17	18.7
	PINEVILL UNIT 3	55-R2.5	(15)	6.00	7	0	0		
	GHENT UNIT 1	55-R2.5	(15)	25,577,292.00	19,103,945	10,309,940	569,356	2.23	18.1
	GHENT UNIT 2	55-R2.5	(15)	29,546,660.86	22,424,968	11,553,692	613,544	2.08	18.8
	GHENT UNIT 3	55-R2.5	(15)	39,424,927.73	24,916,555	20,422,112	798,801	2.03	25.6
	GHENT UNIT 4	55-R2.5	(15)	51,736,214.11	29,734,684	29,761,963	1,137,802	2.20	26.2
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS			209,776,086.48	138,682,019	102,580,478	5,011,648	2.39	20.5
315.00	ACCESSORY ELECTRIC EQUIPMENT								
	TYRONE UNIT 3	70-S3	(5)	570,737.00	599,274	0	0		
	TYRONE UNITS 1 & 2	70-S3	(5)	828,017.00	869,418	0	0		
	GREEN RIVER UNIT 3	70-S3	(5)	741,256.89	778,320	0	0		
	GREEN RIVER UNIT 4	70-S3	(5)	1,145,214.38	1,010,620	191,856	16,603	1.46	11.5
	E W BROWN STEAM UNIT 1	70-S3	(5)	3,329,621.65	2,135,619	1,359,465	69,775	2.10	19.5
	E W BROWN STEAM UNIT 2	70-S3	(5)	997,856.05	954,378	93,372	4,793	0.48	19.5
	E W BROWN STEAM UNIT 3	70-S3	(5)	5,145,132.14	4,865,606	536,781	27,693	0.54	19.4
	PINEVILL UNIT 3	70-S3	(5)	4,091.00	4,298	0	0		
	GHENT UNIT 1 SCRUBBER	70-S3	(5)	3,016,784.00	1,580,263	1,587,360	81,487	2.70	19.5
	GHENT UNIT 1	70-S3	(5)	7,641,004.90	7,214,612	808,444	42,128	0.55	19.2
	GHENT UNIT 2	70-S3	(5)	10,785,959.00	10,038,015	1,287,242	64,799	0.60	19.9
	GHENT UNIT 3	70-S3	(5)	25,961,222.00	19,793,702	7,465,581	268,633	1.03	27.8
	GHENT UNIT 4	70-S3	(5)	21,911,934.44	15,446,906	7,560,624	267,375	1.22	28.3
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT			82,078,830.45	65,292,029	20,890,745	843,366	1.03	24.8
316.00	MISCELLANEOUS PLANT EQUIPMENT								
	TYRONE UNIT 3	70-R1.5	0	508,751.25	329,761	178,990	15,874	3.12	11.3
	TYRONE UNITS 1 & 2	70-R1.5	0	59,096.15	59,096	0	0		
	GREEN RIVER UNIT 3	70-R1.5	0	153,389.71	84,649	68,741	6,085	3.97	11.3
	GREEN RIVER UNIT 4	70-R1.5	0	2,096,051.79	1,455,549	640,502	56,857	2.71	11.3
	GREEN RIVER UNITS 1 & 2	70-R1.5	0	84,747.63	84,748	0	0		
	E W BROWN STEAM UNIT 1	70-R1.5	0	424,040.93	243,531	180,510	9,584	2.26	18.8
	E W BROWN STEAM UNIT 2	70-R1.5	0	85,648.00	74,409	11,239	606	0.71	18.5
	E W BROWN STEAM UNIT 3	70-R1.5	0	4,233,635.78	2,389,102	1,844,533	98,615	2.33	18.7
	PINEVILL UNIT 3	70-R1.5	0	56,611.00	56,611	0	0		
	GHENT UNIT 1 SCRUBBER	70-R1.5	0	985,410.00	454,155	531,255	28,319	2.87	18.8
	GHENT UNIT 1	70-R1.5	0	1,756,976.98	1,308,821	448,156	24,202	1.38	18.5
	GHENT UNIT 2	70-R1.5	0	1,493,092.78	1,187,409	305,684	15,946	1.07	19.2
	GHENT UNIT 3	70-R1.5	0	3,118,291.77	1,956,104	1,162,188	43,528	1.40	26.7
	GHENT UNIT 4	70-R1.5	0	6,052,103.27	2,685,232	3,366,872	122,832	2.03	27.4
	SYSTEM LABORATORY	70-R1.5	0	2,198,264.39	525,026	1,673,239	60,185	2.74	27.8
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT			23,306,111.44	12,894,203	10,411,909	482,613	2.07	21.6
	TOTAL STEAM PRODUCTION PLANT			1,508,477,404.52	893,492,883	862,366,897	39,247,420		

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2008

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	HYDROELECTRIC PRODUCTION PLANT								
330.10	LAND AND LAND RIGHTS								
	DIX DAM	100-R4 *	0	879,311.47	905,781	(26,470)	0		
	TOTAL ACCOUNT 330.1 - LAND RIGHTS			879,311.47	905,781	(26,470)	0		
331.00	STRUCTURES AND IMPROVEMENTS								
	DIX DAM	90-S2.5 *	(5)	453,195.00	316,800	159,057	5,836	1.29	27.3
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS			453,195.00	316,800	159,057	5,836	1.29	27.3
332.00	RESERVOIRS, DAMS & WATERWAY								
	DIX DAM	100-S2.5 *	0	7,954,452.04	6,384,461	1,569,991	56,906	0.72	27.6
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS & WATERWAYS			7,954,452.04	6,384,461	1,569,991	56,906	0.72	27.6
333.00	WATER WHEELS, TURBINES & GENERATORS								
	DIX DAM	60-R3 *	(10)	420,536.56	394,072	68,518	2,770	0.66	24.7
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES & GENERATORS			420,538.56	394,072	68,518	2,770	0.66	24.7
334.00	ACCESSORY ELECTRIC EQUIPMENT								
	DIX DAM	40-L2.5 *	0	85,383.14	76,888	8,495	707	0.83	12.0
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT			85,383.14	76,888	8,495	707	0.83	12.0
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT								
	DIX DAM	35-L1 *	0	101,512.96	39,455	62,058	3,603	3.55	17.2
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT			101,512.96	39,455	62,058	3,603	3.55	17.2
336.00	ROADS, RAILROADS, & BRIDGES								
	DIX DAM	55-R4 *	0	46,976.13	48,390	(1,414)	0		
	TOTAL ACCOUNT 336 - ROADS, RAILROADS & BRIDGES			46,976.13	48,390	(1,414)	0		
	TOTAL HYDROELECTRIC PRODUCTION PLANT			9,941,367.30	8,165,847	1,840,235	69,822		
	OTHER PRODUCTION PLANT								
340.10	LAND RIGHTS								
	E W BROWN CT UNIT 9 GAS PIPE	30-R0.5 *	0	176,409.31	71,698	104,711	5,231	2.97	20.0
	TOTAL ACCOUNT 340.1 - LAND RIGHTS			176,409.31	71,698	104,711	5,231	2.97	20.0

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KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
341.00	STRUCTURES AND IMPROVEMENTS								
	PADDY'S RUN GENERATOR 13	40-R2.5	0	1,910,328.00	374,109	1,536,219	57,947	3.03	26.5
	E W BROWN CT UNIT 5	40-R2.5	0	775,082.20	149,620	625,262	23,569	3.04	26.5
	E W BROWN CT UNIT 6	40-R2.5	0	192,813.69	36,791	156,023	5,890	3.05	26.5
	E W BROWN CT UNIT 7	40-R2.5	0	544,966.20	126,941	418,026	15,978	2.93	26.2
	E W BROWN CT UNIT 8	40-R2.5	0	2,012,654.53	717,642	1,295,013	52,375	2.60	24.7
	E W BROWN CT UNIT 9	40-R2.5	0	4,641,054.53	1,654,146	2,986,909	120,844	2.60	24.7
	E W BROWN CT UNIT 10	40-R2.5	0	1,865,718.54	662,603	1,203,116	48,615	2.61	24.7
	E W BROWN CT UNIT 11	40-R2.5	0	1,858,754.33	579,307	1,279,447	50,541	2.72	25.3
	TRIMBLE COUNTY CT UNIT 5	40-R2.5	0	3,740,231.26	592,365	3,147,866	117,507	3.14	26.8
	TRIMBLE COUNTY CT UNIT 6	40-R2.5	0	3,588,684.33	588,760	2,999,924	112,134	3.12	26.8
	TRIMBLE COUNTY CT UNIT 7	40-R2.5	0	3,559,154.97	343,098	3,216,057	118,324	3.32	27.2
	TRIMBLE COUNTY CT UNIT 8	40-R2.5	0	3,548,851.71	342,104	3,206,748	117,982	3.32	27.2
	TRIMBLE COUNTY CT UNIT 9	40-R2.5	0	3,655,976.41	352,432	3,303,544	121,543	3.32	27.2
	TRIMBLE COUNTY CT UNIT 10	40-R2.5	0	3,653,029.99	352,147	3,300,883	121,445	3.32	27.2
	HAEFLING UNITS 1, 2 & 3	40-R2.5	0	434,853.00	337,009	97,844	28,116	6.47	3.5
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS			35,982,153.69	7,209,274	28,772,881	1,112,810	3.09	25.9
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES								
	PADDY'S RUN GENERATOR 13	45-R2.5	(5)	1,995,102.07	402,765	1,692,092	62,056	3.11	27.3
	E W BROWN CT UNIT 5	45-R2.5	(5)	727,929.00	147,963	616,363	22,611	3.11	27.3
	E W BROWN CT UNIT 6	45-R2.5	(5)	146,515.00	39,566	115,275	4,285	2.92	26.9
	E W BROWN CT UNIT 7	45-R2.5	(5)	145,745.00	38,363	114,669	4,263	2.92	26.9
	E W BROWN CT UNIT 8	45-R2.5	(5)	19,613.00	7,132	13,461	516	2.63	26.1
	E W BROWN CT UNIT 9	45-R2.5	(5)	1,932,186.25	694,487	1,334,308	51,129	2.65	26.1
	E W BROWN CT UNIT 10	45-R2.5	(5)	31,737.00	11,607	21,717	834	2.63	26.0
	E W BROWN CT UNIT 11	45-R2.5	(5)	52,430.00	17,145	37,907	1,436	2.74	26.4
	E W BROWN CT UNIT 9 GAS PIPE	45-R2.5	(5)	8,106,131.85	3,135,265	5,376,173	208,199	2.57	25.8
	TRIMBLE COUNTY CT UNIT 5	45-R2.5	(5)	239,584.84	40,738	210,825	7,685	3.21	27.4
	TRIMBLE COUNTY CT UNIT 6	45-R2.5	(5)	239,245.94	40,695	210,513	7,674	3.21	27.4
	TRIMBLE COUNTY CT PIPELINE	45-R2.5	(5)	4,850,114.45	786,421	4,306,200	156,779	3.23	27.5
	TRIMBLE COUNTY CT UNIT 7	45-R2.5	(5)	578,059.38	57,997	548,965	19,797	3.42	27.7
	TRIMBLE COUNTY CT UNIT 8	45-R2.5	(5)	576,385.74	57,829	547,376	19,739	3.42	27.7
	TRIMBLE COUNTY CT UNIT 9	45-R2.5	(5)	593,786.01	59,574	563,901	20,335	3.42	27.7
	TRIMBLE COUNTY CT UNIT 10	45-R2.5	(5)	593,307.31	59,526	563,447	20,319	3.42	27.7
	HAEFLING UNITS 1, 2 & 3	45-R2.5	(5)	181,132.00	190,189	0	0		
	TOTAL ACCOUNT 342 - FULE HOLDERS, PRODUCERS AND ACCESSORIES			21,009,004.64	5,786,262	16,273,192	607,657	2.89	26.8
343.00	PRIME MOVERS								
	PADDY'S RUN GENERATOR 13	35-R1	(5)	17,420,148.57	3,208,506	15,082,650	831,235	3.62	23.9
	E W BROWN CT UNIT 5	35-R1	(5)	13,164,181.28	2,305,155	11,517,235	480,759	3.65	24.0
	E W BROWN CT UNIT 6	35-R1	(5)	30,399,242.38	6,414,963	25,504,241	1,078,577	3.55	23.6
	E W BROWN CT UNIT 7	35-R1	(5)	30,001,197.85	6,051,567	25,449,672	1,072,644	3.58	23.7
	E W BROWN CT UNIT 8	35-R1	(5)	20,074,864.20	5,994,874	15,083,733	662,762	3.30	22.8
	E W BROWN CT UNIT 9	35-R1	(5)	21,502,645.45	6,950,677	15,627,102	695,270	3.23	22.5
	E W BROWN CT UNIT 10	35-R1	(5)	[illegible]	6,157,303	14,496,817	641,188	3.26	22.6
	E W BROWN CT UNIT 11	35-R1	(5)	34,239,853.35	8,782,372	27,169,474	1,169,194	3.41	23.2
	TRIMBLE COUNTY CT UNIT 5	35-R1	(5)	30,530,609.97	4,681,480	27,375,660	1,134,897	3.72	24.1
	TRIMBLE COUNTY CT UNIT 6	35-R1	(5)	30,442,270.01	4,682,426	27,281,957	1,131,153	3.72	24.1
	TRIMBLE COUNTY CT UNIT 7	35-R1	(5)	22,773,633.23	2,046,994	21,865,531	891,491	3.91	24.5
	TRIMBLE COUNTY CT UNIT 8	35-R1	(5)	22,568,286.07	2,036,130	21,660,571	883,200	3.91	24.5

KENTUCKY UTILITIES
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	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	TRIMBLE COUNTY CT UNIT 9	35-R1	(5)	22,401,685.39	2,020,924	21,500,846	876,686	3.91	24.5
	TRIMBLE COUNTY CT UNIT 10	35-R1	(5)	22,378,127.55	2,018,755	21,478,279	875,765	3.91	24.5
	TOTAL ACCOUNT 343 - PRIME MOVERS			337,567,592.79	63,352,205	291,093,768	12,224,621	3.62	23.8
344.00	GENERATORS								
	PADDY'S RUN GENERATOR 13	55-S3	(5)	5,185,636.00	1,003,503	4,441,415	152,468	2.94	29.1
	E W BROWN CT UNIT 5	55-S3	(5)	2,831,528.00	548,012	2,425,092	83,251	2.94	29.1
	E W BROWN CT UNIT 6	55-S3	(5)	3,712,349.00	930,433	2,967,533	102,435	2.76	29.0
	E W BROWN CT UNIT 7	55-S3	(5)	3,722,788.00	931,357	2,977,570	102,778	2.76	29.0
	E W BROWN CT UNIT 8	55-S3	(5)	4,953,961.00	1,738,820	3,464,839	121,659	2.46	28.5
	E W BROWN CT UNIT 9	55-S3	(5)	5,452,041.03	2,153,184	3,571,459	126,095	2.31	28.3
	E W BROWN CT UNIT 10	55-S3	(5)	4,944,693.00	1,733,570	3,458,358	121,431	2.46	28.5
	E W BROWN CT UNIT 11	55-S3	(5)	5,187,040.00	1,694,228	3,752,164	131,089	2.53	28.6
	TRIMBLE COUNTY CT UNIT 5	55-S3	(5)	3,763,274.68	610,505	3,340,933	114,413	3.04	29.2
	TRIMBLE COUNTY CT UNIT 6	55-S3	(5)	3,757,946.86	609,864	3,335,980	114,243	3.04	29.2
	TRIMBLE COUNTY CT UNIT 7	55-S3	(5)	2,950,282.37	282,683	2,815,113	96,079	3.26	29.3
	TRIMBLE COUNTY CT UNIT 8	55-S3	(5)	2,937,930.22	281,499	2,803,328	95,677	3.26	29.3
	TRIMBLE COUNTY CT UNIT 9	55-S3	(5)	2,957,520.12	283,376	2,822,020	96,315	3.26	29.3
	TRIMBLE COUNTY CT UNIT 10	55-S3	(5)	2,954,148.53	283,053	2,818,803	96,205	3.26	29.3
	HAEFLING UNITS 1, 2 & 3	55-S3	(5)	4,023,003.00	4,224,153	0	0	-	
	TOTAL ACCOUNT 344 - GENERATORS			59,334,141.81	17,306,240	44,994,607	1,554,136	2.62	29.0
345.00	ACCESSORY ELECTRIC EQUIPMENT								
	PADDY'S RUN GENERATOR 13	45-R3	0	2,456,320.00	488,379	1,967,941	70,864	2.88	27.8
	E W BROWN CT UNIT 5	45-R3	0	1,332,167.00	264,860	1,067,307	38,434	2.89	27.8
	E W BROWN CT UNIT 6	45-R3	0	1,354,817.00	349,592	1,005,225	36,700	2.71	27.4
	E W BROWN CT UNIT 7	45-R3	0	1,347,700.00	347,755	999,945	36,508	2.71	27.4
	E W BROWN CT UNIT 8	45-R3	0	1,797,054.00	650,416	1,146,638	43,382	2.41	26.4
	E W BROWN CT UNIT 9	45-R3	0	3,226,185.73	1,256,027	1,970,159	74,763	2.32	26.4
	E W BROWN CT UNIT 10	45-R3	0	1,804,419.00	637,098	1,167,321	43,992	2.44	26.5
	E W BROWN CT UNIT 11	45-R3	0	916,326.00	308,077	608,249	22,764	2.48	26.7
	TRIMBLE COUNTY CT UNIT 5	45-R3	0	1,677,092.15	279,094	1,397,998	50,032	2.98	27.9
	TRIMBLE COUNTY CT UNIT 6	45-R3	0	1,674,719.12	278,801	1,395,918	49,958	2.98	27.9
	TRIMBLE COUNTY CT UNIT 7	45-R3	0	3,146,235.12	308,469	2,837,766	100,487	3.19	28.2
	TRIMBLE COUNTY CT UNIT 8	45-R3	0	3,137,127.45	307,577	2,829,550	100,197	3.19	28.2
	TRIMBLE COUNTY CT UNIT 9	45-R3	0	3,231,827.28	316,862	2,914,965	103,221	3.19	28.2
	TRIMBLE COUNTY CT UNIT 10	45-R3	0	3,229,222.72	316,607	2,912,616	103,138	3.19	28.2
	HAEFLING UNITS 1, 2 & 3	45-R3	0	621,207.00	621,207	0	0		
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT			30,952,419.57	6,730,821	24,221,598	874,440	2.83	27.7

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	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
346.00	MISCELLANEOUS PLANT EQUIPMENT								
	PADDY'S RUN GENERATOR 13	35-R2	0	1,089,549.00	224,313	865,236	34,901	3.20	24.8
	E W BROWN CT UNIT 5	35-R2	0	2,108,910.25	435,769	1,673,141	67,461	3.20	24.8
	E W BROWN CT UNIT 6	35-R2	0	48,958.84	7,842	41,117	1,632	3.33	25.2
	E W BROWN CT UNIT 7	35-R2	0	35,647.85	6,966	28,680	1,153	3.23	24.9
	E W BROWN CT UNIT 8	35-R2	0	230,069.23	86,699	143,370	6,378	2.77	22.5
	E W BROWN CT UNIT 9	35-R2	0	760,256.23	287,309	472,947	21,049	2.77	22.5
	E W BROWN CT UNIT 10	35-R2	0	274,390.79	94,590	179,801	7,833	2.85	23.0
	E W BROWN CT UNIT 11	35-R2	0	548,588.10	111,544	437,044	17,654	3.22	24.7
	TRIMBLE COUNTY CT UNIT 5	35-R2	0	15,274.16	324	14,950	569	3.73	26.3
	TRIMBLE COUNTY CT UNIT 7	35-R2	0	8,688.93	699	7,990	311	3.50	25.7
	TRIMBLE COUNTY CT UNIT 8	35-R2	0	8,861.01	895	7,966	310	3.50	25.7
	TRIMBLE COUNTY CT UNIT 9	35-R2	0	9,113.52	921	8,193	319	3.50	25.7
	TRIMBLE COUNTY CT UNIT 10	35-R2	0	9,105.52	921	8,185	318	3.49	25.7
	HAEFLING UNITS 1, 2 & 3	35-R2	0	35,805.00	35,805	0	0		
	TOTAL ACCOUNT 346 - MISCELLANEOUS PLANT EQUIPMENT			5,183,418.47	1,294,799	3,888,620	159,898	3.08	24.3
	TOTAL OTHER PRODUCTION PLANT			490,205,140.28	101,751,300	409,349,377	16,538,993		
	TRANSMISSION PLANT								
350.10	LAND AND LAND RIGHTS	60-R3	0	23,341,455.00	15,050,587	8,290,867	229,612	0.98	36.1
352.10	STRUCTURES & IMPROVEMENTS-NON SYS CONTROL/COM	65-S2.5	(25)	6,979,653.25	3,813,782	4,910,791	107,419	1.54	45.7
352.20	STRUCTURES & IMPROVEMENTS - SYS CONTROL/COM	60-R3	(25)	1,167,783.17	813,907	645,823	16,739	1.43	38.6
353.10	STATION EQUIPMENT - NON SYS CONTROL/COM	60-R2	(20)	173,142,340.90	59,471,929	148,298,883	3,431,123	1.98	43.2
353.20	STATION EQUIPMENT - SYS CONTROL/COM	30-R2.5	(20)	14,749,280.69	18,016,356	1,682,783	68,381	0.46	24.6
354.00	TOWERS AND FIXTURES	70-R4	(25)	63,308,079.23	42,955,413	36,179,691	763,846	1.21	47.4
355.00	POLES AND FIXTURES	50-R2	(60)	91,302,830.77	64,368,897	81,715,632	2,079,841	2.28	39.3
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R3	(50)	129,755,652.44	100,060,047	94,573,434	2,325,390	1.79	40.7
357.00	UNDERGROUND CONDUIT	40-L2.5	0	448,760.26	134,595	314,165	11,690	2.60	26.9
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-R3	0	1,114,761.90	802,730	312,032	14,059	1.26	22.2
	TOTAL TRANSMISSION PLANT			505,310,597.61	303,488,243	378,924,101	9,048,100		
	DISTRIBUTION PLANT								
360.10	LAND AND LAND RIGHTS	65-R4	0	1,496,173.36	1,022,041	474,132	9,748	0.65	48.6
361.00	STRUCTURES AND IMPROVMENTS	60-R2.5	(10)	4,457,893.55	1,509,377	3,394,311	73,727	1.65	46.0
362.00	STATION EQUIPMENT	52-R2	(15)	100,792,637.54	30,916,216	84,995,316	2,295,433	2.28	37.0
364.00	POLES, TOWERS, AND FIXTURES	48-S0	(45)	193,793,678.56	108,962,347	172,038,489	4,466,396	2.30	38.5
365.00	OVERHEAD CONDUCTORS AND DEVICES	48-R2	(75)	180,861,758.25	105,672,071	210,836,003	6,121,679	3.38	34.4
366.00	UNDERGOUND CONDUIT	55-S4	0	1,728,495.59	702,456	1,026,041	33,382	1.93	30.7
367.00	UNDERGROUND CONDUCTORS AND DEVICES	44-S0.5	(5)	70,302,254.23	18,432,179	55,365,190	1,471,673	2.09	37.6
368.00	LINE TRANSFORMERS	40-R3	(20)	238,783,304.20	85,924,400	200,815,470	7,390,399	3.10	27.1
369.00	SERVICES	43-R1.5	(30)	83,111,706.05	53,033,568	55,011,631	1,652,284	1.99	33.3
370.00	METERS	40-R1.5	0	64,856,075.30	26,969,792	37,886,282	1,375,008	2.12	27.5
371.00	INSTALLATIONS ON CUSTOMER PREMISES	20-R0.5	(10)	18,276,458.22	14,013,191	6,090,914	434,205	2.38	14.0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	33-R1	(5)	53,640,293.35	23,870,883	32,451,424	1,229,177	2.29	26.4
	TOTAL DISTRIBUTION PLANT			1,012,100,728.20	471,028,631	860,205,202	26,553,911		

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	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	GENERAL PLANT								
390.10	STRUCTURES AND IMPROVEMENTS-TO OWNED PROPERTY	60-S0	(5)	32,189,743.43	8,632,707	25,177,023	534,030	1.66	47.1
390.20	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	30-R1	(5)	531,973.44	372,366	186,206	8,315	1.56	22.4
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	6,646,812.13	2,868,652	3,778,161	278,250	4.19	13.6
391.20	NON PC COMPUTER EQUIPMENT	5-SQ	0	11,291,984.97	7,567,325	3,724,660	1,144,982	10.14	3.3
391.30	CASH PROCESSING EQUIPMENT	10-SQ	0	817,574.88	532,363	285,212	45,133	5.52	6.3
391.40	PERSONAL COMPUTER EQUIPMENT	4-SQ	0	1,932,338.58	779,327	1,153,012	407,756	21.10	2.8
393.00	STORES EQUIPMENT	25-SQ	0	738,677.31	289,571	449,105	38,795	5.25	11.6
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	5,333,517.39	1,597,785	3,735,722	253,441	4.75	14.7
395.00	LABORATORY EQUIPMENT	15-SQ	0	3,202,201.94	1,586,334	1,615,868	877,936	27.42	1.8
396.00	POWER OPERATED EQUIPMENT	17-R5	0	270,941.73	99,450	171,492	17,258	6.37	9.9
397.10	COMMUNICATION EQUIPMENT - CARRIER	15-SQ	0	7,578,905.59	1,666,583	5,912,323	540,646	7.13	10.9
397.20	COMMUNICATION EQUIPMENT - REMOTE CONTROL	15-SQ	0	3,913,059.76	1,567,195	2,345,866	311,023	7.95	7.5
397.30	COMMUNICATION EQUIPMENT - MOBILE	15-SQ	0	4,659,773.21	1,806,815	2,852,958	340,124	7.30	8.4
398.00	MISCELLANEOUS EQUIPMENT	10-SQ	0	394,808.70	252,657	142,152	81,105	20.54	1.8
	TOTAL GENERAL PLANT			79,512,313.06	29,819,140	51,529,760	4,878,794		
	TOTAL DEPRECIABLE PLANT			3,605,547,550.97	1,807,546,044	2,562,215,572	96,337,040		
	NONDEPRECIABLE PLANT								
301.00	ORGANIZATION			44,455.58					
302.00	FRANCHISE AND CONSENTS			83,453.04	43,306				
303.00	MISCELLANEOUS INTANGIBLE PLANT			25,522,749.20	14,549,634				
310.10	LAND			10,478,524.56					
340.10	LAND			118,514.41					
350.10	LAND			1,168,238.43	329				
360.10	LAND			1,744,769.88					
389.10	LAND			2,811,100.83					
	TOTAL NONDEPRECIABLE PLANT			41,971,805.93	14,593,269				
	ACCOUNTS NOT STUDIED								
392.00	TRANSPORTATION EQUIPMENT			23,860,353.39	23,717,823				
	TOTAL ACCOUNTS NOT STUDIED			23,860,353.39	23,717,823				
	TOTAL ELECTRIC PLANT			3,671,379,710.29	1,845,857,136	2,562,215,572	96,337,040		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

Attachment to Response to PSC-3 Question No. 20(c)
Responding Witness – Charnas

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
Intangible Plant					
301 Organization	44,456	0.00%	-	0.00%	-
302 Franchises and Consents	83,453	0.00%	-	0.00%	-
303 Misc. Intangible Plant	25,536,344	20.00%	5,107,269	20.00%	5,107,269
Total Intangible Plant	25,664,252		5,107,269		5,107,269
Steam Production Plant					
310.00 Land	10,874,263	0.00%	-	0.00%	-
311.00 Structures and Improvements					
5603 Tyrone Unit 3	5,540,781	0.00%	-	0.00%	-
5604 Tyrone Units 1&2	583,381	0.00%	-	0.00%	-
5613 Green River Unit 3	2,818,745	0.00%	-	0.00%	-
5614 Green River Unit 4	4,584,599	0.00%	-	0.00%	-
5615 Green River Units 1&2	2,596,587	0.00%	-	0.00%	-
5621 Brown Unit 1	4,703,190	0.60%	28,219	0.59%	27,749
5622 Brown Unit 2	2,102,892	0.08%	1,682	0.06%	1,262
5623 Brown Unit 3	20,393,087	0.54%	110,123	0.55%	112,162
5643 Pineville Unit 3	16,204	0.00%	-	0.00%	-
5650 Ghent Unit 1 Scrubber	24,301,127	2.65%	643,980	2.69%	653,700
5651 Ghent Unit 1	17,401,172	0.39%	67,865	0.40%	69,605
5652 Ghent Unit 2	16,011,013	0.50%	80,055	0.52%	83,257
5653 Ghent Unit 3	41,471,559	1.19%	493,512	1.19%	493,512
5654 Ghent Unit 4	29,847,745	1.41%	420,853	1.42%	423,838
5591 System Laboratory	805,716	1.54%	12,408	1.56%	12,569
	173,177,798		1,858,696		1,877,653
312.00 Boiler Plant Equipment					
5603 Tyrone Unit 3	12,871,948	3.99%	513,591	4.30%	553,494
5604 Tyrone Units 1&2	421,900	0.14%	591	0.00%	-
5613 Green River Unit 3	11,306,456	3.08%	348,239	3.39%	383,289
5614 Green River Unit 4	24,333,224	4.20%	1,021,995	4.50%	1,094,995
5615 Green River Units 1&2	127,047	2.18%	2,770	2.52%	3,202
5621 Brown Unit 1	35,820,003	2.98%	1,067,436	3.10%	1,110,420
5622 Brown Unit 2	29,419,949	3.01%	885,540	3.14%	923,786
5623 Brown Unit 3	86,541,309	2.80%	2,423,157	2.95%	2,552,969
5643 Pineville Unit 3	226,832	0.00%	-	0.00%	-
5650 Ghent Unit 1 Scrubber	86,520,141	3.87%	3,348,329	4.01%	3,469,458
5651 Ghent Unit 1	163,735,182	3.84%	6,287,431	4.02%	6,582,154
5652 Ghent Unit 2	89,995,577	2.33%	2,096,897	2.45%	2,204,892
5653 Ghent Unit 3	259,377,006	2.63%	6,821,615	2.76%	7,158,805
5654 Ghent Unit 4	231,652,822	2.79%	6,463,114	2.94%	6,810,593
5659 Coal Cars	7,647,232	2.41%	184,298	2.41%	184,298
5660 Ghent 3 Scrubber	118,758,718	3.87%	4,595,962	4.01%	4,762,225
	1,158,755,347		36,060,966		37,794,579
314.00 Turbogenerator Units					
5603 Tyrone Unit 3	4,717,000	3.44%	162,265	3.68%	173,586
5604 Tyrone Units 1&2	68,206	0.00%	-	0.00%	-

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
5613 Green River Unit 3	4,469,895	2.90%	129,627	3.14%	140,355
5614 Green River Unit 4	10,171,918	3.79%	385,516	4.05%	411,963
5621 Brown Unit 1	4,833,421	1.12%	54,134	1.16%	56,068
5622 Brown Unit 2	11,041,057	2.91%	321,295	3.04%	335,648
5623 Brown Unit 3	27,652,377	3.17%	876,580	3.31%	915,294
5651 Ghent Unit 1	25,577,290	2.23%	570,374	2.36%	603,624
5652 Ghent Unit 2	29,546,661	2.08%	614,571	2.19%	647,072
5653 Ghent Unit 3	40,076,564	2.03%	813,554	2.11%	845,616
5654 Ghent Unit 4	51,922,998	2.20%	1,142,306	2.30%	1,194,229
	210,077,388		5,070,221		5,323,453
315.00 Accessory Electric Equipment					
5603 Tyrone Unit 3	707,890	0.00%	-	0.00%	-
5604 Tyrone Units 1&2	99,211	0.00%	-	0.00%	-
5613 Green River Unit 3	781,287	0.00%	-	0.00%	-
5614 Green River Unit 4	1,147,502	1.46%	16,754	1.47%	16,868
5621 Brown Unit 1	3,329,621	2.10%	69,922	2.09%	69,589
5622 Brown Unit 2	997,856	0.48%	4,790	0.45%	4,490
5623 Brown Unit 3	6,453,917	0.54%	34,851	0.54%	34,851
5650 Ghent Unit 1 Scrubber	3,016,784	2.70%	81,453	2.73%	82,358
5651 Ghent Unit 1	7,703,537	0.55%	42,369	0.57%	43,910
5652 Ghent Unit 2	10,873,596	0.60%	65,242	0.63%	68,504
5653 Ghent Unit 3	25,991,761	1.03%	267,715	1.05%	272,913
5654 Ghent Unit 4	21,911,936	1.22%	267,326	1.24%	271,708
5660 Ghent 3 Scrubber	11,277,367	2.70%	304,489	2.73%	307,872
	94,292,263		1,154,910		1,173,064
316.00 Miscellaneous Plant Equipment					
5603 Tyrone Unit 3	526,592	3.12%	16,430	3.45%	18,167
5604 Tyrone Units 1&2	50,127	0.00%	-	0.00%	-
5613 Green River Unit 3	153,382	3.97%	6,089	4.28%	6,565
5614 Green River Unit 4	2,165,959	2.71%	58,697	3.04%	65,845
5615 Green River Units 1&2	84,750	0.00%	-	0.00%	-
5621 Brown Unit 1	424,540	2.26%	9,595	2.41%	10,231
5622 Brown Unit 2	106,658	0.71%	757	0.82%	875
5623 Brown Unit 3	4,317,609	2.33%	100,600	2.47%	106,645
5650 Ghent Unit 1 Scrubber	985,410	2.87%	28,281	3.00%	29,562
5651 Ghent Unit 1	1,718,709	1.38%	23,718	1.51%	25,953
5652 Ghent Unit 2	1,500,525	1.07%	16,056	1.17%	17,556
5653 Ghent Unit 3	3,150,438	1.40%	44,106	1.41%	44,421
5654 Ghent Unit 4	6,247,981	2.03%	126,834	2.12%	132,457
5591 System Laboratory	2,229,677	2.74%	61,093	2.96%	65,998
	23,662,356		492,257		524,276
317.00 Asset Retirement Obligations - Steam *	9,249,179				
Total Steam	1,680,088,593		44,637,050		46,693,026

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
Hydraulic Production Plant					
5691 Dix Dam					
330 10 Land Rights	879,311	0.00%	0	0 00%	-
331 00 Structures and Improvements	453,195	1.29%	5,846	1 31%	5,937
332.00 Reservoirs, Dams & Waterways	9,025,249	0.72%	64,982	0 73%	65,884
333 00 Water Wheels, Turbines and Generators	436,634	0 66%	2,882	0.68%	2,969
334.00 Accessory Electric Equipment	85,383	0 83%	709	0 93%	794
335.00 Misc. Power Plant Equipment	101,513	3.55%	3,604	4.21%	4,274
336.00 Roads, Railroads and Bridges	46,976	0 00%	0	0.00%	-
337 00 Asset Retirement Obligation - Hydro *	4,970				
	11,033,232		78,022		79,858
Other Production Plant					
340 10 Land Rights - 5645 Brown CT 9 Gas Pipeline	176,409	2 97%	5,239	3 62%	6,386
340.20 Land	118,514	0.00%	-	0.00%	-
341 00 Structures and Improvements					
5697 Paddy's Run Generator 13	1,910,328	3.03%	57,883	3.33%	63,614
5635 Brown CT 5	775,082	3 04%	23,562	3 34%	25,888
5636 Brown CT 6	192,814	3 05%	5,881	3 40%	6,556
5637 Brown CT 7	544,966	2.93%	15,968	3.24%	17,657
5638 Brown CT 8	2,012,655	2.60%	52,329	2 87%	57,763
5639 Brown CT 9	4,641,055	2.60%	120,667	2.87%	133,198
5640 Brown CT 10	1,865,718	2.61%	48,695	2 87%	53,546
5641 Brown CT 11	1,858,754	2 72%	50,558	3.00%	55,763
0470 Trimble County CT 5	3,740,231	3 14%	117,443	3.47%	129,786
0471 Trimble County CT 6	3,588,684	3 12%	111,967	3.44%	123,451
0474 Trimble County CT 7	3,559,155	3.32%	118,164	3 69%	131,333
0475 Trimble County CT 8	3,548,852	3.32%	117,822	3.69%	130,953
0476 Trimble County CT 9	3,655,976	3.32%	121,378	3 69%	134,906
0477 Trimble County CT 10	3,653,030	3.32%	121,281	3 69%	134,797
5696 Haefling Units 1,2,&3	434,853	6 47%	28,135	8.89%	38,658
	35,982,154		1,111,734		1,237,867
342.00 Fuel Holders, Producers and Accessories					
5697 Paddy's Run Generator 13	1,995,101	3 11%	62,048	3.37%	67,235
5635 Brown CT 5	727,929	3.11%	22,639	3 36%	24,458
5636 Brown CT 6	146,515	2.92%	4,278	3 16%	4,630
5637 Brown CT 7	145,745	2 92%	4,256	3 16%	4,606
5638 Brown CT 8	19,613	2.63%	516	2.86%	561
5639 Brown CT 9	1,932,187	2.65%	51,203	2 87%	55,454
5640 Brown CT 10	31,738	2.63%	835	2 85%	905
5641 Brown CT 11	52,430	2.74%	1,437	2.96%	1,552
5645 Brown CT 9 Gas Pipeline	8,106,131	2 57%	208,328	2 79%	226,161
0470 Trimble County CT 5	239,584	3.21%	7,691	3.48%	8,338
0471 Trimble County CT 6	239,246	3.21%	7,680	3.48%	8,326
0473 Trimble County CT Pipeline	4,850,115	3.23%	156,659	3 51%	170,239
0474 Trimble County CT 7	578,059	3 42%	19,770	3 74%	21,619

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
0475 Trimble County CT 8	576,386	3.42%	19,712	3.74%	21,557
0476 Trimble County CT 9	593,786	3.42%	20,307	3.74%	22,208
0477 Trimble County CT 10	622,873	3.42%	21,302	3.74%	23,295
5696 Haefling Units 1,2,&3	227,578	0.00%	-	0.48%	1,092
	21,085,015		608,659		662,235
343.00 Prime Movers					
5697 Paddy's Run Generator 13	17,421,691	3.62%	630,665	4.49%	782,234
5635 Brown CT 5	13,182,503	3.65%	481,161	4.60%	606,395
5636 Brown CT 6	30,423,304	3.55%	1,080,027	4.52%	1,375,133
5637 Brown CT 7	30,024,907	3.58%	1,074,892	4.56%	1,369,136
5638 Brown CT 8	26,344,009	3.30%	869,352	4.13%	1,088,008
5639 Brown CT 9	21,502,647	3.23%	694,536	4.00%	860,106
5640 Brown CT 10	19,670,646	3.26%	641,263	4.04%	794,694
5641 Brown CT 11	34,931,891	3.41%	1,191,177	4.17%	1,456,660
0470 Trimble County CT 5	30,564,294	3.72%	1,136,992	4.66%	1,424,296
0471 Trimble County CT 6	30,443,723	3.72%	1,132,506	4.66%	1,418,677
0474 Trimble County CT 7	22,773,708	3.91%	890,452	5.17%	1,177,401
0475 Trimble County CT 8	22,568,161	3.91%	882,415	5.16%	1,164,517
0476 Trimble County CT 9	22,401,560	3.91%	875,901	5.16%	1,155,920
0477 Trimble County CT 10	22,385,894	3.91%	875,288	5.16%	1,155,112
	344,638,937		12,456,629		15,828,290
344.00 Generators					
5697 Paddy's Run Generator 13	5,185,636	2.94%	152,458	2.96%	153,495
5635 Brown CT 5	2,831,528	2.94%	83,247	2.96%	83,813
5636 Brown CT 6	3,712,620	2.76%	102,468	2.78%	103,211
5637 Brown CT 7	3,722,788	2.76%	102,749	2.78%	103,494
5638 Brown CT 8	4,953,961	2.46%	121,867	2.49%	123,354
5639 Brown CT 9	5,452,041	2.31%	125,942	2.36%	128,668
5640 Brown CT 10	4,944,423	2.46%	121,633	2.49%	123,116
5641 Brown CT 11	5,187,040	2.53%	131,232	2.56%	132,788
0470 Trimble County CT 5	3,763,275	3.04%	114,404	3.06%	115,156
0471 Trimble County CT 6	3,757,947	3.04%	114,242	3.06%	114,993
0474 Trimble County CT 7	2,950,282	3.26%	96,179	3.26%	96,179
0475 Trimble County CT 8	2,937,930	3.26%	95,777	3.26%	95,777
0476 Trimble County CT 9	2,957,520	3.26%	96,415	3.26%	96,415
0477 Trimble County CT 10	2,954,149	3.26%	96,305	3.26%	96,305
5696 Haefling Units 1,2,&3	4,023,002	0.00%	-	0.00%	-
	59,334,142		1,554,918		1,566,764
345.00 Accessory Electric Equipment					
5697 Paddy's Run Generator 13	2,456,320	2.88%	70,742	3.04%	74,672
5635 Brown CT 5	1,332,167	2.89%	38,500	3.04%	40,498
5636 Brown CT 6	1,354,816	2.71%	36,716	2.86%	38,748
5637 Brown CT 7	1,347,700	2.71%	36,523	2.86%	38,544
5638 Brown CT 8	1,799,436	2.41%	43,366	2.56%	46,066
5639 Brown CT 9	3,226,186	2.32%	74,848	2.49%	80,332
5640 Brown CT 10	1,804,419	2.44%	44,028	2.58%	46,554
5641 Brown CT 11	916,326	2.48%	22,725	2.63%	24,099

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
0470 Trimble County CT 5	1,677,092	2.98%	49,977	3.14%	52,661
0471 Trimble County CT 6	1,674,719	2.98%	49,907	3.14%	52,586
0474 Trimble County CT 7	3,146,235	3.19%	100,365	3.35%	105,399
0475 Trimble County CT 8	3,137,127	3.19%	100,074	3.35%	105,094
0476 Trimble County CT 9	3,231,827	3.19%	103,095	3.35%	108,266
0477 Trimble County CT 10	3,229,223	3.19%	103,012	3.35%	108,179
5696 Haefling Units 1,2,&3	623,419	0.00%	-	0.00%	-
	30,957,013		873,877		921,698
346.00 Miscellaneous Plant Equipment					
5697 Paddy's Run Generator 13	1,089,550	3.20%	34,866	3.70%	40,313
5635 Brown CT 5	2,139,353	3.20%	68,459	3.71%	79,370
5636 Brown CT 6	48,960	3.33%	1,630	3.93%	1,924
5637 Brown CT 7	35,647	3.23%	1,151	3.76%	1,340
5638 Brown CT 8	230,069	2.77%	6,373	3.20%	7,362
5639 Brown CT 9	760,255	2.77%	21,059	3.19%	24,252
5640 Brown CT 10	274,391	2.85%	7,820	3.30%	9,055
5641 Brown CT 11	548,588	3.22%	17,665	3.76%	20,627
0470 Trimble County CT 5	28,964	3.73%	1,080	4.81%	1,393
0474 Trimble County CT 7	8,889	3.50%	311	4.13%	367
0475 Trimble County CT 8	8,861	3.50%	310	4.13%	366
0476 Trimble County CT 9	9,114	3.50%	319	4.14%	377
0477 Trimble County CT 10	9,106	3.49%	318	4.13%	376

Kentucky Utilities Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
5696 Haefling Units 1,2,&3	35,805	0.00%	-	1.97%	705
	5,227,550		161,362		187,829
347 00 Asset Retirement Obligations Othe Prod *	70,990				
Total Other Production	497,590,725		16,772,417		20,411,068
Transmission Plant					
350.1 Land Rights	23,341,455	0.98%	228,746	1.12%	261,424
350.2 Land	1,232,665	0.00%	-	0.00%	-
352.1 Struct. and Impr. Non Sys Control	7,228,687	1.54%	111,322	1.75%	126,502
352.2 Struct. and Impr. Sys Control	1,154,520	1.43%	16,510	1.63%	18,819
353.1 Station Equipment	175,730,576	1.98%	3,479,465	2.46%	4,322,972
353.2 Syst Control/Microwave Equip	14,749,281	0.46%	67,847	0.56%	82,596
354 Towers & Fixtures	63,279,467	1.21%	765,682	1.30%	822,633
355 Poles & Fixtures	100,687,186	2.28%	2,295,668	2.91%	2,929,997
356 Overhead Conductors and Devices	132,799,950	1.79%	2,377,119	2.05%	2,722,399
357 Underground Conduit	448,760	2.60%	11,668	3.19%	14,315
358 Underground Conductors & Devices	1,114,762	1.26%	14,046	1.45%	16,164
359 Transmission ARO's *	11,027				
Total Transmission Plant	521,778,335		9,368,072		11,317,822
Distribution Plant					
360.1 Land Rights	1,496,173	0.65%	9,725	0.70%	10,473
360.2 Land	1,998,646	0.00%	-	0.00%	-
361 Structures and Improvements	5,058,913	1.65%	83,472	2.00%	101,178
362 Station Equipment	103,445,343	2.28%	2,358,554	2.82%	2,917,159
364 Poles Towers & Fixtures	212,853,185	2.30%	4,895,623	3.25%	6,917,729
365 Overhead Conductors and Devices	199,717,218	2.70%	5,392,365	4.23%	8,448,038
366 Underground Conduit	1,546,234	1.93%	29,842	2.06%	31,852
367 Underground Conductors & Devices	86,404,514	2.09%	1,805,854	2.86%	2,471,169
368 Line Transformers	248,482,289	3.10%	7,702,951	3.83%	9,516,872
369 Services	83,122,059	1.99%	1,654,129	2.57%	2,136,237
370 Meters	65,364,852	1.76%	1,150,421	2.79%	1,823,679
371 Installations on Customer Premises	18,284,592	2.38%	435,173	3.05%	557,680
373 Street Lighting & Signal Systems	53,771,544	2.29%	1,231,368	3.16%	1,699,181
374 Asset Retirement Cost - Distribution *	18,610				-
Total Distribution Plant	1,081,564,173		26,749,479		36,631,247

Kentucky Utilities Company
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Property Group	Depreciable Balance 4-30-08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
General Plant					
389.2 Land	2,575,973	0.00%	-	0.00%	-
390.1 Structures & Improvements	29,901,859	1.66%	496,371	2.30%	687,743
390 2 Improvements to Leased Property	531,973	1 56%	8,299	2.04%	10,852
391 1 Office Furniture & Equipment	6,548,609	4 19%	274,387	4.19%	274,387
391 2 Non PC Computer Equipment	10,163,473	10.14%	1,030,576	10 14%	1,030,576
391 3 Cash Processing Equpment	*448,191*	*23 26%*	*104,249*	*23.26%*	*104,249*
391.4 Personal Computer Equipment	2,486,306	15.47%	384,631	21 10%	524,610
392 Transportation Equipment	18,955,798	20 00%	3,791,160	20.00%	3,791,160
393 Stores Equipment	735,053	5.25%	38,590	5.25%	38,590
394 Tool, Shop & Garage Equipment	5,473,498	4.75%	259,991	4 75%	259,991
395 Laboratory Equipment	3,160,382	27.42%	866,577	27.42%	866,577
396 Power Operated Equipment	270,942	6 37%	17,259	6.62%	17,936
397 10 Communication Equipment - Carrier	8,835,076	7 13%	629,941	7.13%	629,941
397.20 Communication Equip. - Remote Contro	3,913,060	7.95%	311,088	7 95%	311,088
397.30 Communication Equipment - Mobile	5,087,846	7.30%	371,413	7.30%	371,413
398 Misc Equipment	373,590	20 54%	76,735	20.54%	76,735
Total General Plant	99,461,628		8,661,267		8,995,849
Total Plant in Service	3,917,180,938				
Total Annual Depreciation excluding ARO amounts			111,373,576		129,236,140
Less Amounts not included in Income Statement Depreciation					
Coal Cars			184,298		184,298
Brown Gas Pipeline			208,328		226,161
TC Gas Pipeline			156,659		170,239
Account 139200 Transportation Equip.			3,791,160		3,791,160
Subtotal			4,340,444		4,371,858
Total Annualized Depr less ARO and Amts not in Inc St. Depr			107,033,132		124,864,282
Less ECR Depreciation			12,751,570		13,327,774
Total Annualized Depreciation excluding ECR and ARO			$ 94,281,562		$ 111,536,507

* Represents list of ARO assets. Please note these amounts are not included in the calculation.

Kentucky Utilities Company - ECR April 2008

2001 Plan		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
Project 16 – NOx Ghent Plant					
Ghent 4	1/1/2002				
Investments	4,551,149	2 79%	126,977 06	2 94%	133,803 78
Retirements. Original Cost	(44,311)		(960 00)		(960 00)
Ghent 2	3/1/2002				
Investments	5,224,392	2 33%	121,728 33	2 45%	127,997 60
Retirements. Original Cost	(41,180)		(756 00)		(756 00)
Project 17 – SCRs and NOx Modifications					
Tyrone 3 – Original In-service amount	11/1/2001				
Investments	1,262,166	3 99%	50,360 42	4 30%	54,273 14
Retirements. Original Cost	(216,581)		(4,608 00)		(4,608 00)
Tyrone 3 – December 2004 Additions	12/1/2004				
Investments	87,293	3 99%	3,482 99	4 30%	3,753 60
Green River 3 Original Investments	7/1/2002				
Investments	1,358,579	3 08%	41,844 23	3 39%	46,055 83
Retirements, Original Cost	(149,233)		(2,892 00)		(2,892 00)
Green River 3 December 2004 Additions	12/1/2004				
Investments	269,265	3 08%	8,293 36	3 39%	9,128 08
Brown 2 Original Investment	12/1/2002				
Investments	1,937,045	3 01%	58,305 05	3 15%	61,016 92
Retirements. Original Cost	(918,431)		(26,448 00)		(26,448 00)
Brown 2 December 2004 Additions	12/1/2004				
Investments	776,167	3 01%	23,362 62	3 15%	24,449 25
Ghent 3 Original Investment	3/1/2004				
Investments	71,476,281	2 63%	1,879,826 19	2 76%	1,972,745 36
Retirements, Original Cost	(172,301)		(3,828 00)		(3,828 00)
Ghent 3 December 2004 Additions	12/1/2004				
Investments	2,958,119	2 63%	77,798 53	2 76%	81,644 08
Ghent 3 April 2005 Additions	3/1/2004				
Investments	2,971,181	2 63%	78,142 07	2 76%	82,004 61
Ghent 4 Original Investment	4/1/2004				
Investments	53,324,763	2 79%	1,487,760 89	2 94%	1,567,748 03
Retirements, Original Cost	(216,248)		(4,668 00)		(4,668 00)
Ghent 4 December 2004 Additions	12/1/2004				
Investments	3,288,376	2 79%	91,745 70	2 94%	96,678 26
Ghent 4 April 2005 Additions	4/1/2004				
Investments	3,518,957	2 79%	98,178 91	2 94%	103,457 34
Brown 3 Original Investment	5/1/2004				
Investments	2,102,228	2 80%	58,862 38	2 95%	62,015 73
Retirements, Original Cost	(848,647)		(33,180 00)		(33,180 00)
Brown 3 December 2004 Additions	12/1/2004				
Investments	364,407	2 80%	10,203 40	2 95%	10,750 01
Brown 3 April 2005 Additions	5/1/2004				
Investments	754	2 80%	21 11	2 95%	22 24
Ghent 1 Original Investment	5/1/2004				
Investments	56,004,868	3 84%	2,150,586 93	4 02%	2,251,395 69
Retirements, Original Cost	(113,614)		(3,540 00)		(3,540 00)
Ghent 1 December 2004 Additions	12/1/2004				
Investments	9,617,570	3 84%	369,314 69	4 02%	386,626 31

Kentucky Utilities Company - ECR April 2008

		2006 ASL Rates	Depreciation *Under* 2006 ASL Rates	2006 *Proposed* ELG Rates	Depreciation *Under* 2006 ELG Rates
Ghent 1 April 2005 Additions	5/1/2004				
Investments	3,520,209	3 84%	135 176 02	4 02%	141 512 40
Ghent 2 - December 2004 Addition	12/1/2004				
Investments	13,192	2 33%	307 37	2 45%	323 20
GH1 SCR Catalyst Addition May 2006	5/1/2006				
Investments	2,112,857	3 84%	81,133 70	4 02%	84,936 84
2001 Plan Additions	226,739,818				
2001 Plan Retirements	(2,720,546)				
2003 Plan					
Project 18 -- Ghent Ash Pond					
	12/1/2003				
Investments	16,148 295	2 79%	450,537 43	2 94%	474,759 87
2005 Plan					
Project 19 - Ash Handling at Ghent 1 and Ghent Station					
Ghent Station - Ash Pipe Repl Addition 4/30/06	4/1/2006				
Investments	398,915	2 79%	11,129 74	2 94%	11,728 11
Retirements, Original Cost	(292,425)		(6,312 00)		(6,312 00)
Project 21 - FGDs					
Ghent 3	6/1/2007				
Investments-Total	136,503,019	3 87%	5,282,666 84	4 01%	5,473,771 06
Retirements, Original Cost	(4,047,526)		(89 220 00)		(89,220 00)
Brown Training Bldg/Warehouse	12/1/2007				
Investments-Total	7,334,344	2 80%	205,361 63	2 95%	216,363 14
Retirements -- Original Cost	(74,700)		(2,916 00)		(2,916 00)
2005 Plan Additions	144,236,278				
2005 Plan Retirements	(4,414,651)				
2006 Plan					
Project 25 -- Mercury Monitors					
Tyrone 3	12/31/2006				
Investments	18,149	3 99%	724 13	4 30%	780 39
Brown 3	12/31/2006				
Investments	68,158	2 80%	1,908 42	2 95%	2,010 66
Ghent 4	12/31/2006				
Investments	45,279	2 79%	1 263 29	2 94%	1,331 21
Green River 4	12/31/2006				
Investments	18,164	4 20%	762 87	4 50%	817 36
CEMS Stackvision EDR Upgrade	10/1/2007				
Investments	115,540	20 00%	23,108 00	20 00%	23,108 00
Project 27 -- ESP					
Brown	6/15/2006				
Investments	46,715	2 80%	1,308 03	2 95%	1,378 10
Retirements, Original Cost	(32,691)		(1,284 00)		(1,284 00)
2006 Plan Additions	312,005				
2006 Plan Retirements	(32,691)				
Total Additions	387,436,395 58	Total	12,751,570.32		13,327,774.21
Total Retirements	(7,167,887.87)				
	380,268,507.71				

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Third Data Request of Commission Staff
Dated September 24, 2008

Question No. 21

Responding Witness: Shannon L. Charnas

Q-21. Refer to LG&E's response to Item 75 of Staff's Second Request.

a. Pages 2-10 of the attachment include a comparison of depreciation under "Current rates ASL" and "2006 New ELG" rates. The Direct Testimony of Shannon L. Charnas in Case No. 2007-00564 indicates that John Spanos "studied the Average Service Life ("ASL") and Equal Life Group ("ELG") methodologies for determining depreciation rates . . . " Clarify that the "Current rates ASL" shown in the attachment are not rates developed by Mr. Spanos in conjunction with his 2006 depreciation study, which LG&E submitted in Case No 2007-00564

b. If the response to (a) above indicates that the "Current rates ASL" were not developed by Mr. Spanos in conjunction with Case No. 2007-00564, provide, in the format used on pages 2-10 of the attachment, a comparison of depreciation under the ASL rates developed by Mr. Spanos in conjunction with his 2006 depreciation study and the ELG rates he has recommended for LG&E.

c. Describe all favorable and unfavorable consequences to LG&E if the Commission were to require reclassification of LG&E's asset removal costs from accumulated depreciation to a regulatory liability account for regulatory reporting purposes.

A-21. a. "Current rates ASL" shown in the attachment are the rates approved by the Commission in Case No. 2001-00141.

b. See attached

c. If the Commission were to require the reclassification of LG&E's costs of removal from accumulated depreciation to a regulatory liability account for regulatory reporting purposes, a favorable consequence would be that it would create consistency between GAAP reporting and regulatory reporting. An unfavorable consequence would be the inconsistency that would be created with prior years' regulatory reporting. There should be no impact on the ratemaking treatment of the costs of removal, regardless of where they are recorded, since a basic concept behind including cost of removal as a component of deprecation rates is to prevent generational inequities. No other consequences have been identified by LG&E.

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs proposed 2006 ELG rates

		DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
ELECTRIC PLANT						
Intangible Plant		2,340	0 00%	-	0 00%	-
Steam Production Plant						
310 20	*Land*	6.302 990	0 00%	-	0 00%	-
311 00	Structures and Improvements					
	0112 Cane Run Unit 1	4.233.982	0 00%	-	0 00%	-
	0121 Cane Run Unit 2	2.102.942	0 00%	-	0 00%	-
	0131 Cane Run Unit 3	3.532.141	0 00%	-	0 00%	-
	0141 Cane Run Unit 4	3.819.018	1 14%	43 537	1 26%	48.120
	0142 Cane Run Unit 4 Scrubber	760.360	0 95%	7.223	1 11%	8,440
	0151 Cane Run Unit 5	6.165.918	1 92%	118,386	2 00%	123.318
	0152 Cane Run Unit 5 Scrubber	1.696,435	1 56%	26.464	1 66%	28.161
	0161 Cane Run Unit 6	19.461.771	2 13%	414.536	2 22%	432,051
	0162 Cane Run Unit 6 Scrubber	1.894,851	2 04%	38.655	2 13%	40.360
	0211 Mill Creek Unit 1	19.171.039	1 64%	314.405	1 71%	327,825
	0212 Mill Creek Unit 1 Scrubber	1.716,996	1 65%	28.330	1 74%	29.876
	0221 Mill Creek Unit 2	10.816,688	1 42%	153.597	1 50%	162.250
	0222 Mill Creek Unit 2 Scrubber	1.393.404	1 81%	25,221	1 89%	26.335
	0231 Mill Creek Unit 3	24.851.259	1 51%	375.254	1 58%	392.650
	0232 Mill Creel Unit 3 Scrubber	362.867	1 47%	5,334	1 53%	5.552
	0241 Mill Creek Unit 4	60.488.020	1 85%	1,119,028	1 92%	1.161 370
	0242 Mill Creek Unit 4 Scrubber	5.330.552	1 76%	93,818	1 82%	97.016
	0311 Trimble County Unit 1	160.530.135	2 08%	3.339.027	2 15%	3.451 398
	0312 TC Unit 1 Cooling Tower *PHFU 105*	117.601	2 08%	2.446	2 15%	2.528
	0312 Trimble County Unit 1 Scrubber	511,309	2 28%	11.658	2 35%	12,016
		328 957.286		6.116 919		6 349.266
311 10	*Capital Leased Property*					
	0161 Cane Run Unit 6	1.236.508	2 13%	26.338	2 22%	27,450
	0241 Mill Creek Unit 4	1,640.450	1 85%	30,348	1 92%	31,497
		2,876,958		56.686		58.947
312 00	Boiler Plant Equipment					
	0103 Cane Run Locomotive	51.549	2 67%	1 376	4 79%	2.469
	0104 Cane Run Rail Cars	1.501.773	3 14%	47 156	3 59%	53 914
	0112 Cane Run Unit 1	1.053.743	0 00%	-	0 00%	-
	0121 Cane Run Unit 2	132,837	0 00%	-	0 00%	-
	0131 Cane Run Unit 3	711.483	0 00%	-	0 00%	-
	0141 Cane Run *Unit 4*	30.339.036	5 88%	1,783.935	6 66%	2.020.580
	0142 Cane Run Unit 4 Scrubber	17.076,590	4 93%	841,876	5 74%	980.196
	0151 Cane Run Unit 5	36.914.000	6 11%	2.255.445	6 71%	2.476.929
	0152 Cane Run Unit 5 Scrubber	28.412.993	4 07%	1.156.409	4 62%	1.312,680
	0161 Cane Run Unit 6	48.163.545	5 19%	2.499,688	5 78%	2.783.853
	0162 Cane Run Unit 6 Scrubber	32.098.669	4 46%	1.431.601	4 97%	1.595.304
	0203 Mill Creek Locomotive	613.424	2 90%	17 789	4 04%	24 782
	0204 Mill Creek Rail Cars	3.593.112	3 13%	112,464	3 58%	128.633
	0211 Mill Creek Unit 1	49.106.781	4 24%	2.082.128	4 72%	2.317.840
	0212 Mill Creek Unit 1 Scrubber	42.569.898	4 50%	1.915.645	4 96%	2.111.467
	0221 Mill Creek Unit 2	47.542.433	4 70%	2 234.494	5 22%	2.481.715
	0222 Mill Creek Unit 2 Scrubber	34.482.173	4 28%	1.475.837	4 71%	1,624 110
	0231 Mill Creek Unit 3	140.162.816	3 87%	5.424.301	4 48%	6,279,294
	0232 Mill Creel Unit 3 Scrubber	63.198 506	3 85%	2,433,142	4 38%	2.768,095
	0241 Mill Creek Unit 4	237 317.538	3 85%	9.136.725	4 45%	10,560,630
	0242 Mill Creek Unit 4 Scrubber	114.320.483	3 71%	4 241.290	4 14%	4.732.868
	0311 Trimble County Unit 1	247,714.970	3 62%	8.967 282	4 04%	10,007,685
	0312 TC Unit 1 Cooling Tower PHFU 105	15.510	3 62%	561	4 04%	627
	0312 Trimble County Unit 1 Scrubber	64,095,503	3 62%	2,320,257	4 10%	2.627,916
		1,241.189.365		50.379.403		56,891.588

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

		DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
314 00	Turbogenerator Units					
	0112 Cane Run Unit 1	106.009	0 00%	-	0 00%	-
	0121 Cane Run Unit 2	19.999	0 00%	-	0 00%	-
	0131 Cane Run Unit 3	581.178	0 00%	-	0 00%	-
	0141 Cane Run Unit 4	9.122.982	3 09%	281 900	3 40%	310,181
	0151 Cane Run Unit 5	7.375,366	2 22%	163.733	2 42%	178,484
	0161 Cane Run Unit 6	15.385.129	3 29%	506.171	3 47%	533,864
	0211 Mill Creek Unit 1	14.510.858	2 15%	311.983	2 30%	333.750
	0221 Mill Creek Unit 2	16.626.880	2 46%	409,021	2 62%	435,624
	0231 Mill Creek Unit 3	27.124.236	2 15%	583.171	2 28%	618,433
	0241 Mill Creek Unit 4	42.098.157	2 29%	964,048	2 45%	1 031.405
	0312 TC Unit 1 Cooling Tower PHFU 105	21.816,938	2 48%	541,060	2 68%	584.694
	0311 Trimble County Unit 1	59,415,222	2 48%	1,473,497	2 68%	1,592,328
		214 182.953		5.234.585		5,618,763
315 00	Accessory Electric Equipment					
	0112 Cane Run Unit 1	1.891,013	0 00%	-	0 00%	-
	0121 Cane Run Unit 2	1 277.223	0 00%	-	0 00%	-
	0131 Cane Run Unit 3	767.324	0 00%	-	0 00%	-
	0141 Cane Run Unit 4	5.532.270	3 18%	175.926	3 40%	188.097
	0142 Cane Run Unit 4 Scrubber	987.949	0 82%	8.101	1 12%	11.065
	0151 Cane Run Unit 5	6.892.343	2 97%	204.703	3 12%	215,041
	0152 Cane Run Unit 5 Scrubber	2.221.029	1 49%	33,093	1 67%	37.091
	0161 Cane Run Unit 6	8.518.498	2 80%	238.518	2 93%	249.592
	0162 Cane Run Unit 6 Scrubber	2.124,667	1 44%	30 595	1 61%	34,207
	0211 Mill Creek Unit 1	14.425.286	2 75%	396,695	2 84%	409 678
	0212 Mill Creek Unit 1 Scrubber	5 541.695	1 67%	92.546	1 80%	99.751
	0221 Mill Creek Unit 2	6.428.715	2 03%	130,503	2 13%	136.932
	0222 Mill Creek Unit 2 Scrubber	4 505,053	1 69%	76,135	1 83%	82.442
	0231 Mill Creek Unit 3	13.487.584	1 58%	213,104	1 64%	221 196
	0232 Mill Creel Unit 3 Scrubber	2.531.773	1 56%	39.496	1 62%	41.015
	0241 Mill Creek Unit 4	20.753.935	1 75%	363.194	1 85%	383.948
	0242 Mill Creek Unit 4 Scrubber	5.864.979	1 71%	100,291	1 81%	106.156
	0311 Trimble County Unit 1	56.226,923	2 13%	1,197,633	2 28%	1,281,974
	0312 TC Unit 1 Cooling Tower PHFU 105	63.422	2 13%	1.351	2 28%	1,446
	0312 Trimble County Unit 1 Scrubber	2,736,920	2 12%	58,023	2 28%	62,402
		162.778.602		3,359.908		3,562,033
316 00	Miscellaneous Plant Equipment					
	0112 Cane Run Unit 1	38.746	0 00%	-	0 00%	-
	0131 Cane Run Unit 3	11.664	0 00%	-	0 00%	-
	0141 Cane Run Unit 4	71.143	6 30%	4.482	6 50%	4.624
	0142 Cane Run Unit 4 Scrubber	6.464	2 83%	183	3 16%	204
	0151 Cane Run Unit 5	80,866	5 40%	4 367	5 53%	4.472
	0152 Cane Run Unit 5 Scrubber	47.299	2 85%	1 348	3 12%	1.476
	0161 Cane Run Unit 6	2.753.924	4 32%	118 970	4 51%	124 202
	0162 Cane Run Unit 6 Scrubber	31.569	2 75%	868	2 98%	941
	0211 Mill Creek Unit 1	696.199	3 22%	22,418	3 37%	23,462
	0221 Mill Creek Unit 2	115,871	2 90%	3 360	3 10%	3 592
	0231 Mill Creek Unit 3	318,625	2 59%	8.252	2 79%	8.890
	0241 Mill Creek Unit 4	5,393,692	3 04%	163 968	3 28%	176.913
	0242 Mill Creek Unit 4 Scrubber	53.007	2 83%	1,500	3 02%	1,601
	0311 Trimble County Unit 1	2,713,060	2 89%	78,407	3 16%	85,733
		12.332.130		408.123		436.109
317 00	Asset Retirement Obligations - Steam*	5,697,179				
	Total Steam	1,974,317.463		65,555,625		72,916,706

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

	DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
Hydraulic Production Plant - Project 289					
0451 - Ohio Falls Project 289					
330 20 Land	6	0 00%	-	0 00%	-
331 00 Structures and Improvements	4,550,757	0 08%	3,641	0 08%	3,641
332 00 Reservoirs. Dams & Waterways	9,352,023	3 30%	308,617	3 30%	308,617
333 00 Water Wheels. Turbines and Generators	10.895 237	0 25%	27.238	0 25%	27,238
334 00 Accessory Electric Equipment	4 581,251	2 94%	134,689	2 95%	135 147
335 00 Misc Power Plant Equipment	224.504	2 29%	5.141	2 31%	5.186
336 00 Roads. Railroads and Bridges	28,797	0 00%	-	0 00%	-
	29.632,574		479 325		479 828
Hydraulic Production Plant - Other Than Project 289					
0450 - Ohio Falls Other Than Project 289					
330 20 Land	1	0 00%	-	0.00%	-
331 00 Structures and Improvements	65.796	0 53%	349	0 55%	362
335 00 Misc Power Plant Equipment	7 814	1 61%	126	1 68%	131
336 00 Roads. Railroads and Bridges	1.134	0 00%	-	0 00%	-
337 00 Aset Retirement Obligations - Hydro *	31,163				
	105,907		475		493
Total Hydraulic Plant	29.738,482		479,800		480,322
Other Production Plant					
340 20 Land	49 259	0 00%	-	0 00%	-
341 00 Structures and Improvements					
0171 Cane Run GT 11	68.932	1 34%	924	2 33%	1.606
0410 Zorn and River Road Gas Turbine	8.241	0 61%	50	1 59%	131
0431 Paddys Run Generator 12	42,865	0 60%	257	1 58%	677
0432 Paddys Run Generator 13	2.158.698	3 05%	65,840	3 15%	67 999
0459 Brown CT 5	858.539	3 05%	26.185	3 15%	27 044
0460 Brown CT 6	105,978	3 17%	3.359	3 29%	3.487
0461 Brown CT 7	144,356	3 12%	4.504	3 23%	4,663
0470 Trimble County CT 5	1.555,655	3 16%	49,159	3 27%	50.870
0471 Trimble County CT 6	1.467.924	3 14%	46,093	3 25%	47,708
0474 Trimble County CT 7	2,083.698	3 34%	69,596	3 45%	71,888
0475 Trimble County CT 8	2.075.527	3 34%	69.323	3 45%	71.606
0476 Trimble County CT 9	2 137,402	3 34%	71 389	3 45%	73.740
0477 Trimble County CT 10	2,132,790	3 34%	71,235	3.45%	73.581
	14 840,604		477,914		494.999
342 00 Fuel Holders, Producers and Accessories					
0171 Cane Run GT 11	118.874	3 85%	4.577	4 89%	5.813
0410 Zorn and River Road Gas Turbine	12.802	0 59%	76	1 69%	216
0430 Paddys Run Generator 11	9.238	0 58%	54	1 69%	156
0431 Paddys Run Generator 12	12,197	0 85%	104	1 96%	239
0432 Paddys Run Generator 13	2 255,338 17	3 08%	69.464	3 21%	72 396
0459 Brown CT 5	822.581	3 07%	25.253	3 20%	26,323
0460 Brown CT 6	363.762	2 99%	10.876	3 11%	11.313
0461 Brown CT 7	102.065	2 99%	3,052	3 11%	3.174
0470 Trimble County CT 5	97,997	3 17%	3,107	3 29%	3.224
0471 Trimble County CT 6	97.862	3 17%	3.102	3 29%	3 220
0473 Trimble County CT Pipeline	1.998,391	3 19%	63,749	3 32%	66.347
0474 Trimble County CT 7	338.423	3 36%	11 371	3 50%	11.845
0475 Trimble County CT 8	337.096	3 36%	11.326	3 50%	11.798
0476 Trimble County CT 9	347.147	3 36%	11,664	3 50%	12.150
0477 Trimble County CT 10	361,860	3 36%	12.158	3 50%	12.665
	7.275.631		229,933		240.879

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs proposed 2006 ELG rates

		DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
343 00	Prime Movers					
	0432 Paddys Run Generator 13	19,711,932	3 84%	756,938	4 60%	906,749
	0459 Brown CT 5	14 329 963	3 84%	550,271	4 61%	660,611
	0460 Brown CT 6	19 135 984	3 85%	736,735	4 68%	895 564
	0461 Brown CT 7	19,416,144	3 81%	739,755	4 60%	893,143
	0470 Trimble County CT 5	12,535,260	3 88%	486,368	4 67%	585 397
	0471 Trimble County CT 6	12,417,684	3 88%	481,806	4 67%	579,906
	0474 Trimble County CT 7	13,328,878	3 99%	531,822	4 88%	650,449
	0475 Trimble County CT 8	13 203,913	3 99%	526,836	4 88%	644,351
	0476 Trimble County CT 9	13,094,542	3 99%	522,472	4 88%	639,014
	0477 Trimble County CT 10	13,060,778	3 99%	521,125	4 88%	637,366
		150,235,077		5 854,129		7,092 549
344 00	Generators					
	0171 Cane Run GT 11	2,492,496	5 73%	142,820	5 73%	142,820
	0410 Zorn and River Road Gas Turbine	1,827,581	2 70%	49 345	2 70%	49 345
	0430 Paddys Run Generator 11	1,523,116	2 74%	41,733	2 74%	41 733
	0431 Paddys Run Generator 12	2 991 746	2 63%	78,683	2 63%	78,683
	0432 Paddys Run Generator 13	5,859,858	3 00%	175,796	3 00%	175 796
	0459 Brown CT 5	3,219,205	3 00%	96 576	3 00%	96,576
	0460 Brown CT 6	2,417,995	2 91%	70,364	2 93%	70,847
	0461 Brown CT 7	2,421,079	2 91%	70,453	2 93%	70,938
	0470 Trimble County CT 5	1,539 295	3 09%	47,564	3 09%	47 564
	0471 Trimble County CT 6	1,537,168	3 09%	47,498	3 09%	47,498
	0474 Trimble County CT 7	1 726,824	3 28%	56,640	3 29%	56,813
	0475 Trimble County CT 8	1 717,277	3 28%	56,327	3 29%	56,498
	0476 Trimble County CT 9	1,728,008	3 28%	56,679	3 29%	56,851
	0477 Trimble County CT 10	1,722,674	3 28%	56,504	3 29%	56,676
		32 724,322		1,046,982		1,048,639
345 00	Accessory Electric Equipment					
	0171 Cane Run GT 11	116,627	2 40%	2,799	4 60%	5,365
	0410 Zorn and River Road Gas Turbine	40,936	2 31%	946	4 50%	1 842
	0430 Paddys Run Generator 11	68,109	4 27%	2,908	6 33%	4,311
	0431 Paddys Run Generator 12	114,338	3 82%	4,368	5 93%	6,780
	0432 Paddys Run Generator 13	2,778 993	3 32%	92 263	3 72%	103 379
	0459 Brown CT 5	2 575,301	3 32%	85 500	3 72%	95 801
	0460 Brown CT 6	942 589	3 26%	30,728	3 67%	34,593
	0461 Brown CT 7	943,792	3 26%	30,768	3 67%	34,637
	0470 Trimble County CT 5	685 979	3 38%	23,186	3 78%	25 930
	0471 Trimble County CT 6	685,031	3 38%	23,154	3 78%	25,894
	0474 Trimble County CT 7	1,841,955	3 52%	64,837	3 89%	71,652
	0475 Trimble County CT 8	1,834 732	3 52%	64 583	3 89%	71,371
	0476 Trimble County CT 9	1,889,431	3 52%	66,508	3 89%	73,499
	0477 Trimble County CT 10	1,885,354	3 52%	66,364	3 89%	73,340
		16,403 167		558 911		628,395
346.00	Miscellaneous Plant Equipment					
	0410 Zorn and River Road Gas Turbine	9,488	0 00%	-	0 00%	-
	0430 Paddys Run Generator 11	9,494	0 00%	-	0 00%	-
	0431 Paddys Run Generator 12	1 141	0 00%	-	0 00%	-
	0432 Paddys Run Generator 13	1,274,483	2 81%	35,813	2 83%	36 068
	0459 Brown CT 5	2,395,225	2 81%	67,306	2 83%	67 785
	0460 Brown CT 6	22,456	2 86%	642	2 88%	647
	0461 Brown CT 7	23,048	2 86%	659	2 89%	666
	0470 Trimble County CT 5	14,529	3 22%	468	3 24%	471
	0474 Trimble County CT 7	5 205	3 11%	162	3 13%	163

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

		DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
	0475 Trimble County CT 8	5,183	3 11%	161	3 13%	162
	0476 Trimble County CT 9	5,328	3 12%	166	3 12%	166
	0477 Trimble County CT 10	5,316	3 10%	165	3 12%	166
		3 770,896		105,542		106,294
347 00	Asset Retirement Obligations - Other Prod *	297,215				
	Total Other Production	225,596,172		8,273,411		9,611,755
Transmission Plant						
	350 2 Transmission Lines Land	885,061	0 00%	-	0 00%	-
	350 1 Land Rights	7,781,411	3 92%	305,031	4 30%	334,601
	352 1 Structures & Improvements	3,443 349	1 17%	40,287	1 42%	48,896
	353 1 Station Equipment - Project 289	1,108,850	1 32%	14,637	1 59%	17,631
	353 1 Station Equipment	133,193,694	1 32%	1,758 157	1 59%	2,117 780
	354 Towers & Fixtures	24 705,992	1 38%	340,943	1 58%	390,355
	355 Poles & Fixtures	38,253,365	2 95%	1,128,474	3 69%	1,411,549
	356 1 Overhead Conductors & Devices - Project 289	16,390	2 52%	413	3 14%	515
	356 Overhead Conductors & Devices	38,514,217	2 52%	970,558	3 14%	1,209,346
	357 Underground Conduit	1,880 752	1 85%	34 794	2 13%	40,060
	358 Underground Conductors & Devices	5,303,989	3 65%	193,596	4 21%	223,298
	359 Transmission ARO's *	4,000				
	TOTAL TRANSMISSION PLANT	255,091,069		4 786,890		5 794,030
Distribution Plant						
	360 2 Substation Land	1,981,707	0 00%	-	0 00%	-
	360 2 Substation Land Class A (Plant Held for Future I	637,632	0 00%	-	0 00%	-
	361 Substation Structures	6,130,215	1 01%	61,915	1 16%	71 110
	362 1 Substation Equipment	86,733,151	1 01%	876,005	1 91%	1,656,603
	362 1 Substation Equipment - Class A (Plant Held for I	11,382	0 00%	-	0 00%	-
	364 Poles Towers & Fixtures	106,709,095	3 00%	3,201,273	3 59%	3,830,856
	365 Overhead Conductors &Devices	182,141,013	2 90%	5,282,089	3 92%	7,139,928
	366 Underground Conduit	62,534,874	1 25%	781,686	1 34%	837,967
	367 Underground Conductors & Devices	95,365,944	1 76%	1,678,441	2 24%	2 136,197
	368 1 Line Transformers	97,370,472	2 18%	2,122,676	2 90%	2 823,744
	368 2 Line Transformer Installations	11,107 541	2 18%	242 144	2 90%	322,119
	369 1 Underground Services	3,521,786	2 45%	86,284	3 29%	115,867
	369 2 Overhead Services	21,039,201	4 99%	1,049,856	5 99%	1 260 248
	370 1 Meters	25 560,632	3 79%	968,748	4 73%	1 209,018
	370 2 Meter Installations	8,828,416	3 79%	334,597	4 73%	417,584
	373 1 Overhead Street Lighting	24,651,434	2 77%	682 845	3 84%	946,615
	373 2 Underground Streetlighting	42,382,522	2 95%	1,250,284	3 94%	1 669 871
	373 4 Street lighting Trandformers	87,546	0 00%	-	0 00%	-
	374 ARO Distribution *	37,674				
	TOTAL DISTRIBUTION PLANT	776,832,239		18,618,843		24,437 728
General Plant						
	392 1 Transportation Equip Cars & Trucks	9,070,918	20 00%	1,814 184	20 00%	1 814,184
	392.2 Transportation Equip Trailers	557,110	3.62%	20,167	3 84%	21,393
	394 Tools, Shop, and Garage Equipment	3 194,244	4 39%	140,227	4 39%	140,227
	395 Laboratory Equipment	1,496,151	30 32%	453,633	30 32%	453,633
	396 1 Power Operated Equip Hourly Rated	2,285 136	20 00%	457,027	20 00%	457,027
	396 2 Power operated Equipment Other	51,068	3 17%	1,619	3 83%	1,956
	TOTAL GENERAL PLANT	16,654,627		2 886,857		2 888,420
	TOTAL ELECTRIC PLANT	3,278,232,391		100,601,426		116,128,960
GAS PLANT						
	INTANGIBLE PLANT	1 187	0 00%	-	0 00%	-
	UNDERGROUND STORAGE					
	350 1 Land	32 864	0 00%	-	0 00%	-

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

	DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
350 2 Rights of Way	63.678	0 00%	-	0 00%	-
351 2 Compressor Station Structures	1.704 039	1 36%	23 175	1.68%	28.628
351 3 Reg Station Structures	10.880	0 00%	-	0 00%	-
351 4 Other Structures	1.317,477	0 92%	12.121	1 07%	14 097
352.40 Well Drilling	2,622.898	0 36%	9.442	0 44%	11.541
352 50 Well Equipment	6.142,763	3 46%	212.540	4 05%	248.782
352 1 Storage Leaseholds & Rights	548.241	0 00%	-	0 00%	-
352 2 Reservoirs	400,511	0 00%	-	0 00%	-
352 3 Nonrecoverable Natural Gas	9.648 855	0 92%	88.769	0 92%	88.769
Gas Stored Underground Non-Current	2.139.990	0 00%	-	0 00%	-
353 Lines	12.768,805	1 68%	214.516	2 12%	270.699
354 Compressor Station Equipment	15.120.619	1 28%	193 544	1 47%	222.273
355 Measuring & Regulating Equipment	387 809	1 22%	4 731	1 72%	6.670
356 Purification Equipment	9.933.661	1 92%	190.726	2 44%	242.381
357 Other Equipment	1.067.350	2 18%	23,268	2 81%	29 993
358 ARO Storage *	541,132				
TOTAL UNDERGROUND STORAGE	64.451,571		972.833		1.163,833
TRANSMISSION PLANT					
365 2 Rights of Way	220,659	0 27%	596	0 30%	662
367 Mains	12,681,249	0 37%	46,921	0 44%	55,797
TOTAL TRANSMISSION PLANT Excl ARO Assets	12.901.908		47.516		56,459
DISTRIBUTION PLANT					
374 Land	59.725	0 00%	-	0 00%	-
374 2 Land Rights	74.018	0 04%	30	0 04%	30
375 1 City Gate Structures	224.019	1 06%	2.375	1 23%	2 755
375 2 Other Distribution Structures	505 355	8 35%	42.197	7 71%	38.963
376 Mains	279.586,446	1 76%	4.920.721	2 16%	6.039,067
378 Measuring and Reg Equipment	8,254,321	2 53%	208.834	3 68%	303,759
379 Meas & Reg Equipment - City Gate	3,864.491	2 33%	90,043	2 96%	114.389
380 Services	137,878.756	3 60%	4.963.635	5 03%	6.935.301
381 Meters	22.084.789	3 99%	881 183	5 21%	1.150.618
382 Meter Installations	9.381.447	7 09%	665.145	11 17%	1.047.908
383 House Regulators	4 941.391	2 22%	109,699	2 59%	127.982
384 House Regulator Installations	5.298,054	2 23%	118.147	3 17%	167,948
385 Industrial Meas & Reg Station Equip	159 362	0 94%	1,498	1 07%	1.705
386 Other Equipment	51.112	3 48%	1 779	3 99%	2,039
388 ARO Distribution *	30,769				
TOTAL DISTRIBUTION PLANT	472 394.054		12.005.285		15.932.465
GENERAL PLANT					
392 1 Cars & Trucks	1.932.498	20 00%	386.500	20 00%	386,500
392 2 Trailers	451.395	4 76%	21.486	6 56%	29.612
394 Other Equipment	3,750.330	4 68%	175.515	4 68%	175.515
395 Laboratory Equipment	436.783	36 02%	157.329	36 02%	157.329
396 1 Power Operated Equipment Hourly rated	2.415.942	20 00%	483.188	20 00%	483.188
396.2 Power Operated Equipment Other	51,525	2 69%	1.386	3 25%	1,675
TOTAL GENERAL PLANT	9,038,473		1,225,405		1,233,819
TOTAL GAS PLANT	558,787,193		14,251.039		18,386,576

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

	DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
COMMON UTILITY PLANT					
INTANGIBLE PLANT					
301 Organization	83,782	0.00%	-	0.00%	-
302 Franchises and Consents	4,200	0.00%	-	0.00%	-
303 Software	29,259,188	20.00%	5,851,838	20.00%	5,851,838
TOTAL INTANGIBLE PLANT	29,347,170		5,851,838		5,851,838
GENERAL PLANT					
389.1 Land	1,691,944	0.00%	-	0.00%	-
389.2 Land Rights	202,095	2.95%	5,962	2.95%	5,962
390.10 Structures and Improvements - BOC	18,239,781	3.30%	601,913	4.01%	731,415
390.10 Structures and Improvements - LG&E Building	1,482,088	3.30%	48,909	4.01%	59,432
390.10 Structures and Improvements - BOC (Actors)	493,943	3.30%	16,300	4.01%	19,807
390.10 Structures and Improvements	28,701,014	3.30%	947,133	4.01%	1,150,911
390.20 Structures and Improvements - *Transportation*	431,574	25.92%	111,864	29.19%	125,976
390.30 Structures and Improvements - Stores	10,918,821	1.51%	164,874	1.72%	187,804
390.40 Structures and Improvements - Shops	529,682	1.37%	7,257	1.46%	7,733
390.60 Structures and Improvements - Microwave	855,653	2.31%	19,766	2.67%	22,846
391.10 Office Furniture	12,943,068	6.01%	777,878	6.06%	784,350
391.20 Office Equipment	3,388,007	8.78%	297,467	8.89%	301,194
391.30 Computer Equipment - Non PC	18,405,419	21.96%	4,041,830	22.05%	4,058,395
391.31 Personal Computers	1,870,245	20.68%	386,767	26.19%	489,817
391.40 Security Equipment	2,601,715	6.93%	180,299	6.99%	181,860
392.1 Cars & Trucks	84,479	20.00%	16,896	20.00%	16,896
392.2 Trailers	63,404	2.63%	1,668	3.50%	2,219
393 Stores Equipment	1,208,453	5.60%	67,673	5.60%	67,673
394 Other Equipment	3,636,099	5.17%	187,986	5.17%	187,986
395 Laboratory Equipment	22,282	61.24%	13,645	61.24%	13,645
396.1 Power Operated Equipment Hourly	258,314	20.00%	51,663	20.00%	51,663
396.2 Power Operated Equipment Other	14,147	4.01%	567	4.64%	656
397 Communications Equipment	35,656,730	12.00%	4,278,808	12.00%	4,278,808
397.10 Comm Equip - Computer	6,342,423	0.90%	57,082	0.90%	57,082
398.00 Miscellaneous Equipment	594,390	34.63%	205,837	34.63%	205,837
399.10 ARO Common *	3,735				
TOTAL GENERAL PLANT	150,639,505		12,490,043		13,009,967
TOTAL COMMON UTILITY PLANT	179,986,675		18,341,881		18,861,805
TOTAL PLANT IN SERVICE	4,017,006,260				
Total Annual Depreciation excluding ARO amounts			133,194,346		153,377,340

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs proposed 2006 ELG rates

	DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
Less Amounts not included in Income Statement Depreciation					
Electric					
CANE RUN LOCOMOTIVE			1.376		2.469
CANE RUN RAIL CARS			47,156		53.914
MILL CREEK LOCOMOTIVE			17.789		24.782
MILL CREEK RAIL CARS			112,464		128,633
OTHER PRODUCTION-TRIMBLE County PIPELINE			63.749		66,347
392 1 Cars & Trucks			1 814.184		1,814.184
396 1 Power Operated Equipment Hourly			457,027		457,027
Total Electric			2.513.745		2.547 356
Gas					
392 1 Cars & Trucks			386,500		386.500
396 1 Power Operated Equipment Hourly			483,188		483,188
Total Gas			869,688		869.688
Common					
392 1 Cars & Trucks			16.896		16.896
396 1 Power Operated Equipment Hourly			51,663		51,663
Total Common			68.559		68.559
Subtotal Amounts Not Included in Income Statement Depreciation			3.451.992		3.485.602
Total Annualized Depr less ARO and Amts not in Inc. St Depr.			129,742.355		149,891,738
Less ECR Depreciation			9,406.243		10,803 374
Total Annualized Depreciation excluding ECR and ARO			120,336,111		139,088,364

* Represents list of ARO assets Please note these amounts are not included in the calculation

Louisville Gas and Electric Company
Annualized Depreciation
Depreciation adjustment under 2006 ASL rates vs. proposed 2006 ELG rates

	DEPRECIABLE PLANT 4/30/08	2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 ELG Rates	Depreciation Under 2006 ELG Rates
	Depreciation Totals Recap by Method				
			74% Electric	26% Gas	Total
Total Annualized Depreciation - Electric and Gas Split - New Rates ASL					
Total Plant Depr excl ARO			100,601,426	14 251,039	114,852,465
Total Common Plant %			13,572,992	4,768,889	18,341,881
Less Amts not inc in Income Statement Depr			(2,513 745)	(869,688)	(3,383,433)
Less Amts not inc in Income Statement Depr - Common			(50 733)	(17,825)	(68 559)
Less Annualized ECR Depreciation			(9,406,243)	-	(9,406,243)
Annualized Depreciation under current rates			102,203,696	18,132,415	120,336,111
Total Annualized Depreciation - Electric and Gas Split - New Rates ELG					
Total Plant Depr excl ARO			116,128,960	18,386,576	134,515,535
Total Common Plant %			13,957,736	4,904,069	18,861,805
Less Amts not inc in Income Statement Depr			(2,547,356)	(869,688)	(3,417,044)
Less Amts not inc in Income Statement Depr - Common			(50,733)	(17,825)	(68,559)
Less Annualized ECR Depreciation			(10,803,374)	-	(10,803,374)
Annualized Depreciation under current rates			116,685,232	22,403 132	139,088,364

Louisville Gas and Electric Company - ECR April 2008

2001 Plan		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
Project 6 – NOx all plants					
Trimble County 1 SCR	6/1/2002				
Investments	34,910,939	3 62%	1,263,776	4 04%	1,410.402
Retirements, Original Cost	(184,425)		(4,440)		(4,440)
Trimble County 1 Catalyst	5/1/2005				
Investments	1,444,358	3 62%	52,286	4 04%	58,352
Mill Creek 3	12/1/2003				
Investments	19.730,477	3 87%	763,569	4 48%	883 925
Mill Creek 4	12/1/2003				
Investments	21,669.172	3 85%	834.263	4 45%	964,278
Cane Run 6					
Investments	398,347	5 19%	20,674	5 78%	23,024
Trimble County 1 Investments	12/1/2002				
Investments	3,200,663	3 62%	115,864	4 04%	129,307
Retirements. Original Cost	(300,000)		(7 230)		(7.230)
Cane Run 5	4/1/2003				
Investments	3,150,880	6.11%	192,519	6 71%	211,424
Retirements, Original Cost	(22,747)		(648)		(648)
Cane Run 4	10/1/2003				
Investments	1,963,177	5 88%	115,435	6 66%	130,748
Retirements, Original Cost	(44,432)		(1 308)		(1.308)
Mill Creek 4	12/1/2003				
Investments	43,947,781	3 85%	1,691,990	4 45%	1.955,676
Retirements, Original Cost	(993,467)		(28.020)		(28.020)
Mill Creek 2	3/1/2004				
Investments	550,661	4 70%	25,881	5 22%	28,745
Mill Creek 1	4/1/2004				
Investments	598,446	4 24%	25.374	4 72%	28,247
Retirements, Original Cost	(222,092)		(5,308)		(5.308)
Mill Creek 3	5/1/2004				
Investments	49,365,169	3 87%	1.910.432	4 48%	2.211.560
Retirements, Original Cost	(701,158)		(21,245)		(21,245)
Mill Creek Substation	9/1/2001				
Investments	2,525,302	1 32%	33.334	1 59%	40,152
Retirements, Original Cost	(521,706)		(10,956)		(10,956)
Mill Creek 4 SCR - May 2006 Addition	5/31/2006				
Investments	1,724,257	3 85%	66.384	4 45%	76 729
TC Air Heater Baskets - Dec 2005 Addition	12/1/2005				
Investments	463,939	3 62%	16,795	4 04%	18,743
Retirements. Original Cost	(344.487)		(8.304)		(8,304)

Louisville Gas and Electric Company - ECR April 2008

		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
LG&E NOX - April 2006 Addition	4/1/2006				
Investments	5,373,292	3 85%	206,872	4 45%	239,111
Retirements, Original Cost	(2,516,451)		(70,968)		(70,968)
MC3 - SCR Catalyst Replacement	7/1/2007				
Investments	1,843,984	3 87%	71.362	4 48%	82.611
2001 Plan Additions	192.860,844				
2001 Plan Retirements	(5.850,967)				
2003 Plan					
Project 7 – Mill Creek FGD Scrubber Conversion					
Mill Creek FGD Scrubber Conversion Unit 1	1/1/2003				
Investments	6,780,427	4 50%	305,119	4 96%	336,309
Retirements, Original Cost	(256,099)		(9,984)		(9.984)
Mill Creek 1 FGD Rapid Amortization	1/1/2005				
Investments	(7,575)	4 50%	(341)	4 96%	(376)
Mill Creek FGD Scrubber Conversion Unit 2	1-Aug-2002				
Investments	5,496.522	4.28%	235.251	4 71%	258 886
Retirements, Original Cost	(593,300)		(23,676)		(23,676)
Mill Creek FGD 2 Rapid Amortization	1-Jan-2005				
Investments	203,537	4 28%	8.711	4 71%	9.587
Mill Creek FGD Scrubber Conversion Unit 3	5/1/2004				
Investments	6.192,799	3 85%	238,423	4 38%	271,245
Retirements – Original Cost	(501,511)		(22,769)		(22,769)
Mill Creek FGD Scrubber Conversion Unit 3	5/1/2004				
Investments	5.685,853	3 85%	218,905	4 38%	249,040
Retirements – Original Cost	(4.221,527)		(191.652)		(191,652)
Mill Creek FGD 3 Rapid Amortization	1-Jan-2005				
Investments	19,187	3 85%	739	4 38%	840
Mill Creek FGD Scrubber Conversion Unit 4	6/1/2003				
Investments	6,490,936	3 71%	240,814	4 14%	268,725
Retirements – Original Cost	(365,346)		(19,656)		(19,656)
Project 8 – Precipitators					
Mill Creek 2 – Include in Rate Base Feb 2003	10/1/2001				
Investments	2,076.199	4 70%	97,581	5 22%	108.378
Retirements – Original Cost	(101.069)		(2,316)		(2.316)
Mill Creek 3 – Include in Rate Base Feb 2003	6/1/2001				
Investments	3,484,535	3 87%	134,852	4 48%	156,107
Retirements – Original Cost	(284,031)		(8,604)		(8.604)
Mill Creek 3	5/1/2004				
Investments	2.144,386	3 87%	82,988	4 48%	96.068
Retirements – Original Cost	(1.195,718)		(36,228)		(36,228)
Cane Run 5	6/1/2004				
Investments	4,224,013	6 11%	258,087	6 71%	283,431
Retirements – Original Cost	(264,918)		(7,608)		(7.608)
Project 9 – Clearwell Water System	6/1/2003				
Investments	1,197,310	3 71%	44,420	4 14%	49,569
Retirements – Original Cost	(56,001)		(3,013)		(3 013)

Louisville Gas and Electric Company - ECR April 2008

		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
Project 10 – Absorber Trays					
Mill Creek 3 Include in Rate Base Feb 2003	5/1/2001				
Investments	1.367,310	3 85%	52,641	4 38%	59,888
Mill Creek 4 Include in Rate Base Feb 2003	5/1/2001				
Investments	1,367,310	3 71%	50.727	4 14%	56,607
2003 Plan Additions	46.722,749				
2003 Plan Retirements	(7.839.520)				
2005 Plan					
Project 11 – Special Waste Landfill Expansion					
Mill Creek	8/1/2005				
Investments	2,188,050	3 85%	84,240	4 45%	97.368
Mill Creek	11/1/2005				
Investments	94,931	3 71%	3.522	4 14%	3,930
Retirements -- Original Cost	(83,141)		(4,476)		(4,476)
Project 12 – Special Waste Landfill Expansion					
Cane Run	12/1/2006				
Investments	2.323,293	3 85%	89,447	4 45%	103.387
Project 12 – Special Waste Landfill Expansion - December 2007 Addition					
Cane Run	12/1/2007				
Investments	664,844	3 85%	25,596	4 45%	29.586
Project 13 – Scrubber Refurbishment					
Trimble Co 1	12/1/2007				
Investments	855,968	3 62%	30,986	4 10%	35,095
Project 14 – CR6 SDRS Tank RPLC					
Cane Run 6	1/1/2006				
Investments	154,841	4 46%	6,906	4 97%	7,696
Retirements – Original Cost	(72.799)		(1,584)		(1 584)
Project 14 – CR6 Module Mist Elim Rplc					
Cane Run 6	5/1/2006				
Investments	127,294	4 46%	5,677	4 97%	6,326
Retirements – Original Cost	(89.971)		(1,956)		(1,956)
Project 14 – CR6 Expansion Joint Replacement					
Cane Run 6	12/1/2007				
Investments	26.373	4 46%	1,176	4 97%	1.311
Retirements – Original Cost	(21,578)		(288)		(288)
Project 16 – Scrubber Improvements					
Trimble Co 1	10/1/2005				
Investments	4,281,077	3 62%	154.975	4 10%	175.524
Project 16 – Scrubber Improvements - Sept 2006 Addition					
Trimble Co 1	9/1/2006				
Investments	3,080,000	3 62%	111,496	4 10%	126,280
Retirements – Original Cost	(404,979)		(14,052)		(14.052)
2005 Plan Additions	13,796,671				
2005 Plan Retirements	(672.468)				

Louisville Gas and Electric Company - ECR April 2008

		2006 ASL Rates	Depreciation Under 2006 ASL Rates	2006 Proposed ELG Rates	Depreciation Under 2006 ELG Rates
2006 Plan					
Project 20 – Mercury Monitors					
Cane Run 6 - Data Loggers	12/1/2006				
Investments	27,584	5 19%	1,432	5 78%	1,594
Mill Creek 4 - Data Loggers	12/1/2006				
Investments	38,545	3 85%	1,484	4 45%	1,715
Trimble County 1 - Data Loggers	12/1/2006				
Investments	20,073	3 62%	727	4 04%	811
CEMS Stackvision EDR Upgrade	10/1/2007				
Investments	77,639	3 62%	2,811	4 04%	3,137
Project 21 – Particulate Monitors					
Mill Creek 1	4/1/2006				
Investments	72,995	4 24%	3,095	4 72%	3,445
Mill Creek 2	4/1/2006				
Investments	86,735	4 70%	4,077	5 22%	4 528
Mill Creek 3	3/1/2006				
Investments	87,743	3 87%	3 396	4 48%	3.931
Mill Creek 4	1/1/2005				
Investments	149,675	3 85%	5.762	4 45%	6.661
2006 Plan Additions	560.989				
Total Additions	253,941,254				
Total Retirements	(14,362,955)				
Total	239,578,299		$ 9,406,243		$ 10,803,374

EXHIBIT___(LK-15)

Kentucky Utilities Company
Depreciation Expense Adjustment-Electric Only
Recommended by KIUC-Based on Recommended Depr Rates of AG Witness Majoros
For the Test Year Ended April 30, 2008

	Amount
Annualized Depreciation Expense under Majoros Proposed Rates-KY Jurisdiction	70,834,774
Company Proposed Depreciation Expense in Filing	97,546,483
Total Adjustment Recommended by KIUC	(26,711,709)
Less: Company Computed Effect of Using ALG Methodology Instead of ELG_KY Jurisdiction	15,090,657
Difference Associated with the Majoros Change in Net Negative Salvage	(11,621,052)

Kentucky Utilities Company
***Annualized Depreciation* - Using Majoros Rates**
as of April 30, 2008

Source: Majoros MJM-3 in Case No 2007-00565

Property Group	Depreciable Balance 4-30-08	2006 Majoros Rates	Depreciation Under Majoros Rates	2006 New ELG RATES	Depreciation Under ELG
Intangible Plant					
301 Organization	44,456	0 00%	-	0 00%	-
302 Franchises and Consents	83,453	0 00%	-	0 00%	-
303 Misc Intangible Plant	25,536,344	20.00%	5,107,269	20.00%	5,107,269
Total Intangible Plant	25,664.252		5,107,269		5,107,269
Steam Production Plant					
310 00 Land	10,874,263	0 00%	-	0 00%	-
311 00 Structures and Improvements					
5603 Tyrone Unit 3	5.540,781	0 00%	-	0.00%	-
5604 Tyrone Units 1&2	583,381	0 00%	-	0 00%	-
5613 Green River Unit 3	2,818,745	0 00%	-	0 00%	-
5614 Green River Unit 4	4.584,599	0 00%	-	0 00%	-
5615 Green River Units 1&2	2,596,587	0 00%	-	0 00%	-
5621 Brown Unit 1	4,703.190	0 49%	23,046	0 59%	27.749
5622 Brown Unit 2	2.102,892	-0 03%	(631)	0 06%	1.262
5623 Brown Unit 3	20,393,087	0.43%	87.690	0 55%	112,162
5643 Pineville Unit 3	16.204	0 00%	-	0.00%	-
5650 Ghent Unit 1 Scrubber	24,301,127	2 54%	617,249	2.69%	653,700
5651 Ghent Unit 1	17,401,172	0 27%	46,983	0 40%	69,605
5652 Ghent Unit 2	16,011,013	0 39%	62,443	0 52%	83,257
5653 Ghent Unit 3	41,471,559	1 08%	447,893	1 19%	493.512
5654 Ghent Unit 4	29,847,745	1 31%	391,005	1 42%	423,838
5591 System Laboratory	805,716	1 44%	11,602	1 56%	12,569
	173.177,798		1,687,280		1,877.653
312 00 Boiler Plant Equipment					
5603 Tyrone Unit 3	12,871.948	3 50%	450,518	4 30%	553.494
5604 Tyrone Units 1&2	421,900	-0 38%	(1,603)	0 00%	-
5613 Green River Unit 3	11,306,456	2 57%	290.576	3 39%	383,289
5614 Green River Unit 4	24,333.224	3 70%	900,329	4 50%	1,094.995
5615 Green River Units 1&2	127,047	1.67%	2,122	2 52%	3,202
5621 Brown Unit 1	35,820,003	2.52%	902,664	3 10%	1,110.420
5622 Brown Unit 2	29,419,949	2 55%	750,209	3.14%	923,786
5623 Brown Unit 3	86,541,309	2 34%	2,025,067	2 95%	2,552,969
5643 Pineville Unit 3	226,832	0 00%	-	0 00%	-
5650 Ghent Unit 1 Scrubber	86,520,141	3 42%	2,958,989	4 01%	3,469.458
5651 Ghent Unit 1	163,735,182	3.40%	5,566,996	4 02%	6,582.154
5652 Ghent Unit 2	89.995.577	1 88%	1,691,917	2 45%	2.204,892
5653 Ghent Unit 3	259,377,006	2 23%	5,784,107	2 76%	7.158,805
5654 Ghent Unit 4	231,652,822	2 39%	5,536.502	2 94%	6,810.593
5659 Coal Cars	7,647,232	2.98%	227.888	2 41%	184.298
5660 Ghent 3 Scrubber	118,758,718	4.01%	4,762,225	4 01%	4,762,225
	1.158,755.347		31,848.505		37,794,579
314 00 Turbogenerator Units					
5603 Tyrone Unit 3	4,717.000	3 05%	143.868	3 68%	173,586
5604 Tyrone Units 1&2	68,206	0 00%	-	0 00%	-
5613 Green River Unit 3	4.469,895	2 51%	112,194	3 14%	140.355
5614 Green River Unit 4	10,171,918	3 39%	344,828	4 05%	411.963
5621 Brown Unit 1	4,833.421	0 77%	37,217	1 16%	56.068
5622 Brown Unit 2	11,041,057	2 56%	282,651	3 04%	335,648
5623 Brown Unit 3	27,652,377	2 81%	777,032	3 31%	915.294
5651 Ghent Unit 1	25,577,290	1 88%	480,853	2 36%	603,624
5652 Ghent Unit 2	29.546.661	1 73%	511,157	2 19%	647,072
5653 Ghent Unit 3	40,076,564	1 71%	685,309	2 11%	845.616
5654 Ghent Unit 4	51,922,998	1 88%	976.152	2 30%	1,194,229
	210,077.388		4.351,263		5.323,453

Kentucky Utilities Company
Annualized Depreciation - Using Majoros Rates
as of April 30, 2008

Source: Majoros MJM-3 in Case No 2007-00565

Property Group	Depreciable Balance 4-30-08	2006 Majoros Rates	Depreciation Under Majoros Rates	2006 New ELG RATES	Depreciation Under ELG
5603 Tyrone Unit 3	707,890	0.00%	-	0.00%	-
5604 Tyrone Units 1&2	99,211	0.00%	-	0.00%	-
5613 Green River Unit 3	781,287	0.00%	-	0.00%	-
5614 Green River Unit 4	1,147,502	1.28%	14,688	1.47%	16,868
5621 Brown Unit 1	3,329,621	1.94%	64,595	2.09%	69,589
5622 Brown Unit 2	997,856	0.33%	3,293	0.45%	4,490
5623 Brown Unit 3	6,453,917	0.39%	25,170	0.54%	34,851
5650 Ghent Unit 1 Scrubber	3,016,784	2.55%	76,928	2.73%	82,358
5651 Ghent Unit 1	7,703,537	0.40%	30,814	0.57%	43,910
5652 Ghent Unit 2	10,873,596	0.45%	48,931	0.63%	68,504
5653 Ghent Unit 3	25,991,761	0.91%	236,525	1.05%	272,913
5654 Ghent Unit 4	21,911,936	1.09%	238,840	1.24%	271,708
5660 Ghent 3 Scrubber	11,277,367	2.73%	307,872	2.73%	307,872
	94,292,263		1,047,656		1,173,064
316 00 Miscellaneous Plant Equipment					
5603 Tyrone Unit 3	526,592	3.11%	16,377	3.45%	18,167
5604 Tyrone Units 1&2	50,127	0.00%	-	0.00%	-
5613 Green River Unit 3	153,382	3.97%	6,089	4.28%	6,565
5614 Green River Unit 4	2,165,959	2.70%	58,481	3.04%	65,845
5615 Green River Units 1&2	84,750	0.00%	-	0.00%	-
5621 Brown Unit 1	424,540	2.26%	9,595	2.41%	10,231
5622 Brown Unit 2	106,658	0.71%	757	0.82%	875
5623 Brown Unit 3	4,317,609	2.33%	100,600	2.47%	106,645
5650 Ghent Unit 1 Scrubber	985,410	2.87%	28,281	3.00%	29,562
5651 Ghent Unit 1	1,718,709	1.38%	23,718	1.51%	25,953
5652 Ghent Unit 2	1,500,525	1.07%	16,056	1.17%	17,556
5653 Ghent Unit 3	3,150,438	1.40%	44,106	1.41%	44,421
5654 Ghent Unit 4	6,247,981	2.03%	126,834	2.12%	132,457
5591 System Laboratory	2,229,677	2.74%	61,093	2.96%	65,998
	23,662,356		491,988		524,276
317 00 Asset Retirement Obligations - Steam	9,249,179				
Total Steam	1,680,088,593		39,426,692		46,693,026
Hydraulic Production Plant					
5691 Dix Dam					
330 10 Land Rights	879,311	0.00%	-	0.00%	-
331 00 Structures and Improvements	453,195	1.18%	5,348	1.31%	5,937
332 00 Reservoirs, Dams & Waterways	9,025,249	0.72%	64,982	0.73%	65,884
333 00 Water Wheels, Turbines and Generators	436,634	0.52%	2,270	0.68%	2,969
334 00 Accessory Electric Equipment	85,383	0.83%	709	0.93%	794
335 00 Misc Power Plant Equipment	101,513	3.55%	3,604	4.21%	4,274
336 00 Roads, Railroads and Bridges	46,976	0.00%	-	0.00%	-
337 00 Asset Retirement Obligation - Hydro	4,970				
	11,033,232		76,912		79,858
Other Production Plant					
340 10 Land Rights - *5645 Brown CT 9 Gas Pipeline*	176,409	2.97%	5,239	3.62%	6,386
340 20 Land	118,514	0.00%	-	0.00%	-
341 00 Structures and Improvements					
5697 Paddy's Run Generator 13	1,910,328	3.03%	57,883	3.33%	63,614
5635 Brown CT 5	775,082	3.04%	23,562	3.34%	25,888
5636 Brown CT 6	192,814	3.05%	5,881	3.40%	6,556
5637 Brown CT 7	544,966	2.93%	15,968	3.24%	17,657
5638 Brown CT 8	2,012,655	2.61%	52,530	2.87%	57,763
5639 Brown CT 9	4,641,055	2.61%	121,132	2.87%	133,198
5640 Brown CT 10	1,865,718	2.61%	48,695	2.87%	53,546

Kentucky Utilities Company
Annualized Depreciation - Using Majoros Rates
as of April 30, 2008

Source: Majoros MJM-3 in Case No. 2007-00565

Property Group	Depreciable Balance 4-30-08	2006 Majoros Rates	Depreciation Under Majoros Rates	2006 New ELG RATES	Depreciation Under ELG
5641 Brown CT 11	1,858,754	2.72%	50,558	3.00%	55,763
0470 Trimble County CT 5	3,740,231	3.14%	117,443	3.47%	129,786
0471 Trimble County CT 6	3,588,684	3.12%	111,967	3.44%	123,451
0474 Trimble County CT 7	3,559,155	3.32%	118,164	3.69%	131,333
0475 Trimble County CT 8	3,548,852	3.32%	117,822	3.69%	130,953
0476 Trimble County CT 9	3,655,976	3.32%	121,378	3.69%	134,906
0477 Trimble County CT 10	3,653,030	3.32%	121,281	3.69%	134,797
5696 Haefling Units 1,2,&3	434,853	6.43%	27,961	8.89%	38,658
	35,982,154		1,112,225		1,237,867
342 00 Fuel Holders, Producers and Accessories					
5697 Paddy's Run Generator 13	1,995,101	3.01%	60,053	3.37%	67,235
5635 Brown CT 5	727,929	3.00%	21,838	3.36%	24,458
5636 Brown CT 6	146,515	2.82%	4,132	3.16%	4,630
5637 Brown CT 7	145,745	2.82%	4,110	3.16%	4,606
5638 Brown CT 8	19,613	2.53%	496	2.86%	561
5639 Brown CT 9	1,932,187	2.54%	49,078	2.87%	55,454
5640 Brown CT 10	31,738	2.53%	803	2.85%	905
5641 Brown CT 11	52,430	2.64%	1,384	2.96%	1,552
5645 Brown CT 9 Gas Pipeline	8,106,131	2.47%	200,221	2.79%	226,161
0470 Trimble County CT 5	239,584	3.11%	7,451	3.48%	8,338
0471 Trimble County CT 6	239,246	3.11%	7,441	3.48%	8,326
0473 Trimble County CT Pipeline	4,850,115	3.13%	151,809	3.51%	170,239
0474 Trimble County CT 7	578,059	3.33%	19,249	3.74%	21,619
0475 Trimble County CT 8	576,386	3.33%	19,194	3.74%	21,557
0476 Trimble County CT 9	593,786	3.33%	19,773	3.74%	22,208
0477 Trimble County CT 10	622,873	3.33%	20,742	3.74%	23,295
5696 Haefling Units 1,2,&3	227,578	0.00%	-	0.48%	1,092
	21,085,015		587,772		662,235
343 00 Prime Movers					
5697 Paddy's Run Generator 13	17,421,691	3.52%	613,244	4.49%	782,234
5635 Brown CT 5	13,182,503	3.55%	467,979	4.60%	606,395
5636 Brown CT 6	30,423,304	3.46%	1,052,646	4.52%	1,375,133
5637 Brown CT 7	30,024,907	3.48%	1,044,867	4.56%	1,369,136
5638 Brown CT 8	26,344,009	3.20%	843,008	4.13%	1,088,008
5639 Brown CT 9	21,502,647	3.13%	673,033	4.00%	860,106
5640 Brown CT 10	19,670,646	3.16%	621,592	4.04%	794,694
5641 Brown CT 11	34,931,891	3.32%	1,159,739	4.17%	1,456,660
0470 Trimble County CT 5	30,564,294	3.62%	1,106,427	4.66%	1,424,296
0471 Trimble County CT 6	30,443,723	3.62%	1,102,063	4.66%	1,418,677
0474 Trimble County CT 7	22,773,708	3.82%	869,956	5.17%	1,177,401
0475 Trimble County CT 8	22,568,161	3.82%	862,104	5.16%	1,164,517
0476 Trimble County CT 9	22,401,560	3.82%	855,740	5.16%	1,155,920
0477 Trimble County CT 10	22,385,894	3.82%	855,141	5.16%	1,155,112
	344,638,937		12,127,538		15,828,290
344 00 Generators					
5697 Paddy's Run Generator 13	5,185,636	2.85%	147,791	2.96%	153,495
5635 Brown CT 5	2,831,528	2.85%	80,699	2.96%	83,813
5636 Brown CT 6	3,712,620	2.67%	99,127	2.78%	103,211
5637 Brown CT 7	3,722,788	2.67%	99,398	2.78%	103,494
5638 Brown CT 8	4,953,961	2.37%	117,409	2.49%	123,354
5639 Brown CT 9	5,452,041	2.23%	121,581	2.36%	128,668
5640 Brown CT 10	4,944,423	2.37%	117,183	2.49%	123,116
5641 Brown CT 11	5,187,040	2.44%	126,564	2.56%	132,788
0470 Trimble County CT 5	3,763,275	2.95%	111,017	3.06%	115,156
0471 Trimble County CT 6	3,757,947	2.95%	110,859	3.06%	114,993
0474 Trimble County CT 7	2,950,282	3.17%	93,524	3.26%	96,179
0475 Trimble County CT 8	2,937,930	3.17%	93,132	3.26%	95,777
0476 Trimble County CT 9	2,957,570	3.17%	93,753	3.26%	96,415

Kentucky Utilities Company
Annualized Depreciation - Using Majoros Rates
as of April 30, 2008

Source: Majoros MJM-3 in Case No. 2007-00565

Property Group	Depreciable Balance 4-30-08	2006 Majoros Rates	Depreciation Under Majoros Rates	2006 New ELG RATES	Depreciation Under ELG
0477 Trimble County CT 10	2,954,149	3.17%	93,647	3.26%	96,305
5696 Haefling Units 1,2,&3	4,023,002	0.00%	-	0.00%	-
	59,334,142		1,505,683		1,566,764
345.00 Accessory Electric Equipment					
5697 Paddy's Run Generator 13	2,456,320	2.88%	70,742	3.04%	74,672
5635 Brown CT 5	1,332,167	2.88%	38,366	3.04%	40,498
5636 Brown CT 6	1,354,816	2.71%	36,716	2.86%	38,748
5637 Brown CT 7	1,347,700	2.71%	36,523	2.86%	38,544
5638 Brown CT 8	1,799,436	2.42%	43,546	2.56%	46,066
5639 Brown CT 9	3,226,186	2.31%	74,525	2.49%	80,332
5640 Brown CT 10	1,804,419	2.44%	44,028	2.58%	46,554
5641 Brown CT 11	916,326	2.49%	22,817	2.63%	24,099
0470 Trimble County CT 5	1,677,092	2.99%	50,145	3.14%	52,661
0471 Trimble County CT 6	1,674,719	2.99%	50,074	3.14%	52,586
0474 Trimble County CT 7	3,146,235	3.20%	100,680	3.35%	105,399
0475 Trimble County CT 8	3,137,127	3.20%	100,388	3.35%	105,094
0476 Trimble County CT 9	3,231,827	3.20%	103,418	3.35%	108,266
0477 Trimble County CT 10	3,229,223	3.20%	103,335	3.35%	108,179
5696 Haefling Units 1,2,&3	623,419	0.00%	-	0.00%	-
	30,957,013		875,303		921,698
346.00 Miscellaneous Plant Equipment					
5697 Paddy's Run Generator 13	1,089,550	3.20%	34,866	3.70%	40,313
5635 Brown CT 5	2,139,353	3.20%	68,459	3.71%	79,370
5636 Brown CT 6	48,960	3.33%	1,630	3.93%	1,924
5637 Brown CT 7	35,647	3.23%	1,151	3.76%	1,340
5638 Brown CT 8	230,069	2.77%	6,373	3.20%	7,362
5639 Brown CT 9	760,255	2.76%	20,983	3.19%	24,252
5640 Brown CT 10	274,391	2.85%	7,820	3.30%	9,055
5641 Brown CT 11	548,588	3.23%	17,719	3.76%	20,627
0470 Trimble County CT 5	28,964	3.72%	1,077	4.81%	1,393
0474 Trimble County CT 7	8,889	3.50%	311	4.13%	367
0475 Trimble County CT 8	8,861	3.50%	310	4.13%	366
0476 Trimble County CT 9	9,114	3.50%	319	4.14%	377
0477 Trimble County CT 10	9,106	3.50%	319	4.13%	376
5696 Haefling Units 1,2,&3	35,805	0.00%	-	1.97%	705
	5,227,550		161,338		187,829
347.00 Asset Retirement Obligations - Other Productio	70,990				
Total Other Production	497,590,725		16,375,099		20,411,068
Transmission Plant					
350.1 Land Rights	23,341,455	0.98%	228,746	1.12%	261,424
350.2 Land	1,232,665	0.00%	-	0.00%	-
352.1 Struct. and Impr. Non Sys Control	7,228,687	1.10%	79,516	1.75%	126,502
352.2 Struct. and Impr. Sys Control	1,154,520	0.95%	10,968	1.63%	18,819
353.1 Station Equipment	175,730,576	1.61%	2,829,262	2.46%	4,322,972
353.2 Syst Control/Microwave Equip	14,749,281	-0.04%	(5,900)	0.56%	82,596
354 Towers & Fixtures	63,279,467	0.82%	518,892	1.30%	822,633
355 Poles & Fixtures	100,687,186	1.18%	1,188,109	2.91%	2,929,997
356 Overhead Conductors and Devices	132,799,950	0.88%	1,168,640	2.05%	2,722,399
357 Underground Conduit	448,760	2.60%	11,668	3.19%	14,315
358 Underground Conductors & Devices	1,114,762	1.26%	14,046	1.45%	16,164
359 Transmission ARO's	11,027				
Total Transmission Plant	521,778,335		6,043,946		11,317,822

Kentucky Utilities Company
Annualized Depreciation - Using Majoros Rates
as of April 30, 2008

Source: Majoros MJM-3 in Case No 2007-00565

Property Group	Depreciable Balance 4-30-08	2006 Majoros Rates	Depreciation Under Majoros Rates	2006 New ELG RATES	Depreciation Under ELG
Distribution Plant					
360 1 Land Rights	1,496.173	0 65%	9,725	0 70%	10,473
360 2 Land	1,998,646	0 00%	-	0 00%	-
361 Structures and Improvements	5,058,913	1 49%	75.378	2 00%	101,178
362 Station Equipment	103,445,343	1 97%	2,037,873	2 82%	2.917,159
364 Poles Towers & Fixtures	212,853,185	1 49%	3,171,512	3 25%	6,917,729
365 Overhead Conductors and Devices	199,717,218	1 88%	3,754,684	4 23%	8,448,038
366 Underground Conduit	1,546,234	1 93%	29,842	2 06%	31.852
367 Underground Conductors & Devices	86,404,514	2 00%	1,728,090	2 86%	2.471,169
368 Line Transformers	248,482,289	2 67%	6,634,477	3 83%	9,516.872
369 Services	83,122,059	1 38%	1.147,084	2 57%	2,136.237
370 Meters	65,364,852	2 12%	1.385,735	2 79%	1,823.679
371 Installations on Customer Premises	18,284,592	2 12%	387,633	3 05%	557,680
373 Street Lighting & Signal Systems	53,771,544	2 16%	1,161,465	3 16%	1,699.181
374 Asset Retirement Cost - Distribution	18,611				
Total Distribution Plant	1,081,564,173		21,523.500		36,631,247
General Plant					
389 2 Land	2.575,973	0 00%	-	0 00%	-
390 1 Structures & Improvements	29.901,859	1 58%	472,449	2 30%	687,743
390 2 Improvements to Leased Property	531.973	1 45%	7.714	2 04%	10.852
391 1 Office Furniture & Equipment	6,548,609	4 18%	273,732	4 19%	274.387
391 2 Non PC Computer Equipment	10,163,473	10 00%	1,016,347	10 14%	1,030,576
391 3 Cash Processing Equpment	448,191	5 54%	24,830	23 26%	104,249
391 4 Personal Computer Equipment	2,486,306	21 31%	529,832	21 10%	524.610
392 Transportation Equipment	18.955,798	20 00%	3,791,160	20 00%	3.791,160
393 Stores Equipment	735,053	5 24%	38,517	5 25%	38,590
394 Tool, Shop & Garage Equipment	5.473,498	4 76%	260,539	4 75%	259,991
395 Laboratory Equipment	3,160,382	28 03%	885,855	27 42%	866,577
396 Power Operated Equipment	270,942	6 39%	17.313	6 62%	17,936
397 10 Communication Equipment - Carrier	8,835,076	7 16%	632,591	7 13%	629,941
397 20 Communication Equip - Remote Contro	3,913,060	7 99%	312,653	7 95%	311,088
397 30 Communication Equipment - Mobile	5,087,846	7 29%	370,904	7 30%	371,413
398 Misc Equipment	373,590	20.00%	74,718	20.54%	76,735
Total General Plant	99,461,628		8,709,154		8.995,849
Total Plant in Service	3,917,180,939				
Total Annual Depreciation excluding ARO amounts			97,262,572		129,236,140
Less Amounts not included in Income Statement Depreciation					
Coal Cars			227,888		184,298
Brown Gas Pipeline			200,221		226,161
TC Gas Pipeline			151,809		170.239
Account 139200 Transportation Equip			3,791,160		3,791,160
Subtotal			4,371,077		4,371.858
Total Annualized Depr less ARO and Amts not in Inc St Depr			92,891,495		124,864,282
Less ECR Depreciation			11.897,665		13,327.774
Total Annualized Depreciation excluding ECR and ARO			80,993,830		111,536,507

Depreciation Reduction - Majoros Rates-Total Company (30.542.677)

Kentucky Utilities Company
Annualized Depreciation - Using Majoros Rates
as of April 30, 2008

Source: Majoros MJM-3 in Case No 2007-00565

Property Group	Depreciable Balance 4-30-08	2006 Majoros Rates	Depreciation Under Majoros Rates	2006 New ELG RATES	Depreciation Under ELG
Ky Jurisdictional %			87.457%		
Depreciation Reduction Using Majoros Rates - *KY Jurisdiction*			*(26,711,709)*		97,546,483

Kentucky Utilities Company
ECR Depreciation at April 2008
Using Majoros Depreciation Rates

2001 Plan		2006 Proposed Majoros Rates	Majoros Annual Amount	2006 Proposed ELG Rates	ELG Annual Amount
Project 16 -- NOx Ghent Plant					
Ghent 4	1/1/2002				
Investments	4,551,149	2.39%	108,772.46	2.94%	133,803.78
Retirements, Original Cost	(44,311)		(960.00)		(960.00)
Ghent 2	3/1/2002				
Investments	5,224,392	1.88%	98,218.57	2.45%	127,997.60
Retirements, Original Cost	(41,180)		(756.00)		(756.00)
Project 17 -- SCRs and NOx Modifications					
Tyrone 3 -- Original In-service amount	11/1/2001				
Investments	1,262,166	3.50%	44,175.81	4.30%	54,273.14
Retirements, Original Cost	(216,581)		(4,608.00)		(4,608.00)
Tyrone 3 -- December 2004 Additions	12/1/2004				
Investments	87,293	3.50%	3,055.25	4.30%	3,753.60
Green River 3 Original Investments	7/1/2002				
Investments	1,358,579	2.57%	34,915.48	3.39%	46,055.83
Retirements, Original Cost	(149,233)		(2,892.00)		(2,892.00)
Green River 3 December 2004 Additions	12/1/2004				
Investments	269,265	2.57%	6,920.11	3.39%	9,128.08
Brown 2 Original Investment	12/1/2002				
Investments	1,937,045	2.55%	49,394.65	3.15%	61,016.92
Retirements, Original Cost	(918,431)		(26,448.00)		(26,448.00)
Brown 2 December 2004 Additions	12/1/2004				
Investments	776,167	2.55%	19,792.25	3.15%	24,449.25
Ghent 3 Original Investment	3/1/2004				
Investments	71,476,281	2.23%	1,593,921.07	2.76%	1,972,745.36
Retirements, Original Cost	(172,301)		(3,828.00)		(3,828.00)
Ghent 3 December 2004 Additions	12/1/2004				
Investments	2,958,119	2.23%	65,966.05	2.76%	81,644.08
Ghent 3 April 2005 Additions	3/1/2004				
Investments	2,971,181	2.23%	66,257.34	2.76%	82,004.61
Ghent 4 Original Investment	4/1/2004				
Investments	53,324,763	2.39%	1,274,461.84	2.94%	1,567,748.03
Retirements, Original Cost	(216,248)		(4,668.00)		(4,668.00)
Ghent 4 December 2004 Additions	12/1/2004				
Investments	3,288,376	2.39%	78,592.19	2.94%	96,678.26
Ghent 4 April 2005 Additions	4/1/2004				
Investments	3,518,957	2.39%	84,103.08	2.94%	103,457.34
Brown 3 Original Investment	5/1/2004				
Investments	2,102,228	2.34%	49,192.14	2.95%	62,015.73

ECR Depreciation at April 2008
Using Majoros Depreciation Rates

		2006 Proposed Majoros Rates	Majoros Annual Amount	**2006 Proposed ELG Rates**	**ELG Annual Amount**
Retirements, Original Cost	(848,647)		(33,180.00)		(33,180.00)
Brown 3 December 2004 Additions	12/1/2004				
Investments	364,407	2.34%	8,527.13	2.95%	10,750.01
Brown 3 April 2005 Additions	5/1/2004				
Investments	754	2.34%	17.64	2.95%	22.24
Ghent 1 Original Investment	5/1/2004				
Investments	56,004,868	3.40%	1,904,165.51	4.02%	2,251,395.69
Retirements, Original Cost	(113,614)		(3,540.00)		(3,540.00)
Ghent 1 December 2004 Additions	12/1/2004				
Investments	9,617,570	3.40%	326,997.38	4.02%	386,626.31
Ghent 1 April 2005 Additions	5/1/2004				
Investments	3,520,209	3.40%	119,687.10	4.02%	141,512.40
Ghent 2 - December 2004 Addition	12/1/2004				
Investments	13,192	1.88%	248.01	2.45%	323.20
GH1 SCR Catalyst Addition May 2006	5/1/2006				
Investments	2,112,857	3.40%	71,837.13	4.02%	84,936.84
2001 Plan Additions	226,739,818				
2001 Plan Retirements	(2,720,546)				
2003 Plan					
Project 18 – Ghent Ash Pond	12/1/2003				
Investments	16,148,295	2.39%	385,944.25	2.94%	474,759.87
2005 Plan					
Project 19 - Ash Handling at Ghent 1 and Ghent Station					
Ghent Station - Ash Pipe Repl Additio	4/1/2006				
Investments	398,915	2.39%	9,534.07	2.94%	11,728.11
Retirements, Original Cost	(292,425)		(6,312.00)		(6,312.00)
Project 21 - FGDs					
Ghent 3	6/1/2007				
Investments-Total	136,503,019	4.01%	5,473,771.06	4.01%	5,473,771.06
Retirements, Original Cost	(4,047,526)		(89,220.00)		(89,220.00)
Brown Training Bldg/Warehouse	12/1/2007				
Investments-Total	7,334,344	2.34%	171,623.64	2.95%	216,363.14
Retirements -- Original Cost	(74,700)		(2,916.00)		(2,916.00)
2005 Plan Additions	144,236,278				
2005 Plan Retirements	(4,414,651)				
2006 Plan					
Project 25 – Mercury Monitors					
Tyrone 3	12/31/2006				

ECR Depreciation at April 2008
Using Majoros Depreciation Rates

		2006 Proposed Majoros Rates	Majoros Annual Amount	**2006 Proposed ELG Rates**	**ELG Annual Amount**
Investments	18,149	3.50%	635.20	4.30%	780.39
Brown 3	12/31/2006				
Investments	68,158	2.34%	1,594.90	2.95%	2,010.66
Ghent 4	12/31/2006				
Investments	45,279	2.39%	1,082.17	2.94%	1,331.21
Green River 4	12/31/2006				
Investments	18,164	3.70%	672.06	4.50%	817.36
CEMS Stackvision EDR Upgrade	10/1/2007				
Investments	115,540	20.00%	23,108.00	20.00%	23,108.00
Project 27 -- ESP					
Brown	6/15/2006				
Investments	46,715	2.34%	1,093.14	2.95%	1,378.10
Retirements, Original Cost	(32,691)		(1,284.00)		(1,284.00)
2006 Plan Additions	312,005				
2006 Plan Retirements	(32,691)				
Total Additions	387,436,395.58				
Total Retirements	(7,167,887.87)				
	380,268,507.71				
Total Depreciation Expense - ELG			11,897,664.68		13,327,774.21

Louisville Gas and Electric Company
Depreciation Expense Adjustment-Electric Only
Recommended by KIUC-Based on Recommended Depr Rates of AG Witness Majoros
For the Test Year Ended April 30, 2008

See response to PSC 2-30b where Company computed effect of Majoros Rates Including Switch to ALG

	Amount
Company Computed Annualized Depreciation Expense under Majoros Proposed Rates	85,947,873
Company Proposed Depreciation Expense in Filing	116,685,232
Total Adjustment Recommended by KIUC	(30,737,359)
Less: Company Computed Effect of Using ALG Methodology Instead of ELG	14,481,536
Difference Associated with the Majoros Change in Net Negative Salvage	(16,255,823)

EXHIBIT___(LK-16)

Kentucky Utilities Company
Summary of Revenue Requirement-Electric Operations-With Updated Sect 199 %
Recommended by KIUC
For the Test Year Ended April 30, 2008

		KIUC Adjusted	Updated Sect 199 KIUC Adjusted
1	Adjusted Kentucky Jurisdictional Capitalization	$ 2,081,948,662	$ 2,081,948,662
2.	Total Cost of Capital	7.94%	7.94%
3.	Net Operating Income Found Reasonable *(Line 1 x Line 2)*	$ 165,306,724	$ 165,306,724
4	Pro-forma Net Operating Income	210,886,623	213,013,926
5.	Net Operating Income Deficiency/(Sufficiency)	$ (45,579,899)	$ (47,707,202)
5a	Net Operating Income Deficiency/(Sufficiency) - KY Coal Tax Credit	$ (2,394,816)	$ (2,394,816)
5b.	Net Operating Income Deficiency/(Sufficiency) - CTSA	$ (5,278,420)	$ (5,278,420)
5c.	Net Operating Income Deficiency/(Sufficiency) - All Other	$ (37,906,663)	$ (40,033,966)
6	Gross Up Revenue Factor	0 62175222	0 62825902
7	Overall Revenue Deficiency/(Sufficiency)	$ (68,640,712)	$ (71,395,307)
8	Net Change in Overall Revenue Deficiency/(Sufficiency)		$ (2,754,595)

Gross Up Revenue Factor Before Sect 199 Deduction Change to 9%	0 62175222	
Gross Up Revenue Factor After Sect 199 Deduction Change to 9%		0 62825902
Interest Synchronization Adjustment Before Sect 199 Deduction Change to 9%	295,092	
Interest Synchronization Adjustment Before Sect 199 Deduction Change to 9%		289,986
Change in Interest Synchronization Adjustment Made to Net Operating Income		
Change in Income Tax Expense		
Net Operating Income Per Filing	159,166,162	
Federal and State Income Tax Rate	37 60280%	36 95212%
Net Operating Income Before Taxes	255,085,432	255,085,432
KIUC Operating Income Adjustments Subject to and Before Taxes	71,064,597	71,064,597
Income Tax Amount	(95,919,270)	(94,259,477)
KIUC Income Tax Effect of KIUC Adjustments	(26,722,280)	(26,259,876)
KIUC Operating Income Adjustments Not Subject to Tax Modifications	7,673,236	7,673,236
Interest Synchronization Adjustment	(295,092)	(289,986)
KIUC Net Operating Income	210,886,623	213,013,926

Kentucky Utilities Company
Calculation of Revenue Gross Up Factor
As Filed By Company with Additional KIUC Computations
For the Test Year Ended April 30, 2008

	Company Filed Based on Rates In Effect @ 4/30/08	Without B/D & PSC Assessments @ 4/30/08	With Adjusted Sect 199 Using 9% @ 4/30/08
1. Assume pre-tax income of	$ 100.000000	$100 000000	$ 100 000000
2. Bad Debt at .2030%	0.203000		0 203000
3. PSC Assessment at 1603%	0.160300		0 160300
4 Manufacturing Deduction	3.334700	3.334700	5.007400
5. Taxable income for State income tax	96 302000	96 665300	94 629300
6. State income tax at 6 00%	5.778120	5.799918	5.677758
7. Taxable income for Federal income tax	90 523880	90 865382	88 951542
8. Federal income tax at 35%	31.683358	31.802884	31.133040
9 Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 6 + Line 8)	37 824778	37 602802	37 174098
10 Assume pre-tax income of	$ 100.000000	$100.000000	$ 100.000000
11. Gross Up Revenue Factor	62.175222	62.397198	62.825902

Diff Gross Up Factor Computation of Efffect of Bad Debt and PSC Assess	0.221976
Grossed Up Effects of Separate Gross Up Factor	0.0035702

Kentucky Utilities Company
Calculation of Composite Income Tax Rate
As Filed By Company with Additional KIUC Computations
For the Test Year Ended April 30, 2008

	As Filed By Company	Using 9% Sect 199 As Adjusted By KIUC
1 Assume pre-tax income of	$ 100 000000	$ 100 000000
2. State income tax at 6.00%	$ 5.799918	$ 5.699556
3. Taxable income for Federal income tax before production credit	$ 94.200082	$ 94 300444
Manufacturing Deduction Rate	6.00%	9.00%
Allocation to Production Inc.	0.59	0.59
Allocated Manaufacturing Deduction Rate	3.54%	5.31%
4. Less: Manufacturing Deduction	3.334700	5.007400
5. Taxable income for Federal income tax (Line 3 - Line 4)	90.865382	89 293044
6. Federal income tax at 35% (Line 5 x 35%)	31.802884	31.252565
7. Total State and Federal income taxes (Line 2 + Line 6)	37.602802	36.952121

<u>State Income Tax Calculation</u>

	As Filed By Company	Using 9% Sect 199 As Adjusted By KIUC
1 Assume pre-tax income of	$ 100.000000	$ 100 000000
2. Less: Manufacturing Deduction	$ 3.334700	$ 5.007400
3. Taxable income for State income tax	$ 96 665300	$ 94.992600
4 State Tax Rate	$ 0.060000	$ 0.060000
5 State Income Tax	$ 5.799918	$ 5.699556

Kentucky Utilities Company
Interest Synchronization - Current Tax Adjustment
As Filed By Company with Additional KIUC Adjustments and Computations
For the Test Year Ended April 30, 2008

	With KIUC Capitalization Adjustments	With Cost of Debt Changes Amounts	With Adjusted Sect 199 %
Amounts Based Upon KIUC Recommendations			
Adjusted KIUC Jurisdictional Capitalization	$2,081,948,662	$2,081,948,662	$2,081,948,662
Weighted Cost of Debt - COC Recommended	2.38%	2.37%	2.37%
"Interest Synchronization"	$ 49,550,378	$ 49,342,183	$ 49,342,183
Composite Federal and State Tax Rate	37.602802%	37.602802%	36.952121%
Current Tax Amount from "Interest Synchronization"	$ 18,632,331	$ 18,554,043	$ 18,232,983
Current Tax Expense Increase Due to "Interest Synchronization"	$ 216,805	$ 295,092	$ 289,986
Adjustment Required for Just Cost of Debt Changes		$ 78,287	
Gross Up Revenue Factor		62.175%	
		$ 125,914	
Amounts Included In Company's Filing			
Kentucky Jurisdictional Interest per Filing (excluding other interest)	$ 49,763,118	$ 49,763,118	$ 49,763,118
Kentucky Jurisdictional Interest per Filing With Company Correction	$ 50,126,944	$ 50,126,944	$ 50,126,944
Composite Federal and State Tax Rate Per Filing	37.602802%	37.602802%	36.952121%
Current tax adjustment from "Interest Synchronization" Per Filing	$ 18,849,135	$ 18,849,135	$ 18,522,969

Louisville Gas and Electric Company
Summary of Revenue Requirement-Electric Operations-With Updated Sect 199 %
Recommended by KIUC
For the Test Year Ended April 30, 2008

		KIUC Adjusted	Updated Sect 199 KIUC Adjusted
1	Adjusted Kentucky Jurisdictional Capitalization	$ 1,776,821,740	$ 1,776,821,740
2	Total Cost of Capital	7.57%	7.57%
3	Net Operating Income Found Reasonable (Line 1 x Line 2)	$ 134,505,406	$ 134,505,406
4	Pro-forma Net Operating Income	168,244,697	169,955,685
5	Net Operating Income Deficiency/(Sufficiency)	$ (33,739,291)	$ (35,450,279)
5a.	Net Operating Income Deficiency/(Sufficiency) - KY Coal Tax Credit	$ (1,665,616)	$ (1,665,616)
5b.	Net Operating Income Deficiency/(Sufficiency) - CTSA	$ (3,940,690)	$ (3,940,690)
5c	Net Operating Income Deficiency/(Sufficiency) - All Other	$ (28,132,985)	$ (29,843,973)
6	Gross Up Revenue Factor	0.62143063	0.62771570
7	Overall Revenue Deficiency/(Sufficiency)	$ (50,877,626)	$ (53,150,079)
8	Net Change in Overall Revenue Deficiency/(Sufficiency)		$ (2,272,453)

Gross Up Revenue Factor Before Sect 199 Deduction Change to 9%	0.62143063	
Gross Up Revenue Factor After Sect 199 Deduction Change to 9%		0.6277157
Interest Synchronization Adjustment Before Sect 199 Deduction Change to 9%	2,675,137	
Interest Synchronization Adjustment Before Sect 199 Deduction Change to 9%		2,630,476
Change in Interest Synchronization Adjustment Made to Net Operating Income		
Change in Income Tax Expense		
Net Operating Income Per Filing	140,147,476	
Federal and State Income Tax Rate	37.64688%	37.01837%
Net Operating Income Before Taxes	224,764,157	224,764,157
KIUC Operating Income Adjustments Subject to and Before Taxes	40,360,529	40,360,529
Income Tax Amount	(84,616,681)	(83,204,023)
KIUC Income Tax Effect of KIUC Adjustments	(15,194,478)	(14,940,809)
KIUC Operating Income Adjustments Not Subject to Tax Modifications	5,606,306	5,606,306
Interest Synchronization Adjustment	(2,675,137)	(2,630,476)
KIUC Net Operating Income	168,244,697	169,955,685

Louisville Gas and Electric Company
Calculation of Revenue Gross Up Factor
As Filed By Company with Additional KIUC Computations
For the Test Year Ended April 30, 2008

	Company Filed Based on Rates In Effect @ 4/30/08	Without B/D & PSC Assessments @ 4/30/08	With Adjusted Sect 199 Using 9% @ 4/30/08
1. Assume pre-tax income of	$ 100.000000	$ 100.000000	$100.000000
2. Bad Debt at .1835%	0.183500		0.183500
3. PSC Assessment at .1603%	0.160300		0.160300
4. Manufacturing Deduction	3.221400	3.221400	4.837100
5. Taxable income for State income tax	96.434800	96.778600	94.819100
6. State income tax at 6.00%	5.786088	5.806716	5.689146
7. Taxable income for Federal income tax	90.648712	90.971884	89.129954
8. Federal income tax at 35%	31.727049	31.840159	31.195484
9. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 6 + Line 8)	37.856937	37.646875	37.228430
10. Assume pre-tax income of	$ 100.000000	$ 100.000000	$100.000000
11. *Gross Up Revenue Factor*	62.143063	62.353125	62.771570
Diff Gross Up Factor Computation of Efffect of Bad Debt and PSC Assess	0.210062		(62.771570)
Grossed Up Effects of Separate Gross Up Factor	0.0033803		-1.0000000

Louisville Gas and Electric Company
Calculation of Composite Income Tax Rate
As Filed By Company with Additional KIUC Computations
For the Test Year Ended April 30, 2008

	As Filed By Company	Using 9% Sect 199 As Adjusted By KIUC
1. Assume pre-tax income of	$ 100.000000	$ 100.000000
2. State income tax at 6.00%	$ 5.806716	$ 5.709774
3. Taxable income for Federal income tax before production credit	$ 94.193284	$ 94.290226
Manufacturing Deduction Rate	6.00%	9.00%
Allocation to Production Inc.	0.57	0.57
Allocated Manaufacturing Deduction Rate	3.42%	5.13%
4. Less: Manufacturing Deduction	3.221400	4.837100
5. Taxable income for Federal income tax (Line 3 - Line 4)	90.971884	89.453126
6. Federal income tax at 35% (Line 5 x 35%)	31.840159	31.308594
7. Total State and Federal income taxes (Line 2 + Line 6)	37.646875	37.018368

State Income Tax Calculation		
1. Assume pre-tax income of	$ 100.000000	$ 100.000000
2. Less: Manufacturing Deduction	$ 3.221400	$ 4.837100
3. Taxable income for State income tax	$ 96.778600	$ 95.162900
4. State Tax Rate	$ 0.060000	$ 0.060000
5. State Income Tax	$ 5.806716	$ 5.709774

Louisville Gas and Electric Company
Interest Synchronization - Current Tax Adjustment
As Filed By Company with Additional KIUC Adjustments and Computations
For the Test Year Ended April 30, 2008

	With KIUC Capitalization Adjustments	With Cost of Debt Changes Amounts	With Adjusted Sect 199 %
Amounts Based Upon KIUC Recommendations			
Adjusted KIUC Jurisdictional Capitalization	$1,776,821,740	$1,776,821,740	$ 1,776,821,740
Weighted Cost of Debt - COC Recommended	2.45%	2.06%	2.06%
"Interest Synchronization"	$ 43,532,133	$ 36,602,528	$ 36,602,528
Composite Federal and State Tax Rate	37.646875%	37.646875%	37.018368%
Current Tax Amount from "Interest Synchronization"	$ 16,388,488	$ 13,779,708	$ 13,549,659
Current Tax Expense Increase Due to "Interest Synchronization"	$ 66,357	$ 2,675,137	$ 2,630,476
Adjustment Required for Just Cost of Debt Changes		$ 2,608,780	
Gross Up Revenue Factor		62.143%	
		$ 4,195,851	
Amounts Included In Company's Filing			
Kentucky Jurisdictional Interest per Filing (excluding other interest)	$ 43,708,685	$ 43,708,685	$ 43,708,685
Kentucky Jurisdictional Interest per Filing With Company Correction	43,708,394	$ 43,708,394	$ 43,708,394
Composite Federal and State Tax Rate *Per Filing*	37.646875%	37.646875%	37.018368%
Current tax adjustment from "Interest Synchronization" Per Filing	$ 16,454,844	$ 16,454,844	$ 16,180,134

EXHIBIT___(LK-17)

REDACTED

Kentucky Utilities Company
Consolidated Tax Savings Adjustment
Recommended by KIUC
For the Test Year Ended April 30, 2008

	Federal	State	Total
KU Percentage of Positive Taxable Income Companies	[redacted]		
Total of All Taxable Loss Companies			
KU's Share of Taxable Losses			
KU's Effective Income Tax Rates (No Deduction for Sec 199 Ded)	32.9%	6.0%	
KU Consolidated Tax Savings	[redacted]		
KU Jurisdictional Percentage-Rate Base % in Filing	73.94%	73.94%	
KU Consolidated Tax Savings-KY Jurisdiction-Rate Base/Capitalization	[redacted]		
Grossed Up Cost of Capital In Company's Corrected Filing	11.94%	11.94%	
Revenue Requirement Effect-Consolidated Savings	(4,437,428)	(840,992)	(5,278,420)

Cost of Capital-Company's Corrected Filing

	Company's Cost of Capital	Grossed-Up Cost of Capital
Short-Term Debt	0.07%	0.07%
Long Term Debt	2.32%	2.32%
Common Equity	5.94%	9.55%
	8.33%	11.94%

Kentucky Utilities Company
Consolidated Tax Savings Adjustment-Federal Taxable Income for 2007
Source: Confidential LG&E Response to PSC 2-104

Corporations Included in 2007 Consolidated Federal Income Tax Return:	Taxable Income	Taxable Loss	Total
[redacted]	[redacted]	[redacted]	[redacted]
Total Consolidated Taxable Income - Actual 2007	[redacted]	[redacted]	[redacted]
KU Percentage of Taxable Income Companies		[redacted]	
Taxable Loss Attributable to KU		[redacted]	

Kentucky Utilities Company
Consolidated Tax Savings Adjustment-State Taxable Income for 2006
Source: Confidential LG&E Response to PSC 2-105

Per Response: 2007 Data Not Yet Available

Corporations Included in 2007 Consolidated Federal Income Tax Return:	Taxable Income	Taxable Loss	Total
[redacted]	[redacted]	[redacted]	[redacted]
Total Consolidated Taxable Income - Actual 2007	[redacted]	[redacted]	[redacted]
KU Percentage of Taxable Income Companies		[redacted]	
Taxable Loss Attributable to KU		[redacted]	

Louisville Gas and Electric Company
Consolidated Tax Savings Adjustment
Recommended by KIUC
For the Test Year Ended April 30, 2008

	Federal	State	Total
LG&E Percentage of Positive Taxable Income Companies	[redacted]		
Total of All Taxable Loss Companies			
LG&E's Share of Taxable Losses			
LG&E's Effective Income Tax Rates (No Deduction for Sec 199 Ded)	32.9%	6.0%	
LG&E's Consolidated Tax Savings-Total Company	[redacted]		
LG&E Electric Percentage-Rate Base % in Filing	79.94%	79.94%	
LG&E Consolidated Tax Savings-Electric Only-Rate Base/Capitalization	[redacted]		
Grossed Up Cost of Capital In Company's Corrected Filing	11.94%	11.94%	
Revenue Requirement Effect-Consolidated Savings	(3,140,812)	(799,879)	(3,940,690)

Cost of Capital-Company's Corrected Filing

	Company's Cost of Capital	Grossed-Up Cost of Capital
Short-Term Debt	0.06%	0.06%
Long Term Debt	2.39%	2.39%
Common Equity	5.90%	9.49%
	8.35%	11.94%

Louisville Gas and Electric Company
Consolidated Tax Savings Adjustment-Federal Taxable Income for 2007
Source: Confidential LG&E Response to PSC 2-104

Corporations Included in 2007 Consolidated Federal Income Tax Return:	Taxable Income	Taxable Loss	Total
[redacted]			
Total Consolidated Taxable Income - Actual 2007	[redacted]		
LG&E Percentage of Taxable Income Companies		[redacted]	
Taxable Loss Attributable to LG&E		[redacted]	

Louisville Gas and Electric Company
Consolidated Tax Savings Adjustment-State Taxable Income for 2006
Source: Confidential LG&E Response to PSC 2-105

Per Response: 2007 Data Not Yet Available

Corporations Included in 2007 Consolidated Federal Income Tax Return:	Taxable Income	Taxable Loss	Total
[redacted]			
Total Consolidated Taxable Income - Actual 2007	[redacted]		
LG&E Percentage of Taxable Income Companies		[redacted]	
Taxable Loss Attributable to LG&E		[redacted]	

EXHIBIT___(LK-18)

Kentucky Utilities Company
ECR Capitalization Adjustments-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

	Adjusted Kentucky Jurisdictional Capitalization After EEI Adjust.	As Filed Per Books Capitalization Percentage Applications	KIUC Adjustment To Remove ECR Allocation Differences	KIUC Recommended Kentucky Jurisdictional Capitalization After ECR Adjust.
Short-Term Debt	56,624,255	3.27%	(890,005)	55,734,250
Long Term Debt	934,147,568	43.70%	(11,893,954)	922,253,614
Common Equity	1,118,394,125	53.03%	(14,433,327)	1,103,960,798
Total Capitalization	2,109,165,948		(27,217,286) (1)	2,081,948,662

(1) See KU Filing Requirements 807 KAR 5:001 Section 10(6)(i) Kentucky Jurisdiction Net ECR Reconciliation Amount.

II. Cost of Capital With KIUC EEI Adjustment

	Adjusted Kentucky Jurisdictional Capitalization After EEI Adjust.	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 56,624,255	2.68%	2.63%	0.07%
Long Term Debt	934,147,568	44.29%	5.21%	2.31%
Common Equity	1,118,394,125	53.03%	11.25%	5.97%
	$ 2,109,165,948			8.35%

Kentucky Utilities Company
ECR Capitalization Adjustments-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

II. Cost of Capital With KIUC ECR Adjustment

	Adjusted Kentucky Jurisdictional Capitalization After ECR Adjust.	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 55,734,250	2.68%	2.63%	0.07%
Long Term Debt	922,253,614	44.30%	5.21%	2.31%
Common Equity	1,103,960,798	53.03%	11.25%	5.97%
	$ 2,081,948,662			8.35%

Revenue Requirement Effect Computation

Capitalization Difference			$ (27,217,286)	
COC Computed After KIUC EEI Adjustment			8.35%	
Return on Lower Capitalization				(2,272,643)
Total Capitalization			2,081,948,662	
Additional COC			0.00%	
Additional Return on Capitalization				-
Capitalization Difference	$ 2,109,165,948	$ 2,081,948,662		
Total Debt Rate After EEI Adjustment	2.38%	2.38%		
Lower Interest	50,198,150	49,550,378	(647,771)	
Composite Income Tax Rate			37.603%	
Additional Income Tax Due to Lower Interest				243,580
Total Rate of Return Effect Before Gross-Up				(2,029,063)
Gross Up Revenue Factor				0.621752
Revenue Requirement Effect				(3,263,459)

Louisville Gas and Electric Company
ECR Capitalization Adjustments-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

	Adjusted Kentucky Jurisdictional Capitalization As Filed by Co.	As Filed Per Books Capitalization Percentage Applications	KIUC Adjustment To Remove ECR Allocation Differences	KIUC Recommended Kentucky Jurisdictional Capitalization After ECR Adjust.
Short-Term Debt	42,443,504	7.25%	(30,497)	42,413,007
Long Term Debt	805,334,786	40.27%	(169,395)	805,165,391
Common Equity	936,237,796	52.48%	(220,757)	936,017,039
Total Capitalization	1,784,016,086		(420,649) (1)	1,783,595,437

(1) See LG&E Filing Requirements 807 KAR 5:001 Section 10(6)(i) Kentucky Jurisdiction Net ECR Reconciliation Amount.

II. Cost of Capital As Filed and Corrected by Company

	Adjusted Kentucky Jurisdictional Capitalization After EEI Adjust.	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 42,443,504	2.38%	2.63%	0.06%
Long Term Debt	$ 805,334,786	45.14%	5.30%	2.39%
Common Equity	$ 936,237,796	52.48%	11.25%	5.90%
	$ 1,784,016,086			8.35%

Louisville Gas and Electric Company
ECR Capitalization Adjustments-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

II. Cost of Capital With KIUC ECR Adjustment

	Adjusted Kentucky Jurisdictional Capitalization After ECR Adjust.	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 42,413,007	2.38%	2.63%	0.06%
Long Term Debt	805,165,391	45.14%	5.30%	2.39%
Common Equity	936,017,039	52.48%	11.25%	5.90%
	$ 1,783,595,437			8.35%

Revenue Requirement Effect Computation

Capitalization Difference			$ (420,649)	
COC Computed by Company			8.35%	
Return on Additional Capitalization				(35,124)
Total Capitalization			1,783,595,437	
Additional COC			0.00%	
Additional Return on Capitalization				-
Capitalization Difference	$ 1,784,016,086	$ 1,783,595,437		
Total Debt Rate	2.45%	2.45%		
Additional Interest	43,708,394	43,698,088	(10,306)	
Composite Income Tax Rate			37.647%	
Additional Income Tax Due to Lower Interest				3,880
Total Rate of Return Effect Before Gross-Up				(31,244)
Gross Up Revenue Factor				0.621431
Revenue Requirement Effect				(50,278)

EXHIBIT___(LK-19)

Louisville Gas and Electric Company
Collection Cycle Change Adjustment-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

	Adjusted Kentucky Jurisdictional Capitalization After ECR Adjust.	As Filed Per Books Capitalization Percentage Applications	KIUC Adjustment To Remove ECR Allocation Differences	KIUC Recommended Kentucky Jurisdictional Capitalization After ECR Adjust.
Short-Term Debt	42,413,007	7.25%	(491,093)	41,921,914
Long Term Debt	805,165,391	40.27%	(2,727,768)	802,437,623
Common Equity	936,017,039	52.48%	(3,554,836)	932,462,203
Total Capitalization	1,783,595,437		(6,773,697)	1,776,821,740

Total Revenues -Company Adjusted - Filing Exhibit 1	890,424,838
Add Back Company's Weather Norm Adj.	14,374,348
	904,799,186
Ratio of Filing Compared to Adjusted	1.016143
Sum of RS, GS - Seely Exh 27 P, 43	486,624,196
With Additional Weather Normalization	494,479,891
Per Day Revenues	1,354,739
Revenues for 5 Days	6,773,697

Louisville Gas and Electric Company
Collection Cycle Change Adjustment-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

I. Cost of Capital With KIUC ECR Adjustment

	Adjusted Kentucky Jurisdictional Capitalization After EEI Adjust.	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 42,413,007	2.38%	2.63%	0.06%
Long Term Debt	805,165,391	45.14%	5.30%	2.39%
Common Equity	936,017,039	52.48%	11.25%	5.90%
	$ 1,783,595,437			8.35%

II. Cost of Capital With Collection Days Adjustment

	Adjusted Kentucky Jurisdictional Capitalization After ECR Adjust.	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 41,921,914	2.36%	2.63%	0.06%
Long Term Debt	802,437,623	45.16%	5.30%	2.39%
Common Equity	932,462,203	52.48%	11.25%	5.90%
	$ 1,776,821,740			8.35%

Louisville Gas and Electric Company
Collection Cycle Change Adjustment-Capitalization and Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

Revenue Requirement Effect Computation				
Capitalization Difference			$ (6,773,697)	
COC Computed After KIUC ECR Adjustment			8.35%	
Return on Additional Capitalization				(565,604)
Total Capitalization			1,776,821,740	
Additional COC			0.00%	
Additional Return on Capitalization				-
Capitalization Difference	$ 1,783,595,437	$ 1,776,821,740		
Total Debt Rate After EEI Adjustment	2.45%	2.45%		
Additional Interest	43,698,088	43,532,133	(165,956)	
Composite Income Tax Rate			37.647%	
Additional Income Tax Due to Lower Interest				62,477
Total Rate of Return Effect Before Gross-Up				(503,127)
Gross Up Revenue Factor				0.621431
Revenue Requirement Effect				(809,626)

EXHIBIT___(LK-20)

Kentucky Utilities Company
Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

I. Cost of Capital as Filed and Corrected by the Company

	Company's Adjusted Total Company Capitalization	Jurisdictional Rate Base Percentage	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 76,538,984	73.94%	$ 56,592,925	2.70%	2.63%	0.07%
Long Term Debt	1,262,819,681	73.94%	933,728,872	44.52%	5.21%	2.32%
Common Equity	1,497,213,789	73.94%	1,107,039,876	52.78%	11.25%	5.94%
	$ 2,836,572,454		$ 2,097,361,673	100.00%		8.33%

Kentucky Utilities Company
Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

II. Cost of Capital Adjusted to Most Recent Actual Results as of August 31, 2008

	KIUC Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 55,734,250	2.68%	2.44%	0.07%
Long Term Debt	$ 922,253,614	44.30%	5.20%	2.30%
Common Equity	$ 1,103,960,798	53.02%	11.25%	5.96%
	$ 2,081,948,662	100.00%		8.33%

Revenue Requirement Effect of Above Adjustment:

Total Capitalization	$ 2,081,948,662
COC Difference Between Above Adjustment and ECR Capitalization KIUC Adjustment	-0.02%
COC Computed Adjustment Before Gross-Up Factor	(416,390)
Gross-Up Factor	0.621752
Grossed Up Revenue Requirement Before Interest Synchronization	(669,704)
Interest Synchronization Difference Due to Change ST and LT Debt Rates	125,914
Change in Revenue Requirement	$ (543,790)

Kentucky Utilities Company
Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

III. Cost of Capital With KIUC Recommended ROE

	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 55,734,250	2.68%	2.44%	0.07%
Long Term Debt	922,253,614	44.30%	5.20%	2.30%
Common Equity	1,103,960,798	53.02%	10.50%	5.57%
	$ 2,081,948,662	100.00%		7.94%

Revenue Requirement Effect of Above Adjustment:

Total Capitalization	$ 2,081,948,662
COC Difference Between Adjustment II and III Above	-0.39%
COC Computed Adjustment Before Gross-Up Factor	(8,119,600)
Gross-Up Factor	0.621752
Grossed Up Change in Revenue Requirement	$ (13,059,221)

Louisville Gas and Electric Company
Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

I. Cost of Capital as Filed and Corrected by the Company

	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 42,443,504	2.38%	2.63%	0.06%
Long Term Debt	805,334,786	45.14%	5.30%	2.39%
Common Equity	936,237,796	52.48%	11.25%	5.90%
Total	$ 1,784,016,086	100.00%		8.35%

Louisville Gas and Electric Company
Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

II. Cost of Capital Adjusted to Most Recent Actual Results as of August 31, 2008

	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 41,921,914	2.36%	2.44%	0.06%
Long Term Debt	802,437,623	45.16%	4.42%	2.00%
Common Equity	932,462,203	52.48%	11.25%	5.90%
Total	$ 1,776,821,740	100.00%		7.96%

Revenue Requirement Effect of Above Adjustment:

Total Capitalization	$ 1,776,821,740
COC Difference Between Above Adjustment and Collection Cycle Capitalization KIUC Adjustment	-0.39%
COC Computed Adjustment Before Gross-Up Factor	(6,929,605)
Gross-Up Factor	0.621431
Grossed Up Revenue Requirement Before Interest Synchronization	(11,151,051)
Interest Synchronization Difference Due to Change ST and LT Debt Rates	4,195,851
Change in Revenue Requirement	$ (6,955,200)

Louisville Gas and Electric Company
Cost of Capital
Recommended by KIUC
For the Test Year Ended April 30, 2008

III. Cost of Capital With KIUC Recommended ROE

	Adjusted Kentucky Jurisdictional Capitalization	Adjusted Jurisdictional Capital Structure	Annual Cost Rate	Cost of Capital
Short-Term Debt	$ 41,921,914	2.36%	2.44%	0.06%
Long Term Debt	$ 802,437,623	45.16%	4.42%	2.00%
Common Equity	$ 932,462,203	52.48%	10.50%	5.51%
Total	$ 1,776,821,740	100.00%		7.57%

Revenue Requirement Effect of Above Adjustment:

Total Capitalization	$ 1,776,821,740
COC Difference Between Adjustment II and III Above	-0.39%
COC Computed Adjustment Before Gross-Up Factor	(6,929,605)
Gross-Up Factor	0.621431
Grossed Up Change in Revenue Requirement	$ (11,151,051)

EXHIBIT___(LK-21)

This Report includes proprietary information. Please do not use this report, or information contained herein, outside the context of this proceeding.

Regulatory Research Associates
REGULATORY FOCUS

Special Study October 3, 2008

MAJOR RATE CASE DECISIONS--JANUARY-SEPTEMBER 2008

For the first nine months of 2008, the average of electric equity return authorizations by state commissions was 10.51% (29 determinations) versus the 10.36% average for calendar-2007. The average gas equity return authorization for the first three quarters of 2008 was 10.39% (17 determinations), compared with the 10.24% average for calendar-2007. In addition, we note that on Sept. 17, 2008, the New York Public Service Commission adopted a settlement that incorporates a 9.3% equity return for Consolidated Edison of New York's steam operations (see FN 9/19/08 for additional information).

After reaching a low in the late-1990's and early-2000's, the number of rate case decisions for energy companies has generally increased over the last several years. In fact, the total number of electric and gas rate decisions in 2007 (94) was more than double the number in 2003 (42). Increased costs, including environmental compliance expenditures, and the need for generation and delivery infrastructure upgrades and expansion at many companies argue for a continuation of the increased level of rate case activity over the next several years. However, relatively low interest rates, cost efficiencies from technological advancements, the use of multi-year settlements that do not specify return parameters, and a reduced number of companies due to mergers, may prevent the number of rate cases and equity return determinations from significantly increasing further. We note that electric industry restructuring in many states led to the unbundling of rates, with some state commissions authorizing revenue requirement and return parameters for delivery operations only (which we footnote in our chronology), thus complicating historical data comparability. The tables included in this study are extensions of those contained in the January 8, 2008 Regulatory Study entitled *Major Rate Case Decisions--January 2006-December 2007--Supplemental Study*. Refer to that report for information concerning individual rate case decisions that were rendered in 2006 and 2007.

The table on page 2 shows annual average equity returns authorized since 1990, and by quarter since 2002, in major electric and gas rate decisions, followed by the number of determinations during each period. The tables on page 3 present the composite industry data for items in the chronology of this and earlier reports, summarized annually since 1995, and quarterly for the most recent seven quarters. The individual electric and gas cases decided in the first nine months of 2007 are listed on pages 4 through 6, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

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Average Equity Returns Authorized January 1990 - September 2008

Year	Period	Electric Utilities ROE %	Electric Utilities (# Cases)	Gas Utilities ROE %	Gas Utilities (# Cases)
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
	1st Quarter	10.87	(5)	10.67	(3)
	2nd Quarter	11.41	(6)	11.64	(4)
	3rd Quarter	11.06	(4)	11.50	(3)
	4th Quarter	11.20	(7)	10.78	(11)
2002	**Full Year**	**11.16**	(22)	**11.03**	(21)
	1st Quarter	11.47	(7)	11.38	(5)
	2nd Quarter	11.16	(4)	11.36	(4)
	3rd Quarter	9.95	(5)	10.61	(5)
	4th Quarter	11.09	(6)	10.84	(11)
2003	**Full Year**	**10.97**	(22)	**10.99**	(25)
	1st Quarter	11.00	(3)	11.10	(4)
	2nd Quarter	10.54	(6)	10.25	(2)
	3rd Quarter	10.33	(2)	10.37	(8)
	4th Quarter	10.91	(8)	10.66	(6)
2004	**Full Year**	**10.75**	(19)	**10.59**	(20)
	1st Quarter	10.51	(7)	10.65	(2)
	2nd Quarter	10.05	(7)	10.54	(5)
	3rd Quarter	10.84	(4)	10.47	(5)
	4th Quarter	10.75	(11)	10.40	(14)
2005	**Full Year**	**10.54**	(29)	**10.46**	(26)
	1st Quarter	10.38	(3)	10.63	(6)
	2nd Quarter	10.68	(6)	10.50	(2)
	3rd Quarter	10.06	(7)	10.45	(3)
	4th Quarter	10.39	(10)	10.14	(5)
2006	**Full Year**	**10.36**	(26)	**10.43**	(16)
	1st Quarter	10.27	(8)	10.44	(10)
	2nd Quarter	10.27	(11)	10.12	(4)
	3rd Quarter	10.02	(4)	10.03	(8)
	4th Quarter	10.56	(16)	10.27	(15)
2007	**Full Year**	**10.36**	(39)	**10.24**	(37)
	1st Quarter	10.50	(10)	10.38	(7)
	2nd Quarter	10.57	(8)	10.17	(3)
	3rd Quarter	10.47	(11)	10.49	(7)
2008	**Year-To-Date**	**10.51**	(29)	**10.39**	(17)

Electric Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1995	Full Year	9.44	(30)	11.55	(33)	45.90	(30)	455.7	(43)
1996	Full Year	9.21	(20)	11.39	(22)	44.34	(20)	-5.6	(38)
1997	Full Year	9.16	(12)	11.40	(11)	48.79	(11)	-553.3	(33)
1998	Full Year	9.44	(9)	11.66	(10)	46.14	(8)	-429.3	(31)
1999	Full Year	8.81	(18)	10.77	(20)	45.08	(17)	-1683.8	(30)
2000	Full Year	9.20	(12)	11.43	(12)	48.85	(12)	-291.4	(34)
2001	Full Year	8.93	(15)	11.09	(18)	47.20	(13)	14.2	(21)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	*Full Year*	*8.86*	*(20)*	*10.97*	*(22)*	*49.41*	*(19)*	*313.8*	*(12)*
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1373.7	(36)
2006	Full Year	8.24	(24)	10.36	(26)	48.67	(23)	1465.0	(42)
	1st Quarter	8.44	(8)	10.27	(8)	47.80	(8)	403.5	(9)
	2nd Quarter	7.94	(11)	10.27	(11)	46.02	(11)	718.6	(12)
	3rd Quarter	7.90	(4)	10.02	(4)	48.34	(4)	119.1	(6)
	4th Quarter	8.38	(15)	10.56	(16)	49.59	(14)	160.7	(19)
2007	Full Year	8.22	(38)	10.36	(39)	48.01	(37)	1401.9	(46)
	1st Quarter	8.36	(9)	10.50	(10)	49.25	(8)	803.0	(9)
	2nd Quarter	8.21	(7)	10.57	(8)	47.64	(7)	510.5	(8)
	3rd Quarter	8.32	(10)	10.47	(11)	48.96	(10)	734.3	(13)
2008	**Year-To-Date**	**8.30**	**(26)**	**10.51**	**(29)**	**48.68**	**(25)**	**2047.8**	**(30)**

Gas Utilities--Summary Table*

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
1995	Full Year	9.64	(16)	11.43	(16)	49.98	(15)	-61.5	(31)
1996	Full Year	9.25	(23)	11.19	(20)	47.69	(19)	193.4	(34)
1997	Full Year	9.13	(13)	11.29	(13)	47.78	(11)	-82.5	(21)
1998	Full Year	9.46	(10)	11.51	10)	49.50	(10)	93.9	(20)
1999	Full Year	8.86	(9)	10.66	(9)	49.06	(9)	51.0	(14)
2000	Full Year	9.33	(13)	11.39	(12)	48.59	(12)	135.9	(20)
2001	Full Year	8.51	(6)	10.95	(7)	43.96	(5)	114.0	(11)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.51	(16)	10.43	(16)	47.43	(16)	444.0	(25)
	1st Quarter	8.40	(10)	10.44	(10)	48.33	(9)	158.4	(13)
	2nd Quarter	8.32	(3)	10.12	(4)	49.67	(4)	37.3	(5)
	3rd Quarter	7.88	(7)	10.03	(8)	48.70	(6)	402.0	(12)
	4th Quarter	7.97	(12)	10.27	(15)	47.74	(11)	215.7	(18)
2007	Full Year	8.12	(32)	10.24	(37)	48.37	(30)	813.4	(48)
	1st Quarter	8.78	(7)	10.38	(7)	52.07	(7)	129.6	(7)
	2nd Quarter	8.28	(3)	10.17	(3)	51.80	(3)	52.0	(4)
	3rd Quarter	8.33	(7)	10.49	(7)	50.58	(7)	312.8	(10)
2008	**Year-To-Date**	**8.51**	**(17)**	**10.39**	**(17)**	**51.41**	**(17)**	**494.4**	**(21)**

* Number of observations in each period indicated in parentheses.

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/8/08	Northern States Power-Wisconsin (WI)	9.67	10.75	52.51	12/08-A	39.4
1/17/08	Wisconsin Electric Power (WI)	9.26	10.75	54.36	12/08-A/P	148 4 (Z)
1/28/08	Connecticut Light & Power (CT)	7 72	9 40	48 99	12/06-YE	98.0 (D,Z)
1/30/08	Potomac Electric Power (DC)	7 96	10.00	46.55	2/07-A	28 3 (D,1)
1/31/08	Central Vermont Public Service (VT)	8.50	10.71	50.02	12/06-A	6.4 (B)
2/6/08	Interstate Power & Light (IA)	---	11.70 (2)	---	---	---
2/28/08	Idaho Power (ID)	8 10	---	---	---	32.1 (B)
2/29/08	Fitchburg Gas & Electric (MA)	8.38	10.25	42.80	12/06-YE	2.1 (D)
3/12/08	PacifiCorp (WY)	8.29	10 25	50.80	8/08	23.0 (B,3)
3/25/08	Consolidated Edison of New York (NY)	7.34	9.10	47.98	3/09-A	425.3 (D)
3/31/08	Virginia Electric Power (VA)	---	12.12 (4)	---	---	---
2008	***1ST QUARTER: AVERAGES/TOTAL***	**8.36**	**10.50**	**49.25**		**803.0**
	MEDIAN	**8.29**	**10.48**	**49.51**		---
	OBSERVATIONS	**9**	**10**	**8**		**9**
4/22/08	MDU Resources (MT)	8 58	10.25	50.67	12/06-A	4 1 (B,Z)
4/24/08	Public Service Company of New Mexico (NM)	8.24	10.10	51.37	9/06-YE	34.4
5/1/08	Hawaiian Electric Company (HI)	8.66	10 70	55.79	12/05-A	44 9 (Bp,I)
5/27/08	UNS Electric (AZ)	9.02	10 00	48.85	6/06-YE	4 0
5/30/08	Idaho Power (ID)	--- (5)	---	---	---	8 9
6/10/08	Consumers Energy (MI)	6.93	10 70	41.75 *	12/08-A	221.0 (I)
6/16/08	MidAmerican Energy (IA)	---	11.70 (B,6)	---	---	---
6/27/08	Appalachian Power (WV)	7.65	10.50	41.54	12/07-YE	106.1 (B)
6/27/08	Sierra Pacific Power (NV)	8.41	10 60 (7)	43.49	6/07-YE	87 1
2008	***2ND QUARTER: AVERAGES/TOTAL***	**8.21**	**10.57**	**47.64**		**510.5**
	MEDIAN	**8.41**	**10.55**	**48.85**		---
	OBSERVATIONS	**7**	**8**	**7**		**8**
7/1/08	Central Maine Power (ME)	---	---	---	---	-20 3 (B,D,8)
7/1/08	NorthWestern Corporation (MT)	--- (9)	---	---	---	10 0 (B,I)
7/10/08	Otter Tail Corporation (MN)	8.33	10 43	50 00	12/06-A	3 8 (I)
7/16/08	Orange and Rockland Utilities (NY)	7 69	9.40	48.00	6/09-A	15.6 (B,D)
7/30/08	Empire District Electric (MO)	8 92	10.80	50.78	6/07-YE	22.0
7/31/08	San Diego Gas & Electric (CA)	--- (10)	--- (10)	--- (10)	12/08-A	234.0 (B,Z)
8/11/08	PacifiCorp (UT)	8.29	10 25	50.40	12/08-A	36.2 (R)
8/26/08	Southwestern Public Service (NM)	8.27	10.18	51.23	12/06-YE	13.1
8/27/08	MidAmerican Energy (IA)	---	11.70 (B,11)	---	---	---
9/10/08	Commonwealth Edison (IL)	8 36	10 30	45.04	12/06-YE	273.6 (D)
9/24/08	Central Illinois Light (IL)	8.01	10.65	46 50	12/06-YE	-2 8
9/24/08	Central Illinois Public Service (IL)	8 20	10.65	47.91	12/06-YE	22.0
9/24/08	Illinois Power (IL)	8.68	10.65	51.76	12/06-YE	103 9
9/30/08	Avista Corp. (ID)	8.45	10 20	47 94	12/06-A	23 2 (B)
2008	***3RD QUARTER: AVERAGES/TOTAL***	**8.32**	**10.47**	**48.96**		**734.3**
	MEDIAN	**8.31**	**10.43**	**49.00**		---
	OBSERVATIONS	**10**	**11**	**10**		**13**

ELECTRIC UTILITY DECISIONS (continued)

2008	***YEAR-TO-DATE: AVERAGES/TOTAL***	**8.30**	**10.51**	**48.68**		**2047.8**
	MEDIAN	**8.31**	**10.50**	**48.99**		**---**
	OBSERVATIONS	**26**	**29**	**25**		**30**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/8/08	Northern States Power-Wisconsin (WI)	9 67	10 75	52 51	12/08-A	5 3
1/17/08	Wisconsin Electric Power (WI)	9.15	10 75	54.36	12/08-A/P	4.0
1/17/08	Wisconsin Gas (WI)	10.91	10 75	46 64	12/08-A/P	20.1
2/5/08	North Shore Gas (IL)	7 96	9 99	56 00	9/06-YE	-0 2
2/5/08	Peoples Gas Light & Coke (IL)	7.76	10 19	56 00	9/06-YE	71 2
2/13/08	Indiana Gas (IN)	7 80	10 20	48 99 *	12/06-YE	26 9 (B)
3/31/08	Avista Corp (OR)	8 21	10 00	50 00	12/06-A	2 3 (Z,B)
2008	***1ST QUARTER: AVERAGES/TOTAL***	**8.78**	**10.38**	**52.07**		**129.6**
	MEDIAN	**8.21**	**10.20**	**52.51**		**---**
	OBSERVATIONS	**7**	**7**	**7**		**7**
4/23/08	Atmos Energy (KS)	---	---	---	---	2 1 (B)
5/28/08	Duke Energy (OH)	8 45	10.50	55 76	12/07	18 2 (B)
6/24/08	Atmos Energy (TX)	7.98	10 00	48.27	6/07-YE	19 7
6/27/08	Questar Gas (UT)	8 41	10 00	51 38	12/08-A	12 0
2008	***2ND QUARTER: AVERAGES/TOTAL***	**8.28**	**10.17**	**51.80**		**52.0**
	MEDIAN	**8.41**	**10.00**	**51.38**		**---**
	OBSERVATIONS	**3**	**3**	**3**		**4**
7/1/08	NorthWestern Corporation (MT)	--- (12)	---	---	---	5 0 (B,I)
7/31/08	San Diego Gas & Electric (CA)	--- (10)	--- (10)	--- (10)	12/08-A	33 0 (B,Z)
7/31/08	Southern California Gas (CA)	--- (13)	--- (13)	--- (13)	12/08-A	214 0 (B,Z)
8/27/08	SourceGas Distribution (CO)	8 26	10 25	53.13	8/07-A	14 9 (B)
9/2/08	Chesapeake Utilities (DE)	8 91	10.25	61.81	3/07	0 3 (I,B)
9/17/08	Atmos Energy (GA)	7 75	10.70	45.00	3/09-A	3 4
9/24/08	Central Illinois Light (IL)	8.03	10.68	46.50	12/06-YE	-9 2
9/24/08	Central Illinois Public Service (IL)	8.22	10 68	47.91	12/06-YE	7.7
9/24/08	Illinois Power (IL)	8 70	10 68	51.76	12/06-YE	39 8
9/30/08	Avista Corp (ID)	8 45	10 20	47 94	12/06-A	3 9 (B)
2008	***3RD QUARTER: AVERAGES/TOTAL***	**8.33**	**10.49**	**50.58**		**312.8**
	MEDIAN	**8.26**	**10.68**	**47.94**		**---**
	OBSERVATIONS	**7**	**7**	**7**		**10**
2008	***YEAR-TO-DATE: AVERAGES/TOTAL***	**8.51**	**10.39**	**51.41**		**494.4**
	MEDIAN	**8.26**	**10.25**	**51.38**		**---**
	OBSERVATIONS	**17**	**17**	**17**		**21**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
Bp- Order followed partial stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
D- Applies to electric delivery only
P- Partial inclusion of CWIP in rate base without AFUDC offset to income
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase effective 2/20/08.
(2) ROE applies only to a proposed 200-MW wind generation facility, and is applicable over the 25-year depreciable life of the project.
(3) Rate increase effective 5/1/08.
(4) ROE applies only to a proposed 585-MW coal generation facility, is applicable for AFUDC and CWIP purposes and over the first 12 years of the plant's commercial operation, and includes a 100-basis-point incentive premium
(5) The 8.1% ROR utilized in the company's case decided on 2/28/08, was incorporated into this proceeding
(6) ROE applies only to a proposed 108-MW wind generation facility, and is applicable over the 20-year depreciable life of the project.
(7) Commission also authorized a 150-basis-point ROE premium for the new, 514-MW, combined-cycle Tracy generating plant, and a 500-basis-point premium for demand-side management investments.
(8) Rate reduction ordered in conjunction with the authorization of a new five-year alternative regulation plan
(9) Order noted that an ROR of 7.04% is implied in the approved settement.
(10) Rate of return was not an issue in this proceeding. The authorized rate change incorporated the 10.7% return on equity (49% of capital) and the 8.23% return on rate base previously authorized the company for 2007.
(11) ROE applies only to a proposed 52.5-MW wind generation facility, and is applicable over the 20-year depreciable life of the project.
(12) Order noted that an ROR of 7.59% is implied in the approved settement.
(13) Rate of return was not an issue in this proceeding. The rate change incorpated the 10.82% return on equity (48% of capital) and 8.68% return on rate base authorized the company in its automatic cost of capital adjustment mechanism.

Dennis Sperduto

EXHIBIT___(LK-22)

Regulatory Research Associates Data
Average ROE Data as of October 3, 2008 for the First Three Quarters of 2008
Averages Computed by KIUC after KIUC Exclusions As Detailed

Date	Company (State)	ROE % as Presented in RRA Data	Exclusions	ROE% After Exclusions
1/8/08	Northern States Power-Wisconsin (WI)	10.75		10.75
1/17/08	Wisconsin Electric Power (WI)	10.75		10.75
1/28/08	Connecticut Light & Power (CT)	9.40		9.40
1/30/08	Potomac Electic Power (DC)	10.00		10.00
1/31/08	Central Vermont Public Service (VT)	10.71		10.71
2/6/08	Interstate Power & Light (IA)	11.70	Excluded	
2/28/08	Idaho Power (ID)			
2/29/08	Fitchburg Gas & Electric (MA)	10.25		10.25
3/12/08	PacifiCorp (WY)	10.25		10.25
3/25/08	Consolidated Edison of New York (NY)	9.10		9.10
3/31/08	Virginia Electric Power (VA)	12.12	Excluded	
2008	***1ST QUARTER: AVERAGES/TOTAL***	**10.50**		**10.15**
4/22/08	MDU Resources (MT)	10.25		10.25
4/24/08	Public Service Company of New Mexico (NM)	10.10		10.10
5/1/08	Hawaiian Electric Company (HI)	10.70		10.70
5/27/08	UNS Electric (AZ)	10.00		10.00
5/30/08	Idaho Power (ID)			
6/10/08	Consumers Energy (MI)	10.70		10.70
6/16/08	MidAmerican Energy (IA)	11.70	Excluded	
6/27/08	Appalachian Power (WV)	10.50		10.50
6/27/08	Sierra Pacific Power (NV)	10.60		10.60
2008	***2ND QUARTER: AVERAGES/TOTAL***	**10.57**		**10.41**
7/1/08	Central Maine Power (ME)			
7/1/08	NorthWestern Corporation (MT)			
7/10/08	Otter Tail Corporation (MN)	10.43		10.43
7/16/08	Orange and Rockland Utilities (NY)	9.40		9.40
7/30/08	Empire District Electric (MO)	10.80		10.80
7/31/08	San Diego Gas & Electric (CA)			
8/11/08	PacifiCorp (UT)	10.25		10.25
8/26/08	Southwestern Public Service (NM)	10.18		10.18
8/27/08	MidAmerican Energy (IA)	11.70	Excluded	
9/10/08	Commonwealth Edison (IL)	10.30		10.30
9/24/08	Central Illinois Light (IL)	10.65		10.65
9/24/08	Central Illinois Public Service (IL)	10.65		10.65
9/24/08	Illinois Power (IL)	10.65		10.65
9/30/08	Avista Corp. (ID)	10.20		10.20
2008	***3RD QUARTER: AVERAGES/TOTAL***	**10.47**		**10.35**
2008	***YEAR-TO-DATE: AVERAGES/TOTAL***	**10.51**		**10.30**