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Via Hand Delivery

February 20, 2009

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2008-00409

Dear Mr. Derouen:

Please find enclosed the original and twelve (12) copies of the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON AND LANE KOLLEN on behalf of the KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. filed 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 electronic mail (when available) and first-class postage prepaid mail to all parties on the 20th day of February, 2009.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC	)	
RATES OF EAST KENTUCKY POWER	)	CASE NO.
COOPERATIVE, INC.	)	2008-00409

RECEIVED
FEB 20 2009
PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2009

COMMONWEALTH OF KENTUCKY

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COOPERATIVE, INC.	**)**	**2008-00409**

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").

Q. What is the purpose of your testimony?

A. I am responding to the Direct Testimony of East Kentucky Power Cooperative, Inc. ("EKPC" or the "Company") witness Steven Seelye 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. In general, I believe that the Company's filed cost of service study is reasonable, in particular with regard to the with regard to the allocation of fixed production and transmission demand costs. However, I have identified a number of issues that require adjustments to the filed cost of service study. These issues include both corrections to certain portions of the study, and refinements to reflect a more detailed classification and allocation of purchased power and fuel expense. As I will discuss, the Company has allocated these energy related costs on the basis of rate schedule energy (including losses), rather than recognizing the differential in energy cost by time-of-day and season. Using a more refined allocation methodology for these costs changes the results of the cost of service study and, in particular, reduces cost responsibility for the Large Special Contract ("LSC") rate class, compared to the Company's study. I will present a revised class cost of service study reflecting a more detailed allocation of fuel and purchased energy costs.

The second issue that I address concerns the Company's overall rate proposal to change rates in two phases over a 12 month period. In Phase I, each rate class is increased on an equal percentage basis (except for the pumping station class), while in Phase II, which occurs 12 months later, rates are adjusted to move towards cost of service. As discussed by Mr. Seelye, the purpose of this two-phase approach is to recognize the principle of gradualism. I will address the Company's rate design proposal and recommend an alternative approach that would change rates only once, rather than the two-phase approach.

rather than the two-phase approach. In addition, consistent with this recommendation, I will also discuss the Company's proposed increase in the interruptible credit and recommend that this interruptible credit increase be implemented immediately upon the implementation of the Commission approved rates in this case (whether a single or two-phase increase. The Company has determined that the current interruptible credit is not just and reasonable and there is no reason why this credit should not be changed at the conclusion of this case, rather than in Phase-II, as proposed by EKPC. In addition, I discuss an adjustment to the Company's proposed interruptible credit to incorporate an avoided cost component associated with avoided capacity reserves made possible by interruptible load.

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **The Commission should adopt the EKPC class cost of service study, as adjusted and corrected by KIUC. Based on this study, the Large Special Contract class would pay rates above cost of service with the Company's Phase I rate design proposal.**

- **The Company's proposed Phase I rates should be adopted and there is no need to further adjust rates in Phase II.**

- **EKPC's proposed Large Special Contract interruptible rate credit of \$5.30 per kW should be adjusted to reflect avoided capacity reserves associated with interruptible load. This adjustment increases the interruptible credit to \$5.90 per kW. This credit should be adopted by the Commission and implemented in Phase I of this proceeding.**

implemented in Phase I of this proceeding. Though the Company has developed an alternative interruptible credit based on a 4% cost of capital, for the reasons discussed in section III of this testimony, the $5.90 per kW interruptible credit is reasonable.

II. COST OF SERVICE STUDY ISSUES

Q. Have you reviewed the Company's proposed class cost of service study, presented as Exhibit 7 to Mr. Seelye's testimony?

A. Yes. The Company has prepared a fully projected class cost of service study for the 12 months ending May 2010 using a 6 coincident peak allocation for production demand costs and 12 CP for transmission costs. While I fully support the Company's methodology, I have identified 4 adjustments that should be made to the study to correct errors and to provide a more detailed allocation of purchased power and fuel expenses. As I will discuss, these corrections and refinements result in changes to the rates of return by rate schedule to the extent that the Large Special Contract rate class is shown to be paying an excessive rate of return under proposed Phase I rates, which do not include the full level of the proposed interruptible credit.

Q. Would you please discuss the changes that you have made to correct and refine the EKPC class cost of service study?

A. As I indicated, I have identified 4 changes that need to be made to the class cost of service study. Two of these changes are corrections to the study, but continue to use the EKPC methodology as presented in Mr. Seelye's Exhibit 7. The remaining two changes reflect a changes reflect a more detailed allocation of purchased power and fuel expense, recognizing seasonal and time of day cost differences in the allocation process. KIUC's revised class cost of service study, which is a modification of Mr. Seelye's analysis which he presented in his Exhibit 7, is shown in Baron Exhibit__(SJB-2), page 1 through 28.

The first adjustment that I made to the cost of service study concerns the correction identified by the Company in response to Request 23 of the Commission Staff's Second set of data requests. The Company identified that an additional $2,557,756 of purchased power expense should have been removed from test year expenses. I have incorporated this correction in my class cost of service study [see page 21 of Exhibit__(SJB-2)].

The second adjustment that I made concerns a problem that we identified in the allocation of fuel expense to the Special Contract Pumping Station rate class. As described in EKPC's response to Staff Second Data Request 35c, the Pumping Station Special Contract is a transmission service rate, with market based rates for power. As a result, this rate class is not billed pursuant to the standard fuel adjustment clause rate. In order to properly allocate total fuel expense in the class cost of service study, it is necessary to specifically assign the market based rate amount directly to the Pumping class. The amount should equate exactly amount directly to the Pumping class. The amount should equate exactly to the revenues received from the class for the market based purchases.

Q. Did the Company properly assign pumping station fuel expenses in the class cost of service study?

A. No. According to Seelye Exhibit 9, page 6 of 7, the pumping station class will pay \$3,306,725 for off-peak market purchases and \$6,174,617 for on-peak market purchases during the test year. Since this pumping station contract is essentially a pass-through rate, with regards to power costs, the amount of fuel and purchased power expense that should be specifically assigned to this class would be \$9,481,341 (the sum of the off-peak and on-peak revenues that will be billed to this class in the test year). Likewise, the amount of fuel and purchased power expense and revenue that should be removed in the "Adjustments" that the Company made should also equate to the same \$9,481,341.[1] A review of Seelye Exhibit 7 on page 22 shows that \$10,601,954 of fuel and purchased power expense was removed.[2] The amount of fuel and purchased power expense removed should equate to the specific assignment expense amount of \$9,451,834. By removing \$10,601,954 of fuel and purchased power expense from a total fuel and purchase power expense of \$9,451,834, Mr.

[1] Since this is a pass-through rate, the allocated fuel and purchased power expenses should be equal to the fuel and purchased power expenses removed in the pro-forma adjustment that is made to eliminate theses costs and revenues from the class cost of service study.

$9,451,834, Mr. Seelye's study produces a negative residual expense for the Special Pumping class – this is the principal reason why the Company's cost of service study shows a rate of return for this class of 29.52%. In my revised cost of service study, I have corrected this problem by revising the amount of FAC fuel and purchased power expense such that there is equality with the amount of market rate based expense assigned to the class. This adjustment is shown on pages 27 and 28 of Exhibit__(SJB-2), and the corrected allocated expense is shown on pages 21 and 22.

Q. Would you please discuss the final two adjustments that you have made to the class cost of service study in order to more reasonably allocate fuel and purchased power expense.

A. These two revisions to the Company's cost of service study are designed to more accurately allocate fuel and purchased power costs to rate classes. As discussed by EKPC witness Seelye, the Company's cost of service study allocates all fuel and purchased power costs on the basis of rate schedule energy. Though this is a reasonable approach, a more detailed allocation can be made and is justified in cases where there are material differences in these energy costs by season and time-of-day. These adjustments are shown on pages 21, 22, 27 and 28 of Exhibit__(SJB-2).

[2] Fuel expense of $9,538,606 and purchase power expense of $1,063,348.

The first of these revised allocations concerns EKPC's test year fuel expenses of $426,937,485. In my revised analysis, these expenses are disaggregated monthly and allocated based on monthly energy use to rate classes (details shown on pages 27 and 28 of the study).

The second revised allocation concerns EKPC's $64,242,370 in purchased power expenses. The Company has determined that 70% of these test year expenses are incurred during the on-peak period and 30% in the off-peak period. I have separately allocated the on and off-peak amounts using rate class kWh energy usage during the same on and off-peak periods.

Q. What are the results of the KIUC adjusted class cost of service study?

A. Baron Exhibit__(SJB-2) presents the revised class cost of service study. Table 1 below summarizes the rates of return at Phase I rates based on this corrected and revised cost of service study and as reported in the Company's filed study. Also shown are the relative rate of return index values, which measure the rate of return of each rate class on a relative basis to the system average rate of return (if the "Index" equals 1.0, then the rate class is at the system average rate of return).

Table 1
KIUC Class Cost of Service Study Results
Rates of Return at Phase 1 Proposed Rates

	EKPC as-Filed (Seelye Ex. 7)		KIUC Adjusted (Baron Ex. SJB-2)	
	ROR	Index	ROR	Index
Rate E	6.12%	0.99	6.21%	0.99
Rate B	6.63%	1.07	7.03%	1.12
Rate C	6.02%	0.97	6.36%	1.01
Rate G	4.43%	0.72	4.87%	0.77
Large Special Contract	5.72%	0.92	6.45%	1.02
Spc Cont Pumping Stations	29.52%	4.77	11.64%	1.85
Steam Service	10.66%	1.72	11.33%	1.80
Total	6.19%	1.00	6.30%	1.00

As can be seen from Table 1, the rate of return for the Large Special Contract class exceeds the system average rate of return at proposed Phase I rates (6.45% versus a an average rate of return of 6.30%).

III. RATE DESIGN ISSUES

Q. Would you please discuss the Company's proposal to implement its requested revenue increase in two phases?

A. As discussed in the Direct Testimony of Mr. Seelye, EKPC is proposing to increase rates on an approximate equal percentage basis initially ("Phase I" increase) and then, 12 months later, adjust rates to bring each rate class closer to cost of service ("Phase II"). The entire Commission approved revenue increase would be collected from its customers in Phase I, while in Phase II there would be no net change in overall EKPC revenues. Mr. Seelye explains that this two phase approach is appropriate to provide a gradual transition to cost based rates, which would be addressed in Phase II.[3]

Q. Do you agree with EKPC's two-phase rate plan proposal?

A. No. While I agree that gradualism is a reasonable and appropriate standard to govern the apportionment of the revenue increase and overall rate design, there is no need to implement a two-phase approach in this case. Though I support cost based rates and the

[3] Also, since rates are being increased on an equal percentage basis in Phase I, the Company is not proposing to implement its proposed interruptible credit increase that is supported by an increase in avoided capacity cost. I will address the interruptible credit issue later in my testimony.

rates and the concept of gradualism; a Phase II rate change in which some rate classes receive increases, while others receive decreases is not the best rate design policy. In addition, based on the rates of return at Phase I rates shown in my Table 1, these Phase I rates are not unreasonable. In particular, as I noted, the Large Special Contract class is paying a higher than average rate of return under Phase I rates.

The Company's proposed second phase rate changes may be particularly problematic in light of the current economic stress faced by the Company's customers, especially industrial manufacturing customers. Based on the results of the revised class cost of service study that I discussed previously, I recommend that the Company's proposed Phase I increases be implemented (as adjusted for the Commission approved overall revenue increase), without the Phase II readjustment 12 months later proposed by EKPC. Also, as I discuss next, the Large Special Contract interruptible credit increase should be fully implemented at the same time that rates are increased in Phase I.

Q. Have you reviewed the Company's proposal to change the Large Special Contract interruptible credit in the Phase-II rate design?

A. Yes. EKPC is proposing to revise the Large Special Contract interruptible credit to $5.30 per kW, based on Mr. Seelye's calculation of the avoided capacity cost of peaking capacity. He presents this analysis in Exhibit 8 of his Direct Testimony. Using this avoided capacity cost EKPC has developed an interruptible capacity credit for 10 minute notice interruptible service of $5.30 per kW and an interruptible credit of $4.00 per kW for 90 minute notice service.

Q. Do you agree with Mr. Seelye's proposed Large Special Contract interruptible rate credit?

A. Not completely. While his analysis generally appears to be reasonable, he did not include any factor to reflect the avoidance of "reserves" in the calculation of the $5.30 per kW credit. Since 1 mW of interruptible load, if it were "firm," would require 1.12 mW of capacity at a 12% reserve margin, there should be an adjustment in the avoided capacity calculation to reflect these reserves.[4] Mr. Seelye's analysis also did not reflect any "value" associated with energy costs savings that would be produced during actual interruptions. There are two benefits, or "avoided costs" associated with interruptible load. The first is a reliability benefit, based on the avoided cost of peaking capacity. This reliability component is reflected in the analysis presented in Mr. Seelye's Exhibit 8, though as I

[4] Based on EKPC's 2003 IRP, the Company uses a 12% reserve margin for generation planning.

analysis presented in Mr. Seelye's Exhibit 8, though as I indicated it did not include an adjustment for avoided reserves.

The second component of avoided cost associated with interruptible load is the fuel cost savings that reflect the difference between market energy prices at the time of interruption and the average cost of energy for EKPC. Under the terms of the Large Special Contract agreement, the customer can be interrupted up to 360 hours annually. In any hour when an interruptible load is actually interrupted, the EKPC system avoids the cost of what is likely to be very high cost energy. All other EKPC customers receive benefits from this avoidance of higher cost energy (due to the interruption) in the form of a lower average FAC charge. Even if EKPC was not making purchases during the interruption, the Company would be able to reduce its highest cost generation or make profitable off-system sales, as a result of the interruption of the Large Special Contract customer.

Q. Does Mr. Seelye's proposed interruptible credit reflect this second, avoided energy cost component of interruptible load?

A. No, it does not.

Q. In response to the Commission Staff's Third set of Data Requests, Request 9, EKPC calculated an alternative measure of avoided capacity cost, using a 4% RUS financing rate. Do you have any comments on this analysis?

A. Yes. While I do not know as a factual matter whether EKPC could obtain such financing in now, or in 2010 (the test year in this case) for the construction of peaking capacity, it appears from the Company's data response that there is some uncertainty on the part of EKPC itself on this issue.[5] The data response indicates that EKPC avoided capacity cost would be $4.30 per kW month using a 4% loan rate, compared to a value of $5.30 per kW, using a 7% loan rate. Based on these two calculations, it would appear that a range for avoided capacity cost would be $4.30 per kW to $5.30 per kW. However, neither of these values reflects a reserve margin factor in the calculation of avoided capacity cost. Table 2 below shows a revised calculation of EKPC avoided capacity cost using both the Company's filed 7% cost of capital and the 4% value used in response to Staff Data Request 9, Third set.

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[5] Mr. Seelye's testimony in this case states that a combustion turbine "would likely qualify" for low-cost RUS financing.

Table 2
Development of Interruptible Credit

	Cost of Capital	
	As Filed	Per PSC Req 9
CT Cost	$ 550	$ 550
Cost of Capital	7.00%	4.00%
Depreciation	4.00%	4.00%
ASL for CT	25	25
Annual Capacity Cost	$47.20	$35.21
Fixed O&M Expense	16.5	16.5
Annual Cost	$63.70	$51.71
Reserve Margin	12%	12%
Total Annual Cost	$71.34	$57.91
Monthly Cost	$5.90	$4.80

As can be seen from the table, the avoided capacity cost increases from $5.30 to $5.90 per kW using the 7% cost of capital and from $4.30 to $4.80 using the 4% capital cost. The analysis in Table 2 produces a range of $4.80 to $5.90 per kW for an interruptible credit. Given the uncertainty of actually obtaining such low-cost financing in 2010, coupled with the fact that the Company has not included any value associated with avoided energy cost (as I discussed above) or a reserve margin factor, it is reasonable for the Commission to adopt ten minute notice and ninety minute notice interruptible credits, based on the $5.90

minute notice interruptible credits, based on the <u>$5.90 per kW</u> avoided capacity cost calculation.

Q. Are there any additional reasons why it would be appropriate to utilize a $5.90 per kW interruptible credit in this case?

A. Yes. As discussed by Mr. Seelye on page 27 at lines 15 and 16 of his Direct Testimony, the installed cost of a combustion turbine may be subject to considerable volatility. In particular, in a recent LG&E/KU rate case in 2008, these Companies estimated that the installed cost of a new combustion turbine unit would be $710 per kW, which is 29% greater than the $550 per kW cost used by EKPC.

Q. Do you agree with the Company's proposal to defer implementation of an updated interruptible credit until Phase II rates are implemented?

A. No. First, as I discussed previously, there is no need for the second Phase rate design in this case. KIUC is recommending that rates be revised in Phase I of this case and that the second Phase be eliminated. If this recommendation is accepted by the Commission, the updated interruptible credit would be implemented in Phase I automatically. Even if, the automatically. Even if, the Commission adopts the Company's proposal to realign rates in a Phase II rate design adjustment, it would still be appropriate to implement the updated interruptible credit for the Large Special Contract class in Phase I. If the evidence in this case establishes that an increase in the interruptible credit is justified, and I believe that it does, then there is no reason not to implement the interruptible credit change upon approval by the Commission in this case.

Phase I rates (assuming that there are going to be two phases to the overall EKPC rate adjustments) should reflect the just and reasonable level of the interruptible credit. Effectively, interruptible load is a form of "peaking capacity" for the system. The interruptible credit is the mechanism for "paying" for such peaking capacity. Based on the analysis of avoided cost in this case, it is appropriate to implement the updated credit at the conclusion of this case, not 12 months later, as proposed by EKPC.

Q. Does that complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC	)	
RATES OF EAST KENTUCKY POWER	)	CASE NO.
COOPERATIVE, INC.	)	2008-00409

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	**CASE NO. 2008-00409**

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 February 2009

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.

Expert Testimony Appearances
of
Stephen J. Baron
As of February 2009

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

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

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

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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	U-22092 (Allocated Stranded Cost Issues)	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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			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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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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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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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.

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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.

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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
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC	)	
RATES OF EAST KENTUCKY POWER	)	CASE NO.
COOPERATIVE, INC.	)	2008-00409

EXHIBIT SJB-2

OF

STEPHEN J. BARON

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Plant In Service							
Power Production Plant							
Production Demand	TPIS	PLPDMD	6CP	$ 1.957.897.487	$ 1.657.339.742	$ 100.395.334	$ 45.383.089
Production Energy	TPIS	PLPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TPIS	PLPSTM	STMD	$ 19.796.659	$ -	$ -	$ -
Total Power Production Plant		PLPT		$ 1.977.694.146	$ 1.657.339.742	$ 100.395.334	$ 45.383.089
Transmission Plant	TPIS	PLTRN	12CP	$ 502.384.170	$ 411.511.104	$ 27.740.381	$ 12.524.298
Distribution Substation	TPIS	PLDST	SUBA	$ 172.362.621	$ 170.619.193	$ -	$ -
Distribution Meters	TPIS	PLDMC	Cust05	$ 7.992.137	$ 7.966.535	$ -	$ -
Total		PLT		$ 2.660.433,074	$ 2.247.436,574	$ 128.135,715	$ 57.907.387

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Plant in Service							
Power Production Plant							
Production Demand	TPIS	PLPDMD	6CP	$ 34.154 141	$ 120.625.182	$ -	$ -
Production Energy	TPIS	PLPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TPIS	PLPSTM	STMD	$ -	$ -	$ -	$ 19.796.659
Total Power Production Plant		PLPT		$ 34.154.141	$ 120.625.182	$ -	$ 19.796.659
Transmission Plant	TPIS	PLTRN	12CP	$ 9,377 821	$ 33,164.092	$ 8.066.474	$ -
Distribution Substation	TPIS	PLDST	SUBA	$ 1.743,428	$ -	$ -	$ -
Distribution Meters	TPIS	PLDMC	Cust05	$ 25,602	$ -	$ -	$ -
Total		PLT		$ 45.300.991	$ 153.789.274	$ 8.066.474	$ 19.796.659

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Net Utility Plant							
Power Production Plant							
Production Demand	NTPLANT	NTPDMD	6CP	$ 1.598.626.603	$ 1.353.220.697	$ 81.972.960	$ 37.055.369
Production Energy	NTPLANT	NTPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$ 16.165.799	$ -	$ -	$ -
Total Power Production Plant		NTPT		$ 1.614.792.402	$ 1.353.220.697	$ 81.972.960	$ 37.055.369
Transmission Plant	NTPLANT	NTTRN	12CP	$ 357.008.399	$ 292.431.429	$ 19.713.099	$ 8.900.121
Distribution Substation	NTPLANT	NTDST	SUBA	$ 129.982.225	$ 128.667.470	$ -	$ -
Distribution Meters	NTPLANT	NTDMC	Cust05	$ 6.027.036	$ 6.007.729	$ -	$ -
Total		NTPLT		$ 2.107.810.062	$ 1.780.327.324	$ 101.686.059	$ 45.955.489

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
<u>Net Utility Plant</u>							
Power Production Plant							
Production Demand	NTPLANT	NTPDMD	6CP	$ 27.886.914	$ 98.490.665	$ -	$ -
Production Energy	NTPLANT	NTPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$ -	$ -	$ -	$ 16.165.799
Total Power Production Plant		NTPT		$ 27.886.914	$ 98.490.665	$ -	$ 16.165.799
Transmission Plant	NTPLANT	NTTRN	12CP	$ 6.664,145	$ 23.567.341	$ 5.732.265	$ -
Distribution Substation	NTPLANT	NTDST	SUBA	$ 1.314.755	$ -	$ -	$ -
Distribution Meters	NTPLANT	NTDMC	Cust05	$ 19.307	$ -	$ -	$ -
Total		NTPLT		$ 35.885.120	$ 122.058.006	$ 5.732.265	$ 16.165.799

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Net Cost Rate Base											
Power Production Plant											
Production Demand	RB	RBPDMD	6CP	$	1.697.616.477	$	1.437.014.589	$	87.048.875	$	39.349.905
Production Energy	RB	RBPENG	PENG	$	6.071,375	$	4.632.980	$	445.944	$	175.434
Production - Steam Direct	RB	RBPSTM	STMD	$	17.044.460	$	-	$	-	$	-
Total Power Production Plant		RBPT		$	1.720.732.313	$	1.441.647.569	$	87.494.819	$	39.525.338
Transmission Plant	RB	RBTRN	12CP	$	383,872 188	$	314.435.998	$	21,196.450	$	9.569.827
Distribution Substation	RB	RBDST	SUBA	$	137.916.386	$	136.521.378	$	-	$	-
Distribution Meters	RB	RBDMC	Cust05	$	6.394.928	$	6.374.443	$	-	$	-
Total		RBPLT		$	2.248.915,815	$	1.898.979.388	$	108.691.268	$	49.095,166

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Net Cost Rate Base											
Power Production Plant											
Production Demand	RB	RBPDMD	6CP	$	29.613.722	$	104.589.386	$	-	$	-
Production Energy	RB	RBPENG	PENG	$	160.098	$	434.722	$	105.352	$	116.846
Production - Steam Direct	RB	RBPSTM	STMD	$	-	$	-	$	-	$	17.044.460
Total Power Production Plant		RBPT		$	29.773.820	$	105.024.108	$	105.352	$	17.161.306
Transmission Plant	RB	RBTRN	12CP	$	7.165.601	$	25.340.712	$	6.163.600	$	-
Distribution Substation	RB	RBDST	SUBA	$	1.395.008	$	-	$	-	$	-
Distribution Meters	RB	RBDMC	Cust05	$	20.486	$	-	$	-	$	-
Total		RBPLT		$	38.354.915	$	130.364.820	$	6.268.952	$	17.161.306

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Operation and Maintenance Expenses							
Power Production Plant							
Production Demand	TOM	OMPDMD	6CP	$ 100.226.391	$ 84.840.592	$ 5.139.320	$ 2.323.198
Production Energy	TOM	OMPENG	PENG	$ 546.404,107	$ 416.953,137	$ 40.133.541	$ 15.788.463
Production - Steam Direct	TOM	OMPSTM	STMD	$ 34.811	$ -	$ -	$ -
Total Power Production Plant		OMPT		$ 646.665.308	$ 501.793,729	$ 45.272.861	$ 18.111.661
Transmission Plant	TOM	OMTRN	12CP	$ 37.434.150	$ 30.662.925	$ 2.067.019	$ 933.223
Distribution Substation	TOM	OMDST	SUBA	$ 2.576.279	$ 2.550.220	$ -	$ -
Distribution Meters	TOM	OMDMC	Cust05	$ 119.457	$ 119.075	$ -	$ -
Total		OMPLT		$ 686.795.194	$ 535.125.949	$ 47.339.880	$ 19.044.884

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Operation and Maintenance Expenses							
Power Production Plant							
Production Demand	TOM	OMPDMD	6CP	$ 1.748.378	$ 6.174.903	$ -	$ -
Production Energy	TOM	OMPENG	PENG	$ 14.408.275	$ 39.123.577	$ 9.481.342	$ 10.515.771
Production - Steam Direct	TOM	OMPSTM	STMD	$ -	$ -	$ -	$ 34.811
Total Power Production Plant		OMPT		$ 16.156.654	$ 45.298.480	$ 9.481.342	$ 10.550.582
Transmission Plant	TOM	OMTRN	12CP	$ 698.770	$ 2.471.156	$ 601.057	$ -
Distribution Substation	TOM	OMDST	SUBA	$ 26.059	$ -	$ -	$ -
Distribution Meters	TOM	OMDMC	Cust05	$ 383	$ -	$ -	$ -
Total		OMPLT		$ 16.881.864	$ 47.769.636	$ 10.082.399	$ 10.550.582

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Labor Expenses							
Power Production Plant							
Production Demand	TLB	LBPDMD	6CP	$ 10.696.445	$ 9.054.429	$ 548.483	$ 247.938
Production Energy	TLB	LBPENG	PENG	$ 6.662.807	$ 5.084.293	$ 489.385	$ 192.523
Production - Steam Direct	TLB	LBPSTM	STMD	$ 2.693	$ -	$ -	$ -
Total Power Production Plant		LBPT		$ 17.361.945	$ 14.138.721	$ 1.037.868	$ 440.462
Transmission Plant	TLB	LBTRN	12CP	$ 3.160.179	$ 2.588.555	$ 174.497	$ 78.782
Distribution Substation	TLB	LBDST	SUBA	$ 358.627	$ 355.000	$ -	$ -
Distribution Meters	TLB	LBDMC	Cust05	$ 16.629	$ 16.576	$ -	$ -
Total		LBPLT		$ 20.897.381	$ 17.098.852	$ 1.212.365	$ 519.244

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Labor Expenses							
Power Production Plant							
Production Demand	TLB	LBPDMD	6CP	$ 186.592	$ 659.003	$ -	$ -
Production Energy	TLB	LBPENG	PENG	$ 175 693	$ 477.070	$ 115.615	$ 128.228
Production - Steam Direct	TLB	LBPSTM	STMD	$ -	$ -	$ -	$ 2.693
Total Power Production Plant		LBPT		$ 362.285	$ 1.136.073	$ 115.615	$ 130.922
Transmission Plant	TLB	LBTRN	12CP	$ 58.990	$ 208.614	$ 50.741	$ -
Distribution Substation	TLB	LBDST	SUBA	$ 3.627	$ -	$ -	$ -
Distribution Meters	TLB	LBDMC	Cust05	$ 53	$ -	$ -	$ -
Total		LBPLT		$ 424.956	$ 1.344.687	$ 166.356	$ 130.922

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Depreciation Expenses							
Power Production Plant							
Production Demand	TDEPR	DPPDMD	6CP	$ 59.631.415	$ 50.477.369	$ 3.057.727	$ 1.382.226
Production Energy	TDEPR	DPPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TDEPR	DPPSTM	STMD	$ 603.117	$ -	$ -	$ -
Total Power Production Plant		DPPT		$ 60.234.532	$ 50.477.369	$ 3.057.727	$ 1.382.226
Transmission Plant	TDEPR	DPTRN	12CP	$ 8.917.577	$ 7.304.533	$ 492.406	$ 222.313
Distribution Substation	TDEPR	DPDST	SUBA	$ 4.210.948	$ 4.168.355	$ -	$ -
Distribution Meters	TDEPR	DPDMC	Cust05	$ 195,254	$ 194.628	$ -	$ -
Total		DPPLT		$ 73.558.311	$ 62.144.885	$ 3.550.133	$ 1.604.539

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Depreciation Expenses							
Power Production Plant							
Production Demand	TDEPR	DPPDMD	6CP	$ 1.040.228	$ 3.673,865	$ -	$ -
Production Energy	TDEPR	DPPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	TDEPR	DPPSTM	STMD	$ -	$ -	$ -	$ 603.117
Total Power Production Plant		DPPT		$ 1.040.228	$ 3.673,865	$ -	$ 603,117
Transmission Plant	TDEPR	DPTRN	12CP	$ 166.461	$ 588.680	$ 143,184	$ -
Distribution Substation	TDEPR	DPDST	SUBA	$ 42.593	$ -	$ -	$ -
Distribution Meters	TDEPR	DPDMC	Cust05	$ 625	$ -	$ -	$ -
Total		DPPLT		$ 1.249.908	$ 4.262.544	$ 143,184	$ 603.117

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Property and Other Taxes											
Power Production Plant											
Production Demand	PTAX	PRPDMD	6CP	$	604	$	512	$	31	$	14
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	6	$	-	$	-	$	-
Total Power Production Plant		PRPT		$	610	$	512	$	31	$	14
Transmission Plant	PTAX	PRTRN	12CP	$	140	$	114	$	8	$	3
Distribution Substation	PTAX	PRDST	SUBA	$	48	$	47	$	-	$	-
Distribution Meters	PTAX	PRDMC	Cust05	$	2	$	2	$	-	$	-
Total		PRPLT		$	800	$	675	$	39	$	17

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Property and Other Taxes							
Power Production Plant							
Production Demand	PTAX	PRPDMD	6CP	$ 11	$ 37	$ -	$ -
Production Energy	PTAX	PRPENG	PENG	$ -	$ -	$ -	$ -
Production - Steam Direct	PTAX	PRPSTM	STMD	$ -	$ -	$ -	$ 6
Total Power Production Plant		PRPT		$ 11	$ 37	$ -	$ 6
Transmission Plant	PTAX	PRTRN	12CP	$ 3	$ 9	$ 2	$ -
Distribution Substation	PTAX	PRDST	SUBA	$ 0	$ -	$ -	$ -
Distribution Meters	PTAX	PRDMC	Cust05	$ 0	$ -	$ -	$ -
Total		PRPLT		$ 14	$ 46	$ 2	$ 6

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
<u>Interest Expenses</u>											
Power Production Plant											
Production Demand	INTLTD	INPDMD	6CP	$	102.604.692	$	86.853.799	$	5.261.273	$	2.378.326
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	1.037.609	$	-	$	-	$	-
Total Power Production Plant		INPT		$	103.642.301	$	86.853.799	$	5.261.273	$	2.378.326
Transmission Plant	INTLTD	INTRN	12CP	$	23.697.816	$	19.411.270	$	1.308.533	$	590.780
Distribution Substation	INTLTD	INDST	SUBA	$	8.107.824	$	8.025.814	$	-	$	-
Distribution Meters	INTLTD	INDMC	Cust05	$	375.945	$	374.741	$	-	$	-
Total		INPLT		$	135.823.886	$	114.665.623	$	6.569.806	$	2.969.106

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Interest Expenses											
Power Production Plant											
Production Demand	INTLTD	INPDMD	6CP	$	1,789,866	$	6,321,429	$	-	$	-
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	-	$	-	$	-	$	1,037,609
Total Power Production Plant		INPT		$	1,789,866	$	6,321,429	$	-	$	1,037,609
Transmission Plant	INTLTD	INTRN	12CP	$	442,358	$	1,564,374	$	380,501	$	-
Distribution Substation	INTLTD	INDST	SUBA	$	82,010	$	-	$	-	$	-
Distribution Meters	INTLTD	INDMC	Cust05	$	1,204	$	-	$	-	$	-
Total		INPLT		$	2,315,439	$	7,885,802	$	380,501	$	1,037,609

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Unadjusted							
Operating Revenues							
Sales to Members		REVUC	R01	$ 873.498.600	$ 698.429.398	$ 57.697.996	$ 23.333,746
Off System Sales Revenue			Energy	$ 9.987.006	$ 7.655.465	$ 736.872	$ 289.884
Wheeling Revenue		LSDPR	RBTRN	$ 2,389.123	$ 1.956.970	$ 131.921	$ 59.560
Other Operating Revenue		OTHREV	RBPLT	$ 399,043	$ 336.951	$ 19.286	$ 8,711
Total Operating Revenues		TOR		$ 886.273.772	$ 708.378.784	$ 58.586.075	$ 23.691.901
Operating Expenses							
Operation and Maintenance Expenses				$ 688.795.194	$ 535,125.949	$ 47.339.880	$ 19.044.884
Depreciation and Amortization Expenses				73.558.311	62.144.885	3.550 133	1.604.539
Property and Other Taxes			NPT	800	675	39	17
Total Operating Expenses		*TOE*		$ *760.354.305*	$ *597.271,510*	$ *50.890.052*	$ *20.649.441*
Utility Operating Margin				$ 125.919,467	$ 111.107.274	$ 7.696.023	$ 3.042.461
Non-Operating Items							
Interest Income			RBPLT	$ 4.007.189	$ 3,383,661	$ 193 670	$ 87,479
Other Non-Operating Income			RBPLT	$ (27.912)	$ (23,569)	$ (1.349)	$ (609)
Other Credits			RBPLT	$ 250.000	$ 211.099	$ 12.083	$ 5.458
Interest on Long Term Debt				$ (135.823,886)	$ (114.665,623)	$ (6.569.806)	$ (2.969.106)
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ (2.363 706)	$ (1.995.908)	$ (114.239)	$ (51.601)
Total Non-Operating Items				$ (133.958,315)	$ (113.090.339)	$ (6.479.642)	$ (2.928,379)
Net Utility Operating Margin		TOM		$ *(8.038.848)*	$ *(1.983.065)*	$ *1.216.381*	$ *114.082*
Net Cost Rate Base				$ 2.248.915.815	$ 1.898.979.388	$ 108.691.268	$ 49.095.166

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary – Unadjusted							
Operating Revenues							
Sales to Members		*REVUC*	*R01*	$ *19.703.308*	$ *49.563.171*	$ *11.330.994*	$ *13.439.988*
Off System Sales Revenue			Energy	$ 264.543	$ 718.328	$ 128.839	$ 193.075
Wheeling Revenue		LSDPR	RBTRN	$ 44.597	$ 157.714	$ 38.361	$ -
Other Operating Revenue		OTHREV	RBPLT	$ 6.806	$ 23.132	$ 1.112	$ 3.045
Total Operating Revenues		*TOR*		$ 20.019.253	$ 50.462.345	$ 11.499.306	$ 13.636.108
Operating Expenses							
Operation and Maintenance Expenses				$ 16.881.864	$ 47.769.636	$ 10.082.399	$ 10.550.582
Depreciation and Amortization Expenses				1.249.908	4.262.544	143,184	603.117
Property and Other Taxes			NPT	14	46	2	6
Total Operating Expenses		TOE		$ 18.131.786	$ 52.032.228	$ 10.225.585	$ 11.153.705
Utility Operating Margin				$ 1.887.468	$ (1.569.882)	$ 1.273.721	$ 2.482.402
Non-Operating Items							
Interest Income			RBPLT	$ 68,342	$ 232.288	$ 11.170	$ 30,579
Other Non-Operating Income			RBPLT	$ (476)	$ (1.618)	$ (78)	$ (213)
Other Credits			RBPLT	$ 4.264	$ 14.492	$ 697	$ 1.908
Interest on Long Term Debt				$ (2.315.439)	$ (7.885,802)	$ (380.501)	$ (1.037.609)
Other Interest Expense			RBPLT	$ -	$ -	$ -	$ -
Other Deductions			RBPLT	$ (40.313)	$ (137.019)	$ (6.589)	$ (18.037)
Total Non-Operating Items				$ (2.283.622)	$ (7.777.659)	$ (375.301)	$ (1.023,373)
Net Utility Operating Margin		TOM		$ (396.154)	$ (9.347.541)	$ 898.420	$ 1.459.029
Net Cost Rate Base				$ 38.354.915	$ 130.364,820	$ 6,268.952	$ 17.161.306

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Pro-Forma							
Operating Revenues							
Total Operating Revenue				$ 886.273,772	$ 708.378,784	$ 58.586.075	$ 23.691.901
Pro-Forma Adjustments:							
To Remove Base Fuel Revenue				$ 350.719.383	$ 272.354.902	$ 26.215.336	$ 10.313.066
To Remove FAC Revenue			FACA	108.692.230	77.068.195	7.417.955	2.918.210
To Remove Environmental Surcharge Revenue		ESR		104.725,170	84.331.966	6.966.754	2.817.437
To Adjust Off-System Sales Environmental Sur Rev			RBPLT	1 377.517	1.163,172	66.576	30.072
Total Pro-Forma Operating Revenue				$ 320.759.472	$ 273.462.548	$ 17.919.454	$ 7.613.117

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Rate G		Large Special Contract		Special Contract Pumping Stations		Steam Service
Cost of Service Summary -- Pro-Forma											
Operating Revenues											
Total Operating Revenue				$	20.019.253	$	50.462.345	$	11.499.306	$	13.636.108
Pro-Forma Adjustments:											
To Remove Base Fuel Revenue				$	9.411.524	$	25.555,625	$	-	$	6.868.930
To Remove FAC Revenue			FACA		2.663.107		7.231.280		9.451.834		1.943.649
To Remove Environmental Surcharge Revenue		ESR			2.379.079		5.984.513		622.608		1.622.813
To Adjust Off-System Sales Environmental Sur Rev			RBPLT		23.493		79.852		3.840		10.512
Total Pro-Forma Operating Revenue				$	5.542.051	$	11.611.075	$	1.421.024	$	3.190.204

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 686.795.194	$ 535.125,949	$ 47.339.880	$ 19.044.884
Depreciation and Amortization Expenses				73.558.311	62.144.885	3.550.133	1.604,539
Property and Other Taxes			NPT	800	675	39	17
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable Through FAC			FACAL	$ (403,441,802)	$ (306.806.831)	$ (29.531.483)	$ (11.617.632)
To Remove Purchased Power Expense Recoverable Through FAC			FACAL	(54.242.370)	$ (41.249.889)	$ (3,970,480)	$ (1,561.980)
To Remove O&M Expenses Recoverable Through Env Surcharge			6CP	(31.800,030)	$ (26.918,393)	$ (1.630.614)	$ (737.109)
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	(6.615.208)	$ (5,070.838)	$ (488.090)	$ (192.014)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	(2.098.198)	$ (1.776.103)	$ (107.590)	$ (48.635)
To Remove Depreciation Expense Recoverable Through ESR			6CP	(19,564.992)	$ (16,581.561)	$ (1.003.236)	$ (453.507)
To Remove Promotional Advertising Expense			LBPLT	(658.906)	$ (539.136)	$ (38.227)	$ (16,372)
To Remove Certain Director's Expenses			LBPLT	(93.300)	$ (76,341)	$ (5.413)	$ (2.318)
To Remove Donations			LBPLT	(95.485)	$ (78.129)	$ (5.540)	$ (2,373)
To Remove Affiliate Expenses			LBPLT	(28.712)	$ (23.493)	$ (1.666)	$ (713)
To Remove Lobbying Expenses			LBPLT	(85.422)	$ (69.895)	$ (4.958)	$ (2.123)
To Remove Touchstone Energy Dues			LBPLT	(414.000)	$ (338,747)	$ (24.018)	$ (10.287)
To Remove Other Misc Expenses			LBPLT	(155.940)	$ (127.595)	$ (9.047)	$ (3.875)
To Normalize Rate Case Expenses			RBPLT	100.000	$ 84.440	$ 4.833	$ 2.183
To Amortize 2004 Forced Outage Balance			Energy	3,419.058	$ 2.620.853	$ 252.268	$ 99.242
To Normalize Generation Overhaul Expenses			OMPDMD	$ 2.300.000	$ 1.946.926	$ 117.937	$ 53.313
To Reflect Avoided Costs of Interruptible Service				$ (8.824.500)			
Reallocation of Avoided Cost Savings			6CP	$ 8.824.500	$ 7.469.847	$ 452,495	$ 204.548
Reallocate Purchased Power - Remove on PENG			PPPENG	$ (64.242,370)	$ (42.525.264)	$ (4.093,240)	$ (1.610,273)
Reallocate Purchased Power - Allocate On-Peak/Off-Peak			PPTOU	$ 64,242,370	$ 43,418,578	$ 3,980,511	$ 1,565,125
Reallocate Fuel Expense - Remove on PENGA			PENGA	$ (426,937,485)	$ (331,542,888)	$ (31,912,435)	$ (12,554,295)
Reallocate Fuel Expense - Allocate on Monthly Energy			PENG_MON	$ 426,937,485	$ 331,606,189	$ 31,863,236	$ 12,541,418
Total Expense Adjustments				(513.475,307)	(386.498.269)	(36.154.754)	(14.347.677)
Total Operating Expenses		TOE		$ *246.878.998*	$ *210.773.240*	$ 14.735.297	$ 6.301.763
Utility Operating Margins -- Pro-Forma				$ 73.880.474	$ 62.689.307	$ 3.184.156	$ 1.311.353
Non-Operating Items							
Sum of Non-Operating Items				$ (133.958.315)	$ (113,090.339)	$ (6.479.642)	$ (2.928.379)
Adjustment To Remove Interest Exp Recoverable Through ESR			6CP	$ 37.031.989	$ 31.347.191	$ 1.898.894	$ 858.383
Total Non-Operating Items				$ (96.926.326)	$ (81.743,147)	$ (4.580.748)	$ (2.069.996)
Net Utility Operating Margin				$ (23,045,852)	$ (19.053.840)	$ (1.396.592)	$ (758.643)
Net Cost Rate Base				$ 2.248.915.815	$ 1.898.979.388	$ 108.691.268	$ 49.095.166
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				3.28%	3.30%	2.93%	2.67%

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma							
Operating Expenses							
Operation and Maintenance Expenses				$ 16.881.864	$ 47.769.636	$ 10.082.399	$ 10.550.582
Depreciation and Amortization Expenses				1.249.908	4,262.544	143.184	603.117
Property and Other Taxes			NPT	14	46	2	6
Adjustments to Operating Expenses:							
To Remove Fuel Expense Recoverable Through FAC			FACAL	$ (10.602.048)	$ (28.788,320)	$ (8.357.662)	$ (7.737.825)
To Remove Purchased Power Expense Recoverable Through FAC			FACAL	$ (1,425.435)	$ (3,870.563)	$ (1.123.680)	$ (1.040.343)
To Remove O&M Expenses Recoverable Through Env Surcharge			6CP	$ (554.729)	$ (1,959.186)	$ -	$ -
To Remove Emissions Allowance Expense Recoverable Through ESR			Energy	$ (175.228)	$ (475.807)	$ (85.341)	$ (127.889)
To Remove Property Tax & Insurance Recoverable Through ESR			6CP	$ (36.602)	$ (129.269)	$ -	$ -
To Remove Depreciation Expense Recoverable Through ESR			6CP	$ (341.297)	$ (1.205,390)	$ -	$ -
To Remove *Promotional Advertising* Expense			*LBPLT*	$ (13,399)	$ (42.399)	$ (5,245)	$ (4,128)
To Remove Certain Director's Expenses			LBPLT	$ (1.897)	$ (6,004)	$ (743)	$ (585)
To Remove Donations			LBPLT	$ (1,942)	$ (6.144)	$ (760)	$ (598)
To Remove Affiliate Expenses			LBPLT	$ (584)	$ (1.848)	$ (229)	$ (180)
To Remove Lobbying Expenses			LBPLT	$ (1.737)	$ (5.497)	$ (680)	$ (535)
To Remove Touchstone Energy Dues			LBPLT	$ (8,419)	$ (26.640)	$ (3,296)	$ (2,594)
To Remove Other Misc Expenses			*LBPLT*	$ *(3.171)*	$ *(10.034)*	$ *(1.241)*	$ (977)
To Normalize Rate Case Expenses			RBPLT	$ 1.705	$ 5.797	$ 279	$ 763
To Amortize 2004 Forced Outage Balance			Energy	$ 90.566	$ 245.920	$ 44.108	$ 66.099
To Normalize Generation Overhaul Expenses			OMPDMD	$ 40.122	$ 141.702	$ -	$ -
To Reflect Avoided Costs of Interruptible Service					$ (8.824,500)		
Reallocation of Avoided Cost Savings			6CP	$ 153.937	$ 543.673	$ -	$ -
Reallocate Purchased Power - Remove on PENG			*PPPENG*	$ *(1.469.507)*	$ (3,990.234)	$ (9.481,342)	$ (1.072,509)
Reallocate Purchased Power - Allocate On-Peak/Off-Peak			PPTOU	$ 1,416,964	$ 3,345,244	$ 9,481,342	$ 1,034,607
Reallocate Fuel Expense - Remove on PENGA			PENGA	$ (11,456,830)	$ (31,109,356)	$ -	$ (8,361,681)
Reallocate Fuel Expense - Allocate on Monthly Energy			PENG_MON	$ 11,440,319	$ 31,071,198	$ -	$ 8,355,126
Total Expense Adjustments				(12,949.211)	(45,097.656)	(9.534.490)	(8 893,249)
Total Operating Expenses		TOE		$ 5.182.575	$ 6.934.570	$ 691.096	$ 2.260.456
Utility Operating Margins -- Pro-Forma				$ 359.476	$ 4.676.505	$ 729.929	$ 929.748
Non-Operating Items							
Sum of Non-Operating Items				$ (2.283,622)	$ (7.777.659)	$ (375.301)	$ (1.023,373)
Adjustment To Remove Interest Exp Recoverable Through ESR			6CP	$ 645.997	$ 2.281.524	$ -	$ -
Total Non-Operating Items				$ (1.637.625)	$ (5.496.135)	$ (375.301)	$ (1.023.373)
Net Utility Operating Margin				$ (1.278.149)	$ (819.631)	$ 354.628	$ (93.625)
Net Cost Rate Base				$ 38.354,915	$ 130.364.820	$ 6.268.952	$ 17.161.306
Return on Rate Base -- Utility Operating Margin Divided by Rate Base				0.94%	3.59%	11.64%	5.42%

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector		Total System		Rate E		Rate B		Rate C
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)											
Operating Revenues											
Total Operating Revenue				$	320.759.472	$	273.462.548	$	17.919.454	$	7.613.117
Pro-Forma Adjustments:											
To Reflect Proposed Increase				$	67.858.922	$	55,330.720	$	4.457,951	$	1.811.240
Total Pro-Forma Operating Revenue				$	388.618.394	$	328.793.268	$	22.377.405	$	9.424,357
Operating Expenses											
Total Operating Expenses				$	246.878.998	$	210.773.240	$	14.735.297	$	6.301.763
Utility Operating Margins -- Pro-Formed for Phase I Increase				$	141.739.396	$	118.020.027	$	7.642.107	$	3.122.593
Net Cost Rate Base				$	2.248.915.815	$	1.898.979.388	$	108.691.268	$	49.095.166
Rate of Return					6.30%		6.21%		7.03%		6.36%
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)											
Operating Revenues											
Total Operating Revenue				$	320.759.472	$	273.462.548	$	17.919.454	$	7.613.117
Pro-Forma Adjustments:											
To Reflect Proposed Increase				$	67.699.051	$	55.345.926	$	4.635.408	$	2.168.710
Total Pro-Forma Operating Revenue				$	388.458.523	$	328.808.474	$	22.554.862	$	9.781.827
Operating Expenses											
Total Operating Expenses				$	246.878.998	$	210.773.240	$	14.735.297	$	6.301.763
Utility Operating Margins -- Pro-Formed for Phase II Increase				$	141.579.525	$	118.035.233	$	7.819.564	$	3.480.063
Net Cost Rate Base				$	2.248.915.815	$	1.898.979.388	$	108.691.268	$	49.095.166
Rate of Return					6.30%		6.22%		7.19%		7.09%

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Cost of Service Summary -- Pro-Forma (Proposed Phase I Increase)							
Operating Revenues							
Total Operating Revenue				$ 5.542.051	$ 11.611.075	$ 1.421.024	$ 3.190.204
Pro-Forma Adjustments:							
To Reflect Proposed Increase				$ 1.506.943	$ 3.736.682	$ -	$ 1.015.386
Total Pro-Forma Operating Revenue				$ 7.048,994	$ 15.347.757	$ 1.421.024	$ 4.205.590
Operating Expenses							
Total Operating Expenses				$ 5,182.575	$ 6.934.570	$ 691.096	$ 2.260.456
Utility Operating Margins -- Pro-Formed for Phase I Increase				$ 1.866.419	$ 8.413,187	$ 729.929	$ 1.945.134
Net Cost Rate Base				$ 38.354.915	$ 130.364.820	$ 6.268,952	$ 17.161.306
Rate of Return				4.87%	6.45%	11.64%	11.33%
Cost of Service Summary -- Pro-Forma (Proposed Phase II Increase)							
Operating Revenues							
Total Operating Revenue				$ 5.542.051	$ 11.611.075	$ 1.421.024	$ 3.190.204
Pro-Forma Adjustments:							
To Reflect Proposed Increase				$ 1.858.583	$ 3.017.371	$ -	$ 673.053
Total Pro-Forma Operating Revenue				$ 7.400.634	$ 14.628.446	$ 1.421.024	$ 3.863.257
Operating Expenses							
Total Operating Expenses				$ 5.182.575	$ 6.934.570	$ 691.096	$ 2.260.456
Utility Operating Margins -- Pro-Formed for Phase II Increase				$ 2.218.059	$ 7.693,876	$ 729.929	$ 1.602.801
Net Cost Rate Base				$ 38.354.915	$ 130.364.820	$ 6.268.952	$ 17.161.306
Rate of Return				5.78%	5.90%	11.64%	9.34%

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	1 000000	0 766543	0.073783	0 029026
Customer Allocation Factors							
Rev		R01		873.498.603	698 429.400	57.697.998	23.333,746
Energy		Energy		13 468.652,000	10.324.295.000	993,758.000	390.942.617
FAC Revenue Allocator		FACA		109.031.560 $	77.306.791 $	7.441.113 $	2.927.320
Base Fuel Revenue Allocator		BSFL		13.294.897,000	10.324.295,000	993.758.000	390.942.617
Fuel Expense Applicable to FAC Allocator		FACEX		459.411.613	349.421.098	33.633,291	13.231.276
							407.101.213
Customer Allocators							
Customers (Metering Points)		Cust05		3.746	3,734	-	-
Demand Allocators							
Steam - Direct Assignment		STMD		1	-	-	-
Substation Allocator		SUBA		86.668.910	85.792.264	-	-
Production 6 CP Demands		6CP		15.582.000	13,190,000	799,000	361,183
					0 8465	0 0513	0 0232
Production 12 CP Demands		12CP		29.085,000	23,824,000	1.606,000	725,081
					0 8191	0 0552	0 0249

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
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12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class		E01	Energy	0.026489	0 071926	0 012901	0 019333
Customer Allocation Factors							
Rev		R01		19.703.308	49,563,171	11.330.994	13.439.988
Energy		Energy		356.767.383	968.750.000	173.755,000	260.384.000
FAC Revenue Allocator		FACA		$ 2.671.421	$ 7.253.856	$ 9.481.342	$ 1 949.717
Base Fuel Revenue Allocator		BSFL		356.767.383	968,750.000	-	260.384.000
Fuel Expense Applicable to FAC Allocator		FACEX		12.074.631	32.786,905	9 451.834	8.812.579
				371.513.435	1.008.790.761	18.933.176	-
Customer Allocators							
Customers (Metering Points)		Cust05		12	-	-	-
Demand Allocators							
Steam - Direct Assignment		STMD		-	-	-	1
Substation Allocator		SUBA		876.646	-	-	-
Production 6 CP Demands		6CP		271,817	960,000	-	-
				0 0174	0 0616	-	-
Production 12 CP Demands		12CP		542,919	1.920,000	467,000	-
				0 0187	0 0660	0 0161	-

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Total System	Rate E	Rate B	Rate C
Production Energy Allocation				-			
Production Energy Residual Allocator		PENGA		13,294.897.000	10.324.295.000	993.758.000	390.942.617
Production Energy Costs				$ 546.404.107			
Member Specific Assignment				$ 9.481.342	-	-	-
Production Energy Residual			PENGA	$ 536.922.765	$ 416.953.137	$ 40.133.541	$ 15.788.463
Production Energy Total		PENGT		$ 546,404,107	$ 416.953.137	$ 40.133.541	$ 15.788.463
Production Energy Total Allocator		PENG	PENGT	1.000000	0 76309	0 07345	0.02890
On-Peak kWh		PENG_ON		6.548.900.751	5,346.971.968	456.532.000	179.364.473
Off-Peak kWh		PENG_OFF		6.745.996.249	4.977.323.032	537.226.000	211.578.144
Purchased Power Expense				64,242,370			
Member Specific Assignment				(9.481.342)			
PP Expense Residual			PENGA	54.761,028	$ 42.525.264	$ 4.093.240	$ 1.610.273
PP Expense Total		PPPENG		64.242.370	42.525.264	4.093.240	1.610.273
PP Expense Residual - On-Peak (70%)			PENG_ON	38.332.720	$ 31.297.463	$ 2.672.221	$ 1.049.875
PP Expense Residual - Off-Peak (30%)			PENG_OFF	16,428,308	$ 12.121.115	$ 1.308,289	$ 515.249
PP Expense Total		PPTOU		64.242.370	43,418.578	3.980.511	1,565.125
Monthly Energy - Jun		PENG_JUN		1,034,405,000	785,030,000	82,525,000	32,557,684
Monthly Energy - Jul		PENG_JUL		1,170,414,000	931,157,000	81,768,000	33,106,880
Monthly Energy - Aug		PENG_AUG		1,159,893,000	901,791,000	88,907,000	32,558,806
Monthly Energy - Sep		PENG_SEP		1,003,490,000	752,431,000	84,072,000	32,973,408
Monthly Energy - Oct		PENG_OCT		942,223,000	693,724,000	86,767,000	32,227,879
Monthly Energy - Nov		PENG_NOV		1,069,459,000	823,457,000	80,328,000	32,244,985
Monthly Energy - Dec		PENG_DEC		1,301,930,000	1,064,681,000	78,193,000	32,311,827
Monthly Energy - Jan		PENG_JAN		1,380,682,000	1,131,170,000	83,228,000	32,588,366
Monthly Energy - Feb		PENG_FEB		1,176,215,000	940,163,000	79,622,000	33,230,697
Monthly Energy - Mar		PENG_MAR		1,147,783,000	893,408,000	81,674,000	32,812,434
Monthly Energy - Apr		PENG_APR		952,326,000	708,595,000	81,720,000	32,362,409
Monthly Energy - May		PENG_MAY		957,081,000	700,628,000	84,945,000	31,987,242
Monthly Fuel Exp Jun			PENG_JUN	32,218,785	24,451,460	2,570,420	1,014,080
Monthly Fuel Exp Jul			PENG_JUL	38,694,455	30,784,502	2,703,290	1,094,530
Monthly Fuel Exp Aug			PENG_AUG	38,063,291	28,529,736	2,812,728	1,030,055
Monthly Fuel Exp Sep			PENG_SEP	31,216,738	23,406,810	2,815,310	1,025,738
Monthly Fuel Exp Oct			PENG_OCT	28,713,801	21,140,911	2,644,183	982,129
Monthly Fuel Exp Nov			PENG_NOV	34,125,227	26,275,581	2,563,176	1,028,901
Monthly Fuel Exp Dec			PENG_DEC	41,568,111	33,093,209	2,498,552	1,031,654
Monthly Fuel Exp Jan			PENG_JAN	44,575,491	36,519,985	2,687,026	1,052,119
Monthly Fuel Exp Feb			PENG_FEB	38,946,165	31,130,145	2,636,399	1,100,318
Monthly Fuel Exp Mar			PENG_MAR	38,080,237	28,642,775	2,709,715	1,088,625
Monthly Fuel Exp Apr			PENG_APR	30,787,182	22,843,090	2,642,168	1,046,225
Monthly Fuel Exp May			PENG_MAY	31,348,004	22,948,203	2,782,268	1,047,047
Total Fuel Expense - Monthly Allocation		PENG_MON		426,937,485	331,686,189	31,863,236	12,541,418
FAC Expense Residual Allocator		FACALL		449,959,779	349.421.098	33.633.291	13.231.276
FAC Expense Cost				$ (457,684,172)			
Member Specific Assignment				$ (9,481,342)	-	-	-
FAC Expense Residual			FACALL	$ (448.202.830)	$ (348.056.720)	$ (33.501.963)	$ (13,179.612)
FAC Expense Total		FACT		$ (457,684,172)	$ (348.056,720)	$ (33.501,963)	$ (13,179,612)
FAC Expense Allocator		FACAL	FACT	1.000000	0 76047	0 07320	0 02880

EAST KENTUCKY POWER COOPERATIVE, INC
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
May 31, 2010

Description	Ref	Name	Allocation Vector	Rate G	Large Special Contract	Special Contract Pumping Stations	Steam Service
Production Energy Allocation							
Production Energy Residual Allocator		PENGA		356.767.383	988.750.000	-	260.384.000
Production Energy Costs							
Member Specific Assignment				$ -	-	$ 9.481.342	-
Production Energy Residual			PENGA	$ 14.408.275	$ 39.123.577	$ -	$ 10.515.771
Production Energy Total		PENGT		$ 14.408,275	$ 39.123,577	$ 9.481,342	$ 10.515,771
Production Energy Total Allocator		PENG	PENGT	0 02637	0.07160	0 01735	0 01925
On-Peak kWh		PENG_ON		160.366.939	288.492.371	-	117.173,000
Off-Peak kWh		PENG_OFF		196.400,444	680.257.629	-	143.211.000
Purchased Power Expense							
Member Specific Assignment						(9.481.342)	
PP Expense Residual			PENGA	$ 1.469.507	$ 3.990.234	$ -	$ 1.072.509
PP Expense Total		PPPENG		1,469.507	3.990,234	9,481.342	1.072.509
PP Expense Residual - On-Peak (70%)			PENG_ON	$ 938.677	$ 1,688.634	$ -	$ 685,849
PP Expense Residual - Off-Peak (30%)			PENG_OFF	$ 478.288	$ 1.656.610	$ -	$ 348,757
PP Expense Total		PPTOU		1.416,964	3.345,244	9.481,342	1.034.607
Monthly Energy - Jun		PENG_JUN		29,556,316	84,881,000	-	19,875,000
Monthly Energy - Jul		PENG_JUL		29,377,120	75,239,000	-	19,768,000
Monthly Energy - Aug		PENG_AUG		30,778,194	84,892,000	-	19,956,000
Monthly Energy - Sep		PENG_SEP		29,949,592	84,314,000	-	19,756,000
Monthly Energy - Oct		PENG_OCT		31,141,121	75,711,000	-	22,652,000
Monthly Energy - Nov		PENG_NOV		26,185,015	83,890,000	-	21,354,000
Monthly Energy - Dec		PENG_DEC		29,408,173	72,969,000	-	24,367,000
Monthly Energy - Jan		PENG_JAN		30,429,634	78,666,000	-	24,800,000
Monthly Energy - Feb		PENG_FEB		27,570,303	73,024,000	-	22,505,000
Monthly Energy - Mar		PENG_MAR		30,728,566	88,391,000	-	22,709,000
Monthly Energy - Apr		PENG_APR		29,588,591	80,852,000	-	21,390,000
Monthly Energy - May		PENG_MAY		29,954,758	88,141,000	-	21,445,000
Monthly Fuel Exp Jun			PENG_JUN	920,596	2,643,180	-	619,050
Monthly Fuel Exp Jul			PENG_JUL	971,222	2,487,438	-	653,474
Monthly Fuel Exp Aug			PENG_AUG	973,722	2,885,707	-	631,343
Monthly Fuel Exp Sep			PENG_SEP	931,671	2,822,838	-	614,569
Monthly Fuel Exp Oct			PENG_OCT	949,011	2,307,257	-	690,309
Monthly Fuel Exp Nov			PENG_NOV	899,352	2,676,835	-	681,382
Monthly Fuel Exp Dec			PENG_DEC	938,946	2,320,759	-	777,991
Monthly Fuel Exp Jan			PENG_JAN	982,425	2,539,742	-	794,214
Monthly Fuel Exp Feb			PENG_FEB	916,203	2,417,929	-	745,173
Monthly Fuel Exp Mar			PENG_MAR	1,019,488	2,868,212	-	753,421
Monthly Fuel Exp Apr			PENG_APR	958,552	2,607,351	-	691,796
Monthly Fuel Exp May			PENG_MAY	981,131	2,886,949	-	702,404
Total Fuel Expense - Monthly Allocation		PENG_MON		11,440,319	31,071,198	-	8,355,126
FAC Expense Residual Allocator		FACALL		12.074.631	32.786.905	-	8.812.579
FAC Expense Cost							
Member Specific Assignment				$ -	-	(9.481.342)	-
FAC Expense Residual			FACALL	$ (12.027.483)	$ (32.658.883)	$ -	$ (8.778.169)
FAC Expense Total		FACT		$ (12.027,483)	$ (32.658,883)	$ (9.481,342)	$ (8.778,169)
FAC Expense Allocator		FACAL	FACT	0 02628	0 07136	0 02072	0 01918

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
FEB 20 2009
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	CASE NO. 2008-00409

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

FEBRUARY 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	CASE NO. 2008-00409

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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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. What is your occupation and by whom are you employed?

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, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than thirty years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state and local government agencies and consumers of utility services in the planning, ratemaking, financial, accounting, tax, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies in the planning, financial, and ratemaking areas. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions providing services in the accounting, tax, financial, and planning areas.

I have appeared as an expert witness on planning, ratemaking, accounting, finance, and tax issues before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions, including the Kentucky Public Service Commission ("Commission"). I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group a large customers taking electric service on the East Kentucky Power Cooperative, Inc. ("EKPC" or "Company") system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's revenue requirement and to make recommendations on the appropriate base rate increase amount.

Q. Please summarize your testimony.

A. I recommend that the Commission increase EKPC's base rates by no more than $32.111 million on an annual basis compared to the Company's original computed revenue deficiency of $70.042 million, which is greater than the $67.859 million increase the Company originally requested. I included the correction of an error and the amortization of the 2008 outage costs recently approved in Case No. 2008-00436 as KIUC adjustments to the Company's original computed revenue deficiency. I recommend that the base rate increase in this proceeding be effective June 1, 2009 and that the Commission reject the Company's proposals to either increase base rates on April 1, 2009 or defer the revenue requirement associated with Spurlock 4 from April 1, 2009 through May 31, 2009.

I recommend that the Commission make the adjustments summarized on the following table.

East Kentucky Power Cooperative, Inc.
Case No. 2008-00409
Summary KIUC Revenue Requirement Recommendations
($Millions)

Revenue Requirement as Originally Filed by the Company	$70.042
KIUC Adjustments to Company's Revenue Requirement:	
Capitalization and Rate Base:	
Remove CWIP in Rate Base[1]	(13.636)
Reflect the Delayed In Service Dates for Smith 9 and 10 CT's	(4.665)
Reasonable TIER:	
Reduce TIER to 1.35 from Requested 1.45	(8.613)
Operating Income:	
Include Non-Firm Transmission Revenue in Other Operating Revenue	(1.800)
Correct Company's Error in the Removal of Fuel and Purchased Power Expense	(2.558)
Reduce Purchased Power Expense Related to Forced Outages	(5.199)
Remove Third Party Outage Insurance Expense	(1.236)
Reject Turbine/Boiler Overhaul Expense Normalization	(2.300)
Reduce Payroll and Related Expenses for Vacant or Unfilled Positions	(0.238)
Reduce Payroll Expense for Undistributed 2008 Budgeted Increases	(0.337)
Reduce Depreciation Expense Due to Delayed In-Service Dates for Smith 9 and 10 CTs	(1.450)
Reflect Regulatory Asset Amortization Expense Approved in Case No. 2008-00436	4.101
Total KIUC Adjustments to Company's Revenue Requirement	($37.931)
KIUC Recommended Revenue Requirement	$32.111

[1] If the Commission does not remove the entirety of CWIP from rate base, then KIUC recommends that the Commission remove the CWIP for a 25 mW wind farm and Cooper pollution control retrofit project because they are speculative and/or not known and measurable.

I address each of the adjustments summarized on the preceding table in the remainder of my testimony.

II. CAPITALIZATION AND RATE BASE

CWIP in Rate Base in Lieu of AFUDC

Q. Please describe the Company's request to include CWIP in rate base for all projects that otherwise qualify for AFUDC.

A. The Company proposes a significant change from its historic practice of accruing allowance for funds used during construction (AFUDC) on all qualified construction work in progress (CWIP) projects to now include all CWIP in rate base. The Company plans "to discontinue accruing Allowance for Funds Used During Construction (AFUDC) on current construction projects," according to its response to Staff 3-4(a). More specifically, the Company proposes to discontinue accruing AFUDC on all CWIP projects effective January 1, 2009, except for Spurlock 4, which will continue to accrue AFUDC until its April 1, 2009 commercial operation date.

The projects that no longer will accrue AFUDC include the Smith 1 generating unit and Cooper pollution control retrofit projects that are already under construction, new CT projects that are scheduled to commence construction in January 2010, a new 25 mW wind farm generating project that is scheduled to commence construction in January 2010 and a new "Unknown Site No. 8" project that is scheduled to commence construction in January 2010, according to the Company's response to KIUC 2-21. The Company's response to KIUC 2-21 provides the monthly direct construction expenditures and AFUDC for each project included in the Company's budgets for 2009 and 2010. The Company assumes no AFUDC starting January 2009 even though the Commission to-date has not authorized CWIP in rate base, except for the CWIP projects included in the environmental surcharge. I have attached a copy of the Company's response to KIUC 2-21 as my Exhibit___(LK-2).

Q. How did the Company reflect this change from the AFUDC methodology to the CWIP in rate base methodology in its filing?

A. Under the AFUDC approach, the Company would not have included the CWIP projects eligible for AFUDC in its rate base or capitalization; thus, there would have been no related interest expense or TIER margin for the projects. However, in its filing in this proceeding, the Company included the thirteen month average of all CWIP projects in its rate base and capitalization, which means that it included the interest expense and the TIER margin on these amounts in the revenue requirement for the projected test year. It reflected no AFUDC in its budget or financial forecasts for 2009 or 2010, except for Spurlock 4.

Q. What is the effect in this filing of the Company's proposed change from accruing AFUDC to CWIP in rate base?

A. The Company's proposal increases its revenue requirement by $13.636 million. I computed this amount by multiplying the $185.198 million thirteen month average of the qualifying CWIP projects times the Company's requested 5.078%

test year interest rate times the requested TIER of 1.45. I computed the thirteen month average of the qualifying CWIP using the generation projects and amounts listed in the Company's response to KIUC 2-21; however, I excluded the Spurlock 4 project, which continues to accrue AFUDC, the Spurlock 1 scrubber project, which is included in the Company's ECR and the Smith 9 and 10 CTs, which I address as a separate adjustment. I also excluded the CWIP amounts for the other generation projects for the months after the CWIP projects were placed in service to the extent such projects were placed in service during the test year. The computations are detailed on my Exhibit___(LK-3).

Q. Should the Commission authorize this change in ratemaking recovery?

A. No. It is harmful to ratepayers and to the Company. First, it is harmful to ratepayers because it compounds the effect of the rate increase due to Spurlock 4 in this proceeding. It would be better to delay any such change in ratemaking approach until after the Company completes its major construction program. Second, it is harmful to ratepayers because it adds a TIER margin to the interest recovery. Under the AFUDC approach only the interest is deferred and added to the cost of the plant. Under the CWIP approach, ratepayers must pay the interest and the TIER margin. This is a permanent harm to ratepayers. Third, it is harmful to ratepayers because it accelerates recovery of a portion of the plant costs to the construction period in contrast to generally accepted accounting principles and intergenerational equities, which dictate that the financing cost is a cost of the asset that should be depreciated and recovered over the life of the plant when it provides service. Fourth, it is harmful to ratepayers because it requires the Company and the Commission to speculate as to which projects will be constructed and how much will be expended on those projects and when those amounts will be expended in the projected test year.

In addition, it is harmful to the Company because the Company cannot recover its interest and TIER margin in real time and recoveries will lag the interest incurred even if the Company files for rate increases using a projected test year every twelve months. In contrast to the CWIP in rate base methodology, the AFUDC methodology allows the Company to accrue AFUDC exactly equal to its interest expense on the CWIP projects each month. The Company's fragile financial condition is largely self-imposed. It hardly makes sense for the Commission to allow the Company to expose itself further in this manner.

Further, it is harmful to the Company because the Company proposes to discontinue accruing AFUDC effective January 1, 2009, according to its response to KIUC 2-21. There is no evident reason for the Company to discontinue accruing AFUDC effective January 1, 2009 when its proposed rates will not go into effect until June 1, 2009. This discretionary reduction in AFUDC in 2009 puts additional financial pressure on the Company by unnecessarily reducing its TIER and DSC for 2009 and, once again, forces the Commission to react and grant a higher TIER so that the Company can meet its minimum financial metrics under the RUS loan covenants and the credit facility requirements. This means that the Company loses five months of AFUDC, assuming that the CWIP is included in rate base effective June 1, 2009, but incurs the related interest expense during the first five months of the year. This has the effect of artificially and unnecessarily reducing the Company's margin in 2009 used to compute the TIER and DSC under the RUS loan covenants and the credit facility requirements.

Q. Have you quantified the additional margin the Company would earn in 2009 if it accrued AFUDC during the first five months of the year on all of its qualifying CWIP projects, except for Spurlock 4 and the Spurlock 1 scrubber project recovered through the ECR?

A. Yes. The additional margin would be $5.352 million using an AFUDC rate equivalent to the Company's proposed interest rate in this proceeding as detailed in Mr. Walker's Exhibit DMW-3. This additional margin would have the effect of increasing the Company's projected earned TIER for 2009 by 0.041 from 1.304 to 1.345. I used the projected TIER provided in response to Request 2 of the Staff requests made at the informal conference in this proceeding on November 13, 2008. The projected TIER ratio uses the same income statement data for 2009 that the Company provided in response to 807 KAR 5:001 Section 10(9)(h) Item 1 page 3 of 11, except for a minor difference in the margin used in the numerator of the computation. I have replicated a copy of the Company's response to Request 2 and the referenced page from the Company's filing as my Exhibit___(LK-4). The computations are detailed on my Exhibit___(LK-5).

Q. The Company argues that it should be allowed CWIP in rate base in the same manner as Louisville Gas and Electric Company, Kentucky Utilities Company and Kentucky Power Company. Please comment.

A. First, those utilities have a long history of CWIP in rate base, unlike EKPC. As I noted earlier, the timing for this proposed change is particularly bad because it compounds the effects of the Spurlock 4 rate increase. The best time to make such a change, if the Commission deems such a change is appropriate, is after the Company's major construction program is completed.

Second, those utilities are much stronger financially than EKPC. As I noted earlier, this change will be harmful to EKPC unless it files for rate increases every twelve months using a projected test year. Even still, those rate increases will tend to be front loaded, providing a return greater than actual interest and TIER margin costs in the early months of the rate effective year and then providing a dwindling return that is less than actual interest and TIER margin costs in the latter months of the rate effective year and dwindling further thereafter.

Q. Please summarize your recommendation on the Company's proposal to change to the CWIP in rate base methodology and discontinue accruing AFUDC on all qualifying CWIP projects effective January 1, 2009, except for Spurlock 4.

A. I recommend that the Commission reject this proposal and direct the Company to continue accruing AFUDC on its qualifying projects. The harmful effects of the

Company's proposal outweigh any generalized financial benefits that it asserts. The best approach for the Company to improve its financial metrics is to continue the AFUDC methodology, file for timely rate increases, and timely file to include all qualifying costs in the environmental surcharge.

<u>25 MW Proposed Wind Farm</u>

Q. Please describe the Company's request to include the 2010 construction costs for a proposed 25 mW Wind Farm project.

A. The Company included a thirteen month average of $4.383 million in construction costs and capitalization for a 25 mW Wind Farm project, according to the Company's response to KIUC 2-21. This increased the Company's claimed revenue requirement by $0.323 million, based on the Company's interest rate of 5.078% and its requested TIER of 1.45. This cost is included in the Company's revenue requirement in this proceeding only because of the Company's intent to no longer accrue AFUDC, although this project would have qualified for AFUDC but for the proposed change in methodology. The computation of the thirteen month average is detailed on my Exhibit___(LK-3).

Q. Is it certain that the Company actually will develop and construct this project?

A. No. This project is speculative. The Company has not yet decided whether it will actually develop such a project, according to the Company's response to Staff 2-

39. In fact, the Company doesn't know whether a wind farm can even be justified and acknowledged that the amount included in the test year is nothing more than a "placeholder," according to its response to Staff 2-39. I have attached a copy of the Company's response to Staff 2-39 as my Exhibit___(LK-6).

Q. What is your recommendation?

A. I recommend that the Commission remove the cost of this project from the Company's revenue requirement. If the Commission adopts my previous recommendation to continue the AFUDC methodology, then the cost of this project will be removed from the revenue requirement in conjunction with that recommendation. However, if the Commission does not adopt my recommendation on AFUDC, then it nevertheless should remove the cost of this project because it is speculative as to if and when it ever will be constructed. Such a cost is not known and measurable and should not be included in the revenue requirement.

Cooper Scrubber (Retrofit Project)

Q. Please describe the Company's request to include the construction costs for the Cooper Scrubber Retrofit Project.

A. The Company included a thirteen month average of $25.189 million in construction costs and in capitalization for this project, which is detailed in the Company's response to KIUC 2-21 and described in response to Staff 2-46. I have attached a copy of the relevant pages from the response to Staff 2-46 as my Exhibit___(LK-7). These costs increased the Company's claimed revenue requirement by $1.855 million, based on the Company's interest rate of 5.078% and its requested TIER of 1.45. The Company plans to spend a total of $484 million on this project in the years 2009 through 2012. This cost is included in the Company's revenue requirement in this proceeding only because of the Company's intent to no longer accrue AFUDC, although this project would have qualified for AFUDC but for the proposed change in methodology. The computation of the thirteen month average is detailed on my Exhibit___(LK-3).

Q. Would this project also likely qualify for recovery through the environmental surcharge recovery mechanism?

A. Yes. Thus, the Company could accrue AFUDC on the project and/or at some later date could seek to include the construction costs of the project in the ECR. There is absolutely no reason to include this project in base rates at this time.

Q. Are the Company's construction cost projections for the Cooper retrofit project known and measurable at this time?

A. No. The Company acknowledged that it has not yet developed a detailed cash flow projection and still is working on the design and engineering for the project, according to its response to Staff 3-15. In that same response, the Company stated that its "very rough preliminary estimate of the cash flow indicates that as much as $57 million could be spent" by the end of the test year. The amount included by the Company in the test year assumed that $61.354 million would be spent, according to its responses to KIUC 2-20 and KIUC 2-21.

Q. What is your recommendation?

A. I recommend that the Commission remove the cost of this project from the Company's revenue requirement. If the Commission adopts my previous recommendation to continue the AFUDC methodology, then the cost of this project will be removed in conjunction with that recommendation. However, if the Commission does not adopt my recommendation on AFUDC, then it nevertheless should remove the cost of this project because it is speculative as to the amount and timing of the construction. Such a cost is not known and measurable and should not be included in the revenue requirement. In any event, the Company retains the option of seeking to include the construction costs of this project in the ECR in lieu of base rates. Either the accrual of AFUDC or including the costs in the ECR are superior alternatives to the Company's request for CWIP treatment and will allow the Company to maintain its financial metrics over the next three years of construction on a timely and continuing basis.

Delay in Smith 9 and 10 CTs

Q. Please describe the amounts included by the Company for the Smith 9 and 10 CTs in the test year revenue requirement.

A. The Company included the interest expense and the TIER margin on the cost of these units in each month of the test year despite the fact that the units are not projected to enter commercial operation until December 1, 2009.

Q. Does the cost of these units qualify for AFUDC?

A. Yes. However, the Company made the decision in this proceeding to request the equivalent of CWIP in rate base. Accordingly, it has not reflected any AFUDC in the test year on any CWIP projects, including the Smith 9 and 10 CTs.

Q. If the Commission rejects the Company's request to convert to the CWIP in rate base methodology and includes no Smith 9 and 10 CWIP in rate base for the months June 2009 through November 2009, what effect does that have on the Company's revenue requirement?

A. It will reduce the Company's revenue requirement by $4.665 million. This amount is in addition to the revenue requirement effect of removing the other CWIP projects from rate base and capitalization that qualify for AFUDC. I address this project separately because the units will be in commercial operation during the test year, unlike the other generating unit CWIP projects in the prior adjustment. The Company included a thirteen month average of $63.356 million in rate base in the test year for these six months, according to its response to KIUC 2-21. I computed the revenue requirement effect by multiplying the capitalization amount times the Company's interest rate of 5.078% times the Company's requested TIER of 1.45. The computations are detailed on my Exhibit___(LK-8).

III. REASONABLE TIER

Q. Please describe the Company's requested TIER.

A. The Company requests an increase in its TIER used for ratemaking purposes from the presently authorized level of 1.35 to 1.45. This request is supported by Company witness Mr. Walker.

Q. Please describe the methodology employed by Mr. Walker to support a TIER of 1.45.

A. Mr. Walker developed this recommendation for East Kentucky based on an analysis of credit metrics for generation and transmission ("G&T") cooperatives that were rated BBB+ to A+ by Standard and Poor's.

Q. Mr. Walker included a table on page 10 of his testimony that compared EKPC's three-year average TIER to that of several BBB-rated G&T cooperatives. Does this table accurately portray EKPC in comparison to the other utilities?

A. No. This table does not present a fair picture of the Company's financial situation for the three years 2005-2007 and the expected TIER for EKPC because it includes 2005 and excludes 2008. The 2005 TIER of 0.339 was abnormally low because of the expense effects of the U.S. EPA Consent Decree that the Company was required to recognize on its income statement that year. Since 2005, the TIER ratios have been 1.132, 1.407, and 1.268 for 2006, 2007 and 2008, respectively, or a three year average of 1.269. I also would note that a 1.35 TIER would put EKPC approximately in the middle of the group of comparative G&Ts shown on Mr. Walker's table.

Q. Mr. Walker's Exhibit DMW-1 contains a list of G&Ts that have been rated by Moody's, Standard and Poor's, and Fitch's. Mr. Walker summarized the TIERs for the group and split them into four levels on page 13. How does a 1.35 TIER fit into the levels presented by Mr. Walker?

A. A 1.35 TIER is near the midpoint TIER ratio for the group of G&Ts presented by Mr. Walker. According to Mr. Walker, these companies were rated between BBB+ to A+, so a 1.35 TIER appears reasonable when viewed in this context.

Q. On page 14 of his Direct Testimony, Mr. Walker stated that East Kentucky should earn a consistent TIER above the midpoint of this group in order to "compensate for its basket of risk". Do you agree with Mr. Walker's conclusion?

A. No. Mr. Walker failed to show that a 1.35 TIER would not compensate for the Company's so-called basket of risk. In fact, recent historical data show that the Company's credit position is beginning to stabilize and has become more consistent since 2005. This improvement is due to a combination of base and ECR rate increases, including the recent increase in the authorized TIER from 1.15 to 1.35, and recent accounting orders. These factors demonstrate that the Commission has been responsive to EKPC's financial requirements.

Q. Should EKPC's presently authorized EKPC's TIER of 1.35 be increased to 1.45?

A. No. First, the Company's precarious financial condition is largely self-imposed as the result of delayed rate increases, use of historic test years in prior rate filings, failure to seek to include qualified costs in the environmental surcharge on a timely basis, and use of discretionary and unduly conservative accounting practices, all of which serve to depress the Company's earned TIER and DSC.

Second, the presently authorized TIER of 1.35 was just recently increased and approved in Case no. 2006-00472 with apparent reluctance due to the immediate financial need at that time to increase the Company's actual earned TIER and DSC to avoid default under the RUS loan covenants and the private credit facility.

Third, the Company's request is wildly excessive compared to the minimum TIER of 1.05 required under the RUS loan covenants and the private credit facility and unnecessarily compounds the amount of the increase sought in this proceeding. The better approach is to retain the presently authorized TIER of 1.35 rather than reducing it. This TIER already provides a margin of 35% over the Company's *projected* interest expense. This is a significant margin and should not be increased even further.

Fourth, for the first time in this proceeding, the Company's revenue requirement will be determined on the basis of a projected test year rather than a historic test year. The Commission granted the presently authorized TIER of 1.35 based on a historic test year in Case No. 2006-00472. Due to the use of a historic test year in that proceeding, the Company already was in the hole when those rates became effective. The Commission's approval of the TIER of 1.35 in Case No. 2006-00472 in part reflected this continuing lag problem and the effect on the Company's financial condition. In this case, however, the Company's revenue requirement will be set using a projected test year, which reflects the entirety of the Company's projected cost increases during the first year that the new rates actually will be effective. Thus, it no longer is necessary to "price in" the decline in the Company's ability to earn the authorized TIER, let alone increase it even further. If anything, the use of a projected test year argues in favor of reducing the presently authorized TIER of 1.35.

Fifth, if past is prologue, the Company likely will attempt to transport any increase in the authorized TIER in this base rate proceeding into its next ECR proceeding. Thus, the effect of the Commission's decision in this proceeding likely will have even greater effect than the amount included in the base revenue requirement.

Fifth, the Company failed to show that an increase in the Company's currently authorized TIER of 1.35 is necessary and reasonable or that it would be unable to attract capital at reasonable rates if the 1.35 TIER is maintained.

Q. What level of TIER should the Commission authorize in this proceeding?

A. I recommend that the Commission maintain its currently authorized TIER of 1.35 for East Kentucky. This TIER should allow the Company reasonable access to new capital at reasonable terms, assuming that the Company acts in its self-interest by controlling costs, timely seeking base rate increases, timely seeking to include qualified environmental costs in its environmental surcharge mechanism and engaging in self-help accounting measures such as accruing AFUDC for the first five months of 2009.

Q. What is the effect of retaining the presently authorized TIER of 1.35 on the Company's revenue requirement?

A. The effect is to reduce the Company's revenue requirement by $8.613 million, assuming that the Commission agrees with my recommendation to reject the Company's proposal to change to CWIP in rate base in lieu of AFUDC. I computed this amount by subtracting the $9.404 million in interest on the CWIP in rate base projects, other than for Spurlock 4 and the Spurlock 1 scrubber, and by subtracting the $3.217 million in interest expense on the Smith 9 and 10 CTs for May through November 2009 from the Company's requested interest expense of $98.752 million and then multiplied the result times 0.1, the difference between the TIER of 1.45 and 1.35.

IV. OPERATING INCOME

Other Operating Revenues Budgeting Error

Q. Please describe the Company's other operating revenue budgeting error.

A. The Company failed to include non-firm transmission revenue in other operating revenues, which it acknowledged in response to Staff 2-42. I have attached a copy of the Company's response as my Exhibit___(LK-9). The Company acknowledged that it will include these revenues in future years in response to Staff 2-42 and AG 2-15. I have attached a copy of the Company's response to AG 2-15 as my Exhibit___(LK-10).

Q. What is the effect of the Company's budgeting error?

A. The Company quantified the non-firm transmission revenue in 2007 at $1.9 million and in 2008 at $1.8 million in response to KIUC 2-7. I have attached a copy of this response as my Exhibit___(LK-11).

Q. What amount should the Commission include in the test year other operating revenue?

A. The Commission should include $1.8 million, the same amount the Company received in 2008, absent any further information from the Company that the amount should be different.

Fuel Expense Error

Q. Please describe the error in the Company's filing for the removal of fuel and purchased power expense from the base revenue requirement.

A. The Company understated the adjustment to remove fuel and purchased power expense recoverable through base rates and the fuel adjustment clause shown on Seelye Exhibit 2 lines 15 and 16. The Company acknowledged this error in its response to Staff 2-23.

Q. What is the effect of correcting this error?

A. The effect is to reduce the Company's revenue requirement by $2.558 million. The Company provided the revised fuel and purchased power amounts in response to Staff 2-23 and provided a revised Seelye Exhibit 2 and revised Exhibit 2 Schedule 1.03 in response to Staff 2-25(b).

Purchased Power Expense Due to Forced Outages

Q. Please describe the amount included by the Company for purchased power expense resulting from forced outages.

A. The Company included $10.000 million for purchased power expenses resulting from forced outages of its generating units in the projected test year. The Company's reason for including this purchased power expense is that such expenses in excess of the fuel expense that otherwise would have been incurred are not recoverable through the fuel adjustment clause.

Q. How did the Company quantify this $10.000 million purchased power expense?

A. The Company estimated this $10.000 million based on the "high end" of the range of its recent experience in the years 2005 through 2007, according to its response to KIUC 1-37. The Company incurred $10.3 million in purchased power expense resulting from forced outages in 2005, $5.3 million in 2006 and $3.6 million in 2007. Although it was not a factor in developing the $10.000 million amount, the Company noted in its response to KIUC 1-37 that it had incurred $12.3 million in purchased power expense resulting from forced outages in 2008. I have attached a copy of the Company's response to KIUC 1-37 as my Exhibit___(LK-12).

Q. Did the Company experience purchased power expense in 2004 and 2008 due to forced outages for which it requested and obtained accounting orders from the Commission?

A. Yes. The Company incurred extraordinary purchased power expenses in 2004 due to an extended forced outage at Spurlock 1. The Commission authorized the Company to defer these costs as a regulatory asset and recover them over a three year period in Case No. 2006-00472. The Company also incurred purchased power expenses in 2008 due to forced outages, although they admittedly were not extraordinary. In light of the Company's precarious financial situation, the Commission authorized the Company to defer these costs as a regulatory asset and recover them over a three year period in Case No. 2008-00436.

Q. What is the average annual purchased power expense over the most recent ten years resulting from forced outages if the expenses for all outages, including the 2004 and 2008 outages subject to accounting orders, are included?

A. The average annual expense is $9.150 million in the years 1999 through 2008 if the expenses due to all outages are included, which is $0.850 million less than the Company's requested amount of $10.000 million. The actual purchased power expenses were obtained from the Company's response to KIUC 2-5, a copy of which I have attached as my Exhibit___(LK-13).

Q. What is the average annual purchased power expense resulting from forced outages if the expenses for the 2004 and 2008 outages are excluded?

A. The average annual expense is $4.801 million in the years 1999 through 2008 if the expenses for the 2004 and 2008 outages are excluded and instead the average annual expense incurred in the other eight years is used.

Q. Should the Commission exclude the expenses resulting from the 2004 and 2008 outages in the quantification of the expense amount for the projected test year?

A. Yes. The resulting average annual expense is the maximum that should be allowed. An argument could be made that no purchased power expense in excess of fuel expense that otherwise would have been incurred should be included in the base revenue requirement because the utility should remain at risk for such expenses. The Company's proposed treatment neuters the incentive aspect built in to the FAC by essentially requiring the ratepayers to provide a recovery insurance policy through base rates. In addition, the Company's proposal allows it to retain benefit of recoveries at an excessive level in each year, but still seek and obtain accounting order for 100% of expenses associated with extraordinary outages, thus putting ratepayers in the position of potentially paying multiple times for the same purchased power expense.

However, if the Commission determines that it should include such purchased power expenses in the base revenue requirement, then it should quantify the expense at a "normal" level and exclude the effects of "abnormal" outages whether the result of specific extraordinary outages or excessive levels of outage-related purchased power expense compared to prior years. In this manner, the Company still remains at risk for the purchased power expense associated with extraordinary outages and excessive expenses, although the Commission always retains the discretion to allow deferral and amortization of extraordinary amounts based on the facts and circumstances surrounding particular outages.

Q. What is your recommendation for an appropriate amount to include in the projected test year?

A. I recommend that the Commission include $4.801 million in purchased power expense resulting from forced outages in the projected test year in lieu of the Company's proposed $10.0 million. Alternatively, the Commission should include $0 if its intent is to retain the full incentive effect of the fuel adjustment clause and ensure that the risk of forced outages remains on the utility, not on its ratepayers. The Commission adopted the $0 alternative in Case No. 2006-00472, although it allowed the Company to retroactively defer the 2004 Spurlock 1 outage costs in that case.

Third Party Outage Insurance Expense

Q. Please describe the Company's request to include third party outage insurance expense in its revenue requirement.

A. The Company proposes to include $1.236 million in third party outage insurance expense in its revenue requirement, according to its response to AG 1-91. Presumably, such insurance, if economic to purchase, would mitigate the risk and reduce the amount of purchased power expense due to forced outages, although the Company has incorporated no such savings in its revenue requirement.

Q. Is it certain that the Company will purchase outage insurance in the test year?

A. No. The Company stated that it will purchase outage insurance "only if the terms and conditions are such that the company sees a benefit in doing so," in response to KIUC 2-18. The Company assessed third party insurance in 2008 and was quoted an $825,000 premium covering the winter and summer peak months, subject to a 100 mW and $4 million deductible, a $20 million maximum payout and a strike price of $30/mWh, according to the Company's response to AG 2-13. The Company did not purchase this third party outage insurance because it concluded that it did not provide "financially advantageous coverage," according to its response to AG 2-13.

Q. Has the Company ever collected on third party outage insurance actually purchased in the past?

A. No. The Company never has collected on any of the third party outage insurance policies that it purchased in prior years, according to its response to AG 2-13.

Q. What is your recommendation?

A. I recommend that this expense be removed from the revenue requirement. It is speculative at best and the Company admits that it is unlikely that it actually will or will be able to purchase such insurance at an economic price. In addition, I note that the Company reflected no reduction in its proposed forced outage expense to reflect expected recoveries from any such third party outage insurance.

<u>Turbine/Boiler Overhaul Expense Normalization</u>

Q. Please describe the Company's proposed adjustment to normalize turbine/boiler overhaul expense.

A. The Company proposes to increase the test year turbine/boiler overhaul expense by \$2.300 million from the \$4.800 million included in the budget.

Q. Is it the Commission's historical practice to normalize turbine/boiler overhaul expenses in the manner proposed by the Company?

A. No. The Company acknowledged that it "is unaware of any utility or intervenor proposing a normalization adjustment for turbine overhaul costs in a rate case proceeding," according to its response to KIUC 2-22.

Q. What is the basis for the Company's projection of \$7.100 million, as adjusted, for this expense in the test year?

A. The methodology for computing the \$7.100 million amount is described by Mr. Seelye on pages 19-20 of his Direct Testimony. The amounts reflected in this adjustment by generating unit are listed on Seelye Exhibit 2 Schedule 1.18. The Company estimated the costs "by analyzing historical costs and/or by receiving a contractor's assessment of the required maintenance," according to its response to KIUC 2-24.

Q. How does the Company's request compare to its 10 year history for turbine/boiler overhaul expense?

A. It is wildly excessive. The \$7.100 million amount included in the test year is more than two times the greatest amount of \$2.903 million spent in any of the prior ten years, except for the Spurlock 2 outage in 2008, according to the Company's response to KIUC 2-23. The average over the 10 years was $1.411 million excluding the 2008 Spurlock 2 expense and $2.264 million including the Spurlock 2 expense. I have attached a copy of the Company's response to KIUC 2-23 as my Exhibit___(LK-14).

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request to increase the amount for the test year by $2.300 million over and above the $4.800 million already included in the budget.

Payroll and Related Expenses for Vacant or Unfilled Positions

Q. Does the Company plan to fill all positions that are reflected in its budgets for 2009 and 2010 and included in test year operation and maintenance expense?

A. No. In response to KIUC 1-22, the Company acknowledged that it had no immediate plans to hire four of the positions included in the test year. In response to KIUC 2-37, the Company quantified the effect of these positions on operation and maintenance expense in the test year at $0.238 million.

Q. What is your recommendation?

A. I recommend that the Commission remove $0.238 million in payroll and related expenses from the test year revenue requirement.

<u>Undistributed Payroll Increases Included in Budget</u>

Q. **Were the payroll increases included in the budget for 2009 actually implemented?**

A. No. Only $1.376 million of the $1.713 million included in the budget was distributed, according to the Company's response to AG 2-10. These increases went into effect in November 2008, according to the Company's response to KIUC 2-35. Thus, the test year payroll is overstated by at least $0.337 million.

Q. **What is your recommendation?**

A. I recommend that the Commission reduce the Company's revenue requirement by $0.337 million for this expense that will not be incurred in the test year.

<u>Depreciation Expense on Smith 9 and 10 CTs</u>

Q. **Please describe the depreciation expense included by the Company for the Smith 9 and 10 CTs.**

A. The Company included depreciation expense of $3.405 million for the Smith 9 and 10 CTs for the months June 2009 through May 2010, except for November 2009. The Company did not include any depreciation expense in November 2009 for the Smith 9 and 10 CTs due to a computational error in its spreadsheet. The Company's depreciation expense on these projects and the underlying computations were provided in response to KIUC 2-2. These depreciation computations were based on the Company's financial model, which assumed that the CTs would be placed in service in May 2009, according to the Company's response to KIUC 2-20(b).

Q. Will the Smith 9 and 10 CTs actually be in-service starting June 2009?

A. No. The Company now expects that the Smith 9 and 10 CTs will be placed in-service on December 1, 2009, according to the Company's response to KIUC 2-4.

Q. What is your recommendation?

A. I recommend that the Commission reduce the Company's revenue requirement by $1.450 million to remove the depreciation expense on these CTs for the months June 2009 through November 2009.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	PSC CASE NO. 2008-00409

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

FEBRUARY 2009

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.

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 December 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-SC	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
of
Lane Kollen
As of December 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

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

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
of
Lane Kollen
As of December 2008

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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

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 require-ments.
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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

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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6/95	3905-U Rebuttal	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	U-21485 (Supplemental Direct) 12/95 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. 14965	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.

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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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Date	Case	Jurisdict.	Party	Utility	Subject
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-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	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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Date	Case	Jurisdict.	Party	Utility	Subject
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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Date	Case	Jurisdict.	Party	Utility	Subject
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 Market-Ing, 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 Heallthcare 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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Date	Case	Jurisdict.	Party	Utility	Subject
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 CenterPoint 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 functionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
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.

Expert Testimony Appearances
of
Lane Kollen
As of December 2008

Date	Case	Jurisdict.	Party	Utility	Subject
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 December 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 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 December 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.
09/08	08-935-EL-SSO 08-918-EL-SSO	OH OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
11/08	ER-08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
11/08	35717	TX	Public Utility Commission Of Texas	Cities Served by Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
12/08	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.

EXHIBIT___(LK-2)

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2008-00409

SECOND DATA REQUEST RESPONSE

KIUC'S SECOND DATA REQUEST DATED 1/23/09

REQUEST 21

RESPONSIBLE PERSON: **Frank J. Oliva**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 21. Please refer to Volume 3, Tab 24, page 2 of 2. For each of the generation and transmission budgeted capital projects for 2009 and 2010, please provide the following information by month during 2009 and 2010: Construction beginning balance, direct costs added, AFUDC added, and ending balance.

Response 21. Please see enclosed CD for the balance at 12-31-08 and the monthly expenditures through 2010.

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Jan-09				Feb-09				Mar-09			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	0	208,333	0	208,333	208,333	208,333	0	416,666	416,666	208,333	0	624,999
CT's No 9 and 10	79,109,098	4,554,062	0	83,663,160	83,663,160	4,554,059	0	88,217,219	88,217,219	4,504,059	0	92,721,278
CT's No 9 and 10 Start Up Costs	0	0	0	0	0	0	0	0	0	0	0	0
Unit 1	131,634,908	221,725	0	131,856,633	131,856,633	231,725	0	132,088,358	132,088,358	251,725	0	132,340,083
New CT Site Phases I-IV	0	220,849	0	220,849	220,849	220,849	0	441,698	441,698	1,720,849	0	2,162,547
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	0	0	0	0	0	0	0	0	0	0	0	0
Unit 1 Water Wall Tubes	0	0	0	0	0	0	0	0	0	0	0	0
Unit 1 Reheat Superheater	616,200	0	0	616,200	616,200	0	0	616,200	616,200	0	0	616,200
Retrofit Air Pollution Project	2,865	1,461,602	0	1,464,467	1,464,467	1,461,602	0	2,926,069	2,926,069	1,461,602	0	4,387,671
Replace Unit 1 Reheater	0	0	0	0	0	0	0	0	0	0	0	0
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	5,486,775	1,000,000	0	6,486,775	6,486,775	1,000,000	0	7,486,775	7,486,775	2,000,000	0	9,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	1,529,471	150,000	0	1,679,471	1,679,471	150,000	0	1,829,471	1,829,471	150,000	0	1,979,471
Coal Unloading By-Pass Chutes	0	0	0	0	0	150,000	0	150,000	150,000	150,000	0	300,000
Start Up Costs	0	0	0	0	0	0	0	0	0	0	0	0
Unit 1 Scrubber	123,731,439	5,624,027	0	129,355,466	129,355,466	4,123,025	0	133,478,491	133,478,491	3,123,025	0	136,601,516
Unit 4	496,194,807	9,413,633	1,931,936	507,540,376	507,540,376	8,147,773	1,765,374	517,453,523	517,453,523	6,461,994	1,976,025	525,891,542
Unit 4 Ash Silos	934,718	841,830	0	1,776,548	1,776,548	841,830	0	2,618,378	2,618,378	841,830	0	3,460,208
Construction Road Entrance	0	0	0	0	0	0	0	0	0	0	0	0
Construct Landfill Dam C	0	0	0	0	0	0	0	0	0	0	0	0
Additional Office Space	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas:												
Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0
Unknown Site No. 8	0	0	0	0	0	0	0	0	0	0	0	0
	839,240,281	23,696,061	1,931,936	864,868,278	864,868,278	21,089,196	1,765,374	887,722,848	887,722,848	20,873,417	1,976,025	910,572,290
Transmission Facilities:												
Station Upgrades	70,971	432,268	0	503,239	503,239	432,268	0	935,507	935,507	432,268	0	1,367,775
Breaker & Transmission Stations	623,150	1,311,789	0	1,934,939	1,934,939	1,311,789	0	3,246,728	3,246,728	1,311,789	0	4,558,517
Stations and Taps	741,902	976,704	0	1,718,606	1,718,606	976,704	0	2,695,310	2,695,310	976,704	0	3,672,014
69/138/161/345/KV Lines	21,883,112	2,153,797	0	24,036,909	24,036,909	2,153,797	0	26,190,706	26,190,706	2,153,797	0	28,344,503
Reconductors & Upgrade Lines	2,279,402	829,245	0	3,108,647	3,108,647	829,245	0	3,937,892	3,937,892	829,245	0	4,767,137
Capacitor Banks	0	68,610	0	68,610	68,610	68,610	0	137,220	137,220	68,610	0	205,830
Miscellaneous Work Orders	323,989	197,935	0	521,924	521,924	198,664	0	720,588	720,588	198,664	0	919,252
	25,922,526	5,970,348	0	31,892,874	31,892,874	5,971,077	0	37,863,951	37,863,951	5,971,077	0	43,835,028
Total	**$865,162,807**	**$29,666,409**	**$1,931,936**	**$896,761,152**	**$896,761,152**	**$27,060,273**	**$1,765,374**	**$925,586,799**	**$925,586,799**	**$26,844,494**	**$1,976,025**	**$954,407,318**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Apr-09				May-09				Jun-09			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	624,999	208,333	0	833,332	833,332	208,333	0	1,041,665	1,041,665	208,333	0	1,249,998
CT's No 9 and 10	92,721,278	4,174,059	0	96,895,337	96,895,337	4,174,059	0	101,069,396	101,069,396	4,174,059	0	105,243,455
CT's No 9 and 10 Start Up Costs	0	4,000,000	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	132,340,083	261,725	0	132,601,808	132,601,808	261,725	0	132,863,533	132,863,533	261,725	0	133,125,258
New CT Site Phases I-IV	2,162,547	220,849	0	2,383,396	2,383,396	220,849	0	2,604,245	2,604,245	220,849	0	2,825,094
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	0	475,000	0	475,000	475,000	0	0	475,000	475,000	0	0	475,000
Unit 1 Water Wall Tubes	0	240,000	0	240,000	240,000	0	0	240,000	240,000	0	0	240,000
Unit 1 Reheat Superheater	616,200	0	0	616,200	616,200	0	0	616,200	616,200	0	0	616,200
Retrofit Air Pollution Project	4,387,671	1,461,602	0	5,849,273	5,849,273	1,461,602	0	7,310,875	7,310,875	1,461,602	0	8,772,477
Replace Unit 1 Reheater	0	0	0	0	0	0	0	0	0	0	0	0
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	9,486,775	2,500,000	0	11,986,775	11,986,775	2,000,000	0	13,986,775	13,986,775	1,500,000	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	1,979,471	150,000	0	2,129,471	2,129,471	150,000	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	300,000	150,000	0	450,000	450,000	150,000	0	600,000	600,000	0	0	600,000
Start Up Costs	0	8,348,000	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	136,601,516	2,124,025	0	138,725,541	138,725,541	55,000	0	138,780,541	138,780,541	55,000	0	138,835,541
Unit 4	525,891,542	530,300	0	526,421,842	526,421,842	530,300	0	526,952,142	526,952,142	500,000	0	527,452,142
Unit 4 Ash Silos	3,460,208	841,830	0	4,302,038	4,302,038	841,830	0	5,143,868	5,143,868	841,830	0	5,985,698
Construction Road Entrance	0	0	0	0	0	109,250	0	109,250	109,250	109,250	0	218,500
Construct Landfill Dam C	0	0	0	0	0	0	0	0	0	0	0	0
Additional Office Space	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas:												
Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0
Unknown Site No. 8	0	0	0	0	0	0	0	0	0	0	0	0
	910,572,290	25,685,723	0	936,258,013	936,258,013	10,162,948	0	946,420,961	946,420,961	9,332,648	0	955,753,609
Transmission Facilities:												
Station Upgrades	1,367,775	432,268	0	1,800,043	1,800,043	432,268	0	2,232,311	2,232,311	432,268	0	2,664,579
Breaker & Transmission Stations	4,558,517	1,311,789	0	5,870,306	5,870,306	1,311,789	0	7,182,095	7,182,095	1,311,789	0	8,493,884
Stations and Taps	3,672,014	976,704	0	4,648,718	4,648,718	976,704	0	5,625,422	5,625,422	976,704	0	6,602,126
69/138/161/345/KV Lines	28,344,503	2,153,797	0	30,498,300	30,498,300	2,153,797	0	32,652,097	32,652,097	2,153,797	0	34,805,894
Reconductors & Upgrade Lines	4,767,137	829,245	0	5,596,382	5,596,382	829,245	0	6,425,627	6,425,627	829,245	0	7,254,872
Capacitor Banks	205,830	68,610	0	274,440	274,440	68,610	0	343,050	343,050	68,610	0	411,660
Miscellaneous Work Orders	919,252	198,664	0	1,117,916	1,117,916	198,664	0	1,316,580	1,316,580	198,664	0	1,515,244
	43,835,028	5,971,077	0	49,806,105	49,806,105	5,971,077	0	55,777,182	55,777,182	5,971,077	0	61,748,259
Total	**$954,407,318**	**$31,656,800**	**$0**	**$986,064,118**	**$986,064,118**	**$16,134,025**	**$0**	**$1,002,198,143**	**$1,002,198,143**	**$15,303,725**	**$0**	**$1,017,501,868**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Jul-09				Aug-09				Sep-09			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	1,249,998	208,333	0	1,458,331	1,458,331	208,333	0	1,666,664	1,666,664	208,333	0	1,874,997
CT's No 9 and 10	105,243,455	6,731,059	0	111,974,514	111,974,514	4,231,065	0	116,205,579	116,205,579	4,174,243	0	120,379,822
CT's No 9 and 10 Start Up Costs	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	133,125,258	677,725	0	133,802,983	133,802,983	1,371,725	0	135,174,708	135,174,708	431,725	0	135,606,433
New CT Site Phases I-IV	2,825,094	220,849	0	3,045,943	3,045,943	220,849	0	3,266,792	3,266,792	220,849	0	3,487,641
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	475,000	0	0	475,000	475,000	0	0	475,000	475,000	475,000	0	950,000
Unit 1 Water Wall Tubes	240,000	0	0	240,000	240,000	0	0	240,000	240,000	0	0	240,000
Unit 1 Reheat Superheater	616,200	0	0	616,200	616,200	0	0	616,200	616,200	0	0	616,200
Retrofit Air Pollution Project	8,772,477	1,461,602	0	10,234,079	10,234,079	1,461,602	0	11,695,681	11,695,681	1,461,602	0	13,157,283
Replace Unit 1 Reheater	0	0	0	0	0	0	0	0	0	0	0	0
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	600,000	0	0	600,000	600,000	0	0	600,000	600,000	0	0	600,000
Start Up Costs	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541
Unit 4	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142
Unit 4 Ash Silos	5,985,698	841,830	0	6,827,528	6,827,528	841,830	0	7,669,358	7,669,358	841,860	0	8,511,218
Construction Road Entrance	218,500	109,750	0	328,250	328,250	109,750	0	438,000	438,000	1,000	0	439,000
Construct Landfill Dam C	0	0	0	0	0	0	0	0	0	0	0	0
Additional Office Space	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas:												
Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0
Unknown Site No. 8	0	0	0	0	0	0	0	0	0	0	0	0
	955,753,609	10,251,148	0	966,004,757	966,004,757	8,445,154	0	974,449,911	974,449,911	7,814,612	0	982,264,523
Transmission Facilities:												
Station Upgrades	2,664,579	432,268	0	3,096,847	3,096,847	432,268	0	3,529,115	3,529,115	432,268	0	3,961,383
Breaker & Transmission Stations	8,493,884	1,311,789	0	9,805,673	9,805,673	1,311,789	0	11,117,462	11,117,462	1,311,789	0	12,429,251
Stations and Taps	6,602,126	976,704	0	7,578,830	7,578,830	976,704	0	8,555,534	8,555,534	976,704	0	9,532,238
69/138/161/345/KV Lines	34,805,894	2,153,797	0	36,959,691	36,959,691	2,153,797	0	39,113,488	39,113,488	2,153,797	0	41,267,285
Reconductors & Upgrade Lines	7,254,872	829,245	0	8,084,117	8,084,117	829,245	0	8,913,362	8,913,362	829,245	0	9,742,607
Capacitor Banks	411,660	68,610	0	480,270	480,270	68,610	0	548,880	548,880	68,610	0	617,490
Miscellaneous Work Orders	1,515,244	198,664	0	1,713,908	1,713,908	198,664	0	1,912,572	1,912,572	198,664	0	2,111,236
	61,748,259	5,971,077	0	67,719,336	67,719,336	5,971,077	0	73,690,413	73,690,413	5,971,077	0	79,661,490
Total	**$1,017,501,868**	**$16,222,225**	**$0**	**$1,033,724,093**	**$1,033,724,093**	**$14,416,231**	**$0**	**$1,048,140,324**	**$1,048,140,324**	**$13,785,689**	**$0**	**$1,061,926,013**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Oct-09				Nov-09				Dec-09			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	1,874,997	208,333	0	2,083,330	2,083,330	208,333	0	2,291,663	2,291,663	208,337	0	2,500,000
CT's No 9 and 10	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822
CT's No 9 and 10 Start Up Costs	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	135,606,433	401,725	0	136,008,158	136,008,158	1,254,375	0	137,262,533	137,262,533	1,719,379	0	138,981,912
New CT Site Phases I-IV	3,487,641	220,849	0	3,708,490	3,708,490	220,849	0	3,929,339	3,929,339	220,861	0	4,150,200
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	950,000	0	0	950,000	950,000	1,392,000	0	2,342,000	2,342,000	0	0	2,342,000
Unit 1 Water Wall Tubes	240,000	0	0	240,000	240,000	1,020,000	0	1,260,000	1,260,000	0	0	1,260,000
Unit 1 Reheat Superheater	616,200	0	0	616,200	616,200	1,800,000	0	2,416,200	2,416,200	0	0	2,416,200
Retrofit Air Pollution Project	13,157,283	1,461,602	0	14,618,885	14,618,885	1,461,602	0	16,080,487	16,080,487	1,461,601	0	17,542,088
Replace Unit 1 Reheater	0	0	0	0	0	0	0	0	0	0	0	0
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	600,000	0	0	600,000	600,000	0	0	600,000	600,000	0	0	600,000
Start Up Costs	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541
Unit 4	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142
Unit 4 Ash Silos	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218
Construction Road Entrance	439,000	1,000	0	440,000	440,000	0	0	440,000	440,000	0	0	440,000
Construct Landfill Dam C	0	0	0	0	0	0	0	0	0	0	0	0
Additional Office Space	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas:												
Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0
Unknown Site No. 8	0	0	0	0	0	0	0	0	0	0	0	0
	982,264,523	2,293,509	0	984,558,032	984,558,032	7,357,159	0	991,915,191	991,915,191	3,610,178	0	995,525,369
Transmission Facilities:												
Station Upgrades	3,961,383	432,268	0	4,393,651	4,393,651	432,268	0	4,825,919	4,825,919	432,264	0	5,258,183
Breaker & Transmission Stations	12,429,251	1,311,789	0	13,741,040	13,741,040	1,311,789	0	15,052,829	15,052,829	1,311,796	0	16,364,625
Stations and Taps	9,532,238	976,704	0	10,508,942	10,508,942	976,704	0	11,485,646	11,485,646	976,703	0	12,462,349
69/138/161/345/KV Lines	41,267,285	2,153,797	0	43,421,082	43,421,082	2,162,389	0	45,583,471	45,583,471	2,162,374	0	47,745,845
Reconductors & Upgrade Lines	9,742,607	829,245	0	10,571,852	10,571,852	829,245	0	11,401,097	11,401,097	829,250	0	12,230,347
Capacitor Banks	617,490	68,610	0	686,100	686,100	68,610	0	754,710	754,710	68,606	0	823,316
Miscellaneous Work Orders	2,111,236	198,664	0	2,309,900	2,309,900	198,664	0	2,508,564	2,508,564	199,390	0	2,707,954
	79,661,490	5,971,077	0	85,632,567	85,632,567	5,979,669	0	91,612,236	91,612,236	5,980,383	0	97,592,619
Total	**$1,061,926,013**	**$8,264,586**	**$0**	**$1,070,190,599**	**$1,070,190,599**	**$13,336,828**	**$0**	**$1,083,527,427**	**$1,083,527,427**	**$9,590,561**	**$0**	**$1,093,117,988**

Major Construction Projects	2009
G&T Operations - Power Production	
J. K. Smith:	
New CT Project Consulting	2,500,000
CT's No 9 and 10	41,270,724
CT's No 9 and 10 Start Up Costs	4,000,000
Unit 1	7,347,004
New CT Site Phases I-IV	4,150,200
Cooper Station:	
Unit 1 Primary Superheater Inlet Tubes	2,342,000
Unit 1 Water Wall Tubes	1,260,000
Unit 1 Reheat Superheater	1,800,000
Retrofit Air Pollution Project	17,539,223
Replace Unit 1 Reheater	0
Spurlock Station:	
Unit 1 Low Nox Boiler Modifications	10,000,000
Replace Unit 1 #6 & #7 Feedwater Heaters	750,000
Coal Unloading By-Pass Chutes	600,000
Start Up Costs	8,348,000
Unit 1 Scrubber	15,104,102
Unit 4	25,584,000
Unit 4 Ash Silos	7,576,500
Construction Road Entrance	440,000
Construct Landfill Dam C	0
Additional Office Space	0
Landfill Gas:	
Wind Farm	0
Unknown Site No. 8	0
	150,611,753
Transmission Facilities:	
Station Upgrades	5,187,212
Breaker & Transmission Stations	15,741,475
Stations and Taps	11,720,447
69/138/161/345/KV Lines	25,862,733
Reconductors & Upgrade Lines	9,950,945
Capacitor Banks	823,316
Miscellaneous Work Orders	2,383,965
	71,670,093
Total	**$222,281,846**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Jan-10				Feb-10				Mar-10			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000
CT's No 9 and 10	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822
CT's No 9 and 10 Start Up Costs	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	138,981,912	3,989,595	0	142,971,507	142,971,507	5,109,295	0	148,080,802	148,080,802	6,223,045	0	154,303,847
New CT Site Phases I-IV	4,150,200	2,106,500	0	6,256,700	6,256,700	2,106,500	0	8,363,200	8,363,200	2,106,500	0	10,469,700
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000
Unit 1 Water Wall Tubes	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000
Unit 1 Reheat Superheater	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200
Retrofit Air Pollution Project	17,542,088	9,355,879	0	26,897,967	26,897,967	9,355,879	0	36,253,846	36,253,846	9,355,879	0	45,609,725
Replace Unit 1 Reheater	0	0				0				0		
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	600,000	0	0	600,000	600,000	0	0	600,000	600,000	0	0	600,000
Start Up Costs	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541
Unit 4	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142
Unit 4 Ash Silos	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218
Construction Road Entrance	440,000	0	0	440,000	440,000	0	0	440,000	440,000	0	0	440,000
Construct Landfill Dam C	0	416,666	0	416,666	416,666	416,666	0	833,332	833,332	416,666	0	1,249,998
Additional Office Space	0	0	0	0	0	50,000	0	50,000	50,000	400,000	0	450,000
Landfill Gas:												
Wind Farm	0	3,798,335	0	3,798,335	3,798,335	3,798,335	0	7,596,670	7,596,670	3,798,335	0	11,395,005
Unknown Site No. 8	0	434,084	0	434,084	434,084	434,084	0	868,168	868,168	434,084	0	1,302,252
	995,525,369	20,101,059	0	1,015,626,428	1,015,626,428	21,270,759	0	1,036,897,187	1,036,897,187	22,734,509	0	1,059,631,696
Transmission Facilities:												
Station Upgrades	5,258,183	33,485	0	5,291,668	5,291,668	33,485	0	5,325,153	5,325,153	33,485	0	5,358,638
Breaker & Transmission Stations	16,364,625	342,175	0	16,706,800	16,706,800	342,175	0	17,048,975	17,048,975	342,175	0	17,391,150
Stations and Taps	12,462,349	412,284	0	12,874,633	12,874,633	412,284	0	13,286,917	13,286,917	412,284	0	13,699,201
69/138/161/345/KV Lines	47,745,845	239,801	0	47,985,646	47,985,646	239,801	0	48,225,447	48,225,447	239,801	0	48,465,248
Reconductors & Upgrade Lines	12,230,347	683,601	0	12,913,948	12,913,948	683,601	0	13,597,549	13,597,549	683,601	0	14,281,150
Capacitor Banks	823,316	67,511	0	890,827	890,827	67,511	0	958,338	958,338	67,511	0	1,025,849
Miscellaneous Work Orders	2,707,954	154,019	0	2,861,973	2,861,973	154,748	0	3,016,721	3,016,721	154,748	0	3,171,469
	97,592,619	1,932,876	0	99,525,495	99,525,495	1,933,605	0	101,459,100	101,459,100	1,933,605	0	103,392,705
Total	**$1,093,117,988**	**$22,033,935**	**$0**	**$1,115,151,923**	**$1,115,151,923**	**$23,204,364**	**$0**	**$1,138,356,287**	**$1,138,356,287**	**$24,668,114**	**$0**	**$1,163,024,401**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Apr-10				May-10				Jun-10			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000
CT's No 9 and 10	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822
CT's No 9 and 10 Start Up Costs	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	154,303,847	8,069,595	0	162,373,442	162,373,442	8,568,095	0	170,941,537	170,941,537	14,804,495	0	185,746,032
New CT Site Phases I-IV	10,469,700	2,106,500	0	12,576,200	12,576,200	2,106,500	0	14,682,700	14,682,700	2,106,500	0	16,789,200
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000
Unit 1 Water Wall Tubes	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000
Unit 1 Reheat Superheater	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200
Retrofit Air Pollution Project	45,609,725	9,355,879	0	54,965,604	54,965,604	9,355,879	0	64,321,483	64,321,483	9,355,879	0	73,677,362
Replace Unit 1 Reheater		0				0				0		
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	600,000	0	0	600,000	600,000	0	0	600,000	600,000	0	0	600,000
Start Up Costs	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541
Unit 4	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142
Unit 4 Ash Silos	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218
Construction Road Entrance	440,000	0	0	440,000	440,000	0	0	440,000	440,000	0	0	440,000
Construct Landfill Dam C	1,249,998	416,666	0	1,666,664	1,666,664	416,666	0	2,083,330	2,083,330	416,666	0	2,499,996
Additional Office Space	450,000	400,000	0	850,000	850,000	400,000	0	1,250,000	1,250,000	0	0	1,250,000
Landfill Gas:												
Wind Farm	11,395,005	3,798,335	0	15,193,340	15,193,340	3,798,335	0	18,991,675	18,991,675	3,798,335	0	22,790,010
Unknown Site No. 8	1,302,252	434,084	0	1,736,336	1,736,336	434,084	0	2,170,420	2,170,420	434,084	0	2,604,504
	1,059,631,696	24,581,059	0	1,084,212,755	1,084,212,755	25,079,559	0	1,109,292,314	1,109,292,314	30,915,959	0	1,140,208,273
Transmission Facilities:												
Station Upgrades	5,358,638	33,485	0	5,392,123	5,392,123	33,485	0	5,425,608	5,425,608	33,485	0	5,459,093
Breaker & Transmission Stations	17,391,150	342,175	0	17,733,325	17,733,325	342,175	0	18,075,500	18,075,500	342,175	0	18,417,675
Stations and Taps	13,699,201	412,284	0	14,111,485	14,111,485	412,284	0	14,523,769	14,523,769	412,284	0	14,936,053
69/138/161/345/KV Lines	48,465,248	239,801	0	48,705,049	48,705,049	239,801	0	48,944,850	48,944,850	239,801	0	49,184,651
Reconductors & Upgrade Lines	14,281,150	683,601	0	14,964,751	14,964,751	683,601	0	15,648,352	15,648,352	683,601	0	16,331,953
Capacitor Banks	1,025,849	67,511	0	1,093,360	1,093,360	67,511	0	1,160,871	1,160,871	67,511	0	1,228,382
Miscellaneous Work Orders	3,171,469	154,748	0	3,326,217	3,326,217	154,748	0	3,480,965	3,480,965	154,748	0	3,635,713
	103,392,705	1,933,605	0	105,326,310	105,326,310	1,933,605	0	107,259,915	107,259,915	1,933,605	0	109,193,520
Total	**$1,163,024,401**	**$26,514,664**	**$0**	**$1,189,539,065**	**$1,189,539,065**	**$27,013,164**	**$0**	**$1,216,552,229**	**$1,216,552,229**	**$32,849,564**	**$0**	**$1,249,401,793**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Jul-10				Aug-10				Sep-10			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000
CT's No 9 and 10	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822
CT's No 9 and 10 Start Up Costs	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	185,746,032	14,932,095	0	200,678,127	200,678,127	11,535,795	0	212,213,922	212,213,922	13,856,020	0	226,069,942
New CT Site Phases I-IV	16,789,200	2,106,500	0	18,895,700	18,895,700	2,106,500	0	21,002,200	21,002,200	2,106,500	0	23,108,700
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000
Unit 1 Water Wall Tubes	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000
Unit 1 Reheat Superheater	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200
Retrofit Air Pollution Project	73,677,362	9,355,879	0	83,033,241	83,033,241	9,355,879	0	92,389,120	92,389,120	9,355,879	0	101,744,999
Replace Unit 1 Reheater		0				0				0		
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	600,000	0	0	600,000	600,000	0	0	600,000	600,000	0	0	600,000
Start Up Costs	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541
Unit 4	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142
Unit 4 Ash Silos	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218
Construction Road Entrance	440,000	0	0	440,000	440,000	0	0	440,000	440,000	0	0	440,000
Construct Landfill Dam C	2,499,996	416,666	0	2,916,662	2,916,662	416,666	0	3,333,328	3,333,328	416,666	0	3,749,994
Additional Office Space	1,250,000	0	0	1,250,000	1,250,000	0	0	1,250,000	1,250,000	0	0	1,250,000
Landfill Gas:												
Wind Farm	22,790,010	3,798,335	0	26,588,345	26,588,345	3,798,335	0	30,386,680	30,386,680	3,798,335	0	34,185,015
Unknown Site No. 8	2,604,504	440,744	0	3,045,248	3,045,248	440,744	0	3,485,992	3,485,992	440,744	0	3,926,736
	1,140,208,273	31,050,219	0	1,171,258,492	1,171,258,492	27,653,919	0	1,198,912,411	1,198,912,411	29,974,144	0	1,228,886,555
Transmission Facilities:												
Station Upgrades	5,459,093	33,485	0	5,492,578	5,492,578	33,485	0	5,526,063	5,526,063	33,485	0	5,559,548
Breaker & Transmission Stations	18,417,675	342,175	0	18,759,850	18,759,850	342,175	0	19,102,025	19,102,025	342,175	0	19,444,200
Stations and Taps	14,936,053	412,284	0	15,348,337	15,348,337	412,284	0	15,760,621	15,760,621	412,284	0	16,172,905
69/138/161/345/KV Lines	49,184,651	239,801	0	49,424,452	49,424,452	239,801	0	49,664,253	49,664,253	239,801	0	49,904,054
Reconductors & Upgrade Lines	16,331,953	683,601	0	17,015,554	17,015,554	683,601	0	17,699,155	17,699,155	683,601	0	18,382,756
Capacitor Banks	1,228,382	67,511	0	1,295,893	1,295,893	67,511	0	1,363,404	1,363,404	67,511	0	1,430,915
Miscellaneous Work Orders	3,635,713	154,748	0	3,790,461	3,790,461	154,748	0	3,945,209	3,945,209	154,748	0	4,099,957
	109,193,520	1,933,605	0	111,127,125	111,127,125	1,933,605	0	113,060,730	113,060,730	1,933,605	0	114,994,335
Total	**$1,249,401,793**	**$32,983,824**	**$0**	**$1,282,385,617**	**$1,282,385,617**	**$29,587,524**	**$0**	**$1,311,973,141**	**$1,311,973,141**	**$31,907,749**	**$0**	**$1,343,880,890**

East Kentucky Power Cooperative

SUMMARY OF CAPITAL FUNDS AND CONSTRUCTION BUDGET FOR 2009 - 2011

ESTIMATED EXPENDITURES

Major Construction Projects	Oct-10				Nov-10				Dec-10			
	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.	Const. Beg. Bal.	Direct Costs	AFUDC	Ending Bal.
G&T Operations - Power Production												
J. K. Smith:												
New CT Project Consulting	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000	2,500,000	0	0	2,500,000
CT's No 9 and 10	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822	120,379,822	0	0	120,379,822
CT's No 9 and 10 Start Up Costs	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000	4,000,000	0	0	4,000,000
Unit 1	226,069,942	15,754,620	0	241,824,562	241,824,562	16,710,570	0	258,535,132	258,535,132	17,675,960	0	276,211,092
New CT Site Phases I-IV	23,108,700	2,106,500	0	25,215,200	25,215,200	2,106,500	0	27,321,700	27,321,700	2,106,500	0	29,428,200
Cooper Station:												
Unit 1 Primary Superheater Inlet Tubes	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000	2,342,000	0	0	2,342,000
Unit 1 Water Wall Tubes	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000	1,260,000	0	0	1,260,000
Unit 1 Reheat Superheater	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200	2,416,200	0	0	2,416,200
Retrofit Air Pollution Project	101,744,999	9,355,879	0	111,100,878	111,100,878	9,355,879	0	120,456,757	120,456,757	9,355,878	0	129,812,635
Replace Unit 1 Reheater		0				0				0		
Spurlock Station:												
Unit 1 Low Nox Boiler Modifications	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775	15,486,775	0	0	15,486,775
Replace Unit 1 #6 & #7 Feedwater Heaters	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471	2,279,471	0	0	2,279,471
Coal Unloading By-Pass Chutes	600,000	0	0	600,000	600,000	0	0	600,000	600,000	0	0	600,000
Start Up Costs	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000	8,348,000	0	0	8,348,000
Unit 1 Scrubber	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541	138,835,541	0	0	138,835,541
Unit 4	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142	527,452,142	0	0	527,452,142
Unit 4 Ash Silos	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218	8,511,218	0	0	8,511,218
Construction Road Entrance	440,000	0	0	440,000	440,000	0	0	440,000	440,000	0	0	440,000
Construct Landfill Dam C	3,749,994	416,668	0	4,166,662	4,166,662	416,669	0	4,583,331	4,583,331	416,669	0	5,000,000
Additional Office Space	1,250,000	0	0	1,250,000	1,250,000	0	0	1,250,000	1,250,000	0	0	1,250,000
Landfill Gas:												
Wind Farm	34,185,015	3,798,335	0	37,983,350	37,983,350	3,798,335	0	41,781,685	41,781,685	3,798,315	0	45,580,000
Unknown Site No. 8	3,926,736	440,744	0	4,367,480	4,367,480	440,764	0	4,808,244	4,808,244	440,756	0	5,249,000
	1,228,886,555	31,872,746	0	1,260,759,301	1,260,759,301	32,828,717	0	1,293,588,018	1,293,588,018	33,794,078	0	1,327,382,096
Transmission Facilities:												
Station Upgrades	5,559,548	33,485	0	5,593,033	5,593,033	33,485	0	5,626,518	5,626,518	33,485	0	5,660,003
Breaker & Transmission Stations	19,444,200	342,175	0	19,786,375	19,786,375	342,175	0	20,128,550	20,128,550	342,176	0	20,470,726
Stations and Taps	16,172,905	412,284	0	16,585,189	16,585,189	412,284	0	16,997,473	16,997,473	412,283	0	17,409,756
69/138/161/345/KV Lines	49,904,054	239,801	0	50,143,855	50,143,855	239,801	0	50,383,656	50,383,656	239,797	0	50,623,453
Reconductors & Upgrade Lines	18,382,756	683,601	0	19,066,357	19,066,357	692,265	0	19,758,622	19,758,622	692,264	0	20,450,886
Capacitor Banks	1,430,915	67,511	0	1,498,426	1,498,426	67,511	0	1,565,937	1,565,937	67,514	0	1,633,451
Miscellaneous Work Orders	4,099,957	154,748	0	4,254,705	4,254,705	154,748	0	4,409,453	4,409,453	155,476	0	4,564,929
	114,994,335	1,933,605	0	116,927,940	116,927,940	1,942,269	0	118,870,209	118,870,209	1,942,995	0	120,813,204
Total	**$1,343,880,890**	**$33,806,351**	**$0**	**$1,377,687,241**	**$1,377,687,241**	**$34,770,986**	**$0**	**$1,412,458,227**	**$1,412,458,227**	**$35,737,073**	**$0**	**$1,448,195,300**

Major Construction Projects	2010
G&T Operations - Power Production	
J. K. Smith:	
New CT Project Consulting	0
CT's No 9 and 10	0
CT's No 9 and 10 Start Up Costs	0
Unit 1	137,229,180
New CT Site Phases I-IV	25,278,000
Cooper Station:	
Unit 1 Primary Superheater Inlet Tubes	0
Unit 1 Water Wall Tubes	0
Unit 1 Reheat Superheater	0
Retrofit Air Pollution Project	112,270,547
Replace Unit 1 Reheater	
Spurlock Station:	
Unit 1 Low Nox Boiler Modifications	0
Replace Unit 1 #6 & #7 Feedwater Heaters	0
Coal Unloading By-Pass Chutes	0
Start Up Costs	0
Unit 1 Scrubber	0
Unit 4	0
Unit 4 Ash Silos	0
Construction Road Entrance	0
Construct Landfill Dam C	5,000,000
Additional Office Space	1,250,000
Landfill Gas:	
Wind Farm	45,580,000
Unknown Site No. 8	5,249,000
	331,856,727
Transmission Facilities:	
Station Upgrades	401,820
Breaker & Transmission Stations	4,106,101
Stations and Taps	4,947,407
69/138/161/345/KV Lines	2,877,608
Reconductors & Upgrade Lines	8,220,539
Capacitor Banks	810,135
Miscellaneous Work Orders	1,856,975
	23,220,585
Total	**$355,077,312**

EXHIBIT___(LK-3)

East Kentucky Power Cooperative, Inc.
Case No. 2008-00409
Effect of Discontinuing AFUDC

Source: Company's Response to KIUC 2-21 - Ending Balances of CWIP at the End of Each Month for these Projects

		May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Total	13-Month Average
J. K. Smith:																
New CT Project Consulting		1,041,665	1,249,998	1,458,331	1,666,664	1,874,997	2,083,330	2,291,663	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	26,666,648	2,051,281
Unit 1		132,863,533	133,125,258	133,802,983	135,174,708	135,606,433	136,008,158	137,262,533	138,981,912	142,971,507	148,080,802	154,303,847	162,373,442	170,941,537	1,861,496,651	143,192,050
New CT Site Phases I-IV		2,604,245	2,825,094	3,045,943	3,266,792	3,487,641	3,708,490	3,929,339	4,150,200	6,256,700	8,363,200	10,469,700	12,576,200	14,682,700	79,366,244	6,105,096
Cooper Station:																
Unit 1 Primary Superheater Inlet Tubes	(1)	475,000	475,000	475,000	475,000	950,000	950,000	2,342,000	0	0	0	0	0	0	6,142,000	472,462
Unit 1 Water Wall Tubes	(1)	240,000	240,000	240,000	240,000	240,000	240,000	1,260,000	0	0	0	0	0	0	2,700,000	207,692
Unit 1 Reheat Superheater	(1)	616,200	616,200	616,200	616,200	616,200	616,200	2,416,200	0	0	0	0	0	0	6,113,400	470,262
Retrofit Air Pollution Project		7,310,875	8,772,477	10,234,079	11,695,681	13,157,283	14,618,885	16,080,487	17,542,088	26,897,967	36,253,846	45,609,725	54,965,604	64,321,483	327,460,480	25,189,268
Spurlock Station:																
Unit 4 Ash Silos	(2)	5,143,868	5,985,698	6,827,528	7,669,358	8,511,218	0	0	0	0	0	0	0	0	34,137,670	2,625,975
Wind Farm		0	0	0	0	0	0	0	0	3,798,335	7,596,670	11,395,005	15,193,340	18,991,675	56,975,025	4,382,694
Unknown Site No. 8		0	0	0	0	0	0	0	0	434,084	868,168	1,302,252	1,736,336	2,170,420	6,511,260	500,866

Total 13-Month Average	185,197,644
Interest Rate	5.078%
	9,404,336
TIER	1.45
Effect of Discontinuing AFUDC	13,636,288

(1) - Balances from May 09 through Sept 09 used due to expected in-service date of October 1, 2009.
(2) - Balances from May 09 through Nov 09 used due to expected in-service date of December 1, 2009.

EXHIBIT___(LK-4)

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2008-00409

INFORMATION REQUEST RESPONSE

COMMISSION STAFF'S DATA REQUEST FROM INFORMAL CONFERENCE HELD ON NOVEMBER 13, 2008

REQUEST 2

RESPONSIBLE PERSON: **Frank J. Oliva**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 2. Provide a calculation of 2009 TIER and DSC with and without the $10.5 million in increased revenues estimated to be lost in April and May 2009 without the requested relief.

Response 2. The TIER and DSC projections, with and without the $10.5 million in increased revenues estimated to be lost in April and May 2009, are provided on page 2 of this response. These projections assume that EKPC is granted the full amount of the rate increase requested in this proceeding and assumes no other adverse events. However, as discussed on page 4, lines 11 and 12 of "Testimony of William Steven Seelye in Support of EKPC Motion to Create a Regulatory Asset," it is critical to note that EKPC's equity percentage is projected to be only 6.8 percent during April and May 2009, which is dangerously low. The impact on EKPC equity of the failure to recover the Spurlock 4 costs for April and May 2009 is the most important concern behind EKPC's request for relief.

East Kentucky Power Cooperative, Inc.
Projected TIER & DSC Calculations for year 2009

Rate Increase Effective 6-1-2009

For 2009: Mortgage Agreement and Credit Agreement Compliance Calculations

TIER	(a) Net Margins	39,239,363				
	(b) Interest on Long Term Debt	129,135,000				
	TIER = (a) + (b) / (b) =	168,374,363	/	129,135,000	=	**1.304**
DSC	(a) Depreciation	64,633,000				
	(b) Interest on L-T Debt	129,135,000				
	(c) Margins	39,239,363				
	(d) Interest + Principal	204,233,000				
	DSC = (a) + (b) + (c) / (d) =	**1.141**				

Rate Increase Effective 6-1-2009 Plus $10.5 Million of Revenue Estimated to Be Lost in April and May 2009

For 2009: Mortgage Agreement and Credit Agreement Compliance Calculations

TIER	(a) Net Margins	49,739,363				
	(b) Interest on Long Term Debt	129,135,000				
	TIER = (a) + (b) / (b) =	178,874,363	/	129,135,000	=	**1.385**
DSC	(a) Depreciation	64,633,000				
	(b) Interest on L-T Debt	129,135,000				
	(c) Margins	49,739,363				
	(d) Interest + Principal	204,233,000				
	DSC = (a) + (b) + (c) / (d) =	**1.192**				

EXHIBIT___(LK-5)

East Kentucky Power Cooperative, Inc.
Case No. 2008-00409
Additional Margin if AFUDC Was Accrued for January - May 2009

Source: Company's Response to KIUC 2-21 - Ending Balances of CWIP at the End of Each Month for these Projects

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Total
Total CWIP All Production Projects	864,868,278	887,722,848	910,572,290	936,258,013	946,420,961	
Less:						
Unit 1 Scrubber	129,355,466	133,478,491	136,601,516	138,725,541	138,780,541	
Unit 4	507,540,376	517,453,523	525,891,542	526,421,842	526,952,142	
Additional CWIP Production Projects	227,972,436	236,790,834	248,079,232	271,110,630	280,688,278	
Interest Rate	5.078%	5.078%	5.078%	5.078%	5.078%	
Annual AFUDC	11,576,440	12,024,239	12,597,463	13,766,998	14,253,351	
Monthly AFUDC	964,703	1,002,020	1,049,789	1,147,250	1,187,779	5,351,541
Interest on Long Term Debt - Source PSC Request 2, Page 2 of 2						129,135,000
Additional 2009 Projected Earned TIER Due to Addional AFUDC						0.041
2009 Projected Earned TIER Before Addition of AFUDC						1.304
2009 Projected Earned TIER With Additional AFUDC						1.345

EXHIBIT___(LK-6)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2008-00409
SECOND DATA REQUEST RESPONSE

COMMISSION STAFF'S SECOND DATA REQUEST DATED 12/16/08
REQUEST 39
RESPONSIBLE PERSON: Gary T. Crawford
COMPANY: East Kentucky Power Cooperative, Inc.

Request 39. Refer to page 2 under Tab 24 in Volume 3 of East Kentucky's application.

Request 39a. Provide a detailed description of the wind farm project which shows an estimated construction cost in 2010 of $45,580,000.

Response 39a. EKPC has been studying wind data in southeast Kentucky since 2003. At this time, no decision has been made as to whether EKPC will or will not develop a wind project. The dollars budgeted for 2010 are a placeholder for development of a 25 MW wind farm, if and when it can be justified.

Request 39b. Explain why wind farm generation is not included in the forecasted generation mix on page 7 of 11 under Tab 30 of the application for either 2010 or 2011.

Response 39b. As noted in response 39a, at this time a wind farm has not been justified or approved by EKPC.

EXHIBIT___(LK-7)

G&T OPERATIONS
PRODUCTION, LANDFILL GAS, ENVIRONMENTAL, AND CONSTRUCTION

THREE-YEAR

CONSTRUCTION WORK PLAN

2008 – 2010

(Capital Equipment and Projects)

December 10, 2007
Board Approval

Pending – RUS Approval

Distribution List:

John Twitchell/Judy Riddell	Bob Marshall	Jim Lamb	Stacy Barker
Gary Crawford/Pat McKay	David Eames	David Smart	Craig Johnson
Larry Morris/Diana Pulliam	Jerry Purvis	Ronnie Thomas	Kenny Carroll
Philip Berry	Charlie Leveridge	Mark Moneyhon	Jim Shipp
Richard Kieda	Tom Volz	Chris Pfeffer	Mary Jane Warner
Thea Kamber	Susan Mefford	Frank Oliva	Earl Ferguson

Susan Gill 12/10/07

Meager Number C405	Description	Cost Estimate (2007$)	Scheduled Date
Construction or Production			
Cooper Power Station:			
	ESP Modifications SCRs, Scrubbers, and New Stack For Units 1 & 2 Contract Labor - $242,000,000 Material - $242,000,000	$484,000,000	2009-2012

Need/Justification Comments

Scope: Installation of Emission Control Equipment

Justification: Installation of emission control equipment to meet environmental regulations and for consent decree compliance.

Environmental: New Source Review - Environmental

Contact Person: Charles Leveridge, Cooper Station
(606) 561-4138 ext. 211

EXHIBIT___(LK-8)

East Kentucky Power Cooperative, Inc.
Case No. 2008-00409
Effect of Removing CWIP in Rate Base for Smith CT's 9 and 10 from June 2009 through November 2009

Source: Company's Response to KIUC 2-21 - Ending Balances of CWIP at the End of Each Month for these Projects

	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Total	13-Month Average
CT's No 9 and 10	101,069,396	105,243,455	111,974,514	116,205,579	120,379,822	120,379,822	120,379,822		
CT's No 9 and 10 Start Up Costs	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000		
Total CWIP Smith CT's 9 and 10	105,069,396	109,243,455	115,974,514	120,205,579	124,379,822	124,379,822	124,379,822	823,632,410	63,356,339
Interest Rate									5.078%
									3,217,235
TIER									1.45
Effect of Removing CWIP in Rate Base for Smith CT's 9 and 10									4,664,991

EXHIBIT___(LK-9)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2008-00409
SECOND DATA REQUEST RESPONSE

COMMISSION STAFF'S SECOND DATA REQUEST DATED 12/16/08
REQUEST 42
RESPONSIBLE PERSON: Frank J. Oliva
COMPANY: East Kentucky Power Cooperative, Inc.

Request 42. Refer to Tab 54 in Volume 5 of East Kentucky's application, page 2 of 4 Explain the decrease in "Other Operating Revenue - Income" from $2.6 million in 2007 to $1.55 million in the base year to $399,000 in the forecasted test year.

Response 42. "Other Operating Revenue – Income" decreases from $2.6 million in 2007 to $1.55 million in the base year to $399,000 in the forecasted test year due to the non-budgeting of non-firm transmission revenue. EKPC plans to budget for this item in the future.

EXHIBIT___(LK-10)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2008-00409
RESPONSE TO SUPPLEMENTAL DATA REQUESTS

ATTORNEY GENERAL'S DATA REQUESTS DATED 1/23/09
REQUEST 15
RESPONSIBLE PERSON: Frank J. Oliva
COMPANY: East Kentucky Power Cooperative, Inc.

Request 15. Please refer to the response to PSC 2-42. Please explain the response more fully. For instance, if EKPC intends to budget for "Other Operating Income – Revenue" in the future, why did it not include those amounts in the test year?

Response 15. For the five years prior to 2006, non-firm transmission monthly revenue was inconsistent and relatively insignificant. Because of this uncertainty, the forecasted test year's revenue did not take into account the monthly revenue from non-firm transmission even though such revenue began to increase during the 2005-2006 timeframe. The revenue from this non-firm transmission has only recently become consistent enough to include in a future year's budget and will be included in future budget years.

EXHIBIT___(LK-11)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2008-00409
SECOND DATA REQUEST RESPONSE

KIUC'S SECOND DATA REQUEST DATED 1/23/09
REQUEST 7
RESPONSIBLE PERSON: **Frank J. Oliva**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 7. Please refer to the Company's response to PSC 2-42. Provide the amount of non-firm transmission revenue that should have been included in the Company's budget and forecasted test year projection of "Other Operating Revenue – Income."

Request 7. During the 2007 and 2008 timeframe, non-firm transmission revenue averaged approximately $1.9 million and $1.8 million, respectively.

EXHIBIT___(LK-12)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2008-00409
FIRST DATA REQUEST RESPONSE

KIUC'S FIRST DATA REQUEST DATED 12/15/08
REQUEST 37
RESPONSIBLE PERSON: **Craig A. Johnson**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 37. Please refer to pages 5-6 of Mr. Johnson's Direct Testimony.

Request 37a. Please describe how the Company budgets and forecasts the costs of forced outages. Please provide all data, assumptions, computations, and amounts in O&M expense included in the base year and forecast year for forced outage expense, excluding fuel and purchased power expenses.

Response 37a. Unrecovered EKPC forced outage costs have been $10.3 million for 2005, $5.3 million for 2006, and $3.6 million for 2007, an average of $6.4 million per year for the three-year period. In light of EKPC's financial condition and in view of the fact that forced outage costs would be unrecoverable through the Fuel Adjustment Clause, EKPC decided to estimate forced outage costs at the high end of the recent three-year trend. In developing EKPC's budget, therefore, this estimate was meant to reflect a reasonable level of forced outage costs in order to avoid overstating budgeted net margins for the year. As can be seen from the 2008 year-to-date forced outage cost of $12.3 million, the estimate of $10 million is reasonable.

Request 37b. Please provide the forced outage rates by unit assumed by the Company in the base year and in the forecast year.

<u>**Response 37b.**</u> No specific unit-by-unit forced outage rates were used to compute the projected forced outage budget.

<u>**Request 37c.**</u> Please provide a five year history of forced outage rates by generating unit.

<u>**Response 37c.**</u> A five year history of forced outage rates by generating unit is reflected below.

Plant	YTD 2008	2007	2006	2005	2004	2003
Dale 1	2.45%	4.47%	3.32%	3.40%	0.65%	1.27%
Dale 2	3.42%	2.62%	2.15%	1.08%	0.88%	2.57%
Dale 3	0.97%	5.63%	1.73%	1.64%	2.93%	3.49%
Dale 4	5.81%	4.10%	1.68%	1.08%	2.04%	2.67%
Cooper 1	1.14%	1.51%	1.57%	7.27%	0.97%	1.32%
Cooper 2	3.08%	1.57%	3.24%	1.83%	1.51%	2.74%
Spurlock 1	1.18%	0.07%	0.02%	0.09%	32.46%	1.14%
Spurlock 2	1.71%	1.37%	0.22%	0.23%	1.94%	4.95%
Gilbert	5.72%	0.33%	15.13%	11.34%		

EXHIBIT___(LK-13)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2008-00409
SECOND DATA REQUEST RESPONSE

KIUC'S SECOND DATA REQUEST DATED 1/23/09
REQUEST 5
RESPONSIBLE PERSON: **Craig A. Johnson/Ann F. Wood**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 5. Please refer to the Company's response to KIUC 1-37. Please provide the amount of purchased power costs associated with forced outages for each of the past ten years starting with 1999, the amount allowed in the FAC and the amount not allowed in the FAC.

Response 5. All purchased power costs associated with replacement power for forced outages are not allowed in the FAC. Please see the table below for annual amounts.

Annual Purchases Relating to Forced Outage

1999	830,274
2000	4,497,901
2001	2,605,644
2002	1,630,780
2003	10,050,993
2004	38,776,471
2005	8,215,449
2006	5,927,783
2007	4,647,902
2008	14,312,642

EXHIBIT___(LK-14)

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2008-00409

SECOND DATA REQUEST RESPONSE

KIUC'S SECOND DATA REQUEST DATED 1/23/09

REQUEST 23

RESPONSIBLE PERSON: **William Steven Seelye**

COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 23. Please refer to Seelye Exhibit 2, Schedule 1.18 and to his testimony regarding the proposed turbine overhaul costs on pages 19-20. Please provide the actual turbine overhaul expenses by generating unit for each of the last ten years.

Response 23. Please see the table on page 2 of this response.

	Year 1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Dale Unit #3									$2,687,759.44	$32,672.10
Dale Unit #4							$400,106.24	$2,903,261.91		
Cooper Unit #1		$2,803,037.96	$32,563.16	($30,970.56)						($2,557.25)
Cooper Unit #2					$2,742,319.33	$47,508.91				
Spurlock 1						$2,408,933.59	($35,033.23)			
Spurlock 2						$5,186.58			$116,048.61	$8,528,709.22