CASE NUMBER:

99-082
Filed 5-24-99

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MAY 24 1999
PUBLIC SERVICE COMMISSION

Via Hand Delivery

May 24, 1999

Hon. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40601

Re: Kentucky Industrial Utility Customers, Inc. v. Louisville Gas & Electric Company, Case No. 99-082:

and

Re: In The Matter Of: Application of Louisville Gas & Electric Company for Approval of an Alternative Method of Regulation Of Its Rates and Service, Case No. 98-426

Dear Ms. Helton:

Please find enclosed the original and ten copies of the Additional Direct Testimony of Richard A. Baudino and Lane Kollen on behalf of Kentucky Industrial Utility Customers, Inc. in the above-referenced matters. 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.
BOEHM, KURTZ & LOWRY

MLK/kew
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 regular U.S. mail (unless otherwise noted) to all parties on this 24th day of May, 1999.

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COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF	:	
LOUISVILLE GAS AND ELECTRIC COMPANY	:	CASE NO. 98-426
FOR APPROVAL OF AN ALTERNATIVE METHOD	:	
OF REGULATION OF ITS RATES AND SERVICE	:	
	:	
and	:	
	:	
KENTUCKY INDUSTRIAL UTILITY	:	
CUSTOMERS, INC	:	
	:	
Complainant	:	
v.	:	CASE NO. 99-082
	:	
LOUISVILLE GAS AND ELECTRIC COMPANY	:	
	:	
Defendant	:	

ADDITIONAL DIRECT TESTIMONY AND EXHIBITS

OF

RICHARD A. BAUDINO

AND

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA
MAY 1999

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF AN ALTERNATIVE METHOD OF REGULATION OF ITS RATES AND SERVICE	: : : :	CASE NO. 98-426

and

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. Complainant v. LOUISVILLE GAS & ELECTRIC COMPANY Defendant	: : : : : : : :	CASE NO. 99-082

ADDITIONAL DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF AN ALTERNATIVE METHOD OF REGULATION OF ITS RATES AND SERVICE	:	**CASE NO. 98-426**

and

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.	:	**CASE NO. 99-082**
Complainant	:	
v.	:	
LOUISVILLE GAS & ELECTRIC COMPANY	:	
Defendant	:	

ADDITIONAL DIRECT TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. Richard A. Baudino, J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 35 Glenlake Parkway, Suite 475, Atlanta, Georgia 30328.

Q. Are you the same Richard Baudino who submitted direct testimony in this proceeding on behalf of the Kentucky Industrial Utility Customers ("KIUC")?

A. Yes.

Q. **What is the purpose of your additional direct testimony in this proceeding?**

A. The purpose of my additional direct testimony is to update my cost of equity calculation with more recent data. I am sponsoring Exhibits ____(RAB-7) through ____(RAB-10) which provide the updates to my discounted cash flow ("DCF") analysis and my Capital Asset Pricing Model ("CAPM") analysis.

Q. **Are there any changes to your comparison group?**

A. Yes. I eliminated Northern States Power because of a recently announced merger.

Q. **What is the updated dividend yield for the group?**

A. Exhibit ____(RAB-7) shows that the updated six-month dividend yield for the comparison group is 4.64%.

Q. **What is your recommended growth rate range?**

A. My recommended growth rate range is now 4.40% to 5.20%. The updated growth rates are presented in Exhibit ____(RAB-8). The range encompasses the Value Line earnings and retention growth forecasts and the Institutional Brokers Estimate System ("IBES") earnings forecasts.

Q. **What is your updated DCF return on equity range?**

A. Exhibit ____(RAB-9) presents the updated DCF range, which is 9.14% to 9.96%, with a midpoint of 9.55%. This is slightly higher than the midpoint of 9.45% in my direct testimony.

Q. Please present your results for the CAPM analysis.

A. Updating the analysis results in a CAPM cost of equity range of 7.16% to 9.13%.

Q. Does this conclude your additional direct testimony in this proceeding?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF	:	
LOUISVILLE GAS AND ELECTRIC COMPANY	:	CASE NO. 98-426
FOR APPROVAL OF AN ALTERNATIVE METHOD	:	
OF REGULATION OF ITS RATES AND SERVICE	:	

and

KENTUCKY INDUSTRIAL UTILITY	:	
CUSTOMERS, INC.	:	CASE NO. 99-082
Complainant	:	
v.	:	
	:	
LOUISVILLE GAS & ELECTRIC COMPANY	:	
	:	
Defendant	:	

ADDITIONAL EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

MAY 1999

Exhibit ___(RAB-7)

LOUISVILLE GAS & ELECTRIC COMPANY
ELECTRIC UTILITY COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Nov '98	Dec '98	Jan '99	Feb '99	Mar '99	Apr '99
DPL	High Price ($)	20.500	21.750	22.000	19.000	19.313	17.875
	Low Price ($)	18.938	19.938	18.938	17.438	16.438	16.313
	Avg. Price ($)	19.719	20.844	20.469	18.219	17.875	17.094
	Dividend ($)	0.235	0.235	0.235	0.235	0.235	0.235
	Mo. Avg. Div.	4.77%	4.51%	4.59%	5.16%	5.26%	5.50%
	6 mos. Avg.	4.96%					
FPL Group	High Price ($)	64.750	64.938	61.938	55.438	58.125	57.563
	Low Price ($)	60.750	60.625	54.500	50.313	50.125	52.875
	Avg. Price ($)	62.750	62.781	58.219	52.875	54.125	55.219
	Dividend ($)	0.500	0.500	0.500	0.520	0.520	0.520
	Mo. Avg. Div.	3.19%	3.19%	3.44%	3.93%	3.84%	3.77%
	6 mos. Avg.	3.56%					
OGE Energy	High Price ($)	28.500	29.000	29.063	25.813	25.750	24.250
	Low Price ($)	26.250	27.313	25.313	23.625	22.563	21.813
	Avg. Price ($)	27.375	28.156	27.188	24.719	24.156	23.031
	Dividend ($)	0.333	0.333	0.333	0.333	0.333	0.333
	Mo. Avg. Div.	4.86%	4.72%	4.89%	5.38%	5.51%	5.77%
	6 mos. Avg.	5.19%					
SIGCorp	High Price ($)	36.875	35.750	36.125	32.625	29.563	29.000
	Low Price ($)	33.375	33.625	32.500	28.750	26.250	26.125
	Avg. Price ($)	35.125	34.688	34.313	30.688	27.906	27.563
	Dividend ($)	0.303	0.303	0.310	0.310	0.310	0.310
	Mo. Avg. Div.	3.44%	3.49%	3.61%	4.04%	4.44%	4.50%
	6 mos. Avg.	3.92%					
Wisconsin Energy	High Price ($)	32.125	31.875	31.563	26.875	27.375	26.875
	Low Price ($)	30.188	30.000	25.938	25.063	25.188	25.063
	Avg. Price ($)	31.156	30.938	28.750	25.969	26.281	25.969
	Dividend ($)	0.390	0.390	0.390	0.390	0.390	0.390
	Mo. Avg. Div.	5.01%	5.04%	5.43%	6.01%	5.94%	6.01%
	6 mos. Avg.	5.57%					
Group Dividend Yield, 6 Mo. Avg.		4.64%					

Source: Standard and Poor's Stock Guide, December 1998 through May 1999.

LOUISVILLE GAS & ELECTRIC COMPANY
ELECTRIC UTILITY COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) IBES	(4) Value Line B x R
DPL	1.25%	3.25%	5.00%	3.88%
FPL Group	3.71%	4.81%	6.00%	6.68%
OGE Energy	2.43%	6.06%	3.70%	6.40%
SIGCorp	2.66%	5.76%	4.30%	6.36%
Wisconsin Energy	2.33%	6.40%	3.10%	2.67%
Averages	2.48%	5.25%	4.42%	5.20%

Sources: Institutional Brokers Estimate System, May 1999 Earnings Reports
Value Line Investment Reports, March 12 and April 9, 1999

Value Line Projected Dividend Per Share Growth

Company	1998 DPS	Projected 02 - '04 DPS	Compound Growth Rate
DPL	$ 0.94	$ 1.00	1.25%
FPL Group	$ 2.00	$ 2.40	3.71%
OGE Energy	$ 1.33	$ 1.50	2.43%
SIGCorp	$ 1.21	$ 1.38	2.66%
Wisconsin Energy	$ 1.56	$ 1.75	2.33%
Average			2.48%

LOUISVILLE GAS & ELECTRIC COMPANY
ELECTRIC UTILITY COMPARISON GROUP
DCF Growth Rate Analysis

Value Line Projected Earnings Per Share Growth

Company	3-Year Avg. EPS	Projected 02 - '04 EPS	Compound Growth Rate
DPL	$ 1.20	$ 1.45	3.25%
FPL Group	$ 3.58	$ 4.75	4.81%
OGE Energy	$ 1.76	$ 2.50	6.06%
SIGCorp	$ 1.93	$ 2.70	5.76%
Wisconsin Energy	$ 1.65	$ 2.25	6.40%
Average			5.25%

Note: 1998 EPS is used in place of 3-year average for Wisconsin Energy.

Sustainable Growth Calculation

Company	Forecasted Payout Ratio	Forecasted Retention Ratio	Expected Return	Growth Rate
DPL	68.97%	31.03%	12.50%	3.88%
FPL Group	50.53%	49.47%	13.50%	6.68%
OGE Energy	60.00%	40.00%	16.00%	6.40%
SIGCorp	51.11%	48.89%	13.00%	6.36%
Wisconsin Energy	77.78%	22.22%	12.00%	2.67%
Average	61.68%	38.32%	13.40%	5.20%

Source: Data come from Value Line's 2002-2004 forecasts.

Exhibit ____(RAB-9)

RETURN ON EQUITY CALCULATION
COMPARISON GROUP

Dividend Yield	4.64%	4.64%
Growth Rate Range	4.40%	5.20%
Expected Dividend Yield	4.74%	4.76%
DCF Return on Equity	9.14%	9.96%
Midpoint of Range		9.55%

LOUISVILLE GAS AND ELECTRIC COMPANY
Capital Asset Pricing Model Analysis
Electric Utility Comparison Group Beta

30-Year Treasury Bond

Line No.		(1) S&P 500	(2) Value Line
1	Market Required Return Estimate		
2	Expected Dividend Yield	1.38%	1.58%
3	Expected Growth	7.50%	10.30%
4	Required Return	8.88%	11.88%
5	Risk-free Rate of Return, 30-Year Treasury Bond		
6	Average of Last Six Months	5.34%	5.34%
8	Risk Premium		
9	@ 6 Month Average RFR (Line 4 minus Line 6)	3.54%	6.54%
10	Comparison Group Beta	0.58	0.58
11	Comparison Group Beta * Risk Premium		
12	@ 6 Month Average RFR (Line 10 * Line 9)	2.05%	3.79%
13	CAPM Return on Equity		
14	@ 6 Month Average RFR (Line 12 plus Line 6)	7.39%	9.13%

5-Year Treasury Bond

Line No.		(1) S&P 500	(2) Value Line
1	Market Required Return Estimate		
2	Expected Dividend Yield	1.38%	1.58%
3	Expected Growth	7.50%	10.30%
4	Required Return	8.88%	11.88%
5	Risk-free Rate of Return, 5-Year Treasury Bond		
6	Average of Last Six Months	4.80%	4.80%
8	Risk Premium		
9	@ 6 Month Average RFR (Line 4 minus Line 6)	4.08%	7.08%
10	Comparison Group Beta	0.58	0.58
11	Comparison Group Beta * Risk Premium		
12	@ 6 Month Average RFR (Line 9 * Line 10)	2.37%	4.11%
13	CAPM Return on Equity		
14	@ 6 Month Average RFR (Line 12 plus Line 6)	7.16%	8.90%

LOUISVILLE GAS AND ELECTRIC COMPANY
Supporting Data for CAPM Analyses

S&P Dividend Yield Data:

	Avg. Yield
November 1998	1.43%
December 1998	1.37%
January 1999	1.31%
February 1999	1.32%
March 1999	1.30%
April 1999	1.24%
6 month average	1.33%

Source: S& P's Central Inquiry Unit

Value Screen III Growth Rate Data:

Forecasted Data:	
Earnings	14.10%
Book Value	11.90%
Dividends	4.90%
Average	10.30%

Source: Value Screen III, May 1999

Value Line Industrial Composite Data:

Forecasted Data:	
Earnings	11.50%
Dividends	8.00%
Retention Growth	15.00%
Average	11.50%

Source: Value Line Selection & Opinion, January 22, 1999.

30 Year Treasury Bond Data

	Avg. Yield
November 1998	5.23%
December 1998	5.09%
January 1999	5.18%
February 1999	5.40%
March 1999	5.58%
April 1999	5.56%
6 month average	5.34%

Source: Compuserve Data Base

5 Year Treasury Bond Data

	Avg. Yield
November 1998	4.50%
December 1998	4.53%
January 1999	4.61%
February 1999	4.94%
March 1999	5.16%
April 1999	5.07%
6 month average	4.80%

Source: Compuserve Data Base

Value Line Betas
Comparison Group:

DPL	0.65
FPL Group	0.55
OGE Energy	0.50
SIGCorp	0.65
Wisconsin Energy	0.55
Average	0.58

Source: Value Line Investment Reports, March 12 and April 9, 1999.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF AN ALTERNATIVE METHOD OF REGULATION OF ITS RATES AND SERVICE	: CASE NO. 98-426
and	
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC Complainant v. LOUISVILLE GAS AND ELECTRIC COMPANY Defendant	: CASE NO. 99-082

ADDITIONAL DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

MAY 1999

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF AN ALTERNATIVE METHOD OF REGULATION OF ITS RATES AND SERVICE	CASE NO. 98-426
and	
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC	
Complainant	
v.	CASE NO. 99-082
LOUISVILLE GAS AND ELECTRIC COMPANY	
Defendant	

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COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF AN ALTERNATIVE METHOD OF REGULATION OF ITS RATES AND SERVICE	:	CASE NO. 98-426
and	:	
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC	:	
Complainant	:	
v.	:	CASE NO. 99-082
LOUISVILLE GAS AND ELECTRIC COMPANY	:	
Defendant	:	

ADDITIONAL 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"), 35 Glenlake Parkway, Suite 475, Atlanta, Georgia 30328.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I previously filed Direct Testimony on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC") in this proceeding addressing the Company's overearnings and the necessity for a base revenue reduction.

Q. What is the purpose of your Additional Direct Testimony?

A. The purpose of this testimony is to update and refine the quantification of Louisville Gas and Electric Company's (the "Company" or "LGE") overearnings and the appropriate base revenue reduction.

Q. Please summarize your testimony.

A. The Company's base revenues should be reduced by $61.930 million, or $52.530 million more than the $9.400 million base revenue reduction that will be implemented on July 2, 1999 pursuant to the Commission's April 13, 1999 Order in this proceeding. The Company's ratemaking return on common for the test year 1998 is 16.1% compared to a required return of 9.55%. Thus, the Company's current base revenues are excessive and are not just, fair, and reasonable. The computations underlying my quantification of the base revenue reduction are summarized on my Exhibit___(LK-1).

Q. Please generally describe the changes that you made to the revenue requirement analysis in your Direct Testimony.

A. I utilized the same revenue requirement methodology, based upon the Commission's historic utilization of rate of return regulation. I updated the test year to the calendar year 1998 from the test year ending September 30, 1998 due to the availability of more detailed information provided by the Company in response to discovery. I relied upon the Company's supplemental response to Item 11 of the Commission's Order dated December 2, 1998, other responses to Commission Staff and KIUC discovery in this proceeding, and other publicly available information.

The Company proposed numerous proforma adjustments to the 1998 calendar year per books data. These adjustments were proposed in both the supplemental response to Item 11 of the Commission's Order dated December 2, 1998 and the response to PSC#4-LGE-11. I have accepted certain of these adjustments and included others of my own. In addition, I have rejected other proforma adjustments proposed by the Company. The following two sections of my testimony address the proformas that I have incorporated and those proposed by the Company that I have rejected.

Q. **Did you segregate the base, environmental surcharge ("ECR"), and fuel adjustment clause ("FAC") components of operating income?**

A. No. I assumed that the environmental surcharge cost of service would be incorporated into the base revenue requirement and then reset to zero concurrent with the effective date of the Commission's base revenue reduction in this proceeding. Net incremental environmental costs after that date would be recovered through the ECR. I assumed that FAC revenues were equal to recoverable fuel and purchased power expenses.

Q. **Did you update the rate of return on common equity reflected in your quantification?**

A. Yes. I utilized the updated 9.55% recommended by KIUC witness Mr. Baudino.

Q. **Are the results of your update for the test year 1998 significantly different than for the test year ending September 30, 1998 presented in your Direct Testimony?**

A. Yes. The base revenue reduction was significantly higher based upon the September 30, 1998 test year. This significant change is due primarily to the Company's computation of lower per books electric jurisdiction operating income for the calendar year 1998 compared to the test year ending September 30, 1998. Although I have reviewed the operating income components for the two test years, it is not clear if the Company's per books electric operating income for either period was incorrectly computed by the Company or whether there were nonrecurring revenue or expense items that were not identified by the Company for proforma adjustment purposes.

II. PROFORMA ADJUSTMENTS INCORPORATED

Q. Please identify the proforma adjustments that you have incorporated to the per books data for the calendar year 1998.

A. I have incorporated certain adjustments to operating income and to rate base. The adjustments that I have incorporated to operating income are as follows:

1. Increase revenues to eliminate provision for rate refund.

2. Increase revenues to reflect increase in customers and sales.

3. Increase revenues to reflect lost DSM decoupling revenues.

4. Increase O&M expense to reflect net retained shareholder savings from merger.

5. Reduce O&M expense to remove actual Year 2000 costs and replace with amortization over five years.

6. Reduce O&M expense to eliminate the limestone inventory writeoff at Trimble County.

7. Reduce O&M expense to reflect normalized storm damage.

The adjustments to rate base that I have incorporated are as follows:

1. Reduce rate base to eliminate cash working capital.

2. Reduce rate base to eliminate prepayments.

3. Reduce rate base to reflect customer deposits.

Q. Please explain why the Commission should eliminate the provision for rate refund.

A. The provision for rate refund is due entirely to the ECR refund booked by the Company in December 1998 related to the settlement of the retroactivity issue. The provision for rate refund is nonrecurring and represents a refund for periods back to 1994. It would be inappropriate to allow the Company to recover the effects of this ECR rate refund as a base revenue requirement. It should be noted that the Company also proposed this proforma adjustment as detailed in its supplemental response to Item 11 of the Commission's Order dated December 2, 1998.

Q. Please explain why the Commission should reflect an increase in revenues in order to annualize customer and sales growth during the test year.

A. The Company achieved customer and sales growth during the test year. However, the test year revenues reflect only one half of that growth going forward. For example, if the number of customers increased by 5% during the year, revenues would reflect only 2.5% of that growth on average. Consequently, the Commission should annualize the effects of the customer and sales growth in the computation of base and ECR revenues.

Q. Please describe how you quantified the increase in revenues in order to annualize customer and sales growth during the test year.

A. I determined the weighted average composite growth in customers and applied one half of that growth to the combined test year base and ECR revenues. I determined the weighting of customer growth for this purpose by the combined base and ECR revenues.

Q. Please explain why the Commission should reflect an increase to O&M expense in order to reflect net retained shareholder savings from the merger.

A. This proforma adjustment is necessary in order to provide the Company with its retained shareholder savings from the merger. Absent this adjustment, all merger savings would flow through to ratepayers. It should be noted that the Company proposed a similar adjustment in its supplemental response to Item 11 of the Commission's Order dated December 2, 1998.

Q. Please describe how you quantified the increase to O&M expense in order to reflect the net retained shareholder savings from the merger.

A. I utilized the first year net merger savings of $26.312 million quantified in the merger proceeding. I then allocated the net merger savings 47% to LGE and 53% to KU in accordance with the Merger Order. Finally, I quantified the net retained savings at 50% for the Company, also in accordance with the Merger Order.

Q. Please explain why the Commission should reflect a reduction to O&M expense in

order to remove actual Year 2000 costs and an amortization expense based upon a five year amortization period.

A. Year 2000 costs are nonrecurring. In addition, Year 2000 costs generally extend the useful lives of or otherwise enhance existing software and hardware applications. In some instances, Year 2000 costs replace existing software and hardware applications, thereby creating significant future value. Nevertheless, most Year 2000 costs must be expensed in accordance with generally accepted accounting principles for book accounting purposes. However, the Commission can and should treat these costs as assets with future value and require the Company to defer the costs and amortize them over an appropriate time period. It should be noted the Company also has proposed a similar Year 2000 proforma adjustment in its response to PSC#4-LGE-11 in this proceeding, although it proposed a three year amortization period.

Q. **Why is a five year amortization period for the Year 2000 costs appropriate?**

A. A five year amortization period is appropriate for several reasons. First, five years more closely parallels the merger surcredit period. The amortization period is a matter of judgment and should attempt to balance the effects on ratepayers with the Company's need to recover these costs. It would not be appropriate to set the base revenue requirement to recover these costs over one, two, three, or four years if the Commission does not reasonably anticipate another base rate proceeding within the next four years.

Second, software and hardware costs are commonly amortized or depreciated over five to ten year periods. The Company has provided no rationale for a three year amortization period.

Third, a five year amortization period provides the Company full recovery of its Year 2000 costs incurred during the test year, although these costs are nonrecurring and the Company already has recovered the costs through retained overearnings.

Q. Please explain why the Commission should reduce O&M expense to eliminate the limestone inventory writeoff at Trimble County.

A. This O&M expense was nonrecurring and should not be included in the base revenue requirement as a recurring expense. It should be noted that this proforma adjustment was proposed by the Company in response to PSC#4-LGE-11 in this proceeding.

Q. Please explain why the Commission should reduce O&M expense in order to reflect normalized storm damage.

A. The level of this O&M expense was abnormal during the test year. It is appropriate to normalize this expense to establish the base revenue requirement going forward. In order to normalize this expense, I have accepted the Company's quantification provided in response to PSC#4-LGE-11 in this proceeding.

Q. Did the Company provide a computation of rate base at December 31, 1998?

A. Yes. The Company provided a computation of rate base in response to the PSC#4-LGE-12. I utilized this computation of rate base as a starting point for my computation.

Q. Did you utilize rate base in the KIUC quantification of the Company's revenue requirement?

A. Instead of a return on rate base, I utilized the return on capitalization in accordance with the approach historically employed by the Commission. However, I utilized the rate base computations for the purpose of allocating the Company's capitalization between electric and gas operations.

Q. Please explain why the Commission should set cash working capital equal to zero.

A. First, the Company's claim for cash working capital is based upon the one-eighth formula developed by the FERC in the early part of this century, prior to the development and adoption of today's sophisticated cash management techniques and cash flow measurement capabilities. The one-eight formula ensures a positive cash working capital result regardless of the timing of the Company's actual cash flows and assumes that investors supply capital for cash working capital purposes.

Second, the FERC has recognized that the one-eighth formula no longer provides a reasonable quantification of cash working capital requirements. For gas pipeline utilities, FERC assumes that cash working capital is equal to zero unless a party can show differently through a lead-lag study. 18 CFR § 154.306.

Third, in my experience, it is unusual for an electric utility today to have a positive cash working capital requirement as measured through a properly performed cash lead/lag study. Perhaps understandably, the Company has not performed a cash lead/lag study to enable the Commission actually to quantify the negative amount representing customer supplied cash working capital. Nor has it performed such a study as affirmative evidence that it has a positive cash working capital requirement. In lieu of such a study, it would be reasonable simply to set cash working capital equal to zero for rate base purposes.

Q. Please explain why the Commission should set prepayments equal to zero.

A. The reason to set prepayments equal to zero is that the actual cash working capital is or should be sufficiently negative that it would exceed the Company's rate base claim for prepayments.

Q. Please explain why the customer deposits should be subtracted from rate base.

hA. Customer deposits typically are considered customer supplied capital.

III. PROFORMA ADJUSTMENTS REJECTED

Q. Please identify the proforma adjustments proposed by the Company that you have rejected.

A. I have rejected certain adjustments to operating income and capitalization proposed by the Company. The adjustments to operating income that I have rejected are as follows:

1. Increase to O&M expense for merger dispatch OATT.
2. Reduction to annual ECR revenues.
3. Reduction to revenues to reflect "normal" weather.
4. Increase to purchased power expense to reflect projected 1999 market prices.
5. Reduction of off-system sales margins to reflect historic levels.
6. Reduction to revenues to reflect hypothetical implementation of EPBR tariff in 1998.
7. Reduction to revenues to reflect EPBR rate reduction.

In addition, I have rejected the Company's adjustment to increase the common equity capitalization to reverse the effects of a writeoff of certain merger costs.

Q. Please explain why the Commission should reject the Company's proforma adjustment for merger dispatch OATT.

A. The merger dispatch savings inure to the benefit of the ratepayers in accordance with the Company's Application and the Commission's Merger Order in Case No. 97-300.

Q. Please explain why the Commission should reject the Company's adjustment to

reduce annual ECR revenues.

A. The KIUC quantification of the Company's revenue requirement is based upon combining the base and ECR revenue requirement for the test year and setting the initial ECR rate to zero on the effective date of the base revenue reduction. The integration of the base and ECR revenue requirement provides the Company full (and higher compared to the current ECR) recovery of its environmental costs. Thus, any deficiency in ECR recovery, represented in part by the Company's proforma adjustment to reduce annual ECR revenues, already is included in the KIUC recommendation. If the Company's adjustment is accepted, there will be a double recovery.

Q. Please explain why the Commission should reject the Company's proforma adjustment to reduce revenues to reflect "normal" weather.

A. First, the Commission historically has not adopted weather normalization adjustments for electric utilities. Clearly, the adoption of such an adjustment for the Company would be considered precedential in base revenue proceedings involving other utilities and in future proceedings involving the Company.

Second, the selection of data series and the development of the regression equations and other aspects of the methodologies are subject to considerable judgment. Consequently, a weather normalization adjustment is not a factual determination, but rather an assessment of opinions as to what constitutes "normal" weather for purposes of quantifying this ratemaking adjustment. In the broadest sense, there is disagreement among scientists regarding the extent of global warming, if any, and the duration and measurement of warming cycles. More specifically, the Company has performed its own computation of temperature normals in lieu of the NOAA computations.

Third, this proceeding is not conducive to a thorough assessment of alternative quantifications of this adjustment, if the Commission were to change its historic rejection of such adjustments for electric utilities. There are procedural limitations to the development of a comprehensive record on this issue.

Q. Please explain why the Commission should reject the Company's proposed adjustment to increase purchased power expense to reflect its projections of 1999 market prices.

A. First, this adjustment represents a selective single issue post test year adjustment. The Company adamantly has refused to provide 1999 budget information, alleging that to do so would violate federal securities laws. Yet, on this one issue, it understandably is willing to provide its projections of purchased power costs for 1999. Clearly, this adjustment is self-serving and inappropriate.

Second, the Company has assumed higher market prices for this adjustment, which would increase its revenue requirement, while also assuming lower market prices for its proposed off-system sales margins proforma adjustment. The Company's position is intractably ridiculous and should be rejected. If the Commission were to utilize historic purchased power costs for the Company, the proforma adjustment would be to significantly reduce purchased power costs. For example, purchased power costs were at a three year high in 1998 at $50.176 million compared to $17.229 million in 1997 and $16.626 million in 1996. A three year average of purchased power expense would result in a reduction to purchased power expense of $22.165 million.

Third, apparently the Company believes that "forward prices" will increase for purposes of its proposed purchased power adjustment, but that "forward prices" also will decrease according to its response to KIUC-3-12, a copy of which is attached as my Exhibit ____(LK-2).

Fourth, the Company's proforma adjustment to increase purchased power expense and thus the base revenue requirement is premised, at least in part, upon the assumed non-existence of the FAC. Historically, purchased power costs, to the extent they were shown to be purchased on an economic dispatch basis, were allowed recovery through the FAC. If the FAC remains in effect, then all or part of the higher purchased power costs, assuming there were higher costs, will be recoverable through the FAC.

Fifth, the Company's proforma adjustment is dependent upon the same level of purchases in 1999. There is no evidence to suggest that will be the case. In fact, there is virtually no probability that 1999 purchased power will be at the same levels as in 1998, since new CTs will be operational in 1999, loads will be different, fuel costs will be different, forced outages will be different, and the economics of market purchases will be different.

Q. Please explain why the Commission should reject the Company's proposed adjustment to reduce the off-system sales margins to hypothetical levels based upon historic margins.

A. First, this adjustment is conceptually absurd for the reasons discussed in conjunction with the Company's proposed purchased power adjustment. If the Company believes that market prices are increasing, then its off-system sales margins also should increase, not decline.

Second, this adjustment is an overt attempt to leverage into the future a higher retention of off-system sales margins. These off-system sales margins are possible largely because of the costs (investment and fixed operating) paid for by ratepayers through the base and ECR revenue requirements. Nevertheless, between base revenue proceedings, the Company is allowed to retain the entirety of off-system sales margins in excess of the levels reflected in the test year utilized in its last base revenue proceeding. Unfortunately, the Company apparently is not satisfied with that arrangement and now has proposed that the test year sales margins not be fully reflected in the revenue requirement. This proposed adjustment is inequitable, unfair, and unreasonable. The balance should not be tipped further toward the Company.

Third, it would be complete speculation at this time to adjust the test year level of off-system sales margins based upon the expectation that the Company's units may face extended outages to comply with the pending NOx regulations. The NOx regulations are being challenged in court, the state SIP-call is not due until September 1999, and affected sources have until May 2003 to install control measures (unless granted extensions so that the compliance date is delayed). The Company has not proposed a NOx compliance plan detailing which units will receive certain NOx control technology or when. The Commission certainly has not approved any such compliance plan. Therefore, the NOx rules cannot be the justification for a "known and measureable" change to the test year level of off-system sales margin. To the contrary, the resolution of that matter is uncertain.

Q. **Please explain why the Commission should reject the Company's proposed adjustment to reflect the hypothetical implementation of the EPBR tariff in 1998.**

A. First, the Commission should determine the base revenue requirement without consideration of the EPBR. Conceptually, the EPBR tariff is structured as a reward or penalty to the Company. It would be inappropriate to embed either a reward or penalty pursuant to the EPBR into base rates.

Second, the Company's adjustment would increase fuel costs in the test year compared to actual. The FCR component of the EPBR would have resulted in higher costs to ratepayers than the currently effective fuel adjustment clause. This fact illustrates the poor design and the detrimental impact of the FCR component of the Company's EPBR, if not the entirety of the EPBR.

Third, the Company's adjustment would result in a double recovery of the FCR reward both through base rates and the EPBR tariff. That double recovery should not be allowed.

Q. **Please explain why the Commission should reject the Company's proposed adjustment for the EPBR rate reduction.**

A. The Commission should first determine the Company's revenue requirement and the appropriate base revenue reduction absent consideration of the EPBR. It then can determine the necessary incremental adjustment to the rate reduction already in effect. In this manner, the rate reduction is not dependent upon the adoption of the EPBR, but rather upon the Company's cost of service.

Q. **Does this complete your Additional Direct Testimony?**

A. Yes.

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF REVENUE REQUIREMENT
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Unadjust Total LG&E	Unadjust Gas	Unadjust Electric	Adjust to Electric	Adusted Electric
Capitalization (1)	1,462,652	251,683	1,210,969	NA	1,210,969
Required Overall Rate of Return	7.43%	7.43%	7.43%	7.43%	7.43%
Required Operating Income	108,746	18,712	90,034	0	90,034
Per Books Operating Income	135,121	8,364	126,757	204	126,961
Operating Income Surplus	26,375	(10,348)	36,723	204	36,927
Revenue Surplus	44,233	(17,355)	61,588	342	61,930
Electric Revenues before Rate Reduction	850,054	191,545	658,509	2,937	661,446
Rate Reduction as % of Electric Revenues	5.20%	-9.06%	9.35%		9.36%
Return on Common Equity before Rate Reduction	13.29%	1.02%	15.84%		16.10%
Effect of 1% Change in ROE					9,451

Note 1: Capitalization utilized by Kentucky PSC in lieu of rate base. Approximately equal.

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF OPERATING INCOME
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Unadjust Total LG&E	Unadjust Gas	Unadjust Electric	Adjust to Electric		Adusted Electric
Operating Revenues						
Residential	326,905	113,429	213,476		(1),(2),(3)	213,476
Small (or Commercial)	117,192	40,888	76,304		(1),(2),(3)	76,304
Large (or Industrial)	219,992	11,969	208,023	1,724	(1),(2),(3)	209,747
Public Street and Highway Lighting	6,292	0	6,292	(3,287)	(1),(2),(3)	3,005
Other Sales to Public Authorities	57,667	8,884	48,783		(1),(2),(3)	48,783
Sales for Resale	108,060	8,720	99,340			99,340
Provision for Refund	(4,500)	0	(4,500)	4,500	(4)	0
Other Operating Revenues	18,446	7,655	10,791			10,791
Total Operating Revenues	850,054	191,545	658,509	2,937		661,446
Operating Expenses						
Fuel, Purchased Power, and Other Oper Exp	494,432	159,792	334,640	3,759	(5),(6)	338,399
Maintenance Expense	52,787	5,865	46,922			46,922
Depreciation and Amortization	93,178	13,312	79,866			79,866
Other Taxes	18,325	4,306	14,019			14,019
Federal and State Income Taxes	56,307	(94)	56,401	(1,026)	(7)	55,375
Other	(96)	0	(96)			(96)
Total Operating Expenses	714,933	183,181	531,752	2,733		534,485
Net Operating Income	135,121	8,364	126,757	204		126,961

Note 1: Annualization to year customers/sales levels.
Note 2: No annualization of merger surcredit revenues and no annualization of customers' savings.
Note 3: Discontinuation of DSM decoupling revenues.
Note 4: Provision for rate refund is due to the ECR settlement in December 1998.
Note 5: First year annual amount of LG&E net retained savings (projected by LG&E in merger proceeding as $26.312 million times 47% LG&E share times 50% retained share).
Note 6: Eliminate $.113 million writeoff of limestone inventory at Trimble Co. Eliminate Year 2000 costs of $0.945 million and include 1 year amortization (5 years) of $0.189 million. Reduce storm damage expense by $1.555 million to normalize based on ten year average.
Note 7: Tax effects of revenue and expense adjustments and interest synchronization.

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF COST OF CAPITAL
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Capital$ w/o ITC (1)	Capital% w/o ITC	COC w/o ITC (2)	Wtd COC w/o ITC	Capital $ with ITC
Long and Short Term Debt	626,800	44.96%	5.57%	2.50%	657,681
Preferred Equity	95,328	6.84%	4.79%	0.33%	100,025
Common Equity	671,846	48.20%	9.55%	4.60%	704,946
Total Capitalization without ITC	1,393,974			7.43%	
Investment Tax Credit	68,678				
Total Capitalization with ITC	1,462,652				1,462,652

Note 1: Capitalization amounts are for total Company and were provided by Company in supplemental response to Commission Question No. 11 part (c) attached to Commission Order dated December 2, 1998.

Note 2: Cost of debt and preferred were provided by Company in supplemental response to Commission Question No. 11 Question No. 11 part (c) attached to Commission Order dated December 2, 1998. Cost of common provided by KIUC witness Mr. Baudino.

LOUISVILLE GAS AND ELECTRIC COMPANY
SUMMARY OF RATE BASE
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Unadjust Total LG&E (1)	Unadjust Gas (1)	Unadjust Electric (1)	Adjust to Electric	Adusted Electric
Plant in Service	2,737,637	370,483	2,367,154	NA	2,367,154
CWIP	156,361	42,107	114,254	NA	114,254
Accumulated Depreciation	(1,144,123)	(142,822)	(1,001,301)	NA	(1,001,301)
Accumulated Deferred Inc Taxes and ITC (Net)	(318,038)	(34,083)	(283,955)	NA	(283,955)
Fuel Inventories	26,897	26,897	0	(2)	0
M&S Inventories	53,149	1,248	51,901	NA	51,901
Net Regulatory Assets/Liabilities	(39,164)	1,124	(40,288)	NA	(40,288)
Prepayments	1,872	431	1,441	(1,441)	
Cash Working Capital	46,394	4,971	41,423	(41,423)	
Customer Deposits	(7,050)	(1,588)	(5,462)	NA	(5,462)
Customer Advances	(10,847)	(10,127)	(720)	NA	(720)
Total Rate Base	1,503,088	258,641	1,244,447	(42,864)	1,201,583

Note 1: The unadjusted rate base amounts were provided by the Company in response to PSC#4-LGE-12 page 3. Detail for certain line items was obtained from the Company's supplemental response to Commission Question No. 11 part (c) attached to Commission Order dated December 2, 1998.

Note 2: Electric fuel inventories were included by Company as M&S in response to PSC#4-LGE-12.

Note 3: Cash working capital under a lead/lag methodology should be negative but unavailable from Company; set cash working capital equal to 0 and prepayments equal to 0.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY
CASE NOS. 98-426 AND 98-474

Response to KIUC's 3rd Data Request dated April 30, 1999

Question: KIUC#3-12 Responding Witness: Ronald L. Willhite

Q-12 Provide all documents, memoranda, and other written information to support the assertion that off-system sales are expected to decrease by 40% by 2001.

a) Explain how this forecast includes the added capacity available to KU and LG&E from the two 164 MW CT's currently being built at the Brown site.

b) Explain how this forecast includes the new all requirements sale by KU to the municipal electric system of Pitcarin, Pennsylvania.

A-12. Please see the response to AG Data Request No. 96.

a) The forecast levels of off-system sales include three major considerations: available capacity, native load, and the forward price curve. The CTs being built at the Brown site are included in off-system sales forecast simulations. As such, the CTs increase the amount of capacity available to KU and LG&E. However, the forecast for native load also increases over the period. The magnitude of the increase in native load is partially offset by the increase in available capacity provided by the CT addition. The third factor is the forward price curve, i.e., expected market prices for power for future time periods. Forward prices have a significant impact on the off-system sales forecast because those prices determine how much power may be sold on an economic basis. Data that represent the decline in forward prices is provided in the attached Question AG-16 in PSC Case No. 99-056.

b) The load requirements of the Borough of Pitcarin are included in the KU base load forecast. As such, the sale is included in the forecast for future off-system sales.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY
CASE NO. 99-056

Response to Attorney General's 1st Data Request Dated April 1, 1999

Question: AG-16 Responding Witness: James Kasey

Q-16. On page 9 of his testimony, Mr. Kasey provides January and February forward prices for the summer of 1999. Please provide the present forward prices for future months for power as far into the future as prices are available. For these prices please provide details of the type of power (ex. on-peak 5x16).

A-16. As of April 8, 1999, the following are the prices in $/MWh for 50 MW of On-Peak (5x16 excluding holidays) firm power with liquidated damages delivered into Cinergy with Seller's choice of interface. (Where two or more months are listed together, the months trade as a package for the same price per MWh.) These prices are subject to change on a daily basis.

Term	Bid ($/MWh)	Offer ($/MWh)
May 1999	26.00	26.30
Jun 1999	51.00	52.50
Jul & Aug 1999	104.00	110.00
Sep 1999	32.50	33.50
Q4 1999	24.00	24.40
Jan & Feb 2000	28.25	29.00
Mar 2000	23.25	24.50
Apr 2000	21.75	23.00
May 2000	25.50	26.25
Jun 2000	44.00	48.00
Jul & Aug 2000	80.00	86.00
Jul & Aug 2001	70.00	77.00