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PUBLIC SERVICE COMMISSION

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

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter.

Respectfully submitted,
JACK CONWAY
ATTORNEY GENERAL

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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Jeff Derouen, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

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250 W. Main St.
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Lexington, KY 40507

Hon. Michael L. Kurtz
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this 20th day of February, 2009

Lawrence W. Cook

Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

Direct Testimony of
Michael J. Majoros, Jr.

on Behalf of
the Office of the Attorney General

February 20, 2009

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I. Introduction

Q. Please state your name, position, and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. (Snavely King), located at 1111 14TH Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm, founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Our clients include government agencies, businesses and individuals that purchase public utility, telecom and transportation services.

The firm has a professional staff of eleven economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 39-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes, Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

II. <u>Purpose of Testimony</u>

Q. Explain the purpose of your testimony in this proceeding.

A. The Attorney General asked me to review East Kentucky Power Cooperative's ("EKPC" or, "the COOP") 2008 rate case filing. I am to express an opinion regarding the reasonableness of the COOP's proposals and, if warranted, make alternative recommendations.

III. <u>Prior Experience</u>

Q. Do you have any specific experience in the public utility field?

A. Yes, I have been in the field of public utility regulation since the late 1970s. My testimony has encompassed numerous complex revenue requirement issues. Furthermore, I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject before the regulatory commissions of almost every state in the country. I have testified on the subject of public utility regulation on many occasions before the Kentucky Public Service Commission ("PSC" or "Commission").

IV. <u>Summary of EKPC's Filing</u>

Q. Summarize EKPC's filing.

A. EKPC has requested an 8.1% or $71.6 million revenue increase.[1] The proposed revenue requirement is based on the difference between Mr. Seelye's adjusted net margin and the $44.4 million net margin required to achieve a 1.45 Times Interest Earned Ratio

[1] Note that the $71.6 million figure includes the amortization of the regulatory asset approved in Case No. 2008-00436. See response to AG 2-2.

("TIER").[2] The COOP's revenue requirement model reflects a fully-forecasted test-year ending May 31, 2010 with several pro forma adjustments to the test year budget figures to arrive at its $27.1 million adjusted net deficit.

V. <u>Summary of Snavely King Recommendations</u>

Q. What are the results of your investigation of the COOP's rate request?

A. Based on my investigation, I recommend that the COOP's base rates be increased by $40.1 million, as shown on Exhibit___(MJM-1) Schedule 1.

VI. <u>EKPC Rationalization of Increase</u>

Q. How does the COOP rationalize its requested revenue increase?

A. EKPC claims that it must increase its rates to address new expenses relating to the addition of Spurlock Station Unit No. 4, a new $528 million coal-fired generating unit scheduled to go into service on April 1, 2009. According to COOP witness Robert Marshall, "without rate relief, EKPC's interest and debt coverage ratio ("DSC") will be inadequate to meet the requirements set-forth in the mortgage and credit facility loan agreements after Spurlock 4 goes into commercial operation on April 1, 2009."[3] According to Mr. Marshall, "once Spurlock 4 is placed into commercial operation, EKPC will experience a significant increase in its non-fuel operation and maintenance expenses, depreciation expenses and current interest expenses."[4]

Q. What is EKPC's forecasted TIER for the test year absent the requested revenue increase?

[2] Direct testimony of William S. Seelye, p. 2. Note that due to timing issues between when EKPC's Board approved the rate increase request and the filing, the proposed $67.9 million increase is less than the actual increase calculated using the forecasted test year and proposed 1.45 TIER (Seelye, p. 6)

[3] Direct testimony of Robert Marshall, p. 4.

[4] Id.

A. EKPC forecasted a TIER of 0.941 if the COOP receives no rate relief.[5]

Q. What is the minimum TIER EKPC requires to meet its debt requirements?

A. According to Mr. Walker, the minimum TIER requirement per the debt covenant of EKPC's mortgage is 1.05 x interest expense.[6] Based on its $98.8 million of interest expense, this would indicate a minimum TIER requirement in this case of $4.9 million. EKPC is, however, requesting a TIER of 1.45 which yields a $44.4 million requirement.

Q. Has EKPC received some relief in meeting its debt covenant obligations since this case was filed?

A. Yes. EKPC recently received permission from the Commission to establish a regulatory asset to recover purchased power costs related to the COOP's 2008 forced outages that are not recoverable under the Fuel Adjustment Clause.[7] EKPC requested this regulatory asset to allow the COOP to meet the 2008 DSC ratio requirement contained in its Private Credit Facility Agreement.[8]

Q. Was the proposed regulatory asset reflected in the COOP's filing in this case?

A. No. The regulatory asset had not been granted when EKPC filed its rate case. However, the COOP has since provided the amounts necessary to reflect the amortization in its calculations.[9] It increases the revenue requirement by $0.1 million.

VII. <u>General Comments</u>

Q. Do you have any general comments concerning the COOP's filing?

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[5] Testimony of David Eames, p. 3.
[6] Walker page 13.
[7] Case No. 2008-00436, Order, issued December 23, 2008.
[8] Id., p. 4.
[9] See response to AG 2-2.

A. Yes. I am concerned about the COOP's management. Its O&M expenses are 23 percent higher than the national average. EKPC's 2007 total O&M cost per megawatt hour was $31.89, which was 23 percent higher than the national average of $25.83 per megawatt hour.[10] This is a considerable increase over the national average – given that in 2002 the COOP was only 2.2 percent above the national average. Furthermore, from 2002 to 2007 the national average increased 38 percent, while EKPC's O&M cost per MWh increased 67 percent.[11] For the first ten months of 2008 the cost per MWh increased to $36.33. Per the COOP's response to PSC Data Request No. 2-20, the COOP has not performed any analysis to determine why its O&M costs per MWh are so much higher than the national average. As EKPC builds out more capacity, its O&M cost rate should be improving, not trending higher as it has been.

I do not consider COOP rate cases to be the same as normal rate cases involving investor-owned utilities. That is because a COOP is ultimately owned by its ratepayers. Hence, in my opinion one of the objectives of rate case regulation should be to protect ratepayers from poor management. In my opinion, the situation I described above reflects questionable management at best.

If I were to adjust EKPC's O&M expenses to reflect this questionable management I would reduce them by approximately $26 million to correspond with the national average. However, to do so, would merely serve to cause deterioration of the TIER, which is also a sign of questionable management. Consequently, instead of

[10] Direct testimony of Craig Johnson, p. 7.
[11] See PSC Data Request No. 2-20.

proposing the adjustment, I recommend that O&M expenses be a significant item in the Management audit the Commission ordered in Case No. 2008-00436.

VIII. Proposed Adjustments

Q. Do you have individual adjustments to the COOP's filed cost of service?

A. Yes. I will discuss each adjustment below. My discussions will cite to any exhibits necessary for an understanding of the adjustments. However, all of the actual adjustments are incorporated as Schedules to Exhibit___ (MJM-1).[12]

A. Adjustment No. 1 – TIER

Q. Please explain Adjustment No.1.

A. Adjustment No. 1 removes $22.3 million of EKPC's requested margin requirement.

Q. Why have you made this adjustment?

A. As I explained earlier, EKPC has proposed a TIER of 1.45. I disagree with that TIER. That TIER will accomplish nothing more than to produce more internal cash flow available to offset inordinately high operating and maintenance expenses. The best way to achieve a TIER is to control operating and maintenance expenses, not enable them with additional internally generated cash flow. I recommend a 1.25 TIER which is halfway between the COOP's request and the minimum requirement.

B. Adjustment No. 2 – Depreciation Expense for New Combustion Turbines

Q. Please explain Adjustment No. 2.

A. Adjustment No. 2 removes three months of depreciation expense related to the two new combustion turbines ("CTs") – Smith Units 9 and 10.

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[12] No schedule has been provided for Adjustments Nos. 6 and 9 because they are simply reversals of Mr. Seelye's adjustments 1.17 and 1.18, respectively.

Q. Why have you made this adjustment?

A. In preparing its filing, EKPC assumed these CTs would be in service by September 1, 2009, and as such included nine months of depreciation in the cost of service calculation. However, the actual in-service date is now estimated to be December 1, 2009. Subsequently, I have removed the depreciation expense related to September, October and November, 2009.

Q. How did you calculate your adjustment?

Q. The COOP provided an amount of $1,019,880 in its response to KIUC Data Request No. 2-4. I have removed this amount from the cost of service.

C. Adjustment No. 3 – Purchased Power Assigned to Forced Outages

Q. Please explain Adjustment No. 3.

A. Adjustment No. 3 reduces the amount of purchased power assigned to forced outages.

Q. Why have you made this adjustment?

A. EKPC budgeted $10 million per year for purchased power assigned to forced outages. This is strictly a budgeted amount and is higher than any recent average amount.

Q. How did you make your adjustment?

A. Although the COOP has provided several different sets of numbers regarding purchased power assigned to forced outages, I have used the amounts provided in response to KIUC Data Request No. 2-5 to calculate the three-year average for 2006 through 2008. This amount was $8,296,109, as opposed to the COOP's budget estimate of $10 million. I believe my calculation is conservative. The amounts provided in KIUC 2-5 were higher than those provided in response to PSC 2-25, including the amount for 2008, which was higher than that approved by the Commission for regulatory asset treatment. My adjustment results in a $1.7 million reduction to the cost of service.

D. Adjustment No. 4 – Non-Firm Transmission Revenue

Q. Please explain Adjustment No. 4.

A. Adjustment No. 4 increases revenue to include an amount for non-firm transmission revenue.

Q. Why have you made this adjustment?

A. The amount of "Other Operating Revenue – Income" decreased from $2.6 million in 2007 to $1.55 million in the base year, to $399,000 in the test year. According to the response to Staff Data Request No. 2-42, this was due to the "non-budgeting of non-firm transmission revenue."[13] The response to AG 2-15 further clarifies the issue:

> "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.[14]

In my opinion, the fact that the revenue has stabilized and will be included in future years' budgets indicates that it is appropriate to include it in the budget in this rate case. Hence, I have made an adjustment.

Q. How did you calculate your adjustment?

A. Because the amount was not included in EKPC's test year budget, I had to come up with a suitable estimate. In its response to KIUC Data Request No. 2-7, EKPC states that

[13] See response to PSC 2-42.
[14] See response to AG 2-15.

"During the 2007 and 2008 timeframe, non-firm transmission revenue averaged approximately $1.9 million and $1.8 million, respectively."[15] As such, I have increased revenue by $1.9 million to account for non-firm transmission revenue. Although this is the 2007 amount, it is less than the $2.2 million difference between EKPC's 2008 "Other Revenue" of $2,589,338 and its test year budgeted amount of $400,000.[16]

E. <u>Adjustment No. 5 – Remove Merit Increase</u>

Q. Please explain Adjustment No. 5.

A. Adjustment No. 5 removes the impact of EKPC's budgeted 2010 merit increase from the forecasted test year cost of service.

Q. How much of a merit wage increase did the COOP include in its budget?

A. EKPC budgeted a 5 percent merit increase in 2009 and a 3 percent increase in 2010. In response to PSC Data Request No. 2-51 the COOP notes that the 3 percent estimate is "based on the economic downturn."[17] This increase has not yet been approved by EKPC's Board of Directors.[18]

Q. Has EKPC consistently paid wage increases?

A. No. In 2006 the COOP paid a general increase of 3 percent. In 2007 the compensation plan was modified to move to a merit-based increase, however, no increase was paid that year due to the financial condition of the COOP.[19] In 2008 the COOP budgeted 4.1 percent, but ultimately only paid 3.29 percent.[20]

[15] See response to KIUC 2-7.
[16] See response to PSC 3-13.
[17] See response to PSC 2-51.
[18] See response to PSC 3-16.
[19] See response to AG 1-54.
[20] See response to AG 2-10.

Q. Why do you believe the budgeted wage increase should be eliminated from the forecasted test year?

A. Given both the financial condition of EKPC and the current recession I do not believe it is appropriate to factor any wage increases for the forecasted test year. Furthermore, the increase has not yet been approved by the Board of Directors, and past experience has demonstrated that even though an increase might be budgeted, it is not necessarily paid.

Q. What is the amount of your adjustment?

A. I have removed $828,070 from the forecasted test year expenses. This is the amount EKPC provided in response to PSC Data Request No. 3-16 as the total amount of the increase included in the forecasted test year.

F. <u>Adjustment No. 6 – 2004 Forced Outage Amortization</u>

Q. Please explain Adjustment No. 6.

A. Adjustment No. 6 removes the impact of the COOP's proposed three-year amortization of its remaining 2004 Spurlock 1 forced outage expenses.

Q. Are you aware that the Commission authorized the amortization of these expenses in Case No. 2006-00472?

A. Yes, I am.

Q. Why have you made this adjustment?

A. Although the Commission allowed a certain amount of amortization in the last revenue requirement, it did not recognize a regulatory asset. Consequently, the COOP did not capitalize the losses. In this case, the inclusion of amortization in the revenue requirement merely serves to increase the revenue requirement. It was allowed once, and it is included in the current rates. The COOP should not make an amortization entry on its books and the amortization should not be allowed in rates.

Q. How much is the adjustment?

A. The adjustment removes Mr. Seelye's entire $3.4 million amount.

G. Adjustment No. 7 – Financial Software User Training

Q. Please explain Adjustment No.7.

A. Adjustment No. 7 removes the budgeted expense related to initial user training on a new financial software system.

Q. Why have you made this adjustment?

A. According to the response to PSC Data Request 3-1, this is a one-time expense. I do not believe it should be included in base rates.

Q. What is the amount of the adjustment?

A. The adjustment removes $381,000 from EKPC's forecasted test year expenses.[21]

H. Adjustment No. 8 – Wind Farm Depreciation

Q. Please explain Adjustment No.8.

A. Adjustment No. 8 removes the depreciation expense related to a potential wind farm.

Q. Why have you made this adjustment?

A. Per its response to PSC 3-10, EKPC has included $18,991,675 in construction costs related to a potential wind farm in its test year budget. In addition, the COOP included $133,372 in depreciation expense related to this potential wind farm.[22] However, its response to PSC Data Request No. 2-39 states, "At this time, no decision has been made

[21] See response to PSC 3-1c.
[22] See response to KIUC 2-2.

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."[23] This means that EKPC is requesting $133,372 in depreciation expense for a project that has not even reached the planning stage, much less been approved by the Board of Directors. Expenses related to this speculative project should not be included in EKPC's budget at this time.

Q. What is the amount of your adjustment related to this project?

A. I have removed $133,372 in depreciation expense from the test year cost of service.

I. Adjustment No. 9 – Normalization of Generation Overhaul Expenses

Q. Please explain Adjustment No. 9.

A. Adjustment No. 9 removes Mr. Seelye's adjustment to normalize generation overhaul expenses.

Q. Why have you made this adjustment?

A. Mr. Seelye increased generation overhaul expenses by $2.3 million to normalize the expense level based on the COOP's overhaul schedule. For steam plants he assumed an overhaul every 10 years and for CTs he assumed a six-year schedule.[24] The actual budgeted overhaul expense for the test year is $4.8 million, which is related to Cooper Unit 1 and Dale Units 1 and 2.[25] According to the response to KIUC Data Request No. 2-24, "These estimated costs were derived by analyzing historical costs and/or receiving a contractor's assessment of the required maintenance." In looking at Seelye Exhibit 2, Schedule 1.18, it appears that the estimates are simply rough estimates. I believe a more

[23] See response to PSC 2-39a.
[24] Seelye Direct, p. 19.
[25] Id.

appropriate amount to include in this rate case is the overhaul amount scheduled for the test year. The next set of overhauls is not scheduled until 2012, well outside the test year. Given the amount of construction the COOP is undergoing, I would expect the time between EKPC's rate cases to be relatively short. Therefore, the issue of generation overhaul expenses can be addressed again in the next rate case.

Q. What is the amount of your adjustment?

A. I have simply reversed Mr. Seelye's $2.3 million increase to generation overhaul expenses.

IX. <u>Summary</u>

Q. Please summarize your recommendations.

A. I have made 9 adjustments to the COOP's revenue requirement proposal. In summary, I have:

- Reduced the TIER from 1.45 to 1.25,
- Removed three months of improperly included depreciation related to the new CTs, the 2010 merit increase, a one-time expense related to employee training on financial software, and the depreciation expense related to the potential wind farm,
- Adjusted the amount of purchased power assigned to forced outages from a budgeted amount to a three-year average amount,
- Included non-firm transmission revenue, and
- Reversed Mr. Seelye's adjustments relating to the amortization of the 2004 forced outage balance, and the normalization of generation overhaul expenses.

Q. What is the impact of your adjustments?

A. My adjustments reduce EKPC's calculated revenue deficiency by $31.4 million. This results in a $40.1 million revenue increase.

Q. Does this conclude your testimony?

A. Yes, it does

EAST KENTUCKY POWER COOPERATIVE, INC.
Calculatic 'enue Requirement
Based oı ted Revenues and Expenses
For the 12 ... Period Ended May 31, 2010

Line	Description	Reference	Company Amount	SK Amount	Difference
1	**Total Operating Revenue & Patronage Capital Per Budget**	Eames Exhibit 1, Page 1, Line 8	$ 886,273,772	$ 886,273,772	
2					
3	Adjustments to Revenue:				
4	To Remove Fuel In Base Rates	Schedule 1.01	(350,719,383)	(350,719,383)	
5	To Remove Fuel Adjustment Clause Revenue	Schedule 1.01	(108,692,230)	(108,692,230)	
6	To Remove Environmental Surcharge Revenue	Eames Exhibit 1, Page 1, Line 3	(104,725,169)	(104,725,169)	
7	To Adjust Off-System Sales Environmental Surcharge Revenue	Schedule 1.02	(1,377,517)	(1,377,517)	
8	To Include Non-Firm Transmission Revenue	Exhibit (MJM-1), Schedule 5		1,900,000	$ 1,900,000
9	**Total Adjustments to Revenue**	Lines 4 through 8	(565,514,298)	(563,614,298)	1,900,000
10					
11	**Adjusted Revenue**	Line 1 + Line 9	$ 320,759,474	$ 322,659,474	$ 1,900,000
12					
13	**Total Cost of Service**	Eames Exhibit 1, Page 2, Line 26	$ 898,541,897	$ 898,541,897	
14					
15	Adjustments to Cost of Service:				
16	To Remove Fuel Expense Recoverable through the FAC	Schedule 1.01	$ (403,441,802)	$ (403,441,802)	
17	To Remove Purchased Power Expense Recoverable through the FAC	Schedule 1.03 / Exhibit MJM-1, Schedule 4	(54,242,370)	(55,946,261)	$ (1,703,891)
18	To Remove O&M Expenses Recoverable through the Environmental Surcharge	Schedule 1.04	(31,800,030)	(31,800,030)	
19	To Remove Emissions Allowance Expense Recoverable through the Environmental Surcharge	Schedule 1.05	(6,615,208)	(6,615,208)	
20	To Remove Property Taxes and Property Insurance Recoverable through the Environmental Surcharge	Schedule 1.06	(2,098,198)	(2,098,198)	
21	To Remove Depreciation Expenses Recoverable through the Environmental Surcharge	Schedule 1.07	(19,564,992)	(19,564,992)	
22	To Remove Interest Expenses Recoverable through the Environmental Surcharge	Schedule 1.08	(37,031,989)	(37,031,989)	
23	To Remove Promotional Advertising Expense pursuant to Commission Rule KAR 5:016	Schedule 1.09	(658,906)	(658,906)	
24	To Remove Certain Directors' Expenses	Schedule 1.10	(93,300)	(93,300)	
25	To Remove Donations	Schedule 1.11	(95,485)	(95,485)	
26	To Remove Affiliate Expenses	Schedule 1.12	(28,712)	(28,712)	
27	To Remove Lobbying Expenses	Schedule 1.13	(85,422)	(85,422)	
28	To Remove Touchstone Energy Dues	Schedule 1.14	(414,000)	(414,000)	
29	To Remove Other Miscellaneous Expenses	Schedule 1.15	(155,940)	(155,940)	
30	To Normalize Ratecase Expenses	Schedule 1.16	100,000	100,000	
31	Amortize 2004 Force Outage Balance	Schedule 1.17	3,419,058	-	$ (3,419,058)
32	To Normalize Generation Overhaul Expenses	Schedule 1.18	2,300,000	-	$ (2,300,000)
33	Amortize Net Unrecoverable Forced Outage Replacement Fuel Costs	Schedule 1.19 (Addendum, see AG 2.2)	4,100,399	4,100,399	
33	To Remove Three Months Depreciation Related to the New CTs	Exhibit (MJM-1), Schedule 3		(1,019,880)	$ (1,019,880)
34	To Remove Merit Increase	Exhibit (MJM-1), Schedule 6		(828,070)	$ (828,070)
35	To Remove Employee Financial Software Training	Exhibit (MJM-1), Schedule 7		(381,000)	$ (381,000)
36	To Remove Wind Farm Depreciation Expense	Exhibit (MJM-1), Schedule 8		(133,732)	$ (133,732)
37	**Total Adjustments to Cost of Service**	Lines 16 through 36	(546,406,898)	(556,192,528)	$ (9,785,631)
38					
39	**Adjusted Cost of Service**	Line 13 + Line 37	$ 352,134,999	$ 342,349,369	$ (9,785,631)
40					
41	**Adjusted Operating Margins**	Line 11 less Line 39	$ (31,375,525)	$ (19,689,895)	$ 11,685,631
42					
43	**Non-Operating Items**				
44	Interest Income	Eames Exhibit 1, Page 2, Line 32	$ 4,007,189	$ 4,007,189	
45	Other Non-Operating Income	Eames Exhibit 1, Page 2, Line 34	(27,912)	(27,912)	
46	Other Capital Credits/Patronage Dividends	Eames Exhibit 1, Page 2, Line 35	250,000	250,000	
47					
48	**Total Non-Operating Items**	Lines 39 through 41	$ 4,229,277	$ 4,229,277	
49					
50					
51	**Adjusted Net Margin (Deficit)**	Line 36 plus Line 43	$ (27,146,248)	$ (15,460,618)	
52					
53	**Calculation of Revenue Deficiency**				
54					
55	Adjusted Net Margin (Deficit)	Line 52	$ (27,146,248)	$ (15,460,618)	
56					
57	Interest on Long-Term Debt	Eames Exhibit 1, Page 2, Line 19 Less Line 22, Abc	$98,751,898	$98,751,898	
58					
59	Net Margin Requirement at 1.45 TIER (0.45 x Line 5)		$ 44,438,354		
60	Net Margin Requirement at 1.25 TIER (Exhibit___(MJM-1), Schedule 2)			$ 24,687,975	
61					
62	Revenue Deficiency (Line 7 - Line 3)		$ 71,584,602	$ 40,148,592	$ (31,436,010)

EAST KENTUCKY POWER COOPERATIVE, INC.

Adjustment to COOP's TIER

Line #	Description	Amount
1	Interest	$ 98,751,898
2	COOP Requested Margin at 1.45X	44,438,354
3	AG recommended Margin at 1.25X	24,687,975
4	Reduction to COOP Request	$ 19,750,380

EAST KENTUCKY POWER COOPERATIVE, INC.

Adjustment to Remove Three Months Depreciation Related to New CTs

	Amount
Three Months Depreciation related to Smith Units 9 and 10	$ (1,019,880)

Removes depreciation for September - November, 2009 improperly included in test year.

Source:
KIUC 2-4

Seelye Exhibit 2
Schedule 1.03
(Revised for SK Adjustment)

EAST KENTUCKY POWER COOPERATIVE, INC.
Adjustment to Remove Purchased Power Expense Recoverable Through the Fuel Adjustment Clause

		Total Purchased Power	Purchased Power Assigned to Forced Outages	Purchased Power Recoverable Through the FAC	SK Purchased Power Assigned to Forced Outages	SK Purchased Power Recoverable Through the FAC	Difference
June	2009	3,871,392	833,300	3,038,092	691,342	3,180,050	
July	2009	5,316,797	833,300	4,483,497	691,342	4,625,455	
August	2009	5,207,600	833,300	4,374,300	691,342	4,516,258	
September	2009	3,745,707	833,300	2,912,407	691,342	3,054,365	
October	2009	3,611,051	833,300	2,777,751	691,342	2,919,709	
November	2009	7,484,043	833,300	6,650,743	691,342	6,792,701	
December	2009	7,533,457	833,700	6,699,757	691,342	6,842,115	
January	2010	9,284,117	833,300	8,450,817	691,342	8,592,775	
February	2010	7,024,925	833,300	6,191,625	691,342	6,333,583	
March	2010	4,123,190	833,300	3,289,890	691,342	3,431,848	
April	2010	3,649,035	833,300	2,815,735	691,342	2,957,693	
May	2010	3,391,056	833,300	2,557,756	691,342	2,699,714	
Total		$ 64,242,370	$ 10,000,000	**$ 54,242,370**	8,296,109	55,946,261	1,703,891

Calculation of 3-Year Average 1/	
2006	5,927,783
2007	4,647,902
2008	14,312,642
3 Year Average	8,296,109

1/ Source: KIUC 2-5

EAST KENTUCKY POWER COOPERATIVE, INC.

Adjustment to Include Non-Firm Transmission Revenue

	Amount
Non-Firm Transmission Revenue to be included in test year	$ 1,900,000

Adds provision for non-firm transmission revenue, which EKPC intends to budget for in the future.

Source:
KIUC 2-7 (2007 amount)

EAST KENTUCKY POWER COOPERATIVE, INC.

Adjustment to Remove Test Year Merit Increase

	Amount
Merit Increase Included in Test Year	$ (828,070)

Removes impact of 3 percent budgeted merit increase.

Source:
PSC 3-16.

EAST KENTUCKY POWER COOPERATIVE, INC.

Adjustment to Remove Software Training Expense

		Amount
Non-recurring software training included in test year	$	(381,000)

Removes one-time financial software training expense.

Source:
PSC 3-1.

EAST KENTUCKY POWER COOPERATIVE, INC.

Adjustment to Remove Wind Farm Depreciation Expense

		Amount
Five Months Wind Farm Depreciation Expense	$	(133,732)

Removes depreciation expense for potential wind farm included in test year.

Source:
KIUC 2-2.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant -- Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. –
Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it?," American Water Works Association, Pre-Conference Workshop, March 25, 2008.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility

Federal Courts

2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority

State Legislatures

2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act

Federal Regulatory Agencies

1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

Michael J. Majoros, Jr.

1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

Michael J. Majoros, Jr.

1994	Iowa 6/	RPU-93-9	U.S. West -- Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech -- Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

Michael J. Majoros, Jr.

2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	34/ New Mexico Attorney General
2/ West Virginia Consumer Advocate	35/ Environmental Protection Agency Enforcement Staff
3/ Pennsylvania OCA	36/ Kentucky Attorney General
4/ Florida Office of Public Advocate	37/ North Dakota Public Service Commission
5/ Toms River Fire Commissioner's	38/ Kansas Industrial Group
6/ Iowa Office of Consumer Advocate	39/ City of Witchita
7/ D.C. People's Counsel	40/ Kansas Citizens' Utility Rate Board
8/ Maryland's People's Counsel	41/ NIPSCO Industrial Group
9/ Idaho Public Service Commission	42/ Hawaii Division of Consumer Advocacy
10/ Western Burglar and Fire Alarm	43/ Nevada Bureau of Consumer Protection
11/ U.S. Dept. of Defense	44/ GCI
12/ N.M. State Corporation Comm.	45/ Wisc. Citizens' Utility Rate Board
13/ City of Philadelphia	46/ Vermont Department of Public Service
14/ Resorts International	47/ Oklahoma Corporation Commission
15/ Woodlake Condominium Association	48/ National Assn. of State Utility Consumer Advocates
16/ Illinois Attorney General	49/ Nova Scotia Utility and Review Board
17/ Mass Coalition of Municipalities	50/ Florida Office of Public Counsel
18/ U.S. Department of Energy	51/ Maryland Public Service Commission
19/ Arizona Electric Power Corp.	52/ MCI
20/ Kansas Corporation Commission	53/ Transmission Agency of Northern California
21/ Public Service Comm. – Nevada	54/ Florida Industrial Power Users Group
22/ SC Dept. of Consumer Affairs	55/ Sierra Club
23/ Georgia Public Service Comm.	56/ Our Children's Earth Foundation
24/ Delaware Public Service Comm.	57/ National Parks Conservation Association, Inc.
25/ Conn. Ofc. Of Consumer Counsel	58/ Missouri Office of the Public Counsel
26/ Arizona Corp. Commission	59/ The Utility Reform Network
27/ AT&T	60/ Colorado Office of Consumer Counsel
28/ AT&T/MCI	61/ MD State Senator Paul G. Pinsky
29/ IN Office of Utility Consumer Counselor	62/ MD Speaker of the House Michael Busch
30/ Unitel (AT&T – Canada)	63/ Washington Office of Public Counsel
31/ Public Interest Advocacy Centre	64/ Industrial Customers of Northwestern Utilities
32/ U.S. General Services Administration	65/ Steering Committee of Cities
33/ Michigan Attorney General	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

AFFIDAVIT OF MICHAEL MAJOROS

District of Columbia)
)
)

Michael Majoros, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Michael Majoros

SUBSCRIBED AND SWORN to before me this 19th day of February, 2009.

NOTARY PUBLIC

My Commission Expires: March 14, 2011