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February 2, 2006

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HAND DELIVERED

Ms. Beth O'Donnell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
FEB 0 2 2006
PUBLIC SERVICE COMMISSION

RE: P.S.C. Case No. 2005-00341

Dear Ms. O'Donnell:

Please find enclosed and accept for filing the original and the required copies of the rebuttal testimony filed on behalf of Kentucky Power Company in this proceeding. By copy of this letter I am serving a copy of the rebuttal testimony on counsel for each party of record.

Sincerely yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

cc: Elizabeth E. Blackford
Michael L. Kurtz
Gardner F. Gillespie
Joe F. Childers
Frank F. Chuppe, Jr. (w/o enclosures)

KE057:KE180:13603:1:FRANKFORT

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) CASE NO. 2005 -00341

REBUTTAL TESTIMONY AND EXHIBITS

ON BEHALF OF

KENTUCKY POWER COMPANY

February 2, 2006

BARTSCH, J.B.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF KENTUCKY	)	CASE NO. 2005-00341
POWER COMPANY	)	

REBUTTAL TESTIMONY

OF

JEFFREY B BARTSCH

ON BEHALF OF KENTUCKY POWER COMPANY

February 2, 2006

REBUTTAL TESTIMONY OF
JEFFREY B. BARTSCH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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

A. My name is Jeffrey B. Bartsch. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am the Director of Tax Accounting and Regulatory Support for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent company of Kentucky Power Company (KPCo).

Q. Please briefly describe your educational background and business experience.

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1979. I am an inactive Certified Public Accountant and have been licensed in Ohio since 1981. I am also a member of the American Institute of Certified Public Accountants. I was first employed by Arthur Andersen & Co. in 1979 in the Audit section where I was assigned to various clients, including those in the electric utility industry. In 1985, I accepted a position with the Tax Department at AEPSC. Since that time I have held various positions until June 2000 when I was promoted to my current position.

Q. What are your responsibilities?

A. As Director of Tax Accounting and Regulatory Support, my responsibilities include oversight of the recording of the tax accounting entries and records of AEP and its subsidiaries, including KPCo. I am also responsible for coordinating the development of Federal tax data to be provided by the AEPSC Tax Department in regulatory proceedings. I have attended numerous tax, accounting and regulatory seminars throughout my professional career.

Q. Have you previously testified in any regulatory proceeding?

A. Yes. I have filed testimony before the Public Utilities Commission of Ohio on behalf of Columbus Southern Power Company and Ohio Power Company; with the Michigan Public Service Commission on behalf of Indiana Michigan Power Company; with the Public Service Commission of West Virginia on behalf of Appalachian Power Company and Wheeling Power Company; and have testified before the Public Utility Commission of Texas on behalf of AEP Texas Central Company. Like KPCo these companies are all AEP operating companies.

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

A. The purpose of my testimony in this proceeding is to address the Direct Testimony of Mr. Lane Kollen with regards to the IRC Section 199 Manufacturing Deduction.

Q. How does Mr. Kollen propose to calculate the Section 199 manufacturing deduction for purposes of this proceeding?

A. Mr. Kollen proposes to treat the Section 199 deduction as a tax rate reduction, which he then employs in the development of the Gross Revenue Conversion Factor (GRCF). He then applies this Production GRCF to a hypothetical production capitalization amount.

Q. Do you agree with this approach?

A. No. Mr. Kollen's calculation assumes that the return on production capitalization will approximate the production taxable income which would be used in calculating the

Section 199 manufacturing deduction. The two are not necessarily identical.

Q. Do you believe that the Section 199 deduction should be included in this rate filing as a rate reduction?

A. No. I believe that the Section 199 deduction should be included as a special deduction in the tax calculations as part of the tax component of cost of service, not as a rate reduction.

Q. What is the Company's position on how the Section 199 deduction should be treated in this rate proceeding?

A. Because of the complexities in calculating the Section 199 deduction, and because the IRS has yet to issue final regulations on the deduction, the Company is willing at this time to accept the previous treatment of this deduction by the Commission – which adopts Mr. Kollen's approach. In taking this position, the Company reserves the right to reassert its position on this issue in future proceedings (1) in the event that the actual Section 199 deduction results in a revenue effect different from that produced by the tax rate approach; or (2) in the event that a judicial ruling rejects the current PSC methodology.

Q. Does this conclude your rebuttal testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Jeffrey B. Bartsch, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Jeffrey B. Bartsch

Subscribed and sworn to before me by Jeffrey B. Bartsch this 1st day of February, 2006.

Notary Public

PAULINE A. LUTZ
NOTARY PUBLIC - STATE OF OHIO
MY COMMISSION EXPIRES SEPTEMBER 12, 2006

My Commission Expires ______________

BETHEL, D. [illegible]

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE COMMISSION

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

REBUTTAL TESTIMONY

OF

DENNIS W. BETHEL

ON BEHALF OF
KENTUCKY POWER COMPANY

February 2, 2006

INDEX TO REBUTTAL TESTIMONY OF
DENNIS W. BETHEL
CASE NO. 2005-00341

I. Introduction and Purpose of Rebuttal Testimony

Q. Please state your name and business address.

A. My name is Dennis W. Bethel. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by American Electric Power Service Corporation ("AEPSC" or "AEP"), as Managing Director – Regulated Tariffs. I previously provided Prepared Direct Testimony in this proceeding.

Q. What is the purpose of your Rebuttal Testimony?

A. I will respond to the recommendations of Mr. Robert J. Henkes on behalf of the Kentucky Attorney General, and Witnesses Mr. Lane Kollen and Stephen J. Baron on behalf of the Kentucky Industrial Utility Customers regarding their recommendations as to certain adjustments that I sponsor.

II. Testimony of Mr. Robert Henkes for Kentucky Attorney General

Q. Do you agree with the Attorney General's Witness Robert J. Henkes regarding your adjustments for network and point-to-point transmission in service?

A. No. I do not agree with his testimony relating to these adjustments.

Q. Please respond to the testimony of A.G. Witness Robert Henkes regarding the network and point-to-point transmission service revenue adjustments that you sponsor?

A. Mr. Henkes recommends that the Commission reject my two transmission revenue adjustments on the basis that the underlying information is not known and measurable or indicative of the revenues that are likely during the period that the rates to be set in this case will be effective. Mr. Henkes is mistaken.

First, the AEP zone network and point-to-point transmission rates that I used in my adjustments are identical to those approved by the FERC in its Order in Docket No. ER05-751-000 issued on December 20, 2005. I have included with this testimony a new exhibit, Rebuttal Exhibit DWB-1, consisting of copies of relevant PJM Open Access Transmission Tariff ("OATT") pages showing, in Black-line format, the revisions to AEP Zone transmission charges accepted by the FERC in that Order. When I developed the revenue estimates for this case, a Settlement in Principle had been reached in that FERC case, but because the settlement negotiations were confidential, I could not then reveal why I believed the rates were those that should be relied on. Now that the FERC has approved the Settlement, I can attest that the rates are known and measurable, and that Rebuttal Exhibit DWB-1 accurately shows the approved rates.

Second, as to network transmission service, it was necessary to estimate the network billing demands, but they are also now known for all of 2006. In PJM, network service billing demands are based on the single highest coincident peak of the prior twelve-month period ended October 31. The 2006 network billing demands were recently determined for 2006, and are reasonably close to those I estimated. The approved rates for network transmission service in the

AEP Zone are contained in Attachment H-14 of the PJM OATT, starting on Third Revised Sheet No. 314B in Rebuttal Exhibit DWB-1.

Third, the amount of transmission service revenue that AEP receives from PJM for point-to-point service depends on the rates PJM charges and the amount of such service that PJM customers reserve. There are two types of PJM point-to-point service that produce revenues for AEP, in-zone service, where the point-of-delivery ("POD") is in the AEP zone, and Border service, where the POD is at an external PJM interface, other than the Midwest ISO ("MISO"). PJM does not charge for Border service to MISO, pursuant to an Order of the FERC eliminating such charges between PJM and MISO. PJM's Border rate was known when my adjustments were made, and has not changed. The Border rates can be seen on PJM OATT Tenth Revised Sheet No. 247 in Rebuttal Exhibit DWB-1. The rates for AEP in-zone point-to-point service were set by the same settlement I have already discussed, so they also are known and measurable. The rates for PJM AEP Zone point-to-point transmission service can be seen on Fifth Revised Sheet No. 245.01, for firm service, and Tenth Revised Sheet No. 247 for non-firm service.

In summary, contrary to the testimony of Mr. Henkes, my estimates of network and point-to-point transmission revenues were based on information that is known and measurable and likely to be indicative of transmission revenues that will materialize when the rates to be set in this case are in effect.

Q. Have you prepared an update of your Exhibit DWB-1 reflecting revisions to the billing units for network and point-to-point transmission service?

A. Yes. Attached to this testimony is a Revised Exhibit DWB-1. The Revised Exhibit supports transmission revenues slightly higher than those originally reflected in the case, based on now known network billing determinants, and more recent experience with point-to-point service quantities in PJM. I submit that the revised results reflected in that Revised Exhibit support the validity of the adjustments that I originally filed, because the changes are small in comparison to the test year amounts.

Q. Is there any other problem with Mr. Henkes' recommendation for rejection of your adjustments to test year transmission revenues?

A. Yes. Seams Elimination Cost/Charge Allocations/Adjustments, or "SECA" revenues were the largest component of KPCo's test year transmission revenues. When FERC issued its Order eliminating through-and-out ("T&O") charges between PJM and MISO, it implemented the SECA charges as a temporary lost revenue mitigation measure. The SECA charges apply only during a transition period that ends March 31, 2006. As of April this year, KPC's transmission service revenues will decrease precipitously. Mr. Henkes' recommendation ignores this known and measurable event, and would result in a gross overstatement of the level of transmission revenues that KPCo can presently be expected to receive from PJM during the period that the rates to be set in this case will be effective.

Q. Mr. Henkes claims at page 44, lines 12-14, of his Direct Testimony that "the post-SECA revenue loss could be completely offset if AEP's pending PJM

rate design proposal in FERC Docket No. EL05-121-000 is approved". How do you respond?

A. Mr. Henkes' prediction of the potential outcome of this case at this early stage, before a hearing has even occurred, is based on unsupported speculation and ignores the pleadings currently filed in this proceeding. First, Mr. Henkes is wrong about AEP's proposal completely offsetting the lost T&O revenues. The highway/byway proposal made by AEP and Allegheny Power Company would, if approved without change, replace about 70% of the T&O revenues AEP had previously earned in the PJM and MISO region. Second, Baltimore Gas and Electric Company has proposed a competing highway-byway design that would replace about 1/3 of the revenue AEP now receives from SECA. Finally, thirteen of the sixteen PJM transmission owners oppose any change in PJM's so-called modified License Plate rate design. Clearly, in contrast to the known and measure transmission revenue adjustments that I have made and continue to support, any adjustment to revenues for regional rate design would be premature and speculative.

III. Testimony of Mr. Lane Kollen and Stephen J. Baron for KIUC

Q. Have you reviewed the testimony of Mr. Lane Kollen on behalf of the Kentucky Industrial Utility Customers, the KIUC?

A. Yes I have. Mr. Kollen recommends rejection of RTO formation cost amortization, and my adjustment to reduce KPCo's cost amortization by the net proceeds to KPCo from the RTO formation cost recovery rate approved by the FERC.

Q. What is your response to Mr. Kollen's testimony?

A. Mr. Kollen is mistaken. By his own rationale, my adjustment should be accepted by the KPSC. Although Mr. Kollen admits that the FERC gave the AEP Companies accounting authority to defer the costs, he nevertheless opines at page 38 lines 12-13 that "the FERC's authority for ratemaking purposes does not extend to retail ratemaking unless there is a federal rate." In fact, there is a federal rate. In its order in Docket No. ER05-751-000 issued on December 20, 2005, the FERC approved a rate of $8.60/MW-Month to be charged to all network transmission billing demand in the AEP zone effective April 1, 2006 to collect the AEP Companies' deferred RTO formation costs. The "federal rate" for RTO formation cost recovery can be seen in Rebuttal Exhibit DWB-1 at footnote 5 of Sixth Revised Sheet No. 245A, continued on Original Sheet No. 245B, for firm point-to-point service, footnote 7 of Second Revised Sheet No. 247.01, continued on First Revised Sheet No. 247A, for non-firm point-to-point service, and section 1.b. of Attachment H-14, Third Revised Sheet No. 314B, and Original Sheet No. 314B.01, for network service in the AEP Zone of PJM.

Attached to this testimony is a Revised Exhibit DWB-3 that calculates the net RTO Formation expense that KPCo may be expected to experience during the period that the rates to be set in this proceeding will be effective. The Revised Exhibit DWB-3 uses the federal rate for RTO Formation Cost recovery that will be effective on April 1, 2006, and the 2006 network transmission billing demands for the AEP zone that I have already discussed.

Q. Have you also reviewed the Direct Testimony of Mr. Stephen J. Baron in this case on behalf of the KIUC?

A. Yes I have.

Q. How do you respond to Mr. Baron's suggestion that if the KPSC approves transmission revenue adjustments in this case, they should reflect the step 3 transmission rates for the AEP Zone of PJM that are to become effective following the completion of the Wyoming-Jacksons Ferry 765 kV transmission project being constructed by Kentucky affiliate Appalachian Power Company or APCo?

A. I disagree with Mr. Baron. I have two problems with that recommendation. First, the step 3 rates that will apply after the new 765 kV line enters service are known, but the date that the rates will apply is not fixed. The effective date is specified as the later of August 1, 2006 and the first day of the month next following the month that the line enters service. If AEP is able to bring the line in on the present schedule the effective date will be August 1, 2006, otherwise it will be later. Given the litigious fifteen year history of this project I would not assume that completion of the project is now completely in AEP's hands.

The other problem I have with Mr. Baron's recommendation has to do with fairness. It would be unfair to measure KPCo's transmission revenues reflecting rates that include an allowance for the Wyoming-Jacksons Ferry projects' estimated cost unless an adjustment is also made to reduce KPCo's net proceeds under the AEP Transmission Equalization Agreement for the addition of the cost of the project to APCo's transmission investment. KPCo did not make either of these adjustments because the final cost of the line is not certain, the in-service date is not known, but it is projected to be a year or more beyond the end of the test year in this case.

IV. Revised Exhibits DWB-1 and DWB-3

Q. Please describe how your Revised Exhibit DWB-1 compare to the exhibit filed with your Direct Testimony in this case.

A. Revised Exhibit DWB-1, page 1 of 2, supports point-to-point transmission service revenues of $490,339 on a going-forward basis for KPCo. That amount is $29,878 more than my original calculation. As I have already discussed, the underlying rates have not changed, but AEP's additional experience with PJM from July 2005 through November 2005 supports this change. The Revised Exhibit also reflects the most recent forecast of KPCo's monthly member load ratio in the AEP Pool, and revised PJM allocation shares reflecting the higher AEP transmission revenue requirement approved in December 2005.

Revised Exhibit DWB-1, page 2 of 2, supports going-forward network transmission service revenues of $4,760,660 for KPCo. That amount is $319,255 higher than the amount originally calculated, reflecting the higher than expected summer 2005 peak demand, as well as the most recent MLR projections for KPCo. Overall, the amended transmission revenue calculations shown in Revised Exhibit DWB-1 are $349,133 or 7.1% higher than I originally supported. Most of this change is attributable to the higher than expected 2005 AEP Zone network peak demand that resulted in higher billing demands for 2006.

Q. How does your Revised Exhibit DWB-3 compare to the RTO Formation Cost adjustment exhibit filed with your Direct Testimony in this case?

A. Revised Exhibit DWB-3 supports an annualized net cost of $121,608 for KPCo, compared to the $122,544 net cost originally filed, a change of less than 1%. The KPCo amortization amount originally projected has not changed, but the slightly reduced net expense reflects marginally higher net revenues that KPCo will receive from the RTO Formation rate approved by FERC in December.

Q. Does that complete your rebuttal testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

DENNIS W. BETHEL, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Dennis W. Bethel

WITNESS NAME

Subscribed and sworn to before me by Dennis W. Bethel this 1st day of February, 2006.

Notary Public
FRANKLIN COUNTY

NOTARIAL SEAL
STATE OF OHIO

MANMOHAN K. SACHDEVA
Notary Public, State of Ohio
My Commission Expires 05-18-08

My Commission Expires 05-18-08

Rebuttal Exhibit DWB-1

PJM Tariff Sheets Showing Selected AEP Rates

PJM Tariff Revisions for AEP Zone Showing Changes

in Point-to-Point Transmission Service Schedules 7 and 8

And Attachment H-14

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone [5/]	~~17.040~~	~~1.420~~	~~0.3268~~	~~0.0654~~	~~0.0467~~
Nov 1, 2005	12.97272	1.08106	0.24948	0.04990	0.03564
SECA Ended	19.45680	1.62140	0.37417	0.07483	0.05345
W-JF Line In	21.08880	1.75740	0.40555	0.08111	0.05794
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone	12.79297	1.06608	0.24602	0.04920	0.03505

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 8 below to determine the actual charge to the Transmission Customer.

4/ In addition to other rates set forth in this schedule, pursuant to the Commission's November 10, 2003 Order in Docket No. ER03-1335 (Commonwealth Edison Company, 105 FERC ¶ 61,186 (2003) and the Settlement Agreement in that same docket, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,253,787, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2005-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,253,787 and calculate any credits or surcharges that would be needed to ensure that $1,253,787 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2005-2014, consistent with the above methodology.

5/ Pursuant to the Commission's Order Approving Settlement Agreement in Docket No. ER05-751, the rates in this Service Schedule, for service in the AEP Zone, will be increased in three steps, as of the following effective dates: (1) November 1, 2005, (2) April 1, 2006 or the date that Seams Elimination Cost Allocation charges, pursuant to Docket Nos. EL04-135-000, *et al.* end, and (3) August 1, 2006 or the first day of the next calendar month after the Wyoming-Jacksons Ferry 765 kV transmission project enters service, if later. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2014. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2015.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone, (iv) revenues distributed to the AEP Zone for Transmission Enhancement charges to other PJM Zones pursuant to Schedule 12, and (v) revenues and charges, as applicable under a PJM or expanded regional transmission rate design, if such is implemented after the effective date of this provision. The sum of these revenue credits and potential charges will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1] Charge ($/kW)	Daily Off-Peak[2] Charge ($/kW)	Hourly On-Peak[3] Charge ($/MWh)	Hourly Off-Peak[4] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone	1.876	0.4328	0.0866	0.0618	5.4	2.58
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	2.676	0.6176	0.1235	0.0882	7.7	3.67
ComEd Zone[5]	1.017[6]	0.2346	0.0469	0.0334	2.9	1.39
AEP East Zone[7]	~~1.420~~	~~0.3268~~	~~0.0654~~	~~0.0467~~	~~4.09~~	~~1.95~~
Nov. 1, 2005	1.08106	0.24948	0.04990	0.03564	3.12	2.08
SECA Ended	1.62140	0.37417	0.07483	0.05345	4.68	3.12
W-JF Line In	1.75740	0.40555	0.08111	0.05794	5.07	3.38

Dayton Zone	1.306	0.3014	0.0603	0.0431	3.77	1.79
Duquesne Zone	1.18	0.27	0.0540	0.0386	3.38	1.61
Dominion Zone	1.06608	0.24602	0.04920	0.03505	3.08	1.46

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ In addition to the other rates set forth in this schedule, pursuant to the Commission's November 10, 2003 Order in Docket No. ER03-1335 (Commonwealth Edison Company, 105 FERC ¶ 61,186 (2003) and the Settlement Agreement in that same docket, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,253,787, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2005-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,253,787 and calculate any credits or surcharges that would be needed to ensure that $1,253,787 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2005-2014, consistent with the above methodology.

7/ Pursuant to the Commission's Order Approving Settlement Agreement in Docket No. ER05-751, the rates in this Service Schedule, for service in the AEP Zone, will be increased in three steps, as of the following effective dates: (1) November 1, 2005, (2) April 1, 2006 or the date that Seams Elimination Cost Allocation charges, pursuant to Docket Nos. EL04-135-000, *et al.* end, and (3) August 1, 2006 or the first day of the next calendar month after the Wyoming-Jacksons Ferry 765 kV transmission project enters service, if later. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

~~Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;~~

~~Monthly Rate - $/kW/month, = Annual Rate divided by 12;~~

~~Weekly Rate - $/kW/week = Annual Rate divided by 52;~~

~~Daily Rate - $/kW/day = Weekly Rate divided by 5.~~

~~For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:~~

~~In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2014. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2015.~~

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

ATTACHMENT H-14

Annual Transmission Rates – AEP East Operating Companies
For Network Integration Transmission Service

1. The annual transmission revenue requirement is $~~349,712,000~~449,425,402 and the corresponding rate for Network Integration Transmission Service is $~~1031.31~~1,621.40/MW-month~~, provided, however, that for October and November, 2004 the monthly charges applicable to service to each existing Network Customer in the AEP Zone will be the lower of the charge pursuant to this Attachment H-14 or the charge that would have been applicable under AEP's OATT if that tariff had continued to apply.~~. Effective upon the later of August 1, 2006 or the first day of the next month after the new Wyoming – Jackson's Ferry 765 kV transmission project enters service, the transmission revenue requirement and the corresponding rate for Network Integration Transmission Service shall be $487,562,419 and $1,757.40/MW-month.

   Through March 31, 2006, Seams Elimination Cost Allocation ("SECA") Revenues are to be collected by AEP from entities outside the AEP Zone, subject to hearing and potential refund or surcharge in Docket Nos. EL04-135-000, *et al.* The first rate specified above will be become effective upon expiration the SECA revenues. Until such expiration, the rate for Network Integration Transmission Service will be $1,081.06/MW-month.

   a. **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone, (iv) revenues distributed to the AEP Zone for Transmission Enhancement charges to other PJM Zones pursuant to Schedule 12, and (v) revenues and charges, as applicable under a PJM or expanded regional transmission rate design, if such is implemented after the effective date of this provision. The sum of these revenue credits and potential charges will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

   b. Pursuant to the Commission's Order Approving Settlement Agreement in Docket No. ER05-751, the rates in this Service Schedule, for service in the AEP Zone, will be increased in three steps, as of the following effective dates: (1) November 1, 2005, (2) April 1, 2006 or the date that Seams Elimination Cost Allocation charges, pursuant to Docket Nos. EL04-135-000, *et al.* end, and (3) August 1, 2006 or the first day of the next calendar month after the Wyoming-Jacksons Ferry 765 kV transmission project enters service, if later. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2014. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2015.

2. Within the AEP Zone, a Network Customer's peak load shall be adjusted to include transmission losses equal to 3.3% of energy received for transmission (3.413% at delivery) as well as any applicable distribution losses as reflected in applicable state tariffs and/or service agreements that contain specific distribution loss factors for said Network Customer. Notwithstanding section 15.7 of the Tariff the transmission loss factor of 3.3% also shall apply to point-to-point transmission service with a point of delivery in the AEP Zone.

3. The rate in section 1 of this Attachment shall be effective until amended by the Transmission Owner(s) within the zone or modified by the Commission.

4. In addition to the rate set forth in section (1) above, the Network Customer purchasing Network Integration transmission Service shall pay for transmission congestion charges, and any other applicable charges, in accordance with the provisions of this Tariff, and any amounts necessary to reimburse the Transmission Owners for ay amounts payable to them as sales, excise, "btu," carbon, value-added, or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

5. Contract Demand Network Service provision;

(a) Contract Demand Network Service: Generally, the net output of any generating capacity operated by the Network Customer behind the meter(s) for any Delivery Point(s) in the AEP Zone, at the time of the Transmission Provider's Monthly Transmission System Peak Load, will be added to the load measured at the Delivery Point (adjusted for losses), in order to determine the Network Customer's Network Load. The foregoing

Kentucky Power Company
Point-to-Point Transmission Revenues at Going Level
Projected Post-SECA and Revised AEP OATT Rate Increase Effective 4/1/06

	DESCRIPTION	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	
1	**Actual PTP Rev Credits to AEP Zone**							
2	PJM Non-Firm PTP with POD in AEP Zone	$ 35,611	$ 3,849	$ 3,600	$ 16,235	$ 20,079	$ 31,480	
3	PJM Firm PTP with POD in AEP Zone	$ 1,420	$ 1,420	$ 1,420	$ 1,420	$ 1,467	$ 16,789	
4	In-Zone PTP Revenue Received (L2+L3)	$ 37,031	$ 5,269	$ 5,020	$ 17,655	$ 21,545	$ 48,269	
5	PJM Firm PTP (Border Revenues)	$ 441,985	$ 277,755	$ 269,002	$ 224,128	$ 225,417	$ 224,635	
6	PJM Non-Firm PTP (Border Revenues)	$ 232,472	$ 191,831	$ 250,913	$ 240,584	$ 250,054	$ 246,622	
7	Border PTP Revenue Received (L5+L6)	$ 674,457	$ 469,586	$ 519,915	$ 464,712	$ 475,472	$ 471,257	
8	Actual PTP Revenue Credits Jan - Jul 205	$ 711,488	$ 474,855	$ 524,935	$ 482,367	$ 497,017	$ 519,526	
9	Actual % of PJM Border Revenue To AEP	21.02106%	21.02106%	21.02106%	21.02106%	19.22946%	19.22946%	
10	% of Border Revenue To AEP after Nov 1, 2005	22.99932%	22.99932%	22.99932%	22.99932%	22.99932%	22.99932%	
11	**Actual PTP Rev Credits to AEP Zone**	**Jul-05**	**Aug-05**	**Sep-05**	**Oct-05**	**Nov-05**	**Dec-05 est.**	**2005 Total**
12	PJM Non-Firm PTP with POD in AEP Zone	$ 30,742	$ 33,179	$ 16,604	$ 38,559	$ 29,532	$ 29,532	$ 289,001
13	PJM Firm PTP with POD in AEP Zone	$ 5,541	$ 1,420	$ 1,420	$ 1,420	$ 1,081	$ 1,081	$ 35,898
14	In-Zone PTP Revenue Received (L2+L3)	$ 36,282	$ 34,599	$ 18,024	$ 39,979	$ 30,613	$ 30,613	$ 324,900
15	PJM Firm PTP (Border Revenues)	$ 336,636	$ 368,126	$ 222,094	$ 232,089	$ 212,016	$ 212,016	$ 3,245,900
16	PJM Non-Firm PTP (Border Revenues)	$ 266,849	$ 296,039	$ 303,451	$ 309,605	$ 331,666	$ 331,666	$ 3,251,751
17	Border PTP Revenue Received (L5+L6)	$ 603,486	$ 664,165	$ 525,545	$ 541,694	$ 543,682	$ 543,682	$ 6,497,651
18	Actual PTP Revenue Credits Jan - Jul 205	$ 639,768	$ 698,764	$ 543,569	$ 581,673	$ 574,295	$ 574,295	$ 6,822,551
19	Actual % of PJM Border Revenue To AEP	19.22946%	18.85883%	18.85883%	18.85883%	22.99932%	22.99932%	
20	% of Border Revenue To AEP after Nov 1, 2005	22.99932%	22.99932%	22.99932%	22.99932%	22.99932%	22.99932%	
21	**Projected PTP Rev Credits to AEP Zone**	**Jan-06**	**Feb-06**	**Mar-06**	**Apr-06**	**May-06**	**Jun-06**	
22	PJM Non-Firm PTP with POD in AEP Zone	$ 40,662	$ 4,395	$ 4,111	$ 18,537	$ 22,926	$ 35,945	
23	PJM Firm PTP with POD in AEP Zone	$ 1,621	$ 1,621	$ 1,621	$ 1,621	$ 1,675	$ 19,170	
24	**In-Zone PTP Revenue at Revised PTP Rate**	$ 42,283	$ 6,016	$ 5,732	$ 20,159	$ 24,601	$ 55,115	
25	PJM Firm PTP (Border Revenues)	$ 483,580	$ 303,894	$ 294,317	$ 245,220	$ 269,609	$ 268,674	
26	PJM Non-Firm PTP (Border Revenues)	$ 254,349	$ 209,883	$ 274,526	$ 263,225	$ 299,077	$ 294,971	
27	**Border PTP Revenue with Revised Rev. Req.**	$ 737,929	$ 513,778	$ 568,843	$ 508,446	$ 568,686	$ 563,645	
28	**Going-Level AEP Zone PTP Rev @ Revised Rates**	$ 780,212	$ 519,794	$ 574,575	$ 528,604	$ 593,287	$ 618,760	
29	AEP LSE Percentage	86%	86%	86%	86%	86%	86%	
30	**AEP LSE Portion of Zonal PTP Revenue**	$ 669,721	$ 446,183	$ 493,206	$ 453,745	$ 509,268	$ 531,134	
31	**KPCo MLR ****	**0.07456**	**0.07228**	**0.07228**	**0.07228**	**0.07228**	**0.07228**	
32	**KPCo PTP Revenue Share**	**$ 49,934**	**$ 32,250**	**$ 35,649**	**$ 32,797**	**$ 36,810**	**$ 38,390**	
33	**Projected PTP Rev Credits to AEP Zone**	**Jul-06**	**Aug-06**	**Sep-06**	**Oct-06**	**Nov-06 ***	**Dec-06 ***	**Year Total**
34	PJM Non-Firm PTP with POD in AEP Zone	$ 35,102	$ 37,885	$ 18,959	$ 44,028	$ 33,721	$ 33,721	$ 329,990
35	PJM Firm PTP with POD in AEP Zone	$ 6,327	$ 1,621	$ 1,621	$ 1,621	$ 1,234	$ 1,234	$ 40,990
36	**In-Zone PTP Revenue at Revised PTP Rate**	$ 41,428	$ 39,506	$ 20,580	$ 45,649	$ 34,955	$ 34,955	$ 370,980
37	PJM Firm PTP (Border Revenues)	$ 402,632	$ 448,949	$ 270,855	$ 283,045	$ 212,016	$ 212,016	$ 3,694,809
38	PJM Non-Firm PTP (Border Revenues)	$ 319,164	$ 361,035	$ 370,074	$ 377,580	$ 331,666	$ 331,666	$ 3,687,216
39	**Border PTP Revenue with Revised Rev. Req.**	$ 721,797	$ 809,984	$ 640,929	$ 660,624	$ 543,682	$ 543,682	$ 7,382,024
40	**Going-Level AEP Zone PTP Rev @ Rev Rates**	$ 763,225	$ 849,490	$ 661,509	$ 706,274	$ 578,637	$ 578,637	$ 7,753,005
41	AEP LSE Percentage	86%	86%	86%	86%	100%	100%	
42	**AEP LSE Portion of Zonal PTP Revenue**	$ 655,140	$ 729,189	$ 567,829	$ 606,254	$ 578,637	$ 578,637	$ 6,818,941
43	**KPCo MLR ****	**0.07226**	**0.07079**	**0.07101**	**0.07101**	**0.07101**	**0.07101**	**0.07191**
44	**KPCo PTP Revenue Share**	**$ 47,340**	**$ 51,619**	**$ 40,322**	**$ 43,050**	**$ 41,089**	**$ 41,089**	**$ 490,339**

Rate Effective Nov 1, 2005 $/MW-month	$ 1,621.40	20,620.95	LSE 5-CP MW	$ 449,425,402	AEP RR
Present Rate $/MW-month	$ 1,420.00	24,023.00	EDC 5-CP MW	$ 1,954,080,993	PJM RR
AEP Zone Incr. Factor	1.141830986	85.83836%	LSE / EDC	22.99932%	AEP allocation

* PJM OATT revised Nov. 1, 2005 to allocate only the LSE portion to AEP and therefore no adjustment was required.

** MLRs (Based on 2006 Load Forecast, 9/13/05 w/ update of Additional Wholesale Customers) (a)
Includes Wholesale Customer update --- Sturgis moved to I&M Internal Load in Jan. 2006 - June 2006 (Updated w/ Actual Data through October 2005)
Calculated Jan. 2006 MLR values reflect actual Peak Demands for Jan.2004 - Oct.2005 with no adjustments of Century and Pechiney.
Calculated Feb-Dec. 2006 MLR values reflect actual Peak Demands for months Jan.- Oct.2005 and adjustments of Century and Pechiney loads in forecasted monthly loads for Nov.- Dec. 2005, and include Century and Pechiney in Jan. 2006. (as per Operating Committee and Nick Lycakis Adjustment).

Kentucky Power Company
Network Transmission Revenues at Going Level
Projected Post-SECA AEP OATT Settlement NTS Revised Rate Effective 4/1/06

Month	Days	Non-Affiliate NTS Billing Demand	Non-Affiliate NTS Monthly Revenue	KPCo MLR *	KPCo Share NTS Revenue
January	31	3,402.05	$ 5,621,872	0.07456	419,167
February	28	3,402.05	$ 5,077,820	0.07228	367,025
March	31	3,402.05	$ 5,621,872	0.07228	406,349
April	30	3,402.05	$ 5,440,521	0.07228	393,241
May	31	3,402.05	$ 5,621,872	0.07228	406,349
June	30	3,402.05	$ 5,440,521	0.07228	393,241
July	31	3,402.05	$ 5,621,872	0.07226	406,236
August	31	3,402.05	$ 5,621,872	0.07079	397,972
September	30	3,402.05	$ 5,440,521	0.07101	386,331
October	31	3,402.05	$ 5,621,872	0.07101	399,209
November	30	3,402.05	$ 5,440,521	0.07101	386,331
December	31	3,402.05	$ 5,621,872	0.07101	399,209
Total	365	40,824.60	$ 66,193,006	0.07192	**$ 4,760,660**

Note: Monthly AEP Zone NITS Rate Effective November 1, 2005 = $ 1,621.40

* MLRs (Based on 2006 Load Forecast, 9/13/05 w/ update of Additional Wholesale Customers) (a)

Includes Wholesale Customer update --- Sturgis moved to I&M Internal Load in Jan. 2006 - June 2006 (Updated w/ Actual Data through October 2005)

Calculated Jan. 2006 MLR values reflect actual Peak Demands for Jan.2004 - Oct.2005 with no adjustments of Century and Pechiney.

Calculated Feb-Dec. 2006 MLR values reflect actual Peak Demands for months Jan.- Oct.2005 and adjustments of Century and Pechiney loads in forecasted monthly loads for Nov.- Dec. 2005, and include Century and Pechiney in Jan. 2006. (as per Operating Committee and Nick Lycakis Adjustment).

2/2/2006

Kentucky Power Company
Projected Monthly 2006 Net RTO Formation Costs
RTO Formation Charges and Revenues under PJM OATT, and KPCo RTO Stat-Up Amortization

2006	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Total
RTO Formation Cost Recovery													
AEP-East Zone Load [1]	24,023	24,023	24,023	24,023	24,023	24,023	24,023	24,023	24,023	24,023	24,023	24,023	
AEP RTO Formation Expense [2]	$ 214,766	$ 214,766	$ 214,766	$ 214,766	$ 214,766	$ 214,766	$ 214,766	$ 214,766	$ 214,766	$214,766	$ 214,766	$ 214,766	$ 2,577,187
KP Pole Miles Percentage	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	
KPCo RTO Formation Cost Recovery	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 14,497**	**$ 173,964**
RTO Formation Expense													
AEP LSE Load [1]	20,621	20,621	20,621	20,621	20,621	20,621	20,621	20,621	20,621	20,621	20,621	20,621	
AEP RTO Formation Expense [2]	$ 184,351	$ 184,351	$ 184,351	$ 184,351	$ 184,351	$ 184,351	$ 184,351	$ 184,351	$ 184,351	$184,351	$ 184,351	$ 184,351	$ 2,212,215
KP Pole Miles Percentage	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	0.06750	
KPCo RTO Formation Expense	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 12,444**	**$ 149,328**
Net RTO Formation Cost Revenue Adjustment	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 2,053**	**$ 24,636**
Amortization Expense													
KPCo Amortization Expense [3]	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 12,187	$ 146,244
KPCo NET RTO Start-Up Cost Amortization	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 10,134**	**$ 121,608**

[1] 2005 Zonal Peak and AEP as LSE MW from PJM Billing and Settlements, see page 2
[2] PJM Expansion Cost Recovery Charge approved by FERC = $8.94/MW-Month effective 11/1/06
[3] RTO Formation Cost, includes 15 year amortization of AEP Companies RTO Formation and settlement of FERC imposed MI/WI hold harmless directive

Revised Exhibit DWB-3
Page 1 of 2

AEP Zone
Network Service Peak Loads
Transmission Billing Demands under PJM OATT
2005 Peak Loads for 2006 Billing

		NSPL 7/26/2005 HE 1600
AEPELK	Musser Companies of WV	19
AEPBED	Blue Ridge Power Ag.-Bedford	43
AEPDAN	Blue Ridge Power Ag.-Danville	222
AEPMAR	Blue Ridge Power Ag.-Martinsville	43
AEPRIC	Blue Ridge Power Ag.-Richlands	11
AEPSAL	Blue Ridge Power Ag.-Salem	91
AEPRAD	Blue Ridge Power Ag.-Radford	42
CECGVC	Central Virginia Electric Coop.	24
BVU	Bristol Va.	111
AEPCEC	Craig-Botetourt	10
AESWVP	West Virginia Power	88
ODECW	Old Dominion Electric Coop.	38
AMPO [8]	American Municipal Power-Ohio	162
AMPOCOL [7]	City of Columbus	168
AMPO DOSS [9]	Dover, Orrville, Shelby, St Marys	47
AKSTL	AK Steel	47
DOWG	City of Dowagiac	14
HEREC	Hoosier	4
AEPSCG STRG	City of Sturgis	48
WVPA	Wabash Valley Power	312
WVSDI	Wabash Valley Power (SDI)	25
AEPSCG OMEG	Ohio Municipal Electric Group	158
OPAC	ORMET	18
AEPBCK [6]	Buckeye Power	979
AEP BCK MON PWR	Buckeye Mon Power	15
SELLC [2]	Strategic Energy	58
IMPA AND/FRK [1]	Anderson/Frankton/Columbia Cit\	104
IMPA RPL [5,10]	Richmond Power & Light	41
AEPSCG IMPA FIRM	IMPA Firm Sale	155
AEPSCG MON PWR	AEP Monongahela	284
AEPSCG VANC/OLIVE	Vanceburg/Olive Hill	19
AEP (LSE)	**AEP (LSE)**	**20,621**
Total AEP (EDC)	**Total AEP (EDC)**	**24,023**
	Loads not in the Calculation from CEAS	
Monongahela Power load in Ohio Power		289
Fries Hydro		2
Adjustment for RPL load served by Point-to-Point service		-50
Adjustment for AMPO DOSS load served by Point-to-Point servi		-18
ALM Interruptions [3]		0
AEP Control Area Load	Metered Load From CEAS	23800
Buckeye [4]	Buckeye (FE)	163
Buckeye [4]	Buckeye (CIN)	50

Notes
1 Includes Cadiz, Noblesville, and Lawrenceburg
 of the CT's. Includes 150 MW Firm Sale
2 This LSE services loads that have switched and the load is profiled
3 Cannot include ALM interruptions to NSPL per FERC Ruling and John Reyno
4 This load is not included in the AEP (EDC) load and excludes AEP zonal losse
5 Includes Hodgin-Richmond, Centerville,Roseburg
 generation of the CT's.
6 Buckeye load includes OP and CSP
7 Includes Dublin Rd(98 Vine), High St(Southerly), Vine St(92 Vine), Morse Rd(I
8 Includes Westerville, Woodsfield, Pioneer/Holiday, Jackson, and Glouster lo
9 The CDR load is 47MW including losses and net load of 64.52 MW
10 The CDR load for RPL is 41.4 including losses and net load of 91.7 MW

* LSE values include transmission losses

BRADISH, R.W.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF	)	
GENERAL ADJUSTMENT OF ELECTRIC	)	**Case No. 2005-00341**
RATES OF KENTUCKY POWER COMPANY	)	

REBUTTAL TESTIMONY AND EXHIBITS
OF
ROBERT W. BRADISH

ON BEHALF OF

KENTUCKY POWER COMPANY

February 2, 2006

REBUTTAL TESTIMONY OF
ROBERT W. BRADISH, ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO 2005-00341

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

A. My name is Robert W. Bradish.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. This testimony is in response to the testimony of Mr. Lane Kollen on pages 10 – 15, where he recommends that the 50/50 sharing of incremental off-system sales be discontinued and 100% of the incremental off-system sales go to Kentucky Power Company ratepayers. Mr. Kollen provides a number of reasons for his position with the underlying belief that AEP can merely offer its generating units into the PJM market and produce the same level of off-system sales as it does today. Mr. Kollen's description of how AEP achieves its level of off-system sales is incomplete and an extreme oversimplification of the realities involved in optimizing off-system sales in the PJM market.

In addition, I respond to the testimony of Mr. Robert Henkes on pages 50-51, where he recommends the adjustment for the new PJM stated rate be eliminated.

Q. Please explain why Mr. Kollen's description is incomplete.

A Mr. Kollen identifies only physical short-term transactions involving the sale of excess generation from AEP generating assets into the PJM pool when he discussed off-system sales on pages 11, lines 3-5 and page 13, lines 7-8. However, a significant portion of AEP's off-system sales margins is a result of additional types of transactions. These would include: 1) trading and marketing activities that are not tied to AEP's physical assets (financial transactions or physical transactions supplied from non-AEP resources), 2) forward sales (i.e., long-term) of AEP's east generation, and 3) physical settlement of trading contracts.

Q. Please explain why Mr. Kollen's description of AEP's optimization effort regarding off-system sales is oversimplified.

A. Mr. Kollen incorrectly assumes that all off-system sales margins are merely excess energy that can simply be sold on an hourly or day-ahead basis into the PJM market with little or no effort by AEP. My testimony will explain why this is a gross oversimplification by Mr. Kollen. To maximize margins in this short-term (i.e., hourly or day-ahead) market, AEP evaluates the: 1) relationship of day-ahead to hourly pricing, 2) risks associated with the loss of generation and load variation, 3) costs associated with operating reserves, 4) risks associated with unit start-up and shut-down and 5) risks associated with following the PJM dispatch instructions.

Description of Off-System Sales

Q. Please define off-system sales produced by AEP that are shared with KPCo customers.

A. Off-system sales margins are those derived from our physical operations and our non-physical activities, including financial trading.

Q. Please define non-physical transactions.

A. Non-physical transactions are those in which energy is not physically scheduled. This may include physical transactions that are "booked out" as well as purely financial transactions that do not contemplate physical flow.

A "booked out" transaction occurs when AEP has a purchase and sale of the same quantity for the same specific delivery period at the same specific delivery point. The offsetting sale and purchase transactions are financially settled rather than physically delivered resulting in "booked out" transactions. A simple example of this would be where AEP sold 50 MW to be delivered on February 7, 2006 "into TVA" to counterparty A for $50/MWh. On a different day, Counterparty A sold 50 MW to be delivered on February 7, 2006 "into TVA" to AEP for $49/MWh. AEP could "book out" this transaction for a profit of $1/MWh. Another example of a non-physical transaction is a financially cleared transaction, such as a financially cleared swap of the type that AEP would typically execute through an exchange such as the Intercontinental Exchange, that does not contemplate physical flow. The margins for these types of transactions are included in the off-system sales component as a benefit to KPCo customers.

Q. Please define off-system sales as they relate to physical operations.

A. Physical off-system sales can be best defined as the margin between AEP's cost of goods sold and the revenue received. The cost of goods sold can be either the cost of AEP's generation or purchased power. The revenues are derived from energy sales into the PJM market, hedging activities associated with AEP's east generation, and trading and marketing efforts that settle physically.

Q. Are these transactions more comprehensive than those described by Mr. Kollen in his testimony?

A. Yes, they are. Although Mr. Kollen addresses the physical sale of excess generation as a type of off-system sales transaction that creates margin, he does not address the impact of hedging and trading and marketing transactions and the role Commercial Operations plays in optimizing these activities.

Q. Please explain.

A. In terms of cost of goods sold, in addition to its own resources, there are times when AEP needs to purchase energy because it either does not have enough resources to meet its load and off-system sales or AEP enters into economy purchases at a discount to its existing resources.

With regards to revenues, in addition to selling in the short-term PJM market, AEP will also hedge (enter into contracts to sell) its generation output at attractive prices with third parties for longer periods of time. Further, AEP will enter into forward sales of energy that are not meant as hedges of AEP's generation, but which ultimately settle physically.

Q. Are both physical and non-physical off-system sales included in the KPCo System Sales Clause?

A. Yes. These types of transactions are part of the off-system sales margins that are shared with KPCo customers.

Q. Would AEP be able to achieve its present level of off-system sales by simply selling its excess generation into the PJM market as Mr. Kollen has suggested?

A. No. The impact of hedging and trading and marketing activities is significant and, if not taken into consideration, would result in a far smaller level of off-system sales.

Rather than simply selling into the short-term PJM market as Mr. Kollen states, AEP also hedges forward the output of its power plants as well as takes positions on the movement in the price of power. These latter positions sometimes settle financially and sometimes physically. The net result, however, from these additional types of transactions is to significantly enhance the margins of off-system sales that are shared with the customers of KPCo.

Q. Are there other points regarding short-term transactions that Mr. Kollen does not address?

A. Yes. On the matter of bidding in excess generation relating to short-term physical transactions that Mr. Kollen does identify, the process of optimizing off-system sales margin is much more complex than simply bidding the units into the market.

PJM does not dispatch to maximize off-system sales for AEP. The dispatch performed by PJM is designed to reliably serve the load within the entire PJM footprint in a least-cost manner for PJM. By this, PJM looks to minimize the cost across the entire footprint and does not attempt to maximize revenues for individual market participants. It is up to AEP to maximize the Company's margins for off-system sales.

Q. Please provide an example where AEP has maximized the Company's margin for off-system sales.

A. As a result of PJM's unit commitment process, PJM may want AEP to shut down one of its supercritical units on a weekend. A coal unit of this type is not able to shut down and re-start quickly and therefore would not be available for operation on Monday. However, Commercial Operations performs analyses to determine the most profitable time for the unit to run, which in this example is on Monday. Commercial Operations will self-schedule the unit over the weekend, understanding there is limited margin opportunity and the possibility of a small loss, in order to produce higher margins on Monday. These margins would be lost if we simply allowed PJM to dictate the commitment of our units as Mr. Kollen's has suggested in his testimony.

Q. Please describe other types of activities being performed by Commercial Operations to maximize AEP's off-system sales revenue?

A. In addition to supplementing PJM's unit commitment process described above, Commercial Operations analyzes whether AEP needs a hedge against the volatility of real-time prices. This can be accomplished by ensuring that a certain amount of generation is available to capture price spikes in the real-time market. Another type of activity involves optimizing AEP's generation dispatch. Once a unit has been committed and is being dispatched in real-time, Commercial Operations has in place real-time monitoring of dispatch accuracy to ensure plants are performing as requested and our dispatchers are optimizing the value from the inter-hour price volatility. This is accomplished by adjusting unit output to maximize revenue when the market price is greater than operating costs and by maximizing purchases when the market price is less than operating costs.

Another focus of Commercial Operations is to ensure the capabilities of the units are accurately reflected in PJM's unit commitment and dispatch process. Units often experience curtailments due to a variety of reasons including equipment failure, environmental restrictions, etc. Understanding and communicating unit limitations is critical because if AEP is not able to meet its dispatch obligation, it must purchase energy in the real-time market, often at a higher price than what was awarded day-ahead.

Q. Are there other aspects of our operations in the PJM market that influence the level of off-system sales, but were not discussed in Mr. Kollen's testimony?

A. Yes. AEP is required to bid its load into the PJM market. Costs associated with the deviation in load from forecasted levels impacts off-system sales margins. AEP has detailed weather and load forecasting functions that produce hourly load forecasts for bidding into the PJM market. Accurate load forecasts are critical in managing the operating reserve exposure the Company has in real-time to deviations from the day-ahead settlement results.

Q. Mr. Bradish you have explained what AEP needs to accomplish to maximize off-system sales, please explain how AEP maximizes the margins on off-system sales.

A. First, in regards to hedging and trading and marketing, AEP employs the services of experienced and successful commercial personnel to engage in this activity. AEP also employs experienced and successful mid and back-office personnel and developed premier systems to support these activities. Finally, AEP employs experienced and successful PJM market operation experts in order to allow the Company to extract maximum value from its efforts in the PJM market. These experts include operations, systems, settlements and transmission personnel who understand the complexities of the PJM market and extract the maximum value for AEP and its customers.

These types of value maximizing activities outlined above are what lie behind Mr. Kollen's simplistic characterization of off-system sales within an RTO market environment. It is why the continuous monitoring and intellectual capital are needed to maximize our off-system sales margins, as well as minimize our costs. The combined impact of the activities described in my testimony enables AEP to add value through off-system sales, and Kentucky Power Company to realize its fair share of those margins.

PJM Administrative Fees

Q. On pages 50-51 of Mr. Henkes direct testimony he opposes increasing the PJM administrative costs by 19.5% since this increase is based on a pending rate filing by PJM in which the PJM administrative costs are proposed to be established at a set rate that has not been adopted by FERC. Do you agree with Mr. Henkes' adjustment to the PJM administrative cost estimate?

A. No, I do not. The basis for the 19.5% increase in PJM administrative costs adjustment was to capture the expected increase in PJM administrative fees using the best available information at the time of the filing, which was the stated rate filed with FERC. The stated rate filing was amended by PJM in November 2005 with cost of service information and a different, slightly lower average rate. I have revised my adjustment to reflect the stated rate filed by PJM in November 2005 which revision is shown in Rebuttal Exhibit RWB-1. This rate reflects the most recent PJM filing with FERC and the anticipated costs to operate within PJM.

Q. Do you have any other basis for the reasonableness of your proposed increase in the PJM administrative costs other than the stated rate filed by PJM and pending before FERC?

A. Yes, I do. The Company provided in response to the Attorney General's First Set of Data Requests number 71(g) a historical chart of the increases in the PJM operating expenses, a portion of which includes the PJM administrative costs. PJM's operating costs over the last 7 years has increased by an average of about thirty percent (30%). In fact, PJM has begun billing in 2006 an interim formula rate that increased administrative charges to AEP approximately 15% over the adjusted test year amount. My revised adjustment reflects an increase of 17%, which is very reasonable in light of PJM's historical operating expense experience.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

KPCo 2006 Monthly Forecast for PJM Administrative Fees

2006 (Revenue) / Expense	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2006 Total
PJM Administrative Fees	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 3,455,208
Total KPCo PJM Administrative Fees	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 287,934	$ 3,455,208

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

ROBERT BRADISH, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

ROBERT BRADISH

Subscribed and sworn to before me by ROBERT BRADISH this 1 day of February, 2006.

Notary Public

My Commission Expires 1/4/09

NOTARIAL SEAL STATE OF OHIO

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-09

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE COMMISSION

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

REBUTTAL TESTIMONY
OF
LARRY C FOUST

ON BEHALF OF
KENTUCKY POWER COMPANY

February 2, 2006

REBUTTAL TESTIMONY OF
LARRY C. FOUST, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2005-00341

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REBUTTAL TESTIMONY OF
LARRY C. FOUST, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

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

A. My name is Larry C. Foust. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I currently hold the position of Regulatory Specialist in the Regulated Pricing and Analysis department of the American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP).

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Attorney General Witness David H. Brown Kinloch's suggestion to reject the Company's cost of service study filed in this proceeding.

Use of the Company's Cost of Service Study

Q. What is Attorney General Witness David H. Brown Kinloch's position regarding the use of the Company's cost of service study?

A. Witness Brown Kinloch's position is that the Commission should reject the cost of service study filed by the Company.

Q. On what does he base his position?

A. Witness Brown Kinloch states that none of the calculations or results can be verified and that the Company has not followed "a methodology generally accepted within the industry".

Q. Can the results and calculations be verified?

A. Yes. The Company provided the Attorney General all of the allocation factors, formulas, accounting data and functionalization and classification methods (collectively the inputs) used by the program to perform the calculations. The inputs instruct the program how to calculate each of the values included in the study. A review of the inputs would have shown how the calculations were performed. During the preparation of the study I verified certain calculations in the study to ensure the program was functioning in accordance with the Company's methodology. In response to the Attorney General's second set of data requests, item number 71, I explained how the software calculates certain allocation methods.

Q. Did the Company provide a working copy of the program to the Attorney General?

A. Yes. The Company provided a working copy of the program on a personal computer along with the instruction manual. This information allows the Attorney General to test the program to verify its integrity. Additionally, Kentucky Industrial Utility Customers Witness Stephen J. Baron testifies that he was able to make an independent verification of the cost of service study I performed.

Q. On page 8 of Witness Brown Kinloch's testimony, beginning on line 6, he states, "Consequently, it is impossible to follow the study back to determine how each of the input costs with which the Company started were allocated." Did the Company provide information that indicated how each of the input costs was allocated?

A. Yes, the information provided does identify the allocation methodology used for each individual cost item included in the cost of service study. That information was provided on the Accounts tab of the input spreadsheet that was provided.

Q. Did the Company use a cost of service study based on a methodology generally accepted within the industry?

A. Yes. As stated in my direct testimony beginning on page 9, the Company used a 12 CP allocation methodology. This is the same methodology the Company used in its previous case and which has been accepted by this Commission.

Q. Witness Brown Kinloch suggests that since the Company did not use the "Zero Intercept" or "Minimum System" methodology to allocate distribution line cost between demand and customer costs, the methodology used by the Company is not an accepted methodology. Is the methodology used by the Company to allocate distribution costs an accepted methodology?

A. Yes. The Company's methodology was used and accepted in the Company's last retail rate case and has been used by all the other AEP operating companies in the East.

Q. Does the TACOS Gold Software utilize any specific methodology?

A. No. The TACOS Gold Software is simply the tool the Company uses to perform the methodology the Company decides to utilize. The allocation factor statistics are developed outside of the software in accordance with the Company's methodology and input into the software for its use. The tool the Company used in the previous case was the Ebasco software run on a mainframe computer. The methodologies are the same, but the tools used are different.

Q. Is the TACOS Gold software used by others?

A. Yes. At the time AEP purchased the software, AEP was provided a reference list of 11 utilities that were using the software. The Company is aware of one additional utility that has used the software in a rate proceeding within the last year.

Q. Does this conclude your rebuttal testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

LARRY C. FOUST, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Larry C Foust

LARRY C. FOUST

Subscribed and sworn to before me by LARRY C. FOUST this 1st day of February, 2006.

NOTARIAL SEAL STATE OF OHIO

CATHERINE HURSTON
Notary Public, State of Ohio
My Commission Expires 11 15 2009

Catherine Hurston

Notary Public

My Commission Expires 11-15-09

HENDERSON, J.E.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE COMMISSION

<u>IN THE MATTER OF</u>

GENERAL ADJUSTMENTS IN ELECTRIC RATES OF KENTUCKY POWER COMPANY **CASE NO. 2005-00341**

<u>REBUTTAL TESTIMONY</u>

OF
JAMES E. HENDERSON

ON BEHALF OF
KENTUCKY POWER COMPANY

<u>February 2, 2006</u>

REBUTTAL TESTIMONY OF
JAMES E. HENDERSON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

INTRODUCTION

Q. Please state your name, business address and position in the company.

A. My name is James E. Henderson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Senior Staff Accountant in the Accounting Policy and Research Section of American Electric Power Service Corporation (AEPSC).

Q. Did you provide Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut statements made and exhibits prepared by Michael Majoros, who is testifying on behalf of the Attorney General for the Commonwealth of Kentucky, and by Lane Kollen, testifying on behalf of Kentucky Industrial Utility Customers, Inc.

Q. What revised schedules and workpapers are you sponsoring?

A. I am sponsoring Revised Exhibit JEH-1 that contains the following revised schedules: Schedule of Revised Depreciation Rates by Account; Comparison of Existing Rates to Revised Rates by Account; Revised Depreciation Reserve; Revised Calculation of Average Remaining Life for Big Sandy Plant; Revised Summary of Production Plant.

Q. Would you please summarize the areas you will address in your Rebuttal Testimony?

A. First, I am proposing a revision to my depreciation study to reflect an increase in the estimated life span for Big Sandy Unit 1. I am now recommending that the estimated retirement date for Big Sandy Unit 1 be extended from year 2015 as shown in my original study to year 2034. This results in a decrease in my recommended accrual rate for Production Plant from 3.57% to 3.51%. This translates to a recommended decrease in total company annual depreciation accruals of $268,986 based on depreciable plant in service at December 31, 2004.

I will provide rebuttal testimony addressing Mr. Majoros' Direct Testimony on the following subjects: (1) The exclusion of Big Sandy demolition costs from depreciation rates; (2) The use of a five-year actual net salvage average to determine the appropriate net salvage to incorporate into depreciation rates; and (3) The proposal to transfer removal costs that are not defined as Asset Retirement Obligations by SFAS 143 from accumulated depreciation to a regulatory liability account. Last, I will provide rebuttal testimony related to Mr. Kollen's Direct Testimony on the following subjects: (1) The exclusion of Big Sandy demolition costs from depreciation rates; (2) The calculation of interim retirement rates for production plant and (3) The calculation of net salvage rates.

Q. Are there any revisions that you wish to make to the depreciation study that you submitted as part of your Direct Testimony in this case?

A. Yes. I am recommending that the retirement date for Big Sandy Unit 1 be extended from year 2015 as shown in the study to year 2034. This will result in a total life span of 65 years for each of the Big Sandy Units.

Q. Please explain the reasons for your revision of the life span for Big Sandy Unit 1.

A. At the time I performed the depreciation study, I was provided forecasted retirement dates for Big Sandy Units 1 and 2 by the Asset Outage and Planning Section of AEP's Generating Division. Further, it was explained that a decision had been made to install flue gas desulphurization (FGD) equipment on Unit 2 at Big Sandy plant, but at that time there were no plans to install FGD equipment on Unit 1. There was a concern expressed that without the addition of FGD equipment, there could be environmental constraints that would require Unit 1 to be shut down. Since that time, the Asset Outage and Planning Section has concluded that they will recommend installation of FGD equipment on Big Sandy Unit 1. While no formal approval has been obtained to go forward with this installation, the likelihood that it will occur has caused me to recognize that possibility, and for Big Sandy Unit 1, to move from the 52-year life span used in the depreciation study to a 65-year life.

Q. Have you calculated revised depreciation rates for Big Sandy plant as a result of this revision?

A. Yes. The revised calculations are attached as Rebuttal Exhibit JEH-1.

Q. Will you please quantify the results of this revision?

A. The revision to the Big Sandy Accrual rate reduced my recommended rate for Production plant from 3.57% to 3.51% and resulted in an additional recommended decrease in annual Production plant depreciation accruals of $268,986. Based on the results of this revision, I am now recommending an increase in total company annual depreciation expense of $3,387,986 or 0.26% in the annual accrual rate. A comparison of Kentucky Power's current accrual rates and accruals and the revised annual accrual rates and accruals are as follows:

Composite Rates and Accruals

	Existing		Study	
Functional Plant Group	Rates	Accruals	Rates	Accruals
Steam Production Plant	3.90%	$17,713,144	3.51%	$15,946,240
Transmission Plant	1.71%	6,551,727	2.71%	10,398,016
Distribution Plant	3.52%	15,393,620	3.64%	15,907,812
General Plant	2.54%	728,364	5.31%	1,522,723
Total	3.10%	$40,386,855	3.38%	$43,774,791

Q. Do you agree with Mr. Majoros' statement on page 6 of his Direct Testimony that the revised demolition cost estimate demonstrates the old estimate was vastly overstated?

A. No. The current demolition cost estimate contains a revised demolition cost based on the current plant configurations and current costs that would be required to demolish Big Sandy Plant. While I agree the current cost estimate of $32 million is less than the previous estimate of $43.2 million, I do not agree that this fact alone demonstrates that the previous estimate was vastly overstated. Just as there are changes in the estimates of averages service lives of property, there will also be changes in the estimates of demolition costs.

Q. Do you agree with Mr. Majoros' recommendation on page 23 of his Direct Testimony, that the cost of removal factors should be based on the most recent five-year average actual cost of removal experienced by the Company?

A. No. Implementing a five-year average net actual salvage allowance defers costs to future periods and to customers who receive no benefit from those costs. In fact, Mr. Majoros, through his five-year average calculations, has rejected the inclusion of demolition costs for Big Sandy plant in depreciation rates. Since the Company has only one generating plant, this would not only propose to defer an estimated $32 million of future costs to future ratepayers, but it may also preclude the Company from recovering costs that will ultimately be required to pay for the demolition of Big Sandy Plant.

Page 18 of the Public Utility Depreciation Practices published in August 1996 by The National Association of Utility Regulatory Commissioners (NARUC) states:

> ...The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.

This treatment of net salvage is in harmony with generally accepted accounting principles and tends to remove from the income statement any fluctuations caused by erratic, although necessary, abandonment and removal operations. It also has the advantage that current consumers pay or receive a fair share of costs associated with the property devoted to their service, even though the costs may be estimated.

Q. Do you agree that Kentucky Power's current depreciation rates for Transmission, Distribution and General plant do not contain any future cost of removal?

A. No. Kentucky Power's current depreciation rates for Transmission, Distribution and General plant were based on a net salvage ratio that was not separated into gross removal and gross salvage components. While the net salvage ratios in the Company's last depreciation study did not indicate a net removal cost for the Transmission, Distribution and General plant functions, removal costs as well as salvage costs were considered for determining the net salvage recommendations, just as they were in the current case.

Q. Do you agree with Mr. Majoros' statement on pages 10 and 11 of his Direct Testimony that FERC Order 631 requires separate identification of "non legal" asset retirement obligations in sub-accounts of accumulated depreciation and depreciation expense?

A. I do not agree that FERC Order 631 identified specific sub-accounts for "non-legal" asset retirement obligations. FERC Order 631 did provide for specific sub-accounts of Account 403, Depreciation Expense and Account 108, Accumulated Provision for

Depreciation, to account for depreciation expense and accumulated provisions for depreciation for Legal Asset Retirement Obligations. However, for removal costs that do not qualify as legal retirement obligations, FERC Order 631 provides that a utility will maintain subsidiary records for cost of removal for non-legal retirement obligations that are included as specifically identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis and rate setting purposes. The FERC did not specify specific sub–accounts for removal costs that do not qualify as Legal Asset Retirement Obligations. Although Kentucky Power has established sub-accounts to facilitate the reporting of these amounts as regulatory liabilities for SEC reporting purposes, the FERC did not specify the numbering for the sub accounts in FERC Order 631.

The FERC specifically addressed accounting for cost of removal that does not constitute a legal obligation in Section III, paragraphs 36 through 38 of Order 631 as follows:

> As proposed in the NOPR, the rule applies to legal obligations associated with the retirement of tangible long-lived assets. Under the existing requirements of the Uniform System of Accounts removal costs that are not asset retirement obligations are included as a component of the depreciation expense and recorded in accumulated depreciation. The Commission notes that certain jurisdictional entities may have been receiving specific allowances

for cost of removal for non-legal retirement obligations as a specific component in their rates approved by their regulators. The Commission did not propose any changes to its existing accounting requirements for cost of removal for non-legal retirement obligations. Accordingly, jurisdictional entities are accounting for such costs consistent with the requirements of the Uniform System of Account under part 101 for public utilities and licensees, part 201 for natural gas companies and Part 352 for oil pipeline companies.

The purpose of this rule is to establish uniform accounting requirements for the recognition of liabilities associated with the retirement of tangible long-lived assets. The accounting for removal costs that do not qualify as legal retirement obligations falls outside the scope of this rule. The Commission is aware that there is an ongoing discussion in the accounting community as to whether the cost of removal should be considered as a component of depreciation. However, this issue is beyond the scope of this rule and we are not convinced that there is a need to fundamentally change accounting concepts at this time.

Instead we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specifically identifiable allowances recorded in accumulated depreciation in order to separately identify

> such information to facilitate external reporting and for regulatory analysis and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation-Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in depreciation accruals.

Q. Do you agree with Mr. Majoros' opinion, as stated on page 12 of his Direct Testimony, that removal costs that are not Asset Retirement Obligations should be reclassified from FERC Account 108, Accumulated Depreciation, to FERC Account 254, Other Regulatory Liabilities?

A. No. As described above in Section III, paragraphs 36-38 of Order 631, FERC has instructed utilities to continue following the existing instructions contained in the FERC Uniform System of Accounts (USOA) for removal costs that are not Asset Retirement Obligations; i.e. to continue to record removal costs that are not Legal Asset Retirement in Account 108, Accumulated Provision for Depreciation. In addition, as described in the USOA instructions for Account 108, Accumulated Provision for Depreciation, a utility must seek FERC Commission approval to make any transfers from Account 108. FERC has concluded that removal costs that are not asset retirement obligations should continue to be shown in Account 108, Accumulated Provision For Depreciation, for FERC Form 1 reporting purposes.

Q. Do you agree with Mr. Majoros' contention that transferring removal costs to a Regulatory Liability account automatically provides that the removal costs would be refunded to ratepayers in the event that Kentucky Power's electric utility operations are deregulated?

A. No. I have observed the deregulation of utility generation operations in the States of Ohio, Virginia and Texas and have noted that filings were required to be made with the State Utility Commissions to determine what amounts, if any, will be refunded to ratepayers and what amounts, if any, ratepayers will be required to pay through transmission and distribution line charges to transition to a non-regulated environment.

Q. Do you have any rebuttal relative to Mr. Kollen's Direct Testimony?

A. Yes. I disagree with statements that Mr. Kollen has made concerning the exclusion of demolition costs for Big Sandy plant from the depreciation study, the calculation of interim retirement rates for production plant, and the calculation of net salvage rates.

Q. Do you agree with Mr. Kollen's recommendation of pages 58 and 59 of his Direct Testimony that the demolition costs for Big Sandy plant be excluded from the production plant depreciation rates?

A. No. For the reasons I previously discussed in my rebuttal to Mr. Majoros' exclusion of demolition costs from the production plant deprecation rates, this exclusion wrongly defers the recovery of these costs to future ratepayers and defeats the basic matching principle that underlies the fairness doctrine inherent in rate making.

Q. Do you agree with Mr. Kollen's statement on page 61 of his Direct Testimony that the retirement of the SCR catalysts in years 2007 and 2009 should be excluded from the interim retirement rate for Account 312, Boiler Plant Equipment, because they are abnormal?

A. No. The SCR equipment is a new item of plant that has been installed in the Big Sandy plant. Any retirement history associated with SCR's would not be included in the historical interim retirements. The replacement of the SCR catalysts will be ongoing as part of the normal operations of the SCR equipment. The inclusion of these known and specific future retirements are properly included as an addition to historical interim retirements because the retirement history for the SCR's is not included in the historical analysis.

Q. Do you agree with Mr. Kollen's assertions on page 60 of his Direct Testimony that any retirements that were made that relate to the installation of pollution control equipment should have been removed from the historical interim retirement analysis because they were abnormal?

A. No. The basis for my recommended revision to extend the life spans for Big Sandy plant are due to the possible addition of new pollution control equipment to the plant. Retirements that result from the additions of new equipment do not qualify those retirements as extraordinary. The continued installation of additional pollution control equipment at Big Sandy plant clearly demonstrates that point.

Q. Do you agree with Mr. Kollen's statement on page 63 of his Direct Testimony that using only 30 years of interim retirement history instead of the 35 years of interim retirement history that is available understates the average service life of steam production plant?

A. No. Actually Mr. Kollen used a 42-year period of retirement history (1963 through 2004) to calculate his recommended interim retirement rates for the production plant accounts. As I explained on page 2 of 443 in my depreciation study workpapers, I used the 30 year period of 1975 through 2004 to develop the interim retirement rates for steam production plant because interim retirements are not usually considered representative of the future until the generating units have experienced a few years of actual operation. At the inception of the operation of a new generating plant, there would be very few retirements expected since all of the installed equipment is new. Big Sandy Unit 2 was placed in-service in 1969 and the use of the 30-year period beginning in 1975 provided a five-year period of actual operation experience before the interim retirements would become predictive of the future.

Mr. Kollen's use of a 42-year period of interim retirements actually overstates the average service life of steam production plant and understates the depreciation accrual because the longer 42-year period considers the early years of the operation of a new plant when few retirements were actually experienced.

Q. Do you agree with Mr. Kollen's assertions on pages 63 through 65 of his Direct Testimony that the Company should apply the same composite net salvage/removal ratio to each plant account within a functional plant group; i.e. production, transmission, distribution and general plant?

A. No. On pages 7 and 8 of my Direct Testimony, I explained that Kentucky Power currently applies depreciation rates and maintains the accumulated depreciation at a composite functional plant group level. I recommended that the Commission authorize Kentucky Power to adopt and apply depreciation accrual rates and maintain the accumulated provision for depreciation at the primary plant account level because it will enable the Company to monitor depreciation accruals and salvage/removal costs actually recorded in each primary plant depreciation reserve account and will eliminate the requirement to allocate the accumulated depreciation to primary plant accounts in future depreciation studies. In order to apply a depreciation rate at the primary plant account level, a separate average service life must be determined for each primary plant account. Logically, a separate gross salvage and gross cost of removal amount should also be established for each primary plant account.

Since the Company currently records salvage and removal costs at the functional plant group level, I related the gross salvage and cost of removal recorded by the Company each year for the 15 year period (1990-2004) to the original cost retirements for that same period. The relationships were expressed as a percentage of the total gross salvage to the original cost retired and a percentage of gross removal cost to the original cost retired. I then detailed the original cost retirements by primary plant account and applied a gross salvage and gross cost of removal to each account that would, when composited for all plant accounts within a functional group, reflect the same percentages as that shown for the functional group for the 15-year period 1990-2004.

In the depreciation study workpapers for each primary plant account, I stated my reasons for choosing the salvage and removal percentages. For example, on page 56 of 447 of the workpapers that summarizes my recommendations for Account 3502, Rights-of-Way, I stated, "Any retirements from the land rights account would not be expected to produce any salvage and no removal costs should be expected to be incurred. Therefore, the recommendation is 0% for both gross removal and salvage resulting in a recommendation of 0% net salvage." On page 93 of 443 of the workpapers for account 355, Transmission Poles, I stated, "There are significant labor and equipment costs involved in replacing transmission poles. Any salvage would be expected to be insignificant. The recommendation is for a o% gross salvage and a 50% cost of removal."

I recommend that the Commission adopt the gross salvage and cost of removal percentages by primary account, as presented in my depreciation study in order for the depreciation accrual rates to establish specific parameters for salvage and cost of removal amounts by primary account. Future depreciation studies can then determine whether the gross salvage and cost of removal factors for each account should be modified based on the actual historical experience that is incurred.

Q. Do you agree with Mr. Kollen's recommendation on page 66 of his Direct Testimony that a 30-year period of history should be utilized to determine the net salvage factors instead of the 15-year period that you utilized?

A. No. Salvage and removal costs are affected by changes in labor and transportation costs as well as by changes in amounts that are received for the material removed due to scrap values and changes in the composition of the material being removed as well as changes in the methods and equipment utilized for the removal of property. The use of a 30-year historical period to estimate current salvage and removal costs places too much emphasis on earlier periods of history and fails to adequately reflect the recent salvage and removal cost history.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

COUNTY OF FRANKLIN

CASE NO. 2005-00341

AFFIDAVIT

James E. Henderson, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

James E. Henderson

WITNESS NAME

Subscribed and sworn to before me by WITNESS NAME this 1st day of Feb, 2006.

NOTARIAL SEAL STATE OF OHIO

CATHERINE HURSTON
Notary Public, State of Ohio
My Commission Expires 11 15 2009

Catherine Hurston

Notary Public

My Commission Expires 11-15-09

McCOY, H.E.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE COMMISSION

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

REBUTTAL TESTIMONY

OF
HUGH E. MCCOY

ON BEHALF OF
KENTUCKY POWER COMPANY

February 2, 2006

**REBUTTAL TESTIMONY OF
HUGH E. MCCOY ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

Introduction

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

A. My name is Hugh E. McCoy. I am a Director of Accounting Policy and Research for the American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. What are your principal areas of responsibility?

A. I am responsible for performing accounting research, recommending accounting policy and procedures, reporting on the financial effects of potential transactions, and developing accounting instructions for certain non-routine transactions and new accounting rules. In addition, I serve as AEP's primary internal advisor with regard to issues surrounding the accounting for employee benefits, including pensions and postretirement benefits. Finally, I administer the internal continuing professional education program for AEP's nearly three hundred certified public accountants and other professional accountants and serve as class discussion leader for many technical accounting subjects.

Background

Q. Please summarize your educational background and professional experience.

A. I graduated magna cum laude from West Virginia University in 1977, with a Bachelor of Science in Business Administration degree in Accounting.

From 1977 to 1981, I was employed by Peat, Marwick, Mitchell and Co., where I was promoted to Audit Supervising Senior. I have been a Certified Public Accountant since 1979, and a member of the American Institute of Certified Public Accountants since 1980.

Since 1981, I have been employed by AEPSC. I served from 1981 to early 1998 in Accounting Policy and Research, initially as a Treasury Staff Accountant and beginning in 1989 as a Senior Treasury Staff Accountant. In 1998, I was promoted to Manager of Utility Ledgers for AEP's operating companies in Ohio. In 2000, I was promoted to Assistant Controller of Non-Regulated Accounting. Following two years in that position and a one-year rotational assignment to Corporate Finance, I returned to Accounting Policy and Research in my current position in 2003.

Q. Have you previously testified before any regulatory commissions?

A. Yes, I have previously testified on pension and postretirement benefits before the Indiana Utility Regulatory Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Public Utility Commission of Ohio, the Corporation Commission of the State of Oklahoma, the Tennessee Public Service Commission, the Virginia State Corporation Commission, the Public Service Commission of West Virginia, and the Federal Energy Regulatory Commission.

Purpose of Testimony

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

A. I will rebut the direct testimony of Kentucky Industrial Utility Customers, Inc. witness Mr. Lane Kollen with regard to the Kentucky Power Company's (Kentucky Power or

Company) pension contributions, pension expense, and postretirement benefits (OPEB) expense.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibits HEM-1 through HEM-4. Exhibit HEM-1 is an example that I created to illustrate that partial funding of an underfunded pension has no effect on the FAS 87 additional minimum pension liability. Exhibit HEM-2 is an excerpt of Mr. Kollen's October 2004 direct testimony before the Louisiana Public Service Commission. Exhibits HEM-3 and HEM-4 are mid-January 2006 updates of 2006 pension and postretirement benefits (OPEB) cost, respectively, that were prepared by our actuaries, Towers Perrin, except that I added the total column to Exhibit HEM-3.

Pension Contributions

Q. What does Mr. Kollen recommend for pension contributions?

A. Mr. Kollen agrees with the Company's proposed adjustment to eliminate from common equity the effect of the December 31, 2004 additional minimum pension liability recorded under FASB Statement No. 87, *Employers' Accounting for Pensions* (FAS 87), but he thinks that the Company's computation is incomplete.

Q. Before you discuss the specifics of Mr. Kollen's recommendation, please remind the Commission about the Company's proposed adjustment.

A. In accordance with FAS 87, the Company recorded an additional minimum pension liability at December 31, 2004, which was recorded as an after-tax equity reduction to Accumulated Other Comprehensive Income (AOCI) of $9.588 million. This negative adjustment to common equity represents the current excess of the present value of the

Company's pension obligation over the fair market value of its pension fund assets. FAS 87 includes deferrals that smooth the effects of such pension fluctuations that are recognized in pension cost and cost of service so that pension cost is recognized systematically and gradually. The additional minimum liability and related AOCI that are recorded on the company's balance sheet for its underfunded pension plans represent possible future pension expense changes that will be included in pension cost and cost of service in future periods, if they do not reverse as a result of interest rate increases and/or pension fund investment value increases. For ratemaking purposes it is not appropriate to reduce equity before a cost is actually fixed, known and certain and before it has been included in the cost of providing service. The company cannot recover this possible future pension cost until it is included in cost of service as an expense. In order to exclude the effect of this possible future pension expense, which may never be included in cost of service and recovered, from the determination of current rates, the negative AOCI charge to equity was added back to capitalization.

Q. What specifically is Mr. Kollen recommending with regard to the additional minimum pension liability?

A. Mr. Kollen's direct testimony states that the Company's adjustment to common equity is correct but that it is incomplete because it fails to reflect March and June 2005 pension contributions made to "partially eliminate the minimum pension funding liability prior to June 30, 2005." He recommends that the Commission reduce the Company's capitalization by $6.092 million on a total company basis to reflect the effect of March and June 2005 pension contributions, thereby updating the December 31, 2004 additional minimum pension liability.

Q. Do you agree with Mr. Kollen's recommendation?

A. No, I disagree with Mr. Kollen's recommendation for two reasons, both related to the proper recording of an additional minimum pension liability under FAS 87. The first and most important reason that I disagree with Mr. Kollen's recommendation is that partial contributions such as the March and June 2005 contributions have no effect on the FAS 87 additional minimum pension liability. Although a contribution to fully fund the pension will eliminate the additional minimum pension liability, partial funding of pension underfunding does not reduce the FAS 87 additional minimum pension liability at all. Therefore, the appropriate adjustment to update the additional minimum pension liability for the March and June 2005 partial contributions is zero.

Q. Please explain.

A. FAS 87 requires the recording of an additional minimum pension liability only if the pension plan is underfunded, that is, if the present value of the accumulated pension obligation exceeds the fair value of pension assets. In that case, an additional minimum pension liability must be recorded for the amount of the underfunding, minus any net pension liability or plus any net pension prepayment recorded on the balance sheet. In the event of a partial funding contribution such as that in question here, the contribution would decrease the underfunding amount and increase the net pension prepayment (or decrease the net pension liability) by the same amount, thereby making no change to the resulting amount of the additional minimum pension liability or the resulting after-tax AOCI reduction to common equity. This is illustrated in the example shown on Exhibit HEM-1. Therefore, no adjustment should be made to the December 31, 2004 additional minimum pension liability or the resulting AOCI reduction to common equity as a result of the March and June 2005 pension contributions.

Q. What is the other reason that you disagree with Mr. Kollen's recommendation?

A. Second, even if an adjustment were appropriate in this instance, and it is not, the amount of the additional contributions to reduce pension underfunding would have to be reduced by thirty-five percent because only the after-tax effect of the additional minimum pension liability affects common equity. Mr. Kollen's computations do not include the effect of deferred income taxes.

Pension Expense

Q. What does Mr. Kollen recommend for pension expense?

A. Mr. Kollen recommends that the Commission reduce the Company's pension expense by $428 thousand on a total company basis. His recommended adjustment is based on using projected 2006 pension cost versus the Company's use of actual calendar year 2005 pension cost from the 2005 actuarial report, in order to reflect lower future cost resulting from investment income on quarterly discretionary contributions made throughout 2005 under the Company's plan to fully fund its pension plan by the end of 2005.

Q. What is the source of Mr. Kollen's recommended 2006 pension cost?

A. In addition to the actual pension cost for the current year, the 2005 actuarial report includes a forecast of costs over each of the next ten years. Mr. Kollen recommends that the Commission use the projection of 2006 pension cost from the 2005 actuarial report.

Q. Do you agree with Mr. Kollen's recommendation?

A. No. Mr. Kollen's recommended use of 2006 cost would inappropriately reflect the lower costs that result in the future from pension contributions that were not made until after June 30, 2005.

Q. When did the Company make these contributions?

A. In order to meet its goal of fully funding the qualified pension plan by the end of 2005, the Company made discretionary contributions near the end of each calendar quarter of 2005. The discretionary contributions for the first three quarters of 2005 were in the amount of $3,045,764 each, while the December contribution required to attain full funding in light of unfavorable 2005 investment return was $6,638,236. Mr. Kollen's recommended use of 2006 pension cost would unfairly take credit for the $9,684,000 or sixty-one percent of 2005 contributions made after June 30, 2005. Without the 2005 discretionary contributions, 2006 pension cost would have been significantly higher than 2005 pension cost.

Q. Is Mr. Kollen's recommendation to use an actuarial report's projected costs for future years consistent according to your experience?

A. No. In this case, Mr. Kollen argues that lower costs in future years as projected in the actuarial report should be used for ratemaking purposes. In his October 2004 direct testimony before the Louisiana Public Service Commission in a revenue requirement review of AEP operating company Southwestern Electric Power Company, Docket No. U-23327, Subdocket A, Mr. Kollen testified on page 22, line 15 (see Exhibit HEM-2), in light of a forecasted increase in pension cost in the actuarial report in that instance, that "post-test year projections are speculative and should not be relied on. They are not known and measurable."

Q. If the Commission were to decide to use projected 2006 pension cost instead of actual 2005 cost, is the forecasted amount used in Mr. Kollen's recommendation the appropriate amount to use?

A. No. The Company in its November and December responses to data requests in this case cautioned that the 2006 projected costs in the March 2005 actuarial report were not certain enough to use for ratemaking purposes and pointed out in particular that recent reviews indicated that actual investment return and interest rates, two of the more significant assumptions, had been worse than projected so far in 2005, which would have the effect of increasing 2006 cost. In mid-January 2006, after the final 2005 investment return and interest rate were known, our actuaries, Towers Perrin, updated their computation of 2006 pension cost (see Exhibit HEM-3) in order to provide the Company an updated estimate to record on its books of account beginning in January 2006. Although this amount of 2006 pension cost recorded in January 2006 is substantially lower than it otherwise would have been as a result of the 2005 discretionary contributions, the total reduction from 2005 actual pension cost on a total company basis is less than $34 thousand, rather than the $428 thousand that Mr. Kollen used in his recommendation.

Q. If the Commission were to decide to use 2006 pension cost instead of 2005 cost, are there any other corresponding adjustments that would be appropriate?

A. Yes, if the lower 2006 pension cost is used, the September and December 2005 discretionary pension payments of $3,045,764 and $6,638,236, respectively, should be added to rate base as prepayments, in the same manner as the March and June 2005 contributions were treated on Workpaper S-4, Page 40, since additional investment earnings on these payments is what helped to reduce 2006 pension cost.

Postretirement Benefits (OPEB) Expense

Q. What does Mr. Kollen recommend for postretirement benefits (OPEB) expense?

A. Mr. Kollen recommends that the Commission reduce the Company's postretirement benefits (OPEB) expense by $142 thousand on a total company basis. As with pension expense, his recommended adjustment is based on using projected 2006 cost versus the Company's use of actual calendar year 2005 cost from the 2005 actuarial report.

Q. Do you agree with Mr. Kollen's recommendation?

A. No. The Company's OPEB cost is declining from year to year as a result of investment income on the Company's monthly contributions to the postretirement benefits trust fund. Using the projected 2006 cost would improperly reflect the benefit of monthly contributions made in 2006.

Q. Did the Company's actuary provide a January 2006 updated computation of 2006 cost for OPEB similar to the one you mentioned for pension?

A. Yes. The updated 2006 OPEB cost is shown on Exhibit HEM-4.

Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

HUGH E. MCCOY, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Hugh E McCoy

WITNESS NAME

Subscribed and sworn to before me by Hugh E. McCoy this 1st day of February, 2006.

[signature]

Notary Public

NOTARIAL SEAL STATE OF OHIO

MANMOHAN K. SACHDEVA
Notary Public, State of Ohio
My Commission Expires 05-18-08

My Commission Expires 05-18-08

Exhibit HEM-1

Effect of Partially Funding an Underfunded Pension

Fully funding an underfunded pension plan will eliminate the FAS 87 additional minimum liability and the related after-tax charge to AOCI. However, **partial** funding has no effect on the cliff nature of the additional minimum liability, as shown in the following example. This is because partial funding also improves the net position of the balance sheet, which must be adjusted back to the underfunded amount.

	Before Partial Funding	+	Partial Funding	=	After Partial Funding
Unfunded Pension Obligation	500		(400)		100
Plus Book Prepaid Pension	300		400		700
Equals Additional Minimum Pension Liability	800		0		800
Minus Deferred Income Tax	(280)		0		(280)
Equals AOCI Reduction to Equity	520		0		520

Therefore, partial funding has no effect on the amount of the FAS 87 additional minimum pension liability.

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

IN RE:	INVESTIGATION OF	)	
	SOUTHWESTERN ELECTRIC POWER	)	
	COMPANY; REVENUE REQUIREMENT	)	DOCKET NO. U-23327
	REVIEW CONDUCTED PURSUANT TO	)	SUBDOCKET A
	MERGER ORDER U-23327	)	

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

LOUISIANA PUBLIC SERVICE COMMISSION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 2004

Q. Has the Commission consistently utilized per books pension expense for its other jurisdictional utilities?

A. Yes. Subsequent to the adoption of SFAS 87, the Commission consistently has utilized the per books SFAS 87 expense for electric utilities rather than funding levels.

Q. Should the Commission adopt the Company's proforma adjustment to utilize projected funding levels for pension expense in lieu of the SFAS 87 per books expense?

A. No. First, there is no compelling reason for the Commission to change its longstanding policy to use the per books pension expense for ratemaking purposes. Second, the proposed pension expense is based on projections of pension funding for four years after the end of the test year. These post-test year projections are speculative and should not be relied on. They are not known and measurable.

<u>Incentive Compensation Tied to AEP Financial Performance</u>

Q. Please describe the AEP incentive compensation plans.

Exhibit HEM-3

AMERICAN ELECTRIC POWER
PENSION
2006 EXPENSE ESTIMATES - REVISED

January 2006

	Estimated Net Periodic Pension Cost				
	East Qualified	**West Qualified**	**East SERP**	**West SERP**	**Total**
AEP Energy Services, Inc.	$9,954	$15,016	$2,083	$0	$27,053
AEP Communications	0	0	0	0	0
AEP Pro Serv, Inc.	(1,581)	0	0	0	(1,581)
AEP T & D Services, LLC	0	0	0	0	0
American Electric Power Service Corporation	20,779,106	5,823,016	6,357,328	2,433,540	35,392,990
Appalachian Power Co - Distribution	2,680,373	10,786	29,406	0	2,720,565
Appalachian Power Co - Generation	3,687,017	7,592	42	0	3,694,651
Appalachian Power Co - Transmission	666,236	0	0	0	666,236
C3 Communications, Inc.	(333)	(2,280)	0	0	(2,613)
Cardinal Operating Company	826,210	0	135	0	826,345
AEP Texas Central Company - Distribution	184,179	2,228,077	0	265,822	2,678,078
AEP Texas Central Company - Generation	0	(527,257)	0	19,315	(507,942)
AEP Texas Central Company - Nuclear	0	11,874	0	0	11,874
AEP Texas Central Company - Transmission	29,037	242,787	0	0	271,824
Columbus Southern Power Co - Distribution	702,737	6,162	2,161	0	711,060
Columbus Southern Power Co - Generation	908,136	0	26	0	908,162
Columbus Southern Power Co - Transmission	203	0	0	0	203
Conesville Coal Preparation Company	75,685	0	0	0	75,685
Cook Coal Terminal	34,856	0	0	0	34,856
CSW Energy, Inc.	34,201	169,041	0	0	203,242
Elmwood	275,045	0	0	0	275,045
EnerShop Inc.	0	10,651	0	0	10,651
Indiana Michigan Power Co - Distribution	1,254,040	0	3,807	0	1,257,847
Indiana Michigan Power Co - Generation	1,444,744	0	0	0	1,444,744
Indiana Michigan Power Co - Nuclear	5,618,009	0	6,389	0	5,624,398
Indiana Michigan Power Co - Transmission	456,871	0	12,683	0	469,554
Kentucky Power Co - Distribution	729,800	0	19,187	0	748,987
Kentucky Power Co - Generation	496,488	4,624	0	0	501,112
Kentucky Power Co - Transmission	222,093	0	0	0	222,093
Kingsport Power Co - Distribution	119,657	0	0	0	119,657
Kingsport Power Co - Transmission	33,673	0	0	0	33,673
Memco	1,126,992	0	9,263	0	1,136,255
Ohio Power Co - Distribution	1,788,781	0	0	0	1,788,781
Ohio Power Co - Generation	2,272,641	0	142	0	2,272,783
Ohio Power Co - Transmission	612,966	0	0	0	612,966
Public Service Co of Oklahoma - Distribution	255,942	1,354,593	0	47,010	1,657,545
Public Service Co of Oklahoma - Generation	94,207	1,042,559	0	30,626	1,167,392
Public Service Co of Oklahoma - Transmission	4,126	189,843	0	0	193,969
Southwestern Electric Power Co - Distribution	150,489	1,302,531	0	0	1,453,020
Southwestern Electric Power Co - Generation	73,208	1,394,249	0	93,100	1,560,557
Southwestern Electric Power Co - Texas - Distribution	23,565	734,113	0	0	757,678
Southwestern Electric Power Co - Texas - Transmission	0	(3,344)	0	0	(3,344)
Southwestern Electric Power Co - Transmission	20,536	210,126	0	0	230,662
Water Transportation (Blackhawk)	783,016	0	0	0	783,016
AEP Texas North Company - Distribution	50,369	1,040,237	0	77,545	1,168,151
AEP Texas North Company - Generation	7,069	(72,795)	0	52,766	(12,960)
AEP Texas North Company - Transmission	9,743	121,469	0	0	131,212
Wheeling Power Co - Distribution	106,605	7,491	0	0	114,096
Wheeling Power Co - Transmission	(16,522)	0	0	0	(16,522)
Cedar Coal Co	(47,473)	0	0	0	(47,473)
Central Coal Company	0	0	0	0	0
Central Ohio Coal	(131,880)	0	0	0	(131,880)
Southern Ohio Coal - Martinka	(85,687)	0	0	0	(85,687)
Southern Ohio Coal - Meigs	(137,258)	0	0	0	(137,258)
Windsor	(49,703)	0	0	0	(49,703)
Price River Coal	(6,000)	0	0	0	(6,000)
Houston Pipeline (HPL)	(14,720)	(411)	6,122	0	(9,009)
Total	$48,157,448	$15,320,750	$6,448,774	$3,019,723	$72,946,695

Discount rate	5.50%
Expected return on assets	8.50%
Crediting rate	5.50%

Demographic assumptions match those from the assumption study forecast sent on November 22, 2005.

Exhibit HEM-4

AMERICAN ELECTRIC POWER
POSTRETIREMENT WELFARE
2006 EXPENSE ESTIMATES

January 2006

	Estimated Net Periodic Postretirement Welfare Cost		
	Non-UMWA	**UMWA**	**Total**
AEP Energy Services, Inc.	$43,670	$0	$43,670
AEP Pro Serv, Inc.	(1,571)	0	(1,571)
AEP Service Corporation	18,791,654	0	18,791,654
AEP Texas Central Co - Distribution	5,062,235	0	5,062,235
AEP Texas Central Co - Generation	1,205,247	0	1,205,247
AEP Texas Central Co - Nuclear	4,371	0	4,371
AEP Texas Central Co - Transmission	649,000	0	649,000
AEP Texas North Co - Distribution	1,951,328	0	1,951,328
AEP Texas North Co - Generation	802,268	0	802,268
AEP Texas North Co - Transmission	283,996	0	283,996
Appalachian Power Co - Distribution	7,357,106	0	7,357,106
Appalachian Power Co - Generation	5,384,856	0	5,384,856
Appalachian Power Co - Transmission	940,984	0	940,984
Cardinal Operating Company	1,138,979	0	1,138,979
Cedar Coal Co.	110,659	4,713,101	4,823,760
Central Ohio Coal Co.	209,948	0	209,948
Central Coal Co.	0	116,460	116,460
Columbus Southern Power Co - Distribution	4,480,007	0	4,480,007
Columbus Southern Power Co - Generation	2,053,345	0	2,053,345
Columbus Southern Power Co - Transmission	413,193	0	413,193
Conesville Coal Preparation Company	50,311	717,735	768,046
Cook Coal Terminal	49,582	1,595,110	1,644,692
CSW Energy, Inc.	126,091	0	126,091
Elmwood	366,220	0	366,220
Houston Pipeline (HPL)	859,469	0	859,469
Indiana Michigan Power Co - Distribution	3,917,052	0	3,917,052
Indiana Michigan Power Co - Generation	1,924,449	0	1,924,449
Indiana Michigan Power Co - Nuclear	3,870,443	0	3,870,443
Indiana Michigan Power Co - Transmission	779,357	0	779,357
Kentucky Power Co - Distribution	1,202,211	0	1,202,211
Kentucky Power Co - Generation	621,008	0	621,008
Kentucky Power Co - Transmission	159,924	0	159,924
Kingsport Power Co - Distribution	304,384	0	304,384
Kingsport Power Co - Transmission	48,385	0	48,385
Memco	901,127	0	901,127
Ohio Power Co - Distribution	5,812,277	0	5,812,277
Ohio Power Co - Generation	4,155,534	0	4,155,534
Ohio Power Co - Transmission	1,119,529	0	1,119,529
Price River Coal Co. (Blackhawk Coal)	(406)	609,226	608,821
Public Service Co of Oklahoma - Distribution	4,177,735	0	4,177,735
Public Service Co of Oklahoma - Generation	1,786,711	0	1,786,711
Public Service Co of Oklahoma - Transmission	399,645	0	399,645
Southern Ohio Coal - Martinka	86,269	0	86,269
Southern Ohio Coal - Meigs	238,169	0	238,169
Southwestern Electric Power Co - Distribution	2,376,397	0	2,376,397
Southwestern Electric Power Co - Generation	2,271,505	0	2,271,505
Southwestern Electric Power Co - Texas - Distribution	1,127,088	0	1,127,088
Southwestern Electric Power Co - Texas - Transmission	54,031	0	54,031
Southwestern Electric Power Co - Transmission	335,563	0	335,563
Water Transportation (Lakin)	997,381	0	997,381
Wheeling Power Co - Distribution	411,379	0	411,379
Wheeling Power Co - Transmission	31,418	0	31,418
Windsor Coal Co.	75,186	0	75,186
Total	$91,516,698	$7,751,632	$99,268,330

Discount rate	5.65%
Expected return on assets	8.00%
Initial trend rate	8.00%
Ultimate trend rate	5.00%
Years to reach ultimate trend	3

Demographic assumptions for non-UMWA match those from the assumption study forecast sent on November 22, 2005.

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF	)	
GENERAL ADJUSTMENT OF ELECTRIC	)	
RATES OF KENTUCKY POWER COMPANY	)	**Case No. 2005-00341**

REBUTTAL TESTIMONY
OF
TIMOTHY C. MOSHER

ON BEHALF OF
KENTUCKY POWER COMPANY

February 2, 2006

REBUTTAL TESTIMONY OF
TIMOTHY C. MOSHER ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005-000341

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

A. My name is Timothy C. Mosher. I am President and Chief Operating Officer of Kentucky Power Company (Kentucky Power or Company). My business address is address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut direct testimony presented by the Attorney General's Witness Robert Henkes and the KIUC's Witness Lane Kollen on a number of the adjustments.

Q. Do you agree with the testimony of the Attorney General's witness R.J. Henkes concerning Public/Community Relations Expenses?

A. No, we do not. AEP will celebrate 100 years of serving customers in 2006. During that proud history the Company has expended its employees' talents as well as corporate dollars in the development of the communities within our service territory footprint. In 1934 AEP President George Tidd wrote a corporate creed entitled "Our Job." In it he specifically described the Company's responsibility to actively participate in the community. "...We are citizens of each community we serve and take an active part in its affairs. Like any other citizen, we want our neighbors to think well of us. Besides, it makes good business sense. We prosper only as the community prospers; so we help it thrive in every way we can…". Just last year our current Chairman, President, and CEO, Michael G. Morris, reaffirmed the "Our Job" philosophy as the reason we're in business. Corporate community involvement has a direct positive correlation to economic development. All of our customers benefit directly by that involvement. As the community grows and prospers, there's a larger base of customers over which to spread the cost of doing business, reducing the average cost to each customer.

Q. What activities are included in Public/Community Relations Expenses?

A. We have two community affairs managers in Kentucky, one in Ashland responsible for the northern half of our service territory and one in Hazard responsible for the southern half. Both report directly to the Company president. Their primary function is to work with local officials on both the county and city level. From the county judge executive to the small city mayors, they participate in the community to discuss directly the importance of safety, reliability, economic development and customer service. They continually monitor our progress in meeting our customers' needs. To do that, they attend fiscal court meetings, city council meetings and participate in various community organizations where the interface needed to measure our progress in meeting our customer's expectations can be determined. The costs related to these activities should be recoverable from the customers since there is a direct ratepayer benefit in the areas of safety, reliability, economic development and customer service.

Q. Please describe the Company's incentive compensation plans.

A. As part of a market competitive total compensation program, the Company provides base compensation and three incentive compensation plans in which various Kentucky Power employees are eligible to participate. The first is the Annual Incentive Compensation Plan, covering employees in the three functional areas of Generation, Energy Delivery and General Services. The second incentive plan is the Safety Focus Plan and the third is the Long-Term Incentive (LTI) plan. This total package of base compensation and the three incentive compensation plans is designed to provide average total compensation for each position equivalent to the median (50^{th} percentile) of national survey data for comparable positions in the electric utility industry. This approach to compensation design, including the use of incentive compensation, has a very high prevalence among large U.S. industrial companies and electric utilities.

Q. Please explain what you mean when you say that these incentive plans are part of a total compensation package.

A. The Company's incentive compensation plans are not designed as simple additions to an already appropriate level of compensation. Instead, the Company designs an overall compensation package that includes several incentive compensation components. It is the entire compensation package that allows the Company to attract and retain qualified, highly motivated employees able to support reliable, cost effective service to customers. Therefore, if the Company were to eliminate its incentive compensation program, the Company would be required by the reduced competitiveness of its pay package, to largely, if not entirely, offset this lost incentive compensation with additional base pay. If this were to occur, the Company would lose the motivational, communication and alignment benefits of its incentive program.

Q. Why is a portion of an employee's compensation dependent on meeting incentive targets?

A. Tying a portion of compensation to incentives better motivates and aligns employee efforts towards achievement of the balanced scorecard of financial, reliability, safety, and customer service objectives included in the various incentive plans. The Company also uses incentive compensation to align pay with performance so that median compensation is not paid for below median levels of performance and, conversely, the opportunity for above median pay exists for high levels of performance. Finally, the Company is better able to attract, retain and motivate highly qualified and dedicated employees because these employees themselves place a high value on incentive compensation.

Q. Are incentive compensation packages common in the electric industry?

A. Yes, they are. Incentive compensation plans similar to the plans that the Company employs are widespread in the electric, gas and similar industries as well as in U.S. companies in general. As such, these plans are important to the Company's ability to attract and retain highly qualified and dedicated employees and this has a very real, if not direct, effect on the quality of AEP's service. Additionally, the number of companies offering incentive compensation programs continues to increase.

Q. Should the Commission recognize all incentive compensation as a proper expense for ratemaking purposes?

A. Yes. Incentive compensation is necessary to provide the Company's employees with a market competitive total compensation package. Without such a package, it would be difficult to attract and retain qualified and dedicated employees. Securing and retaining such employees benefits customers and shareholders alike. The principal objective of the Company's incentive compensation programs is to motivate and align employee efforts with a scorecard of performance measures that balances the Company's financial, reliability, safety, and customer service performance objectives. A balanced set of performance objectives sends a clear message to all employees that high incentive award scores will be achieved only if success is attained in all areas (financial, reliability, safety, and customer service). This broad emphasis leads Company employees to focus in all areas (financially, reliability, safety, and customer service), and to better performance in all of them. Success or failure in any of these categories has a positively correlated influence on the other categories so that it would be self-defeating to achieve results in one category by sacrificing another, particularly when multiple plan years are considered.

Customers clearly benefit from incentive compensation plans which contain financial performance measures because employees have an incentive to (1) optimize the use of the Company's limited financial resources, (2) pursue all sources of additional earnings, and (3) contribute to the financial health of the Company - all of which benefits customers through delayed rate filings and lower capital and O&M costs.

Q. Do you agree with the position of the Attorney General, which opposes recognition of incentive compensation?

A. I do not. The AG wrongly concludes that the portion of incentive compensation based on financial measures is not in the public interest because it does not, in the view of the AG, directly benefit ratepayers. Indeed, the financial measures work together with operational measures to promote the financial integrity of, and low cost service provided by, the Company. Customers' interests are furthered when the Company controls costs in an effective and efficient manner from a financial perspective. In addition, to the extent that financial targets are more consistently met, the need for rate relief is lessened. In the long run, all these measures benefit customers.

Q. Are there other reasons why employee incentives linked to the Company's earnings benefit the customers of the Company?

A. Yes. Strong earnings improve access to the capital markets on lower cost terms, lower the cost of service, and result in fewer requests for rate increases over time. Customers' benefit by Company policies designed to ensure fiscal discipline, which tends to make the cost of service lower than it would be otherwise. In truth, the financial incentive compensation programs benefit both shareholders and customers because their interests in this area are aligned.

Q. Mr. Kollen characterizes the off-system sales margins as being shared on a 50%/50% basis between ratepayers and the Company. Is this characterization accurate?

A. No. The Company's base rates currently have a level of $11.3 million in off-system sales margins that are credited 100% to the ratepayers of the Company. Only if the Company realizes off-system sales margins above $11.3 million is there any sharing between the ratepayers and the Company. For the test year, the Company realized off-system sales margins of $24.9 million, or $13.6 million above the base level currently included in rates. So, for the test year, total off-system sales margins to the customers was $11.3 million in base rates plus one-half of $13.6 million or $18.1 million in total off-system sales margins, which is approximately 73% to the ratepayer and 27% to the Company. In this rate filing, the Company is proposing to increase the base level of off-system sales margins from $11.3 million to $24.9 million, and then sharing off-system sales margins equally above or below that level. In other words if the ongoing levels remained at $25 million there would be no sharing. If, through the Company's initiative, we were able to increase margins by 20% to approximately $30 million, 91% would go to the customers, well above the 73% that is given to the customers today.

Q. Mr. Kollen proposes to eliminate the sharing of off-system sales revenue margins between ratepayers and the Company. On page 14 at lines 6-11, Mr. Kollen points to AEP's Appalachian Power Company subsidiary's proposed treatment of off-system sales margins within the Expanded Net Energy Cost ("ENEC") recovery clause. How are off-system sales margins treated in the other AEP Operating Companies?

A. The treatment of off-system sales margins varies with each Operating Company due, in part, to differences in the regulatory requirements in which each Operating

Company operates. Mr. Kollen points out just one such regulatory difference. In West Virginia, Appalachian Power Company has requested in its current case authority to reinstate the ENEC mechanism, which had been suspended since 2000. The ENEC mechanism passes through to ratepayers 100% of a variety of costs and revenues. The State of Kentucky does not have the same mechanism in place for Kentucky Power Company. This is just one difference of many among the various jurisdictions in which AEP operates. In fact, KPCo customers have realized one of the highest percentages of off-system sales credits among any AEP Operating Company. Within some of the AEP jurisdictions, a tiered sharing mechanism is employed, while others have a specified percentage that is split between the customer and the Operating Company. Texas does not currently pass any off-system sales revenues to retail ratepayers, due in part to the regulatory structure in that State.

The difference in treatment has nothing to do with being second class, as Mr. Kollen alleges at page 15, line2. Rather, sharing off-system sales margin is a win-win situation providing the customer with a credit to their bill and AEP with the proper incentive to maximize off-system sales. This incentive is not only used to hire and maintain experts in Commercial Operations, but also to allow the Company to re-invest in operations in order that it will not have to continually request base rate increases.

The Company has proposed that certain highly volatile revenues and costs be tracked through a tracker mechanism as explained by witnesses Roush and Bradish. The Company is willing to work with all interested parties to this case in a collaborative process to develop an acceptable mechanism similar to the ENEC mechanism in West Virginia.

Q. Mr. Kollen also claims at page 12 that given Kentucky Power's small size, an incentive to maximize off-system sales will not be effective. Do you agree?

A. No, I do not. As explained by Company Witness Bradish in his rebuttal testimony the Commercial Operations department of AEPSC engages in significant activities to maximize total off-system sales margins realized, which includes margins realized through trading activity that is not based on the physical assets of the Company. The Company should be incentivized to put the necessary resources of capital and personnel in place to optimize the AEP System's off-system sales margins.

Q. Mr. Kollen claims on page 15 that the allocation of off-system sales margins between AEP East and AEP West is changing and should not be split 50/50 because these margins arise "simply as a result of reallocation." Do you agree?

A. No, I do not. Off-system sales margins arise from concerted efforts by AEP. The activity underlying these off-system sales margins is the same as what has been outlined in the rebuttal testimony of Mr. Bradish. Changing the allocation of off-system sales margins as between the AEP East and AEP West does not change the effort, risks, or policy reasons for a fair sharing of even these margins.

Q. How do you propose to share off-system sales margins?

A. In the filing, the Company has proposed increasing the rate base level of off-system system margins from $11.3 million to $24.9 million and continuing the sharing above or below that level on a 50%/50% basis as has been the past practice. Alternatively, removing the base level of off-system sales margins from rates designed in this proceeding and sharing all realized off-system sales margins on a 75% split to customers and 25% to the Company through an offsystem sales tracker would fairly maintain the current incentives while providing customers with additional upside gain from any higher-than-expected off-system sales margins. As Mr. Bradish explains, off-system sales margins are achieved through the value added activity of the entire AEP organization engaging in wholesale transactions, not only around the assets of the Company, but also through hedging, trading and marketing. It is proper public policy to reward the shareholders and the Company for allocating capital and personnel to the successful realization of and maximization of off-system sales margins to the benefit of all stakeholders.

Q. Can you address Mr. Kollen's statement on page 30 of his testimony that the Company has not provided any assurance that the company will actually incur the projected reliability expenditures if they are included in the revenue requirement?

A. Yes, I can. I can assure the Commission that if the expenditures are included in the revenue requirement the Company will expend the funds and would be willing to document the expenditure to the Commission in a report.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Timothy C. Mosher, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

T. C. Mosher

Timothy C. Mosher

Subscribed and sworn before me by Timothy C. Mosher this 1st day of February 2006.

Judy K Tackett

Notary Public

My Commission Expires January 14, 2009

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

GENERAL ADJUSTMENTS IN ELECTRIC RATES OF KENTUCKY POWER COMPANY

CASE NO. 2005-000341

REBUTTAL TESTIMONY OF PAUL R. MOUL

ON BEHALF OF KENTUCKY POWER COMPANY

February 2, 2006

Kentucky Power Company
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REBUTTAL TESTIMONY OF
PAUL R. MOUL, ON BEHALF OF
KENTUCKY POWER COMPANY,
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005-000341

Q: Please state your name and business address.

A: My name is Paul R. Moul and I am managing consultant at P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q: Have you previously submitted testimony in this proceeding?

A: Yes. My direct testimony was included as part of the Company's case-in-chief.

Scope of Testimony

Q: What is the purpose of your testimony?

A: Kentucky Power Company ("Kentucky Power" or the "Company") has requested that I comment on and rebut testimony presented by Dr. J. Randall Woolridge, a witness appearing on behalf of the Office of Attorney General ("AG"), and Mr. Richard A. Baudino, a witness appearing on behalf of the Kentucky Industrial Utility Consumers, Inc. ("KIUC"). I will also comment on the issue of incentive compensation.

Q: Please identify the areas of disagreement with the rate of return testimony submitted by AG witness Woolridge and KIUC witness Baudino.

A: The central areas of dispute involving the cost of equity issue are: (i) the cost of equity that will be acceptable to the financial community, (ii) the proxy group of companies that should be considered in applying the various models of the cost of equity, (iii) the determination of a reasonable DCF cost rate, (iv) the modification to account for the divergence of the market capitalization from book value, (v) the flotation cost adjustment, and (vi) the use of other methods to measure of the cost of equity. For the reasons that follow, it is my opinion that the cost of equity proposals by the opposing witnesses are far too low as compared to returns being granted in other rate cases and do not provide the types of returns expected by investors.

Q: Why, in your view, are the recommendations of the AG and KIUC too low?

A: The proposed returns are too low by reference to returns authorized in other rate case proceedings and by reference to the returns expected by investors. The PUR Utility Regulatory News ("URN") issue dated December 23, 2005 provides the results of the annual survey of regulatory authorized rates of return on common equity. The distribution of the returns were:

	Electric & Gas		Electric Only	
	Number	Percent	Number	Percent
Less than 10%	5	10%	1	4%
10% to 10.9%	27	52%	15	58%
11 to 11.9%	19	36%	9	34%
Higher than 12%	1	2%	1	4%

The average authorized rate of return on common equity for all cases listed above for the twelve-months ended September 15, 2005 was 10.68%, the median return was 10.56%, and the midpoint return was 10.88%, taken from the overall range of 9.50% to 12.25%[1]. For the electric rate cases, the average return was 10.73%, the median return was 10.60% and the midpoint return was 10.94%. This data, which were taken from

[1] The 2005 survey published in PUR Utility Regulatory News contained an error where one return was erroneously reported as an equity return, when it actually was an overall rate of return. The tabulation shown above corrects this error. PUR Utility Regulatory News, December 23, 2005 (Letter #3749), at 2-5.

recently decided rate cases, show that returns below 10% are uncommon for electric utilities. It also shows that returns on equity of 8.75% or 9.35% proposed by AG witness Woolridge and KIUC witness Baudino do not come close to mainstream returns that have been granted in public utility rate cases. Indeed, the Commission just granted Union Light, Heat & Power Co. a 10.2% return in its rate case decision dated December 22, 2005. While the return that was granted to Union Light, Heat & Power Co. may be viewed as low, it does demonstrate the unreasonable positions of the AG and KIUC witnesses. By comparison, the return I recommend for Kentucky Power Company is 11.5%. This return contains both a leverage adjustment to the traditional DCF model (i.e., 0.74%) and a flotation adjustment (i.e., 0.21%). Without these modifications, which I firmly believe should be recognized, my return would be 10.55% (11.50% - 0.74% - 0.21%), a figure more consistent with Commission history and investor expectations.

Q: What type of returns do investors expect electric utility companies to earn?

A: According to the Value Line report dated December 30, 2005, the electric utility industry is forecast to earn the following returns:

2005	10.5%
2006	10.5%
2008-10	11.0%

Based upon these returns, the AG's proposed rate of return on common equity of 8.75% and KIUC's rate of return on common equity of 9.35% is inadequate to satisfy investor expectations.

Q: Please summarize your assessment of the equity analysis presented by Dr. Woolridge?

A: In my opinion, the costs of equity recommended by Dr. Woolridge (i.e., 8.75%) is inadequate to provide Kentucky Power with a reasonable opportunity to achieve the earnings required by investors. An 8.75% common equity allowance would not adequately compensate investors for the additional risk they would incur vis-a-vis the 6.17% return they could receive on far less risky Baa rated public utility bonds. The proposal of AG witness Woolridge provides a woefully inadequate 2.58% spread between the cost of debt and cost of equity.

Q: Do you have the same concern regard the proposal of KIUC witness Baudino?

A: Yes. Although Mr. Baudnio's position is not quite as extreme as Dr. Woolridge, his proposal is outside the mainstream of acceptable returns. As noted above, no other regulatory agency has granted a return that low according to the URN survey.

Q: What has caused this to happen?

A: For a variety of technical reasons that I will cover later in my rebuttal testimony, the rate of return proposals by Dr. Woolridge and Mr. Baudino rely upon inadequate inputs in the models used to measure the cost of equity. Dr. Woolridge and Mr. Baudino, relied upon data for groups of non-comparable companies, they have understated the growth component of the DCF model, and they have failed to adequately measure investor expectations of their required returns (partially so for Mr. Baudino) in their CAPM approach. In addition, both witnesses have failed to adjust the market determined cost rate for application to a book value capitalization.

Comparable Companies

Q: Have proxy groups of companies been employed in this case to determine the Company's cost of equity?

A: Yes. All rate of return witnesses have used proxy groups of companies to measure the cost of equity for Kentucky Power because the Company's stock is not traded.

Dr. Woolridge's proxy group includes companies that are substantially dissimilar from one another and are generally not comparable to Kentucky Power. Only one of Dr. Woolridge's companies (i.e., Ameren) has been used in my Electric Group. The other companies used by Dr. Woolridge operate in areas geographically remote to Kentucky, such as Louisiana, Kansas, Oklahoma, Vermont, Hawaii, and Idaho. There is just no commonality among his companies, which is required to substantiate their comparability to Kentucky Power. For example, CLECO Corporation was one of Dr. Woolridge's companies and it is faced with substantial costs associated with hurricanes Katrina and Rita. These are not costs faced by Kentucky Power. In addition, one of his companies, Hawaiian Electric Industries, has no interconnections with other utilities and it owns American Savings Bank. The Public Utilities Commission of Hawaii does not even use HEI data when setting the rate of return for HEI's own electric subsidiaries. Other unusual selections include Westar Energy, where two of its former executives have been convicted of criminal charges. Further, approximately 46% of Kentucky Power's sales are to industrial customers, which is high by industry standards. This higher concentration of load in relatively fewer customers increases risk. The Value Line reports for Dr. Woolridge's companies show no other company with this magnitude of industrial sales. Moreover, size and financial risk differences make Kentucky Power a more risky company. According to Exhibit JRW-3, the proxy group used by Dr. Woolridge had an average common equity ratio of 52%, and had average operating revenues of $1.8 billion. The common equity ratio proposed by the Company is just 39.54% and its revenues are $426 million. This makes Kentucky Power a more risky company than Dr. Woolridge's proxy group.

Q: Please comment on the group of companies proposed by KIUC witness Baudino.

A: Mr. Baudino has assembled an even more unusual collection of electric companies to measure the cost of equity for Kentucky Power. The wide divergence of risk traits of his companies makes their usefulness questionable for this case. Mr. Baudino's group of electric companies included companies that are also geographically remote to Kentucky Power, such as those operating in Arkansas, Kansas, Connecticut, Massachusetts, Hawaii, New Mexico, Arizona, Washington, Oregon, and Oklahoma. Mr. Baudino should have considered a geographic criteria when selecting his proxy group companies. This omission is surprising given the criteria specified in the Bluefield case, which states:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that <u>generally being made</u> at the same time and <u>in the same general part of the country</u> on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. (emphasis supplied). Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 43 S. Ct. 675, 67 L.Ed. 1176, 1182-1183 (1923). (emphasis added).

Geographical differences create cost differences from region to region and can lead to markedly different utility rates that reflect conditions particular to a specific service area. For example, the cost structures are distinctly dissimilar between Hawaii, Connecticut, Vermont, and Kentucky as exemplified by the Energy Information

Administration ("EIA") data.[2]

Q: Do you have other observations concerning Mr. Baudino's group?

A: His unusual selections include Pinnacle West and UniSource, which operates in Arizona; Puget Energy and Avista, which operates in the State of Washington; PNM that operates in New Mexico; and Progress Energy that operates in Florida. These are not service territories similar to Kentucky Power. Further, Mr. Baudino's inclusion of Duquesne Light, Energy East, and Northeast Utilities, which divested most of their generation assets, do not fit as comparables to Kentucky Power. On balance, Mr. Baudino's group provides a poor proxy for Kentucky Power. Therefore the companies used by Mr. Baudino, and Dr. Woolridge, as well, are inappropriate to measure the Company's cost of equity because they generally are not comparable.

<u>Discounted Cash Flow</u>

Q: What form of the DCF model has been employed in this case?

A: The constant growth or "Gordon" form of the DCF model has been used by Dr. Woolridge, Mr. Baudino and me.

Q: Do you have specific concerns regarding the DCF model as it has been applied in this case by the opposing witnesses?

A: The fallacy of the DCF model is shown by results that can provide a wholly unrealistic representation of a fair rate of return on common equity. When mechanically applied, the DCF mode can produce improbable results. While disavowing the result, the DCF could produce a return as low as 7.79% (see Mr. Baudino's response to Company

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2 The average retail price of electricity in 2004 was 15.70 cents per KWh in Hawaii, 10.26 cents per KWh in Connecticut, 11.02 cents per KWh in Vermont, and 4.63 cents per KWh in Kentucky (see EIA, "Annual Electric Power Industry Report").

Interrogatory No. 32). Any calculation that would produce a result as low as 7.79% shows that the methodology is seriously flawed. Likewise, Dr. Woolridge has provided DCF calculations that provide returns below 9% (i.e., 8.6% and 8.9%). The DCF results of Dr. Woolridge and Mr. Baudino are arrayed as follows:

Less than 9%	Above 9% but less than 10%
8.60%	9.29%
8.90%	9.54%
8.95%	9.57%

These returns provide insufficient compensation for the higher risk of equity vis-à-vis debt, as revealed by a 6.17% yield on Baa rated public utility bonds on January 26, 2006.

Q: Has undue emphasis been placed on the DCF model by the opposing witnesses?

A. Mr. Baudino, in particular, has given too much weight to the results of the DCF. It must be recognized that the "Gordon" form of the DCF model is not without its limitations because many of the assumptions that must be made to utilize this model simply are not realistic. These include constant and infinite growth and the assumption that earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same constant rate absent any change in dividend payout and price-earnings multiple. The Gordon model does not account for, or reflect changes in the variables that are common characteristics of the equity market. Indeed, the evidence shows that these steady-state (i.e., constant growth) conditions represent unrealistic assumptions of investor expectations. With declining dividend payout ratios, earnings per share and price appreciation (i.e., the capital gains yield, or growth component of the DCF) will be at a higher rate than dividend growth in the future for the electric companies. This is shown by the dividend payout ratios for the companies in Dr. Woolridge's and Mr. Baudino's proxy groups, which are forecast to decline in the next several years:

	Payout	
Year	Woolridge	Baudino
2006	77.5%	72.3%
2007	72.6%	65.5%
2009-11	68.2%	63.9%

With the forecasted trend of declining payout ratios, the use of dividend growth is particularly inappropriate for DCF purposes. Therefore, both the historical dividend per share growth rates and projected Value Line dividend per share growth rates should be discounted.

Q: As to the DCF growth component, did Mr. Baudino and Dr. Woolridge give appropriate weight to earnings growth?

A: No. The opposing witnesses failed to adequately consider earnings growth in their analysis. The theory of DCF indicates that the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share, and that dividend growth will equal earnings growth with a constant payout ratio. Unfortunately, a constant payout ratio reflects neither the reality of the equity markets, nor investor expectations. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given primary emphasis. Mr. Baudino failed to accomplish this by providing 25% weight to dividend growth. While less specific in the derivation of his growth rate, Dr. Woolridge provided a table of growth rates that averaged dividend per share and book value per share growth rates with earnings per share growth rates. He also provided separate recognition for internal growth (although erroneously calculated) in his table (see his testimony page 25).

Q: Are there other reasons that the opposing witnesses should have emphasized growth in earnings per share?

A: Yes. Earnings per share growth is the primary determinant of investor expectations concerning their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is important to recognize that analysts' forecasts significantly influence investor growth expectations. Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases (and the individual whose name is most commonly associated with the DCF model) has determined that the best measure of growth in the DCF model is analysts' forecasted earnings per share growth[3]. Hence, to follow Professor Gordon's findings, earnings per share forecasts must be given primary weight. For this reason, Mr. Baudino's DCF analysis that included growth in dividends, and to some extent Dr. Woolridge's analysis, does not represent the returns expected by investors.

Q: Dr. Woolridge's testimony at pp. 57-64 suggests that analyst forecasts of earnings per share contain some form of bias. Please comment.

A: Dr. Woolridge claims that there is an upward bias in the analysts' forecasts. I am somewhat perplexed by Dr. Woodridge's assertion in this regard because he relied

[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

extensively on analysts' forecasts in his testimony concerning the DCF growth rate. Indeed, the Value Line forecasts would not suffer from the same problems alluded to by Dr. Woolridge concerning other analysts forecasts, because Value Line is not in the business of providing brokerage services. It is important to recognize that analysts' forecasts significantly influence investor growth expectations as noted above.

Q: Please comment on the growth rate proposed by Mr. Baudino.

A: As noted previously, his dividend per share growth rate is entirely too low because it produces an unrealistic DCF result (i.e., less than 9%). The growth rates that he proposes using the Value Line (i.e., 5.41%) Zacks (i.e., 5.43%), and First Call (i.e., 5.16%) data are plausible because they contain inputs that conform with both the assumption of the DCF model and expectations of investors.

Q: Did the opposing witnesses erroneously consider retention growth?

A: Yes, the retention growth formula was misapplied.

Q: Please demonstrate how the retention growth formula has been inappropriately applied in the context of the DCF methodology.

A: Mr. Baudino develop retention growth for his proxy group by assuming that the selected companies will experience an average 10.31% earned return on book value with a retention rate of about 36.10% after payment of common dividends (see page 2 of Exhibit RAB-4). However, his average is suppressed by the poor forecast performance for Avista (i.e., 8.0% where Value Line warns of gas-trading problems), CLECO (i.e., 7.5%), Empire District (i.e., 9.0%), Pinnacle West (i.e., 8.5%), PNM Resource (i.e., 8.0%), Puget Energy (i.e., 9.0%), and UniSource Energy (i.e., 8.0% where Value Line describes "this untimely stock's finances are among the weakest in the group."). These returns are in contrast to the industry-wide returns that are forecast to be 10.5% to 11.0%.

Dr. Woolridge also includes a significant number of poor performers in his group that artificially suppresses his DCF results (e.g., Dr. Woolridge includes IDACORP that is forecast to earn just 7.0%). Once again this demonstrates how the inclusion of poor performing, non-geographically comparable, electric companies serves to create a downward bias in the DCF returns proposed by Dr. Woolridge and Mr. Baudino. Further, neither of these witnesses has reconciled their DCF calculations (9.34% for Mr. Baudino and 8.6% for Dr. Woolridge) with the investor expected return of 10.31% for Mr. Baudino's group and 8.9% for Dr. Woolridge's group.

Q: Has Dr. Woolridge or Mr. Baudino included external financing growth in their internal growth/sustainable growth analyses?

A: No. This omission results in a further downward bias in their growth rate analysis. Forecasts indicate future growth from external stock financing will add to the growth in equity for these groups. This would result in an internal/external growth rate higher than that developed by Dr. Woolridge and Mr. Baudino. Indeed, my direct testimony indicates that external financing can add 0.25% to the growth rate.

Q: Has Dr. Woolridge and Mr. Baudino committed other omissions in their retention growth analysis?

A: Yes. They failed to adjust the Value Line forecast return from year-end to average book common equity. The Federal Energy Regulatory Commission ("FERC") adjusts the year-end returns to derive the average yearly return. The FERC uses the formula: 2 (1 + G) / (2 + G), where the growth in common equity is represented by "G" (see 92

FERC ¶ 61,070). In fact, the retention growth analysis contained in my direct testimony provides this recognition.

Q: Why is it important to adjust the Value Line returns for average book common equity values?

A: Without an adjustment to convert the Value Line forecast return from year-end to average book values, there is a downward bias in the results. Value Line uses year-end (rather than average yearly book value) to calculate its returns. Value Line's definition is:

> "***Percent Earned Common Equity*** – *net profit less preferred dividends divided by common equity (i.e., net worth less preferred equity at liquidation or redemption value), expressed as a percentage. See Percent Earned Total Capital.*"

When using what KIUC witness Mr. Baudino refers to as sustainable growth (or internal growth used by Dr. Woolridge the FERC makes the required adjustment).

Q: If this had been done, what would have been the effect on the DCF conclusions?

A: Using the data contained in my Exhibit No. PRM-1, page 16 of 32, moving to average book values increases the yearly average return by 0.35%, and increases the retention growth rate by 0.15%. By combining the average book value adjustment with the external growth rate discussed above, the growth rate is increased by 0.40% (0.15% + 0.25%) using the data for my Electric Group as a basis.

<u>Flotation Cost Adjustment</u>

Q: Do you agree with Dr. Woolridge's and Mr. Baudino's testimony where they reject a flotation cost adjustment as part of their cost of equity analysis?

A: No. A flotation cost adjustment is appropriate to compensate a utility for the cost of raising equity capital. To the extent that the proxy group of companies experienced flotation costs, and those groups play a role in the determination of the Company's cost of equity, then a similar adjustment should be incorporated into the final cost of equity determination. Moreover, regardless of the theoretical justification for this allowance, the facts in this case support a flotation cost adjustment.

Q: Please identify those facts for the Commission.

A: According to its Form 10-K filing with the SEC, Kentucky Power received $50 million of the proceeds from the newly underwritten share offering by AEP in 2002. Moreover, for the past several years, AEP has been selling new shares of common stock thorough its Dividend Reinvestment and Stock Purchase Plan. Indeed, recognition of flotation costs in this case would be consistent with the actual experience of AEP and Kentucky Power and supports my allowance for flotation costs.

<u>Capital Asset Pricing Model</u>

Q: Do you have observations concerning the CAPM as applied by Dr. Woolridge?

A: Yes. It appears to me that he has probably misstated the total return for the market as a whole. The return he provides, such as 8.2% (see his testimony at page 42) cannot possibly be correct. First, such return for the more risky market as a whole is <u>less than</u> the DCF returns he calculates for his electric groups (see his testimony page 26). Second, using the First Call growth rate for the S&P 500, the market return would be:

	D/P	$(1+g)$	+	g	=	km
S&P 500	1.9%	(1.05255)	+	10.51%	=	12.51%

Mr. Baudino's calculations substantiate a total market return above 12% (see page 1 of Exhibit RAB-5). Dr. Woolridge's 8.2% return using CAPM thus is not supportable.

Q: Have you revised Dr. Woolridge's CAPM proposed for these results?

A: Yes, I have restated the total market returns for the S&P 500 by employing the First Call forecast and have used the remaining inputs from Dr. Woolridge.

	Rf	+	β	(Rm – Rf)	=	K
Group A	4.75%	+	.70	(12.51% - 4.75%)	=	10.18%
Group B	4.75%	+	.75	(12.51% - 4.75%)	=	10.57%

The total market (Rm) which is indicated to be 12.51% is derived from the First Call growth forecasts.

Q: Mr. Baudino also submits a series of CAPM determined cost of equity at pp. 24-32 of his testimony. Do you agree with his assertions concerning the results of his CAPM analysis?

A: No. First, there is no reason to ignore the CAPM results shown on page 1 of Exhibit RAB-5. There he shows CAPM results of 12.56% and 12.49% using the yields on 20-year and 5-year Treasury bond/notes, respectively. He also provides results on Exhibit RAB-6 for an alternative CAPM calculation (i.e., 8.98%), that mistakenly employs geometric means. The corresponding CAPM calculation using the correct arithmetic means is 10.64%, as shown on Exhibit RAB-6.

Q: Why is Mr. Baudino's use of geometric means in the alternative CAPM calculation erroneous?

A: The arithmetic mean should be used directly in the CAPM approach, to the exclusion of the geometric mean. The arithmetic mean provides an unbiased estimate, provides the correct representation of all probable outcomes, and has a measurable variance. As stated by Ibbotson:

> Arithmetic Versus Geometric Differences
>
> For use as the expected equity risk premium in the CAPM, the arithmetic or simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, not geometric, subtraction.
>
> Arithmetic Versus Geometric Means
>
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values....This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) in order to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation-1996 Yearbook, pages 153-154)

The geometric mean, which Mr. Baudino uses on Exhibit RAB-6, consists merely of a rate of return taken from two data points that have no measurable variance. Although a geometric mean will represent the growth from an initial to a terminal value, it should not be used in the CAPM approach. Hence, it is only the 10.64% alternative CAPM results (see Exhibit RAB-6) using arithmetic means that is appropriate. Accordingly, the average of Mr. Baudino's correct CAPM results is 11.57% (12.56% + 12.49% + 11.11% + 11.04% + 10.64% = 57.84% ÷ 5). This result is consistent with the return recommended in my testimony.

Leverage Adjustment

Q: Both Mr. Baudino and Dr. Woolridge have criticized the leverage adjustment that you propose to account for the divergence of stock prices and book values. Please comment.

A: It must be recognized that, in order to make the DCF results relevant to the weighted average cost of capital (WACC) calculated using the capitalization measured at original cost, the market-derived cost rate cannot be used without modification. The importance of the leverage modification to the DCF results was fully supported in my direct testimony, wherein it was shown that the market value of the equity in the Electric Group's capitalization was much higher than its book value. To make the market-derived DCF results applicable in the ratesetting context, it is necessary to account for the higher financial risk that arises from the lower common equity ratio measured by book value as compared to the higher common equity ratio measured by market value. Viewed from another perspective, if all parties used market-determined capital structure ratios of 36.89% debt, 0.60% preferred stock, and 62.51% common equity) then no adjustment would be needed. However, because book value capital structures are used instead, my adjustment procedure is required.

Q: Dr. Woolridge has criticized the leverage adjustment that you propose to account for the divergence of stock prices and book values. Please comment.

A: First, Dr. Woolridge submitted these same arguments to the Pennsylvania Public Utility Commission ("PPUC") in a rate case at Docket No. R-00038304. In its order in that case, the PPUC rejected Dr. Woolridge's argument and increased the cost of equity by 0.60% for this factor. The Pennsylvania Commission accepted PAWC's argument, stating that they were "persuaded by PAWC's reasoning that a financial risk adjustment is necessary to compensate PAWC for the application of a market based cost of common equity to a book value common equity ratio." In reaching its decision, the Pennsylvania Commission relied in part upon *Lower Paxton Township v. Pennsylvania Public Utility Commission*, 317 A.2d 917 (Pa. Cmwlth. 1974), a case in which the Pennsylvania Commonwealth Court recognized that the Commission should consider factors that affect the cost of capital such as financial structure, credit standing and risk. Afterward, Dr. Woolridge's client, the Pennsylvania Office of Consumer Advocate, appealed the Commission Order to the Commonwealth Court. The Commonwealth Court affirmed the Commission Order on this point on November 8, 2004. Hence, there is no reason to follow Dr. Woolridge's same arguments in this case.

Dr. Woolridge also claims in his testimony at p. 56 that when market value exceeds book value, a utility is expected to earn more than investors require. This observation, even if correct, has nothing to do with my adjustment. First, my DCF calculations produce the returns that investors expect on their market value. The DCF formula is derived from the standard valuation model: P = D/ (k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. The assumptions implicit in the model were described previously. By rearranging the terms, we obtain the familiar DCF equation: k = D/P+g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock ("P"). The need for the leverage adjustment arises when the results of the DCF model ("k") are to be utilized with a book value capital structure that is different than the market value capital structure ("P"). My leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices are different from book value. Hence, Dr. Woolridge's observations are not on point.

Finally, Dr. Woolridge asserts that the Modigliani and Miller support that I offered does not demonstrate or prove that my adjustment is necessary. Yet I never stated that the scholars who studied the leverage/return relationship dealt with this phenomenon in the public utility ratesetting context. In any event, Dr. Woolridge has not disputed the fact that there is less financial risk associated with a 64.94% equity ratio than there is with a 46.60% equity ratio. As financial risk increases when the common equity ratio is lower, then the cost of equity must likewise increase.

Q: Dr. Woolridge has also criticized your leverage-adjusted betas. Please comment.

A: I presented in my direct testimony at pp. 42-43 the reasons why that the regulatory determined cost of equity must be adjusted for the book value measures concerning the market models, such as CAPM. The Hamada formula that I used to adjust the betas is merely an extension of the Modigliani and Miller formula that I used in the DCF calculation. It must be recognized that, in order to make the CAPM results relevant to the rate base measured at original cost, the market derived cost rate cannot be used without modification.

Taxation of Dividends

Q: Both Dr. Woolridge and Mr. Baudino provide an extensive discussion of the impact on the cost of equity related to Jobs and Growth Tax Relief Reconciliation Act of 2003. What are your observation concerning this issue?

A: There is no significance to the impact of the Federal income tax treatment of dividend receipts on the cost of equity analysis for this case. First, the reduced income tax treatment of qualified dividends is scheduled to expire in 2008. Second, the treatment of dividends for state income tax purposes (unless linked to federal taxes payable) was not changed. Third, for shares held in non-taxable accounts, i.e., those held by pension funds, IRAs, and 401Ks, there was no change. Fourth, all of the market data used by all parties in the case were assembled with stock market data after May 29, 2003. The price performance of utility stocks after May 28, 2003 would reflect whatever benefit investors see in the tax code change regarding dividend receipts. Essentially, Dr. Woolridge and Mr. Baudino have raised an issue that has already been incorporated into the market evidence considered by all witnesses.

Risk Premium Method

Q: Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A: Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate.

Q: Do you have any comments concerning Dr. Woolridge's criticism of the Risk Premium approach?

A: Yes. Dr. Woolridge criticizes my use of long-term public utility bond yields as the interest rate measure. This criticism is unfounded because: (1) common stock investors are subject to changing levels of interest rates because a primary determinant of the cost of equity is the level of interest rates (especially for utility stocks), and (2) the credit risk associated with a company's bonds is also a major concern for common stock investors (e.g., default on a company's bonds would adversely affect the common stockholders). Moreover, the capital losses (alluded to by Dr. Woolridge at p. 47 of his testimony) concerning historical bond returns were non-existent for long-term government bonds (used by Dr. Woolridge as a proxy for bond yields). Over the period 1926-2004, they were: 0.0% as the geometric mean and 0.4% as the arithmetic mean for capital appreciation. Further, Dr. Woolridge does not identify the magnitude of any difference between the published yield and investor expected returns on bonds. With bond portfolio immunization strategies and the extremely high probability of realizing expected returns on public utility bonds from issuance to maturity, Dr. Woolridge's reasoning provides no basis to reject my risk premium approach.

In addition, Dr. Woolridge criticizes my use of arithmetic means. However, as stated in the 2003 Yearbook published by Ibbotson Associates:

> "The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values....This makes the arithmetic mean return appropriate for forecasting, discounting, and computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their expected (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will, therefore, require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment."

It is for this reason that I have reviewed arithmetic mean returns, as well as geometric mean returns. In response to other criticisms by Dr. Woolridge, there is every reason to believe that the historical returns were attainable by investors through dividend re-investment plans and other investment plans offered by brokerage firms (stock-index mutual funds, for example).

Market-To-Book Ratios

Q: Dr. Woolridge uses market-to-book ratios to analyze the cost of equity. Please comment.

A: Dr. Woolridge uses market-to-book ratios to check on the reasonableness of his 8.75% cost of equity recommendation. It should be recognized when assessing relative market-to-book (M/B) ratios that the market valuation of a particular company is not solely a function of forecast earnings. Rather, general market sentiment can significantly influence the price of stock. This is especially evident with the emergence of a more global market for capital, the advent of program trading, and the effect on the market of leveraged financed stock acquisitions which have boosted stock prices by both shrinking the supply of shares and by fueling takeover speculation.

Q: In your opinion, what relevance do M/B ratios have in the ratesetting framework?

A: The market prices of utility stocks in relation to their book value cannot simply be attributed to the notion that these companies are expected to earn a return on book equity that differs from their market-determined cost of equity. Stock prices above book value are common for utility stocks, and indeed non-regulated stock prices exceed book values by even greater margins. In this regard, according to the Barron's January 23, 2006, the major market indices' market-to-book ratios are well above unity. Utility stocks trade at a multiple of 2.64 times book value which is well below the market multiple of other indices. For example, the S&P 500 index trades at 3.04 times book value, the S&P Industrial index is at 3.54 times book value, and the Dow Jones

Industrial index is at 3.18 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are over-achieving their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

<u>Comparable Earnings Approach</u>

Q: Dr. Woolridge and Mr. Baudino also take issue with your Comparable Earnings approach. Please comment.

A: The Comparable Earnings approach was established in the landmark <u>Bluefield</u> & <u>Hope</u> decisions, which set forth the two principal standards of a fair return, namely, comparability and capital attraction. In the <u>Hope</u> decision, the United States Supreme Court defined these requirements in the following terms:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, more-over, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

The Comparable Earnings approach satisfies the comparability standard. Recently, there has been renewed interest in this approach. The financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets. The Comparable Earnings approach directly reflects this reasoning and fits the established standards for a fair rate of return set forth in the <u>Bluefield</u> and <u>Hope</u> decisions. The Hope decision requires that a fair rate of return must be equal to that earned by firms of comparable risk. With the ongoing restructuring of the utility business and the introduction of greater competition, the returns on non-regulated businesses will be much more relevant to investor required returns for regulated utilities in the future.

The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. It must be recognized that the purpose of regulation is to substitute for the normal economic function of a free enterprise system. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Because the Comparable Earnings method is derived from a firm's overall performance (i.e., its average return), it is likely that the approach has measured blended returns on a variety of projects that have produced returns above and below the cost of capital during the measurement period. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital. I have used this approach in connection with the other market models (i.e., DCF, Risk Premium, and CAPM) and the combined results of all methods fulfill both established standards of a fair rate of return. As I indicated previously, there is no reason to evaluate market-to-book ratios in the context of the Comparable Earnings approach as suggested by Dr. Woolridge. And, to the extent that I considered earnings forecasts, the assertion that the returns I consider may not reflect long-term earnings expectations represents a baseless criticism by Dr. Woolridge.

Finally, Mr. Baudino levels two baseless criticisms at my Comparable Earnings approach. He fails to recognize that regulation is a substitute for competition and that the ten-year time frame that I analyzed is fairly representative of an entire business cycle.

Incentive Compensation

Q: Mr. Henkes, a witness for the AG, has rejected a portion of the Company's incentive compensation plan that is linked to AEP'S financial performance. Do you agree with that position?

A: No. When reviewing the financial performance of utilities, investors expect that reasonable expenses will be recovered in the cost of service. As part of those expenses, compensation that is tied to financial performance provides benefits to customers, employees, and stockholders because a financially strong utility has the ability to attract both debt and equity capital on favorable terms. That is to say, a financially strong utility will have enhanced credit quality, which would promote more attractive borrowing costs. Likewise, a financially strong utility will have a more attractive stock, which would allow for the issuance of additional equity. As such, rejecting incentive compensation linked to financial performance is shortsighted and fails to grasp the benefits that customers, employees, and stockholders derive from these plans. A proposal that includes a disallowance of these expenses sends a negative signal to the Company's stockholders, because they do not expect that reasonable costs will not be recovered through the regulatory process.

Summary

Q: Please summarize your rebuttal testimony.

A: The equity allowances recommended by Dr. Woolridge and Mr. Baudino significantly understate the Company's cost of equity. The proposed rate of return on common equity advocated by Dr. Woolridge is particularly unrealistic. The opposing parties' recommendations do not come close to providing Kentucky Power the level of support that investors expect. Their returns are too low by reference to the returns expected by investors and those granted by regulators. Moreover, the Company's higher risk profile characterized by its relatively small size, its high proportion of sales to industrial customers, and low common equity ratio warrants a higher cost of equity.

Q: Does this conclude your rebuttal testimony?

A: Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF NEW JERSEY

CASE NO. 2005-000341

COUNTY OF CAMDEN

AFFIDAVIT

Paul R. Moul, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Paul R. Moul

Paul R. Moul

Subscribed and sworn to before me by Paul R. Moul this 20th day of September, 2005.

Ruby Marie Tucker

Notary Public

Notary Public of New Jersey
I.D.#2165661 Com.Exp. 5/12/09
Ruby Marie Tucker

My Commission Expires 5/12/09

PHILLIPS, E.G.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

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PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF KENTUCKY	)	CASE NO. 2005-00341
POWER COMPANY	)	

REBUTTAL TESTIMONY

OF

EVERETT G. PHILLIPS

ON BEHALF OF KENTUCKY POWER COMPANY

February 2, 2006

**REBUTTAL TESTIMONY OF
EVERETT G. PHILLIPS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2005-00341**

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

A. My name is Everett G. Phillips. My business address is 11233 Kevin Avenue, Ashland, KY 41102. I am the Director of Distribution Operations for the Kentucky Power Company ("Kentucky Power, KPCo or Company").

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my Rebuttal Testimony is to respond to the prepared Kentucky Industrial Utility Customers, Inc. (KIUC) testimony of Lane Kollen filed on January 9, 2006.

Q. Please refer to Witness Kollen's Direct Testimony on page 25. He indicates that the Commission's Management Audit (Audit) only applies to the Hazard Service Territory. Do you agree with this statement?

A. The Commission's original intent of the Audit was to focus on the reliability concerns of the Company's Hazard service territory. However, in the Audit Report, the auditor stated it was important that such a review also encompass issues relating to the practices and provision of service throughout the entire Kentucky Power system. Therefore, the Audit focused not only on the Hazard service territory, but the entire Kentucky Power service territory.

Q. Please refer to the KIUC's Witness Kollen's Direct Testimony, on page 25, which states: "The Company's proposal does not include any increased costs related to potential revisions to the Northern Electric Reliability Council (NERC) standards in the aftermath of the widespread August 14, 2003, Northeast blackout, which would apply to transmission circuits operating at 200 kV and above along with critical transmission lines of lower voltage as determined by the applicable Regional Reliability Council." Do you agree with this statement?

A. Yes.

Q. Can you explain why additional costs related to the NERC standards were not included?

A. Yes. The Company has elected not to request a higher level of reliability funding for transmission circuits because the NERC has not yet finalized its tree trimming standards for transmission circuits operating at 200 kV and above; nor for those critical transmission lines of lower voltages as determined by the applicable Regional Reliability Council. Until the standards are finalized, we cannot estimate the extent or the cost of the additional work that will be required to meet the standards.

Q: Witness Kollen states on page 26 and page 29 of his Direct Testimony that the Company has failed to provide any studies and/or statistical reliability improvements as measured by standard reliability metrics. In addition, he asserts the Company has no basis to assess the reasonableness of the proposed costs. Do you agree with Witness Kollen?

A. No. It is extremely difficult to quantify the effect of the proposed improvements in vegetation management. Stated otherwise, spending "X" dollars will not guarantee "Y" improvement in CAIDI and SAIFI indices because of the inter-relationship between outages caused by vegetation and those caused by weather challenges. Tree caused interruptions often do not occur in calm, blue-sky days. They more often occur during periods of high winds, thunderstorms, and icing conditions. The challenge is to separate the anticipated weather challenge from the vegetation management practice.

Q. What is the basis for the Company's position that making the investments recommended by the Audit will result in improved reliability?

A. Based on my experience, a significant improvement in reliability can be obtained with a significant increase in the number of trees being cut and/or removed, along with expanding the current rights of way, under the proposed cycle based program. In addition, the Audit noted that tree exposure on power lines is extremely high. Using these factors, the Company provided a table summarizing the incremental work that will be performed under the proposed cycle based program in Table 1 on page 9 of my Direct Testimony, rather than a specific index target for reliability improvement.

Q. Please refer to page 27-28 of KIUC's Witness Kollen testimony. Kollen states the proposal should be rejected based on his assertions that a reduction in O&M is not quantified, that there should be a reduction in annual transmission and distribution plant investment, and that there should be an increase in revenues. Do you agree with his assertion to reject the cycle-based program?

A. The Company does not agree with Witness Kollen that the cycle-based program should be rejected. Any O&M reductions will not be recognized immediately as each tree is cut. The benefits are not linear with the trimming or removal of trees, but rather are realized over time. While over-time the manner in which reliability resources are allocated may change, the Company expects to continue with a substantially similar level of expenditures. We do expect to see a reduction in tree trimming costs once the program is fully implemented, we then anticipate our focus to turn to replacing damaged equipment that will be better identified once the trees are removed. In addition, the Company has no evidence that Witness Kollen's assertion regarding a reduction in both recurring annual transmission and distribution plant investment is valid. As to Mr. Kollen's belief that revenues will increase due to increased usage that otherwise would have been foregone during outages, it is my opinion that such amounts are minimal.

Q. Please refer to KIUC's Witness Kollen's testimony on page 28 and 29. He states, "The Company has failed in this respect as well as to justify the proposed expansion of the vegetation management program. It fails to make the case that the present level of reliability is unacceptable." Do you agree with his conclusion?

A. No. The increased reliability expenditures are not driven by any belief by the Company that the Company's present service is unreasonable, particularly given the nature of the terrain in large parts of the Company's service territory. Rather, the increased reliability expenditures are required to meet customers' increased reliability expectations and the recommendations of the 2002 Staff Management Audit commissioned by the Commission. As I previously indicated in my Direct

Testimony, in 2002, the Kentucky Commission Staff initiated an Audit of KPCo's management and operational efforts regarding maintenance of service quality and service reliability. The Audit focused on KPCo's Hazard service area customers who were experiencing a higher level of service interruptions than other parts of KPCo's service territory, but it encompassed a review of all KPCo's management and operational efforts to gain a full understanding of how KPCo manages reliability. The overall Audit points out the difficulty in providing reliable service in mountainous territory and the need to invest additional financial resources in areas with challenging terrain and accessibility. The increase in reliability expenses is an attempt by the Company to invest the additional resources recommended by the Commission's Audit.

In short, the Commission initiated a thorough third party audit/investigation (Audit) into the service and reliability practices of Kentucky Power Company in 2002. Recommendations stemming from the Audit support a cycle-based approach as described in my direct testimony. As such, the Company agrees to implement the proposal if cost recovery is granted.

Q. Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Everett G. Phillips, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Everett G. Phillips

Everett G. Phillips

Subscribed and sworn before me by Everett G. Phillips this 1st day of February, 2006.

Judy K Tackett

Notary Public

My Commission Expires January 14, 2009

ROUSH, D.M.

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

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PUBLIC SERVICE
COMMISSION

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY **CASE NO. 2005-00341**

REBUTTAL TESTIMONY
OF
DAVID M. ROUSH

ON BEHALF OF
KENTUCKY POWER COMPANY

February 2, 2006

REBUTTAL TESTIMONY OF
DAVID M. ROUSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2005-00341

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REBUTTAL TESTIMONY OF
DAVID M. ROUSH, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

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

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed as a Manager – Regulated Pricing and Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP).

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Attorney General witness David H. Brown Kinloch's suggested revenue increase allocation and recommendation to eliminate the residential declining block rate. In addition, I will address Attorney General Witness Robert J. Henkes' recommendations concerning the year-end customer revenue annualization adjustment.

Revenue Increase Allocation

Q. What is Attorney General Witness David H. Brown Kinloch's position regarding the allocation of any revenue increase in this proceeding?

A. Witness Brown Kinloch's position is that any revenue increase should be allocated to the rate classes based upon percentages established in a 1991 settlement agreement in the Company's last rate case.

Q. On what does he base his position?

A. Witness Brown Kinloch bases his position on his opinion that no reliable cost of service study is available. In the Company's last rate case, Witness Brown Kinloch performed his own cost of service study. He prepared his study without an electronic copy of the Company's cost of service study, since no electronic copy was available. At that time, the Company was using a mainframe EBASCO program, so only hardcopy output was available. Similarly, Witness Brown Kinloch could have performed a cost of service study in this case based upon available information.

Q. Does Witness Brown Kinloch's recommendation produce reasonable results?

A. No. His recommended revenue increase allocation would assign a portion of the revenue increase to an interruptible (IRP) class that does not even exist for the Company today. Further, it is not reasonable to assume that the makeup of each class is the same today as it was 15 years ago. For example, residential class energy usage has grown by 37% during that time, while the municipal waterworks (MW) class energy usage has declined by more than 50%. This clearly shows that what was a reasonable allocation 15 years ago has little relevance today.

Residential Rate Design

Q. In Exhibit DHBK-2, Witness Brown Kinloch calculates a full cost customer (service) charge of $5.86 for the residential customer class. Did Witness Brown Kinloch properly calculate this service charge?

A. No. Witness Brown Kinloch's calculation is incomplete. The most significant item missing from his calculation is customer-related administrative and general expense. Correcting for this item alone would result in a service charge of nearly

$7.40. The complete calculation is the result shown in the Company's workpaper provided in response to the Commission Staff 1st Set Data Request Item No. 8-c.

Year-End Customer Revenue Annualization

Q. Do you agree with Attorney General Witness Robert J. Henkes' proposals concerning the year-end customer revenue annualization adjustment?

A. No. First of all, Witness Henkes suggests that the Company should include the number of customers in the month before the test year in the calculation of test year average number of customers. This simply does not make sense. The Company's billing systems count someone as a customer in a given month if they receive a bill for service for even one day of that month. For example a customer that moved on June 1, 2004 and received a final bill for usage through June 1, 2004 would be counted as a customer in June 2004. To then count such a customer that stopped receiving service from the Company 29 days before the test year began in the test year average number of customers is not appropriate.

Secondly, Witness Henkes calculates an operating ratio in Schedule RJH-17 that excludes both fuel revenue and fuel expense. Unfortunately, he then applies that operating ratio to the revenue annualization amount that includes fuel to determine the operating expense adjustment. This results in a substantial understatement of the operating expense adjustment, and thus inappropriately overstates his net year-end customer revenue annualization by more than $11,000.

For these reasons, the Commission should reject Witness Henkes' proposed modifications to the Company's year-end customer revenue annualization adjustment and adopt the Company's adjustment as filed.

Q. Does this conclude your rebuttal testimony?
A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

COUNTY OF FRANKLIN

CASE NO. 2005-00341

AFFIDAVIT

DAVID M. ROUSH, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

DAVID M. ROUSH

Subscribed and sworn to before me by DAVID M. ROUSH this 1st day of February, 2006.

NOTARIAL SEAL STATE OF OHIO

CATHERINE HURSTON
Notary Public, State of Ohio
My Commission Expires 11 15 2009

Notary Public

My Commission Expires 11-15-09

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

FEB 0 2 2006

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF

GENERAL ADJUSTMENTS IN
ELECTRIC RATES OF
KENTUCKY POWER COMPANY

CASE NO. 2005-00341

REBUTTAL TESTIMONY
OF
ERROL K. WAGNER

ON BEHALF OF
KENTUCKY POWER COMPANY

February 2, 2006

REBUTTAL TESTIMONY OF
ERROL K. WAGNER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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REBUTTAL TESTIMONY OF
ERROL K. WAGNER
ON BEHALF OF KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Introduction

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

A. My name is Errol K. Wagner and I am the Director of Regulatory Services, Kentucky Power Company ("Kentucky Power, KPCo or Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut portions of the direct testimony presented by the Attorney General's Witness Robert Henkes, Kentucky Industrial Utility Customers (KIUC) Witness Lane Kollen and the Kentucky Cable Television Association (KCTA) Witness James Freeman on a number of the adjustments.

Other Accounts/Clearing Accounts

Q. Please refer to the AG's Witness Henkes testimony, at page 23, line 18 which states: "The payroll expenses charged to the remaining "Other Accounts" including accounts 152 (Fuel Stock Expense Undistributed), 186 (Miscellaneous Deferred Debits), 188 (Research & Development) and 242 (Miscellaneous Current & Accrued Liabilities) are *not* cleared to O&M, Construction, and Plant Removal." Do you agree with this statement?

A. No. The AG Witness Henkes indicates the payroll expenses charged to the remaining "Other Accounts" are *not* cleared to O&M, Construction, and Plant Removal, but he does not indicate to which accounts these payroll expenses are cleared. These "Other Accounts" are generally "clearing" type accounts which initially accumulate costs including labor charges, equipment charges, material charges and overhead charges. The balances in these accounts are subsequently cleared to the appropriate Operation and Maintenance, Construction and/or Plant Retirement Removal accounts. The amounts shown on Section V, Workpaper S-7, page 4 of 5 (Rebuttal Exhibit EKW-1 page 2) are the amounts of direct labor charged to the "Other Accounts" during the twelve months ending June 30, 2005.

Q. What supports your conclusion that the labor amounts on Section V, Workpaper S-7, page 4 of 5 recorded in "Other Accounts" are cleared to O&M, Construction, and/or Plant Removal?

A. In the Company's response to the Commission Staff-1st Set, Item No. 13, the Company provided the Company's Balance Sheet at June 30, 2005. In reviewing the Company's response to the Commission Staff-1st Set, Item No. 13, page 3 of 13, it can be determined that the June 30, 2005 balance in Account 152 (Fuel Stock Expense Undistributed) was $155,721. Please keep in mind that the amount recorded on the Balance Sheet includes more than the direct labor charged to the account. The June 30, 2005 balance of $155,712 is $742,567 ($898,288 - $155,721) less than the direct labor charged to Account 152 during the test year (Rebuttal Exhibit EKW-1 page 2). The amounts recorded in Account 152 were in fact cleared to Account 501 (Fuel Procurement, Loading and Handling), which is an Operation Expense Account in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USofA) instructions. The FERC USofA instructions for Account 152 state "Amounts included herein shall be charged to expense as the fuel is used…" Also, in reviewing this response one can readily determine that since Account 188 (Research and Development) is not listed on the June 30, 2005 Balance Sheet, the June 30, 2005 balance in Account 188 is zero yet during the twelve months ended June 30, 2005 there was $914 of direct labor charged to Account 188 (See Rebuttal Exhibit EKW-1 page 2). The $914 of labor was in fact cleared to Accounts 506 (Miscellaneous Steam Power Expenses), 566 (Miscellaneous Transmission Expenses) and 588 (Miscellaneous Distribution Expense). All are Operation and Maintenance Expense Accounts. The FERC USofA instructions for Account 188 state "Costs that are minor or of a general or recurring nature shall be transferred from this account to the appropriate operating expense function…" The same type of analysis can be performed on Account 242 (Miscellaneous Deferred Debits) and it would be determined that this account is cleared to Account 506 (Miscellaneous Steam Power Expenses). This $22,000 credit labor amount reduces the labor charged to Account 506. With respect to Account 186 (Miscellaneous Deferred Debits), the $653,745 test year labor was cleared to Operation & Maintenance, Construction and Plant Removal accounts. In the case as filed, the Company incorrectly placed the entire $653,745 in Operation and Maintenance instead of allocating the $653,745 labor amount to all three categories. When the Company corrects this error, the Operation and Maintenance Expense percentage changes from the 67.65% as filed to 66.91% (See Rebuttal Exhibit EKW-1 page 1).

Big Sandy Plant Average Daily Burn Rate

Q. Please refer to AG's Witness Henkes' testimony, page 16, line 12. Do you agree with the following statement made by Witness Henkes "... that an average daily burn rate of 7,048 tons should be used for purposes of calculating the appropriate pro forma Big Sandy coal stock balance to be used for ratemaking purposes in this case"?

A. No.

Q. What is the basis for your disagreement?

A. The Big Sandy Plant's actual average daily consumption for the twelve months ending December 31, 2005 were 8,017.13 tons (See Rebuttal Exhibit EKW-2 page 1). When developing the Coal Inventory Policy's 8,000 tons per day burn rate for the Big Sandy Plant, the Company considered factors such as the historical burn rate, forecasted burn rate, scheduled outages and availability factors. The 8,000 tons per day utilized in the Company's application is reasonable because it is consistent with both the Coal Inventory Policy and actual experience.

On the other hand, the average daily burn rate of 7,048 tons per day being suggested by Witness Henkes is derived by averaging monthly daily burn averages over the period September 2003 through October 2005 (Schedule RJH-6A), i.e. Witness Henkes is averaging averages. This calculation style tempers the true risk impact of daily burn variability, which is more accurately in the value contained in the Company's Coal Inventory Policy.

Net Merger Savings Adjustment

Q. Have you reviewed the AG's Witness Henkes' adjustment with respect to the Net Merger Savings at page 30 of his testimony?

A. Yes.

Q. Do you agree with his adjustment?

A. Yes. The Company should have increased the retail revenues by $4,037,000 versus the $4,018,275 adjustment as originally proposed by the Company. (See Rebuttal Exhibit EKW-3, page 27)

Storm Damage Expense

Q. Do you agree with the AG's Witness Henkes' Storm Damage Expense Adjustment at page 32 of his testimony?

A. No. Although in the abstract the Company does not have a problem with using a longer period than three years to calculate a normalized storm damage expense level if the costs in the historical data are comparable, it is not possible to do so in this case because of the change in the manner in which the costs information was maintained. As the Company stated in its response to the Commission Staff-2nd Set, Item No. 16, the cost information between 1997 and 2000 is on a Total Storm Damage Expense (Capital and O&M) basis only. The cost information for years 2001 and 2002 is on a Total O&M Expense basis only (includes Company in-house labor). Using historical cost data that are not comparable will tend to distort the result.

Big Sandy Plant Maintenance Expense Adjustment

Q. Have you reviewed the AG's Witness Henkes' Big Sandy Maintenance Expense Adjustment at page 34 of his testimony?

A. Yes. Again, the Company does not have a problem in the abstract with using a longer period than three years to calculate a normalized plant maintenance expense level as long as the historical cost levels are comparable. Again, the historical cost levels are not comparable. The investment at the Big Sandy Plant in 1997 was very different than the investment at the Big Sandy Plant today. In the 2002 and 2003 timeframe, the Company invested approximately $175 Million in environmental facilities (Over-Fire Air Burners, May 2002; Electrostatic Precipitator, December 2002; and Selective Catalytic Reduction, May 2003). The maintenance levels prior to 2001 could not have contained any maintenance associated with these newly installed environmental facilities. Therefore, the normal level of Big Sandy Plant Maintenance Expense built into rates should have an amount of plant maintenance that reflects maintenance associated with these environmental facilities.

Q. What is your position as to KIUC Witness Kollen's adjustment to the Big Sandy Plant Maintenance Expense?

A. The Company's three-year maintenance cycle is supported by reviewing the Company's response to Staff-2nd Set, Item No. 19. The level of Plant Maintenance Expense in 1997, 2000 and 2003 is higher than the two years following each of the above mentioned years. Again the reason the Company used a three-year period to calculate the normal level of Plant Maintenance is because the generating facilities at Big Sandy in 1997 and 2000 were much different than generating facilities at Big Sandy in 2003 because of the additional environmental controls.

AEP Pool Capacity Cost Adjustment

Q. Have you reviewed the AG's Witness Henkes's adjustment to the AEP Pool Capacity Cost Adjustment at page 38 of his testimony?

A. Yes. Witness Henkes accepted the Company's AEP Pool Capacity adjustment for item number 3 (Net Effect of the Addition of 289 MW of Load to CSP's System) and item number 4 (Effect of Removing 250 MW from CSP's Capacity) but did not accept the Company's fifth adjustment associated with Annualize Load Changes. The effective date of all three of these adjustments was January 1, 2006. Therefore, if two of these adjustments are known and measurable then all three of these adjustments are known and measurable.

Off-System Sales Adjustment

Q. Have you reviewed KIUC Witness Kollen's adjustment to Off-System Sales at page 41 lines 15 through 19 of his testimony?

A. Yes. The Company is in agreement with the adjustment. (See Rebuttal Exhibit EKW-3, page 44)

Q. Have you reviewed KIUC Witness Kollen's adjustment to Off-System Sales at page 44 lines 18 through 20 of his testimony?

A. Yes. The Company disagrees with the $5.145 Million adjustment for two primary reasons. First, the $30 Million is the Company's forecasted level of Off-System Sales for the twelve months ended December 31, 2006. However, some of these transactions, if consummated, will not take place until some 17 months (July 2005 to December 2006) after the test year of June 30, 2005. Second, the $30 Million of Off-System Sales profit forecasted for the twelve months ending December 31, 2006 is prior to any associated environmental costs. The Commission in its order in Case No. 2004-00420 has authorized the Company to deduct environmental costs allocated to Off-System Sales in the environmental surcharge calculations from the Off-System Sales margins used in calculating the Off System Sales profit used in the System Sales Clause Tariff.

Environmental Costs Roll-in

Q. Have you reviewed Mr. Kollen's testimony and KIUC's responses to data requests concerning the Company's proposed treatment of the roll-in to base rates of costs for environmental compliance currently included in the Company's environmental surcharge?

A. Yes. Mr. Kollen and the KIUC propose that the Commission disallow a portion of the environmental costs, which the Company has incurred to comply with the Federal Clean Air Act, which were incurred for the benefit of the Company's ratepayers.

Q. What specifically are the Company's environmental costs proposed by the KIUC to be disallowed for retail ratemaking purposes?

A. Though the various formulas are both complex and technical, essentially the KIUC, through Mr. Kollen, is proposing that a percentage of the Company's environmental costs be "trapped" without rate recovery through an assignment of those costs on a revenue basis to various aspects of the Company's revenue base. Basically, the Company has four sources of revenue:

Source of Revenue	%
1. Retail Revenues	67.4
2. Off-System Sales	22.1
3. Sales to AEP Pool Members	9.8
4. Wholesale	.7
	100.0

The KIUC proposes that only the portion of environmental costs associated with retail sales (i.e. 67.4%) be recovered from retail customers. I understand that this position assumes that the environmental costs associated with off-system sales are still to be recovered through the system sales tracker, and that the costs associated with the Company's wholesale customers are recovered in the FERC-approved wholesale rates.

Q. What is the effect of the KIUC proposal?

A. The KIUC approach would exclude 9.8% of environmental costs from retail rates, with the result being that the annual cost associated with such 9.8%, estimated to be $2,753,800, being trapped without a means for including such costs in any rates.

Q. How does Mr. Kollen's proposal differ from the Company's?

A. The Company has proposed that all environmental costs (except wholesale) be included in retail rates. The Company has proposed the formula (EM = CRR – BRR) to accomplish this. This approach is consistent with the process established by this Commission for KPCo more than a decade ago.

Q. Please explain why the KIUC approach is inappropriate.

A. The KIUC approach is erroneous for the following reasons. First, retail rates must be designed to reflect costs that are reasonable and prudently incurred on behalf of the utility's ratepayers. The costs of the environmental facilities have been approved either by the Kentucky Public Service Commission or the Federal Energy Regulatory Commission as being necessary, appropriate, reasonable and prudently incurred.

Second, the entirety of the Company's environmental costs were incurred for the benefit of KPCo's ratepayers, and they receive much more than 67.4% of the benefit of environmental compliance expenditures. All generating capacity is fully utilized by the full-requirement customer.

Third, the use of the revenue allocation disregards established ratemaking principles recognizing how costs are allocated among the different classes of customers.

Q. Why do you say that KPCo ratepayers receive the full benefit of the environmental costs when KPCo receives revenues from AEP Pool members who obviously benefit from receipt of KPCo generation and environmental equipment?

A. This is the point of the KIUC confusion. When the Kentucky full-requirement customers do not use all of KPCo's generating facilities, as a member of the AEP Pool, KPCo shares its capacity (including environmental costs) with its sister AEP Pool member companies. The AEP Pool membership authorizes, indeed requires, KPCo to make its facilities available to the Pool when the generating facilities are not needed to meet the Company's full-requirement customer's load; and in return, the Company is entitled to receive the benefit of AEP Pool generation when the Company is in need of additional capacity. Indeed, this Commission recently recognized this benefit in its Order in Case No. 2005-00068, which included in the Company's Environmental Surcharge Tariff Kentucky Power's share of the costs of the environmental facilities of the surplus sister companies. The position of the KIUC in this case would minimize the Commission's ruling on this point since the AEP environmental costs authorized to be recovered through the surcharge would be lost by allocating a portion of these same costs out of the rates the retail customers pay to the Company for service.

Q. Is the KIUC position consistent with Commission precedent involving Kentucky Power Company?

A. No. Again, the KIUC approach is a departure from the procedure established by the Commission more than a decade ago. The current formula takes the current revenue requirement minus the base rate revenue requirement, which results in the environmental costs that flow through the environmental surcharge.

Q. Is Mr. Kollen's approach consistent with the approach used by the Commission involving Louisville Gas & Electric and Kentucky Utilities Company?

A. Yes, but a strict application of this approach to Kentucky Power would be, and is, improper.

Q. Please explain.

A. Louisville Gas & Electric and Kentucky Utilities Company are not members of a FERC-approved Pool, and therefore would not be unable to recover such environmental costs because of the membership in such a Pool. The

Commission's "White Paper", at pages 1 and 2 discusses the fact that the Commission needs to be mindful that there are unique differences or circumstances of each utility.

Q. Do you agree with the KIUC's position at page 17 of Witness Kollen's testimony which states "the credit to the ECR is intended to reflect the amount of ECR revenues achieved through base rates, not the costs included at the time of the roll-in"?

A. No. KRS 278.183(3) clearly states "*Every two (2) years the commission . . . shall disallow improper expenses, and to the extent appropriate, incorporate surcharge amounts found just and reasonable into the existing base rates of each utility*". And KRS 278.183(1) states "*Notwithstanding any other . . . . a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act*[1] *as amended . . . .*", therefore, what is rolled into the utility's base rates are costs not revenues. There is nothing in the statute that states a percentage of the revenues at the time of the roll-in and that the credit in the ECR be a reduction to the percentage of revenues. In fact, the statute references <u>costs</u>, which are dollars, not percentage of revenues.

Q. What is the Company's general response to the KIUC position?

A. The Company asks this Commission to once again recognize and affirm that KPCo's membership in the AEP Pool has brought tremendous benefits to the Company and its ratepayers, and that the recipients of these benefits (i.e. the retail ratepayer) should bear the costs associated with that membership. To do otherwise would violate the principles of the AEP Pool, and damage the Pool's effectiveness.

Kentucky State Income Tax Rate

Q. Has the Company proposed a change to the Kentucky State Income Tax rate used in this filing?

A. Yes. The Company originally proposed a 7.20% Kentucky Income Tax Rate in its filing. Upon further reflection the Company is proposing a phase-in State Income Tax Rate of 6.25. This phase-in rate was calculated for 9 months at a 7% rate and 27 months at a 6% rate. Using a 36 month time period, results in an effective rate of 6.25%.

Q. Why has the Company used a 36 month time period in calculating the effective state rate?

A. The Company looked at the time period we believe the newly established rates will be in effect and concluded they would be in effect for approximately three years.

Q. What supports your conclusion that these newly established rates will be in effect only three years considering the fact that the last time Kentucky Power's base rates changed was in April 1991?

A. There were several factors that occurred that allowed Kentucky Power Company to refrain from requesting a change in base rates between April 1991 through June 30, 2005. First, the Company's average long term debt cost was 8.20% versus 5.70% in the current rate case . The short term debt cost was 9.16% versus 3.34% in the current rate case. Also, the requested Common Equity cost in the last rate case was 13.5% versus 11.5% in the current rate case. These facts support the conclusion that today's cost of money is relatively low when compared to historical trends. Second, in the last rate case Off-System Sales profits were at a level of $11.3 Million versus $24.9 Million in the current case. One half of the margin above the base was retained by the Company which helped in delaying a request for an increase in base rates. Third, the Company's planned construction program, which could include the installation of a scrubber at Big Sandy Unit No. 2, for the next three years supports the fact that the Company expects to file for a change in base rates in approximately three years.

Ohio and West Virginia Taxes

Q. Has the Company made any changes with respect to its initial proposal concerning Ohio and West Virginia taxes?

A. Yes. The Company is proposing to remove the effect of the Ohio and West Virginia tax from the Gross Revenue Conversion Factor. However, the actual level of Ohio and West Virginia tax paid during the test year will remain in the base case calculations.

Recalculation of Requested Increase in Base Rates

Q. Has the Company recalculated the requested increase in base rates reflecting the Company's changes included in its rebuttal testimony?

A. Yes. Reflecting the above changes as well as Witnesses Bethel, Bradish and Henderson's changes included in their rebuttal testimony, the Company's requested increase in base rates will change from $64.8 Million as filed to $61.1 Million. This results in an overall percent increase of 18.12% versus the 19.2% as originally requested. Attached as part of Rebuttal Exhibit EKW-3, is a revised Section V that supports the revised base rates increase of $61.1 Million. Also, Rebuttal Exhibit EKW-4 demonstrates the net effect of each adjustment.

CATV Adjustment

Q. Have you reviewed the testimony of Witness Freeman?

A. Yes.

Q. Please summarize your understanding of Mr. Freeman's position.

A. Mr. Freeman is recommending some adjustments to Exhibit EKW-10 that he claims are necessary "to calculate CATV Pole Attachment Rates on a consistent basis". Witness Freeman argues that Exhibit EKW-10 does not remove capital leases from the Total Utility Plant investment, which reduced the Net Pole Investment on Line 18 by $3,661 (0.0047%); he then attempts to estimate KPCo's investment in wooden poles by height (Freeman Exhibit 2) after December 31, 2001, since KPCo has not been retaining property record units for wood poles of different sizes since that date. Mr. Freeman claims that such information is necessary because KPCo previously based its pole rates on the investment in 35 and 40-foot poles, less 15% for minor appurtenances for "two-party" poles and KPCo's investment in 40 and 45-foot poles, less 15% for minor appurtenances for "three-party" poles. Mr. Freeman makes such adjustments by "reconstructing" KPCo's accounting records.

Q. Please comment on Mr. Freeman's first recommended adjustment.

A. KPCo's investment in capital leases does not have a material impact on costs that should be included in pole attachment rates. Mr. Freeman's recommendation to remove the $6,683,310 capital lease investment in the allocation of appropriate costs associated with pole attachments results in lowering the assignment of certain expenses by 0.0047%.

Q. Please comment on Mr. Freeman's second recommended adjustment.

A. Mr. Freeman suggests that 35 and 40-foot poles be used for two-party poles and that 40 and 45-foot poles be used for three-party poles. He has attempted to estimate the costs of such poles by reconstructing KPCo's accounting records since December 31, 2001. In 2001, KPCo's average investment in its 190,340 poles was $587.17 (Freeman Exhibit 2) and KPCo's investment in 35, 40 and 45-foot poles averaged $585.13 (which can be calculated from Mr. Freeman's Exhibit 2, Attachment B), or only 0.35% lower than the average cost of all poles. However, the impact of Mr. Freeman's "reconstruction" calculations for the period January 1, 2002 to June 30, 2005 is to reduce KPCo's Net Costs of a Bare Pole noted on Exhibit EKW-10 from $335.32 to $209.54, a reduction of 37.5%. Mr. Freeman supports such an adjustment by reviewing the average investment in wood poles from 1990 to 2002 to determine the average percentage increase in such costs over eleven of the twelve year period to be 3.83%, but excludes 1999's increase over 1998 average wood pole cost of 42.85%, which he apparently believes is an abnormal increase totally attributable to the installation of major appurtenances for all historical periods. He then uses the one-year "outlier" increase of 42.85% to estimate the major appurtenances that should be removed from the Net Plant Investment. Frankly, the Company does not understand how the 1999 percentage increase in average wood pole cost is an appropriate method to determine an adjustment to remove major appurtenances associated with distribution investments made over many years. The Company does not agree with Mr. Freeman that a "major appurtenances" adjustment is appropriate, but even if it were, Mr. Freeman's calculations do not result in a reasonable "reconstruction" of KPCo's accounting records to make such an adjustment.

Q. Please explain how you reached this conclusion.

A. If Mr. Freeman is interested in estimating the costs of 35-foot, 40-foot and 45-foot poles that have been installed between January 1, 2002 and June 30, 2005, KPCo will supply the number of such poles that have been installed once the information is obtained, and the estimated costs to install such "bare poles", including the costs of the required NESC grounding; however, given the fact that KPCo's 2002 investment in such poles was within 0.35% of our average pole costs, we do not see how it will result in a 39% exclusion as recommended by Mr. Freeman.

The Company believes that the KPCo practice of removing 15% of the Net Pole Investment from the average Net Pole Investment to estimate the cost of all appurtenances is appropriate and that Mr. Freeman's recommended adjustments should be excluded.

Q. Please summarize Kentucky Power's position.

A. Mr. Freeman noted in his answer to question 6 of his testimony that "utilities are required to adopt a consistent approach to the calculations" to avoid a perceived "strong incentive" that a utility might have "to run all possible iterations of the numbers and simply adopt the methodology which yields the highest individual rate increase". However, it is unclear how Mr. Freeman's selection of 1999's percentage increase in pole investment over 1998's levels is an appropriate method to estimate the adjustment necessary to remove "major appurtenances" from KPCo's Net Pole Investment. In fact, utilities do not have a strong incentive to run all possible iterations of the numbers and simply adopt the methodology which yields the highest individual rate increase because any additional annual revenues which results in a higher annual revenue in a test year from the CATV customers offsets or reduces the annual level of rate increase the utilities will receive from its retail customers. As noted in Rebuttal Exhibit EKW-5, it is instructive to compare the annual costs per mile that KPCo's recommended CATV rates would be versus the annual costs per mile to a CATV company to install its own poles, excluding the costs of obtaining right-of-way. If a CATV company attaches to KPCo's poles, the proposed annual effect of the CATV rate would be $164.75 to $265.75 per mile (See Rebuttal Exhibit EKW-5 pg 1, line 1). However, as Rebuttal Exhibit EKW-5, lines 2-4 demonstrate, a CATV company would incur costs of $3,500 for a 30' communications pole; $1,584 for underground service or $1,056 for joint trench with electric utility. Kentucky Power's proposed costs are only 16 to 26% of the costs that a CATV company would incur to install its own facilities.

Q. Has KPCo "reconstructed" the Company's accounting records, as Witness Freeman suggests?

A. AEP personnel have been attempting to "reconstruct" the Company's accounting records and we will provide the information to all parties when it is available.

Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2005-00341

COUNTY OF FRANKLIN

AFFIDAVIT

Errol K. Wagner, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K Wagner

Errol K. Wagner

Subscribed and sworn to before me by Errol K. Wagner this 2nd day of February 2006.

Judy K Tackett

Notary Public

My Commission Expires January 14, 2009

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
DIRECT AND ALLOCATED PAYROLL DISTRIBUTION
FUNCTION PERCENTAGE
TWELVE MONTHS ENDED 06/30/2005

SECTION V
WORKPAPER S-7
PAGE 3 of 5
Revised 02/02/06

LINE NO. (1)	DESCRIPTION (2)	TOTAL (3)	TOTAL (4)
1	Operation & Maintenance (WP S - 7, P 4, L 19)	$19,915,827	66.91%
2	Construction (WP S - 7, P 4, L 20)	8,221,792	27.62%
3	Retirement (WP S - 7, P 4, L 21)	1,570,099	5.27%
4	All Other (WP S - 7, P 4, L 31)	59,282	0.20%
5	Other (WP S - 7, P 4, L 32)	$29,767,000	100.00%

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
DIRECT AND ALLOCATED PAYROLL DISTRIBUTION
TWELVE MONTHS ENDED 06/30/2005

SECTION V
WORKPAPER S-7
PAGE 4 of 5
Revised 02/02/06

LINE NO. (1)	FUNCTION (2)	DIRECT PAYROLL DISTRIBUTION (3)	Allocation of Payroll Charges for Clearing Accounts (4)	Total (5)	% (6)
	Operation				
1	Production	$4,355,237	$1,304,118	$5,659,355	
2	Transmission	406,059	38,989	445,048	
3	Distribution	752,671	72,271	824,942	
4	Customer Accounts	1,620,383	155,588	1,775,971	
5	Customer Service & Informational	464,174	44,569	508,743	
6	Administrative & General	951,515	91,364	1,042,879	
7	TOTAL Operation	$8,550,039	$1,706,899	$10,256,938	
	Maintenance				
8	Production	$3,398,792	$316,706	$3,715,498	
9	Transmission	840,937	80,746	921,683	
10	Distribution	3,911,414	375,571	4,286,985	
11	Administrative & General	670,357	64,366	734,723	
12	TOTAL Maintenance	$8,821,500	$837,389	$9,658,889	
	Total Operation & Maintenance				
13	Production (LINE 1 + LINE 8)	$7,754,029	$1,620,824	$9,374,853	
14	Transmission (LINE 2 + LINE 9)	1,246,996	119,735	1,366,731	
15	Distribution (LINE 3 + LINE 10)	4,664,085	447,842	5,111,927	
16	Customer Accounts (LINE 4)	1,620,383	155,588	1,775,971	
17	Customer Service & Informational (LINE 5)	464,174	44,569	508,743	
18	Administrative & General (LINE 6 + LINE 11)	1,621,872	155,730	1,777,602	
19	TOTAL Operation & Maintenance	$17,371,539	$2,544,288	$19,915,827	66.91%
20	Construction	$7,501,864	$719,928	$8,221,792	27.62%
21	Plant Removal (Retirement)	$1,432,616	$137,483	$1,570,099	5.27%
	Other Accounts				
22	Fuel Stock Expense Undistributed	$898,288	($898,288)	$0	
23	Stores Expense Undistributed	1,122,693	(1,122,693)	0	
24	Clearing Accounts	748,059	(748,059)	0	
25	ODD Temporary Facilities	29,250	0	29,250	
26	Miscellaneous Deferred Debits	653,745	(653,745)	0	
27	Research and Development	914	(914)	0	
28	Miscellaneous Current and Accrued Liabilities	(22,000)	22,000	0	
29	Donations	30,032	0	30,032	
30	All Other General Ledger (GL)	0	0	0	
31	TOTAL Other Accounts	$3,460,981	($3,401,699)	$59,282	0.20%
32	TOTAL Salaries & Wages (LINES 19+20+21+31)	$29,767,000	$0	$29,767,000	100.00%

KENTUCKY POWER COMPANY
d/b/a AMERICAN ELECTRIC POWER
DIRECT AND ALLOCATED PAYROLL DISTRIBUTION
TWELVE MONTHS ENDED 06/30/2005

SECTION V
WORKPAPER S-7
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LINE NO. (1)	FUNCTION (2)	DIRECT PAYROLL DISTRIBUTION (3)	Account 163 & Account 184 (4)	Account 152 (5)	Account 185 (6)	Account 186 (7)	Account 188 (8)	Account 242 (9)	Account 426 (10)	Subtotal (11)	Total (12)
	Operation										
1	Production	$4,355,237	$309,723	$898,288	$0	$108,234	$230	($12,357)	$0	$1,304,118	$5,659,355
2	Transmission	406,059	28,877	0	0	10,091	21	0	0	38,989	445,048
3	Distribution	752,671	53,526	0	0	18,705	40	0	0	72,271	824,942
4	Customer Accounts	1,620,383	115,234	0	0	40,269	85	0	0	155,588	1,775,971
5	Customer Service & Informational	464,174	33,010	0	0	11,535	24	0	0	44,569	508,743
6	Administrative & General	951,515	67,667	0	0	23,647	50	0	0	91,364	1,042,879
7	TOTAL Operation	$8,550,039	$608,037	$898,288	$0	$212,481	$450	($12,357)	$0	$1,706,899	$10,256,938
	Maintenance										
8	Production	$3,398,792	$241,705	$0	$0	$84,465	$179	($9,643)	$0	$316,706	$3,715,498
9	Transmission	840,937	59,803	0	0	20,899	44	0	0	80,746	921,683
10	Distribution	3,911,414	278,160	0	0	97,205	206	0	0	375,571	4,286,985
11	Administrative & General	670,357	47,672	0	0	16,659	35	0	0	64,366	734,723
12	TOTAL Maintenance	$8,821,500	$627,340	$0	$0	$219,228	$464	($9,643)	$0	$837,389	$9,658,889
	Total Operation & Maintenance										
13	Production (LINE 1 + LINE 8)	$7,754,029	$551,428	$898,288	$0	$192,699	$409	($22,000)	$0	$1,620,824	$9,374,853
14	Transmission (LINE 2 + LINE 9)	1,246,996	88,680	0	0	30,990	65	0	0	119,735	1,366,731
15	Distribution (LINE 3 + LINE 10)	4,664,085	331,686	0	0	115,910	246	0	0	447,842	5,111,927
16	Customer Accounts (LINE 4)	1,620,383	115,234	0	0	40,269	85	0	0	155,588	1,775,971
17	Customer Service & Informational (LINE 5)	464,174	33,010	0	0	11,535	24	0	0	44,569	508,743
18	Administrative & General (LINE 6 + LINE 11)	1,621,872	115,339	0	0	40,306	85	0	0	155,730	1,777,602
19	TOTAL Operation & Maintenance	$17,371,539	$1,235,377	$898,288	$0	$431,709	$914	($22,000)	$0	$2,544,288	$19,915,827
20	Construction	$7,501,864	$533,495	$0	$0	$186,433	$0	$0	$0	$719,928	$8,221,792
21	Plant Removal (Retirement)	$1,432,616	$101,880	$0	$0	$35,603	$0	$0	$0	$137,483	$1,570,099
	Other Accounts										
22	Fuel Stock Expense Undistributed	$898,288	$0	($898,288)	$0	$0	$0	$0	$0	($898,288)	$0
23	Stores Expense Undistributed	1,122,693	(1,122,693)	0	0	0	0	0	0	(1,122,693)	0
24	Clearing Accounts	748,059	(748,059)	0	0	0	0	0	0	(748,059)	0
25	ODD Temporary Facilities	29,250	0	0	0	0	0	0	0	0	29,250
26	Miscellaneous Deferred Debits	653,745	0	0	0	(653,745)	0	0	0	(653,745)	0
27	Research and Development	914	0	0	0	0	(914)	0	0	(914)	0
28	Miscellaneous Current and Accrued Liabilities	(22,000)	0	0	0	0	0	22,000	0	22,000	0
29	Donations	30,032	0	0	0	0	0	0	0	0	30,032
30	All Other General Ledger (GL)	0	0	0	0	0	0	0	0	0	0
31	TOTAL Other Accounts	$3,460,981	($1,870,752)	($898,288)	$0	($653,745)	($914)	$22,000	$0	($3,401,699)	$59,282
32	TOTAL Salaries & Wages (LINES 19+20+21+31)	$29,767,000	$0	$0	$0	$0	$0	$0	$0	$0	$29,767,000

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Pile	Date	Consumed Tons
Big Sandy Low Sulfur	01/01/05	5,563
Big Sandy Low Sulfur	01/02/05	6,331
Big Sandy Low Sulfur	01/03/05	3,177
Big Sandy Low Sulfur	01/04/05	2,572
Big Sandy Low Sulfur	01/05/05	7,470
Big Sandy Low Sulfur	01/06/05	8,993
Big Sandy Low Sulfur	01/07/05	8,388
Big Sandy Low Sulfur	01/08/05	8,342
Big Sandy Low Sulfur	01/09/05	7,623
Big Sandy Low Sulfur	01/10/05	7,644
Big Sandy Low Sulfur	01/11/05	7,901
Big Sandy Low Sulfur	01/12/05	7,691
Big Sandy Low Sulfur	01/13/05	8,619
Big Sandy Low Sulfur	01/14/05	6,468
Big Sandy Low Sulfur	01/15/05	5,415
Big Sandy Low Sulfur	01/16/05	5,265
Big Sandy Low Sulfur	01/17/05	8,598
Big Sandy Low Sulfur	01/18/05	8,521
Big Sandy Low Sulfur	01/19/05	9,590
Big Sandy Low Sulfur	01/20/05	5,880
Big Sandy Low Sulfur	01/21/05	1,565
Big Sandy Low Sulfur	01/22/05	2,244
g Sandy Low Sulfur	01/23/05	2,706
g Sandy Low Sulfur	01/24/05	3,130
Big Sandy Low Sulfur	01/25/05	5,462
Big Sandy Low Sulfur	01/26/05	9,534
Big Sandy Low Sulfur	01/27/05	8,699
Big Sandy Low Sulfur	01/28/05	8,856
Big Sandy Low Sulfur	01/29/05	9,265
Big Sandy Low Sulfur	01/30/05	7,245
Big Sandy Low Sulfur	01/31/05	8,647
Big Sandy Low Sulfur	02/01/05	8,053
Big Sandy Low Sulfur	02/02/05	9,087
Big Sandy Low Sulfur	02/03/05	8,949
Big Sandy Low Sulfur	02/04/05	8,655
Big Sandy Low Sulfur	02/05/05	8,184
Big Sandy Low Sulfur	02/06/05	7,721
Big Sandy Low Sulfur	02/07/05	9,271
Big Sandy Low Sulfur	02/08/05	9,525
Big Sandy Low Sulfur	02/09/05	8,956
Big Sandy Low Sulfur	02/10/05	9,279
Big Sandy Low Sulfur	02/11/05	8,847
Big Sandy Low Sulfur	02/12/05	8,643
Big Sandy Low Sulfur	02/13/05	8,505
Big Sandy Low Sulfur	02/14/05	9,708
Big Sandy Low Sulfur	02/15/05	8,781
Big Sandy Low Sulfur	02/16/05	9,078
Big Sandy Low Sulfur	02/17/05	8,653
g Sandy Low Sulfur	02/18/05	9,961
g Sandy Low Sulfur	02/19/05	9,330
Big Sandy Low Sulfur	02/20/05	8,774

Big Sandy Coal Consumption

Survey adjustments excluded from data.

01/01/2005 to 12/31/2005
Average Daily Consumed Tons
8017.13

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Big Sandy Low Sulfur	02/21/05	8,044
Big Sandy Low Sulfur	02/22/05	9,353
Big Sandy Low Sulfur	02/23/05	9,565
Big Sandy Low Sulfur	02/24/05	10,163
Big Sandy Low Sulfur	02/25/05	8,901
Big Sandy Low Sulfur	02/26/05	9,328
Big Sandy Low Sulfur	02/27/05	7,554
Big Sandy Low Sulfur	02/28/05	8,285
Big Sandy Low Sulfur	03/01/05	9,743
Big Sandy Low Sulfur	03/02/05	9,866
Big Sandy Low Sulfur	03/03/05	10,097
Big Sandy Low Sulfur	03/04/05	8,192
Big Sandy Low Sulfur	03/05/05	9,317
Big Sandy Low Sulfur	03/06/05	7,635
Big Sandy Low Sulfur	03/07/05	8,371
Big Sandy Low Sulfur	03/08/05	9,303
Big Sandy Low Sulfur	03/09/05	9,595
Big Sandy Low Sulfur	03/10/05	10,710
Big Sandy Low Sulfur	03/11/05	8,121
Big Sandy Low Sulfur	03/12/05	9,282
Big Sandy Low Sulfur	03/13/05	9,282
Big Sandy Low Sulfur	03/14/05	10,119
Big Sandy Low Sulfur	03/15/05	7,366
Big Sandy Low Sulfur	03/16/05	10,215
Big Sandy Low Sulfur	03/17/05	10,006
Big Sandy Low Sulfur	03/18/05	9,021
Big Sandy Low Sulfur	03/19/05	8,488
Big Sandy Low Sulfur	03/20/05	7,746
Big Sandy Low Sulfur	03/21/05	10,045
Big Sandy Low Sulfur	03/22/05	9,339
Big Sandy Low Sulfur	03/23/05	8,754
Big Sandy Low Sulfur	03/24/05	8,812
Big Sandy Low Sulfur	03/25/05	7,871
Big Sandy Low Sulfur	03/26/05	10,075
Big Sandy Low Sulfur	03/27/05	6,200
Big Sandy Low Sulfur	03/28/05	7,123
Big Sandy Low Sulfur	03/29/05	9,371
Big Sandy Low Sulfur	03/30/05	8,259
Big Sandy Low Sulfur	03/31/05	8,403
Big Sandy Low Sulfur	04/01/05	6,956
Big Sandy Low Sulfur	04/02/05	9,004
Big Sandy Low Sulfur	04/03/05	7,724
Big Sandy Low Sulfur	04/04/05	8,498
Big Sandy Low Sulfur	04/05/05	8,943
Big Sandy Low Sulfur	04/06/05	8,550
Big Sandy Low Sulfur	04/07/05	9,266
Big Sandy Low Sulfur	04/08/05	4,929
Big Sandy Low Sulfur	04/09/05	8,233
Big Sandy Low Sulfur	04/10/05	7,425
Big Sandy Low Sulfur	04/11/05	9,599
Big Sandy Low Sulfur	04/12/05	8,184
Big Sandy Low Sulfur	04/13/05	8,599
Big Sandy Low Sulfur	04/14/05	8,890
Big Sandy Low Sulfur	04/15/05	8,557

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Big Sandy Low Sulfur	04/16/05	4,652
Big Sandy Low Sulfur	04/17/05	8,353
Big Sandy Low Sulfur	04/18/05	8,065
Big Sandy Low Sulfur	04/19/05	8,433
Big Sandy Low Sulfur	04/20/05	7,756
Big Sandy Low Sulfur	04/21/05	7,589
Big Sandy Low Sulfur	04/22/05	1,775
Big Sandy Low Sulfur	04/23/05	6,496
Big Sandy Low Sulfur	04/24/05	9,072
Big Sandy Low Sulfur	04/25/05	9,046
Big Sandy Low Sulfur	04/26/05	8,757
Big Sandy Low Sulfur	04/27/05	8,738
Big Sandy Low Sulfur	04/28/05	7,172
Big Sandy Low Sulfur	04/29/05	8,576
Big Sandy Low Sulfur	04/30/05	5,304
Big Sandy Low Sulfur	05/01/05	6,226
Big Sandy Low Sulfur	05/02/05	6,972
Big Sandy Low Sulfur	05/03/05	6,554
Big Sandy Low Sulfur	05/04/05	7,364
Big Sandy Low Sulfur	05/05/05	6,143
Big Sandy Low Sulfur	05/06/05	7,378
Big Sandy Low Sulfur	05/07/05	6,450
Big Sandy Low Sulfur	05/08/05	5,898
Big Sandy Low Sulfur	05/09/05	8,092
Big Sandy Low Sulfur	05/10/05	6,040
Big Sandy Low Sulfur	05/11/05	7,774
Big Sandy Low Sulfur	05/12/05	5,263
Big Sandy Low Sulfur	05/13/05	6,926
Big Sandy Low Sulfur	05/14/05	6,680
Big Sandy Low Sulfur	05/15/05	5,990
Big Sandy Low Sulfur	05/16/05	6,484
Big Sandy Low Sulfur	05/17/05	6,962
Big Sandy Low Sulfur	05/18/05	6,596
Big Sandy Low Sulfur	05/19/05	6,292
Big Sandy Low Sulfur	05/20/05	7,683
Big Sandy Low Sulfur	05/21/05	6,959
Big Sandy Low Sulfur	05/22/05	6,248
Big Sandy Low Sulfur	05/23/05	7,026
Big Sandy Low Sulfur	05/24/05	6,675
Big Sandy Low Sulfur	05/25/05	6,145
Big Sandy Low Sulfur	05/26/05	6,646
Big Sandy Low Sulfur	05/27/05	6,757
Big Sandy Low Sulfur	05/28/05	5,338
Big Sandy Low Sulfur	05/29/05	3,812
Big Sandy Low Sulfur	05/30/05	3,290
Big Sandy Low Sulfur	05/31/05	5,670
Big Sandy Low Sulfur	06/01/05	6,487
Big Sandy Low Sulfur	06/02/05	6,920
Big Sandy Low Sulfur	06/03/05	6,644
Big Sandy Low Sulfur	06/04/05	8,440
Big Sandy Low Sulfur	06/05/05	7,220
Big Sandy Low Sulfur	06/06/05	10,629
Big Sandy Low Sulfur	06/07/05	8,920
Big Sandy Low Sulfur	06/08/05	8,075

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Big Sandy Low Sulfur	06/09/05	9,216
Big Sandy Low Sulfur	06/10/05	9,614
Big Sandy Low Sulfur	06/11/05	9,478
Big Sandy Low Sulfur	06/12/05	8,095
Big Sandy Low Sulfur	06/13/05	9,074
Big Sandy Low Sulfur	06/14/05	8,644
Big Sandy Low Sulfur	06/15/05	7,900
Big Sandy Low Sulfur	06/16/05	7,788
Big Sandy Low Sulfur	06/17/05	5,721
Big Sandy Low Sulfur	06/18/05	2,786
Big Sandy Low Sulfur	06/19/05	4,043
Big Sandy Low Sulfur	06/20/05	9,185
Big Sandy Low Sulfur	06/21/05	8,141
Big Sandy Low Sulfur	06/22/05	8,314
Big Sandy Low Sulfur	06/23/05	8,200
Big Sandy Low Sulfur	06/24/05	7,858
Big Sandy Low Sulfur	06/25/05	9,219
Big Sandy Low Sulfur	06/26/05	7,927
Big Sandy Low Sulfur	06/27/05	8,570
Big Sandy Low Sulfur	06/28/05	9,369
Big Sandy Low Sulfur	06/29/05	9,024
Big Sandy Low Sulfur	06/30/05	8,965
Big Sandy Low Sulfur	07/01/05	8,639
Big Sandy Low Sulfur	07/02/05	7,644
Big Sandy Low Sulfur	07/03/05	6,687
Big Sandy Low Sulfur	07/04/05	9,379
Big Sandy Low Sulfur	07/05/05	8,257
Big Sandy Low Sulfur	07/06/05	9,231
Big Sandy Low Sulfur	07/07/05	8,136
Big Sandy Low Sulfur	07/08/05	8,691
Big Sandy Low Sulfur	07/09/05	7,461
Big Sandy Low Sulfur	07/10/05	7,649
Big Sandy Low Sulfur	07/11/05	8,260
Big Sandy Low Sulfur	07/12/05	9,165
Big Sandy Low Sulfur	07/13/05	10,493
Big Sandy Low Sulfur	07/14/05	9,116
Big Sandy Low Sulfur	07/15/05	9,279
Big Sandy Low Sulfur	07/16/05	8,362
Big Sandy Low Sulfur	07/17/05	5,820
Big Sandy Low Sulfur	07/18/05	8,997
Big Sandy Low Sulfur	07/19/05	9,507
Big Sandy Low Sulfur	07/20/05	9,312
Big Sandy Low Sulfur	07/21/05	8,179
Big Sandy Low Sulfur	07/22/05	10,117
Big Sandy Low Sulfur	07/23/05	8,216
Big Sandy Low Sulfur	07/24/05	8,248
Big Sandy Low Sulfur	07/25/05	6,223
Big Sandy Low Sulfur	07/26/05	9,065
Big Sandy Low Sulfur	07/27/05	8,788
Big Sandy Low Sulfur	07/28/05	8,465
Big Sandy Low Sulfur	07/29/05	8,698
Big Sandy Low Sulfur	07/30/05	9,864
Big Sandy Low Sulfur	07/31/05	8,473
Big Sandy Low Sulfur	08/01/05	9,319

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Big Sandy Low Sulfur	08/02/05	9,223
Big Sandy Low Sulfur	08/03/05	7,663
Big Sandy Low Sulfur	08/04/05	11,151
Big Sandy Low Sulfur	08/05/05	9,326
Big Sandy Low Sulfur	08/06/05	8,521
Big Sandy Low Sulfur	08/07/05	8,208
Big Sandy Low Sulfur	08/08/05	9,327
Big Sandy Low Sulfur	08/09/05	9,388
Big Sandy Low Sulfur	08/10/05	9,093
Big Sandy Low Sulfur	08/11/05	11,010
Big Sandy Low Sulfur	08/12/05	8,348
Big Sandy Low Sulfur	08/13/05	8,457
Big Sandy Low Sulfur	08/14/05	8,937
Big Sandy Low Sulfur	08/15/05	8,043
Big Sandy Low Sulfur	08/16/05	9,704
Big Sandy Low Sulfur	08/17/05	8,336
Big Sandy Low Sulfur	08/18/05	9,442
Big Sandy Low Sulfur	08/19/05	9,994
Big Sandy Low Sulfur	08/20/05	8,747
Big Sandy Low Sulfur	08/21/05	8,013
Big Sandy Low Sulfur	08/22/05	8,650
Big Sandy Low Sulfur	08/23/05	7,751
Big Sandy Low Sulfur	08/24/05	7,571
Big Sandy Low Sulfur	08/25/05	2,204
Big Sandy Low Sulfur	08/26/05	1,419
Big Sandy Low Sulfur	08/27/05	2,687
Big Sandy Low Sulfur	08/28/05	2,538
Big Sandy Low Sulfur	08/29/05	9,228
Big Sandy Low Sulfur	08/30/05	7,350
Big Sandy Low Sulfur	08/31/05	8,617
Big Sandy Low Sulfur	09/01/05	8,111
Big Sandy Low Sulfur	09/02/05	10,176
Big Sandy Low Sulfur	09/03/05	8,598
Big Sandy Low Sulfur	09/04/05	6,831
Big Sandy Low Sulfur	09/05/05	7,238
Big Sandy Low Sulfur	09/06/05	9,104
Big Sandy Low Sulfur	09/07/05	9,370
Big Sandy Low Sulfur	09/08/05	7,401
Big Sandy Low Sulfur	09/09/05	8,012
Big Sandy Low Sulfur	09/10/05	8,481
Big Sandy Low Sulfur	09/11/05	6,923
Big Sandy Low Sulfur	09/12/05	9,093
Big Sandy Low Sulfur	09/13/05	9,345
Big Sandy Low Sulfur	09/14/05	9,168
Big Sandy Low Sulfur	09/15/05	8,571
Big Sandy Low Sulfur	09/16/05	9,852
Big Sandy Low Sulfur	09/17/05	6,186
Big Sandy Low Sulfur	09/18/05	5,098
Big Sandy Low Sulfur	09/19/05	8,764
Big Sandy Low Sulfur	09/20/05	9,269
Big Sandy Low Sulfur	09/21/05	8,604
Big Sandy Low Sulfur	09/22/05	9,415
Big Sandy Low Sulfur	09/23/05	9,942
Big Sandy Low Sulfur	09/24/05	8,784

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Big Sandy Low Sulfur	09/25/05	6,553
Big Sandy Low Sulfur	09/26/05	8,449
Big Sandy Low Sulfur	09/27/05	9,225
Big Sandy Low Sulfur	09/28/05	8,931
Big Sandy Low Sulfur	09/29/05	7,779
Big Sandy Low Sulfur	09/30/05	7,785
Big Sandy Low Sulfur	10/01/05	7,752
Big Sandy Low Sulfur	10/02/05	6,793
Big Sandy Low Sulfur	10/03/05	8,869
Big Sandy Low Sulfur	10/04/05	9,688
Big Sandy Low Sulfur	10/05/05	8,830
Big Sandy Low Sulfur	10/06/05	9,551
Big Sandy Low Sulfur	10/07/05	9,521
Big Sandy Low Sulfur	10/08/05	8,412
Big Sandy Low Sulfur	10/09/05	7,837
Big Sandy Low Sulfur	10/10/05	9,254
Big Sandy Low Sulfur	10/11/05	8,761
Big Sandy Low Sulfur	10/12/05	9,716
Big Sandy Low Sulfur	10/13/05	9,240
Big Sandy Low Sulfur	10/14/05	8,010
Big Sandy Low Sulfur	10/15/05	7,727
Big Sandy Low Sulfur	10/16/05	6,552
Big Sandy Low Sulfur	10/17/05	9,588
Big Sandy Low Sulfur	10/18/05	8,247
Big Sandy Low Sulfur	10/19/05	7,912
Big Sandy Low Sulfur	10/20/05	8,649
Big Sandy Low Sulfur	10/21/05	7,718
Big Sandy Low Sulfur	10/22/05	8,035
Big Sandy Low Sulfur	10/23/05	7,092
Big Sandy Low Sulfur	10/24/05	7,328
Big Sandy Low Sulfur	10/25/05	8,875
Big Sandy Low Sulfur	10/26/05	9,203
Big Sandy Low Sulfur	10/27/05	9,887
Big Sandy Low Sulfur	10/28/05	8,558
Big Sandy Low Sulfur	10/29/05	8,647
Big Sandy Low Sulfur	10/30/05	6,828
Big Sandy Low Sulfur	10/31/05	9,197
Big Sandy Low Sulfur	11/01/05	8,327
Big Sandy Low Sulfur	11/02/05	8,439
Big Sandy Low Sulfur	11/03/05	9,183
Big Sandy Low Sulfur	11/04/05	9,478
Big Sandy Low Sulfur	11/05/05	7,495
Big Sandy Low Sulfur	11/06/05	7,099
Big Sandy Low Sulfur	11/07/05	9,328
Big Sandy Low Sulfur	11/08/05	8,686
Big Sandy Low Sulfur	11/09/05	8,856
Big Sandy Low Sulfur	11/10/05	8,142
Big Sandy Low Sulfur	11/11/05	9,543
Big Sandy Low Sulfur	11/12/05	9,411
Big Sandy Low Sulfur	11/13/05	7,938
Big Sandy Low Sulfur	11/14/05	9,433
Big Sandy Low Sulfur	11/15/05	8,747
Big Sandy Low Sulfur	11/16/05	9,478
Big Sandy Low Sulfur	11/17/05	9,121

Kentucky Power Company
Twelve Months Ended 12/31/05
Big Sandy's Daily Tons Burned

Big Sandy Low Sulfur	11/18/05	8,434
Big Sandy Low Sulfur	11/19/05	7,816
Big Sandy Low Sulfur	11/20/05	6,060
Big Sandy Low Sulfur	11/21/05	9,202
Big Sandy Low Sulfur	11/22/05	7,148
Big Sandy Low Sulfur	11/23/05	7,093
Big Sandy Low Sulfur	11/24/05	1,734
Big Sandy Low Sulfur	11/25/05	2,405
Big Sandy Low Sulfur	11/26/05	1,345
Big Sandy Low Sulfur	11/27/05	2,892
Big Sandy Low Sulfur	11/28/05	1,778
Big Sandy Low Sulfur	11/29/05	10,031
Big Sandy Low Sulfur	11/30/05	8,730
Big Sandy Low Sulfur	12/01/05	9,831
Big Sandy Low Sulfur	12/02/05	8,699
Big Sandy Low Sulfur	12/03/05	9,757
Big Sandy Low Sulfur	12/04/05	8,191
Big Sandy Low Sulfur	12/05/05	9,168
Big Sandy Low Sulfur	12/06/05	10,197
Big Sandy Low Sulfur	12/07/05	9,394
Big Sandy Low Sulfur	12/08/05	10,276
Big Sandy Low Sulfur	12/09/05	10,019
Big Sandy Low Sulfur	12/10/05	9,075
Big Sandy Low Sulfur	12/11/05	8,749
Big Sandy Low Sulfur	12/12/05	9,468
Big Sandy Low Sulfur	12/13/05	9,159
Big Sandy Low Sulfur	12/14/05	9,793
Big Sandy Low Sulfur	12/15/05	7,432
Big Sandy Low Sulfur	12/16/05	6,436
Big Sandy Low Sulfur	12/17/05	7,197
Big Sandy Low Sulfur	12/18/05	10,270
Big Sandy Low Sulfur	12/19/05	8,969
Big Sandy Low Sulfur	12/20/05	11,607
Big Sandy Low Sulfur	12/21/05	8,880
Big Sandy Low Sulfur	12/22/05	9,399
Big Sandy Low Sulfur	12/23/05	7,823
Big Sandy Low Sulfur	12/24/05	5,985
Big Sandy Low Sulfur	12/25/05	5,010
Big Sandy Low Sulfur	12/26/05	7,030
Big Sandy Low Sulfur	12/27/05	8,998
Big Sandy Low Sulfur	12/28/05	9,350
Big Sandy Low Sulfur	12/29/05	8,764
Big Sandy Low Sulfur	12/30/05	9,307
Big Sandy Low Sulfur	12/31/05	7,403

Kentucky Power Company
Revenue, Return, Capitalization and Rate Base - Ky PSC Jurisdiction
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 1

Ln No (1)	Description (2)	Present Rates Adjusted PSC Jurisdiction (3)	Proposed Change (4)	PSC Jurisdiction with Proposed Change (5)
	Operating Revenues			
1	Sales of Electricity	$337,362,413	$61,119,336	$398,481,749
2	Other Operating Revenues	$9,407,869	$0	$9,407,869
3	Total Operating Revenues	$346,770,282	$61,119,336	$407,889,618
	Operating Expenses			
4	Operation & Maintenance	$264,883,715	$288,911	$265,172,626
5	Depreciation	$47,426,057	$0	$47,426,057
6	Taxes Other Than Income Taxes	$9,197,270	$0	$9,197,270
7	State Income Tax	($973,341)	$3,801,902	$2,828,561
	Federal Income Tax:			
8	Current	($5,248,350)	$19,959,983	$14,711,633
9	Deferred	$3,636,693	$0	$3,636,693
10	ITC Adjustment	($1,156,997)	$0	($1,156,997)
11	Total Operating Expenses	$317,765,047	$24,050,796	$341,815,843
12	Net Electric Operating Income (Lns 3-11)	$29,005,235	$37,068,540	$66,073,775
13	AFUDC Offset Adjustment	$1,234,029	$0	$1,234,029
14	Net Electric Operating Income - Adjusted	$30,239,264	$37,068,540	$67,307,804
15	Total Rate Base			$858,135,035
16	Rate of Return			7.84%
17	Capitalization			$853,082,950
18	Rate of Return			7.89%
19	Proposed Increase Percentage			18.12%

Kentucky Power Company
Revenue Requirement
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 2

Ln No (1)	Description (2)	Amount (3)
1	Capitalization (Per Sch 3, Ln 7, Col 12)	$853,082,950
2	Rate of Return (WP S-2, Pg 1, Ln 5, Col 6)	7.89%
3	Required Net Electric Operating Income (Ln 1 x Ln 2)	$67,308,245
4	Test Year Net Electric Operating Income (Per Sch 4, Ln 14, Col 5)	$30,239,264
5	Net Electric Operating Income Change (Ln 3 - Ln 4)	$37,068,981
6	Gross Revenue Conversion Factor (Per WP S-2, Pg 2, Ln 8)	1.6488
7	Change in Revenue Requirement (Ln 5 x Ln 6) Increase / (Decrease)	$61,119,336

Kentucky Power Company
Cost of Capital
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-2
Page 1 of 3

Ln No (1)	Description (2)	Reapportioned Kentucky Jurisdictional Capital [1/] (3)	Percent of Total (4)	Annual Cost Percentage Rate (5)	Weighted Average Cost Percent (6)=(4)x(5)
1	Long Term Debt	$482,392,123	56.55%	5.70% [2/]	3.22%
2	Short Term Debt	$3,340,763	0.39%	3.34% [3/]	0.01%
3	Accts Receivable Financing [4/]	$30,052,250	3.52%	2.99% [5/]	0.11%
4	Common Equity	$337,297,815	39.54%	11.50% [6/]	4.55%
5	Total	$853,082,950	100.00%		7.89%

1/ Schedule 3, Col. 12, Lns. 1, 2 & 3
2/ Per Workpaper S-3, Pg. 1, Col. 12
3/ Per Workpaper S-3, Pg. 2, Ln 17
4/ Per Commission Order March 31, 2003 Case No 2002-00169
5/ 13 Month Average Cost of Accounts Receivable Financing
6/ Per Recommendation of Paul R Moul

Kentucky Power Company
Compution of the Gross Revenue
Conversion Factor
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Percent of Incremental Gross Revenues (3)
1	Operating Revenues	100.00%
2	Less: Uncollectable Accounts Expense [1/]	0.47%
3	Income Before Income Taxes	99.53%
4	Less: State Income Taxes (Ln 3 x 6.25%)[2/]	6.22%
5	Income Before Federal Income Taxes	93.31%
6	Less: Federal Income Taxes (Ln 5 x 35%)	32.66%
7	Operating Income Percentage	60.65%
8	Gross Revenue Conversion Factor (100% / Ln 7)	1.6488

1/ Per Workpaper S-2, Page 3, Col 5, Line 5

2/ State Income Tax Effective Rate Calculations

State Income Tax Rate - Ky	7.00%	
Number of Months	9	
Effective Kentucky State Income Tax Rate		63.00%
State Income Tax Rate - WVA	6.00%	
Number oF Months	27	
Effective West Virginia State Income Tax Rate		162.00%
Total		225.00%
Total Number of Month		36
Average Rate		6.25%

Kentucky Power Company
Computation of Factor to be Applied to Additional Revenues Generated by Rate Increase, In Determination of Uncollectible Accounts Adjustment to be Added to O&M Expense
Test Year Twelve Months Ended 6/30/2005

		PSC of KY. Jurisdiction		
Ln No (1)	Description (2)	Electric Revenues (3)	Accounts-Net Charged Off (4)	Percent of Elect. Revenues (5)
1	12 Months Ended 6/30/2003	$284,001,565	$1,675,722	0.59%
2	12 Months Ended 6/30/2004	$295,830,716	$1,439,263	0.49%
3	12 Months Ended 6/30/2005	$328,104,695	$1,177,282	0.36%
4	Total	$907,936,976	$4,292,267	1.44%
5	Three Year Average	$302,645,659	$1,430,756	0.47%

Kentucky Power Company
Capitalization
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 3

Ln No (1)	Description (2)	Per Book Balance (3)	Big Sandy Coal Stock Adjustment (4)	KPCo's Equity Pension Adjustment (5)	Reliability Capital Adjustment (6)	FRECO A/C 124 Property (7)	Carrs Site (8)	Non-Utility Property (9)	Sub-Total (10)	Kentucky Jurisdiction GP-TOT (11)	Reapportioned Kentucky Jurisdictional (12)
1	Long Term Debt	$487,716,122	$0	$0	$3,181,718	($2,638,456)	($3,892,927)	($572,237)	$483,794,220	$478,956,278	$482,392,123
2	Short Term Debt	$0	$3,592,837	$0	$196,622	($163,050)	($240,573)	($35,363)	$3,350,473	$3,316,968	$3,340,763
3	Acct Receivable Financing	$30,139,598	$0	$0	$0	$0	$0	$0	$30,139,598	$29,838,202	$30,052,250
4	Common Equity	$331,354,481	$0	$9,588,250	$2,161,660	($1,792,568)	($2,644,856)	($388,778)	$338,278,189	$334,895,407	$337,297,815
5	Sub - Total	$849,210,201	$3,592,837	$9,588,250	$5,540,000	($4,594,074)	($6,778,356)	($996,378)	$855,562,480	$847,006,855	$853,082,950
6	Job Development Tax Credit	$6,137,470	$0	$0	$0	$0	$0	$0	$6,137,470	$6,076,095	$0
7	Total	$855,347,671	$3,592,837	$9,588,250	$5,540,000	($4,594,074)	($6,778,355)	($996,378)	$861,699,950	$853,082,950	$853,082,950
8	Allocation Factor (GP-TOT)	0.990									

Kentucky Power Company
Long-Term Debt
Test Year Twelve Months Ended 6/30/2005
($000)

Ln No (1)	Description (2)	Interest Rate (%) (3)	Date of Offering (4)	Date of Maturity (5)	Principal Amount Outstanding (6)	Original Principal Amount (7)	Total Original Discount (Prem) & Expense [1/] (8)	Net Proceeds on Principal Amt. Based on Original Disc. (Prem) & Exp (9)	Cost of Debt Based on Principal Amount Outstanding (10)	Annual Cost of Debt Based on Carrying Value (11)	Average Cost of Debt (12)	Name of Issuer (13)
1	Global Note Payable to Parent Company (AEP)	6.501%	05/05/2004	05/15/2006	$40,000	$60,000	$0	$60,000	6.500%	$2,600		KPCo
2	Global Note Payable to Parent Company (AEP)	5.250%	02/05/2004	06/01/2015	$20,000	$20,000	$0	$20,000	5.249%	$1,050		KPCo
3	Senior Unsecured Notes - Series B	4.315%	11/12/2002	11/12/2007	$80,400	$80,400	$1,393	$79,007	4.708%	$3,785		KPCo
4	Senior Unsecured Notes - Series C	4.368%	12/23/2002	12/12/2007	$69,564	$69,564	$1,975	$67,589	5.020%	$3,492		KPCo
5	Senior Unsecured Notes - Series A	5.500%	06/28/2002	07/01/2007	$124,973	$125,000	$1,255	$123,745	5.733%	$7,165		KPCo
6	Senior Unsecured Notes - Series D	5.625%	06/13/2003	12/01/2032	$75,000	$75,000	$2,383	$72,617	5.852%	$4,389		KPCo
7	Senior Unsecured Notes - Series A	6.450%	11/10/1998	11/10/2008	$30,000	$30,000	$239	$29,761	6.560%	$1,968		KPCo
8	Senior Unsecured Notes	6.910%	10/01/1997	10/01/2007	$48,000	$48,000	$363	$47,637	7.017%	$3,368		KPCo
9	Sub-Total											
10	Total Long Term Debt				$487,937	$507,964	$7,608	$500,356		$27,817		
11	Other Long Term Debt				$0	$0	$0	$0		$0		
12	Sub-total				$487,937	$507,964	$7,608	$500,356		$27,817		
13	Total Kentucky Power				$487,937	$507,964	$7,608	$500,356		$27,817	5.70%	

1/ Includes Commissions and All Other Issuance Expenses

Kentucky Power Company
Schedule of Short Term Debt
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-3
Page 2 of 3

Ln No (1)	Month / Year (2)	Notes Payable Outstanding at End of Month (3)
1	June '04	$0
2	Jul '04	$0
3	Aug '04	$0
4	Sep '04	$0
5	Oct '04	$0
6	Nov '04	$0
7	Dec '05	$0
8	Jan '05	$0
9	Feb '05	$0
10	Mar '05	$0
11	Apr '05	$0
12	May '05	$0
13	Jun '05	$0
14	Total	$0
15	Average Borrowings Outstanding During the Period	$0
16	Interest Expense for the Twelve Months Ended 6/30/2005	$0
17	The Borrowing Rate of the AEP Money Pool as of June 30, 2005	3.34%

Kentucky Power Company
Coal Stock Adjustment - Big Sandy Plant
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Tons (3)	Cost / Ton (4)	Total Dollar Amount (5)
1	Balance End of Test Year	207,146	$49.32	$10,216,763
2	Daily Burn Rate	8,000		
3	Days Supply on Hand (Ln 1 / Ln 2)	26		
4	Target Days Supply	35		
5	Fuel Stock Level (Ln 2 x Ln 4)	280,000	$49.32	$13,809,600
6	Adjustment to Test Year End - Coal Stock	72,854		$3,592,837
7	Allocation Factor - PDAF			0.986
8	KPSC Jurisdictional Amount (Ln 6 X Ln 7)			$3,542,537

Kentucky Power Company
Adjustment Summary
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 4
Page 1

Ln No (1)	Description (2)	Base Case PSC Jurisdiction (3)	Rate Case Adjustments (4)	Adjusted PSC Jurisdiction (5)
	Operating Revenues			
1	Sales of Electricity	$336,751,863	$610,550	$337,362,413
2	Other Operating Revenues	$12,983,134	($3,575,265)	$9,407,869
3	Total Operating Revenues	$349,734,997	($2,964,715)	$346,770,282
	Operating Expenses			
4	Operation & Maintenance	$235,483,553	$29,400,162	$264,883,715
5	Depreciation	$44,043,880	$3,382,177	$47,426,057
6	Taxes Other Than Income Taxes	$8,937,315	$259,955	$9,197,270
7	State Income Tax	$922,665	($1,896,006)	($973,341)
	Federal Income Tax:			
8	Current	$4,705,661	($9,954,011)	($5,248,350)
9	Deferred	$4,900,291	($1,263,598)	$3,636,693
10	ITC Adjustment	($1,156,997)	$0	($1,156,997)
11	Total Operating Expenses	$297,836,368	$19,928,679	$317,765,047
12	Net Electric Operating Income (Lns 3-11)	$51,898,629	($22,893,394)	$29,005,235
13	AFUDC Offset Adjustment	$608,522	$625,507	$1,234,029
14	Net Electric Operating Income - Adjusted	$52,507,151	($22,267,887)	$30,239,264
	Rate Base			
15	Electric Plant in Service - Gross	$1,331,453,536	$5,484,600	$1,336,938,136
16	Accum. Prov. For Deperciation	$432,998,450	$0	$432,998,450
17	Electric Plant in Service - Net	$898,455,086	$5,484,600	$903,939,686
18	Plant Held for Future Use	$83,282	$0	$83,282
19	Prepayments	$655,315	$4,039,158	$4,694,473
20	Material & Supplies	$16,502,178	$3,542,537	$20,044,715
21	Cash Working Capital	$45,119,645	$3,675,020	$48,794,665
22	Construction Work in Progress	$19,159,718	$0	$19,159,718
	Less:			
23	Customer Advance & Deposits	$10,598,069	$0	$10,598,069
24	Accumulated Deferred Income Taxes	$127,983,435	$0	$127,983,435
25	Total Rate Base	$841,393,720	$16,741,315	$858,135,035

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Total Adjustments Page 3 (3)	Page 4 (4)	Page 5 (5)	Page 6 (6)	Page 7 (7)	Page 8 (8)	Page 9 (9)	Grand Total (10)
	Operating Revenues								
1	Sales of Electricity	$1,579,800	$0	$0	($969,250)	$0	$0	$0	$610,550
2	Other Operating Revenues	$0	$0	$983,167	$0	$4,726,948	($9,285,380)	$0	($3,575,265)
3	Total Operating Revenues	$1,579,800	$0	$983,167	($969,250)	$4,726,948	($9,285,380)	$0	($2,964,715)
	Operating Expenses								
4	Operation & Maintenance	$8,675,151	$1,698,943	$632,477	$520,453	$15,217,879	$1,432,957	$1,222,302	$29,400,162
5	Depreciation	$3,382,177	$0	$0	$0	$0	$0	$0	$3,382,177
6	Taxes Other Than Income Taxes	$229,279	$30,676	$0	$0	$0	$0	$0	$259,955
7	State Income Tax	($457,790)	($108,101)	$91,235	($19,374)	($655,684)	($669,898)	($76,394)	($1,896,006)
	Federal Income Tax:								
8	Current	($2,403,395)	($567,531)	$478,987	($101,713)	($3,442,337)	($3,516,954)	($401,068)	($9,954,011)
9	Deferred	($931,717)	$0	$81,020	($412,901)	$0	$0	$0	($1,263,598)
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$8,493,705	$1,053,987	$1,283,719	($13,535)	$11,119,858	($2,753,895)	$744,840	$19,928,679
12	Net Electric Operating Income (Lns 3-11)	($6,913,905)	($1,053,987)	($300,552)	($955,715)	($6,392,910)	($6,531,485)	($744,840)	($22,893,394)
13	AFUDC Offset Adjustment	$0	$0	$625,507	$0	$0	$0	$0	$625,507
14	Net Electric Operating Income - Adjusted	($6,913,905)	($1,053,987)	$324,955	($955,715)	($6,392,910)	($6,531,485)	($744,840)	($22,267,887)
	Rate Base								
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$5,484,600	$0	$0	$5,484,600
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$0	$0	$0	$0	$5,484,600	$0	$0	$5,484,600
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$4,039,158	$0	$4,039,158
21	Material & Supplies	$0	$0	$0	$3,542,537	$0	$0	$0	$3,542,537
22	Cash Working Capital	$1,084,394	$212,368	$79,060	$65,057	$1,902,234	$179,119	$152,788	$3,675,020
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0	$0
	Less:								
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$1,084,394	$212,368	$79,060	$3,607,594	$7,386,834	$4,218,277	$152,788	$16,741,315

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Annualization Postage Increase (1)	Annualization Emp. Related Expense (2 - 6)	Annualization of Property Taxes (7)	Annualized Depreciation Expense (8)	Net Merger Savings Adjustment (9)	Adjust State Issues Revenues (10)	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$0	$0	$0	$4,037,000	($2,457,200)	$1,579,800
2	Other Operating Revenues	$0	$0	$0	$0	$0	$0	$0
3	Total Operating Revenues	$0	$0	$0	$0	$4,037,000	($2,457,200)	$1,579,800
	Operating Expenses							
4	Operation & Maintenance	$38,146	$1,252,005	$0	$0	$7,385,000	$0	$8,675,151
5	Depreciation	$0	$0	$0	$3,382,177	$0	$0	$3,382,177
6	Taxes Other Than Income Taxes	$0	$66,919	$162,360	$0	$0	$0	$229,279
7	State Income Tax	($2,384)	($82,433)	($10,148)	$0	($209,250)	($153,575)	($457,790)
	Federal Income Tax:							
8	Current	($12,517)	($432,772)	($53,274)	$0	($1,098,563)	($806,269)	($2,403,395)
9	Deferred	$0	$0	$0	($931,717)	$0	$0	($931,717)
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$23,245	$803,719	$98,938	$2,450,460	$6,077,187	($959,844)	$8,493,705
12	Net Electric Operating Income (Lns 3-11)	($23,245)	($803,719)	($98,938)	($2,450,460)	($2,040,187)	($1,497,356)	($6,913,905)
13	AFUDC Offset Adjustment	$0	$0	$0	$0	$0	$0	$0
14	Net Electric Operating Income - Adjusted	($23,245)	($803,719)	($98,938)	($2,450,460)	($2,040,187)	($1,497,356)	($6,913,905)
	Rate Base							
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$0	$0	$0	$0	$0	$0	$0
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$0	$0
21	Material & Supplies	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	$4,768	$156,501	$0	$0	$923,125	$0	$1,084,394
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$4,768	$156,501	$0	$0	$923,125	$0	$1,084,394

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Annualized PSC Assessment (11)	KPSC Consultants Expense (12)	Amortization of Rate Case Expense (13)	Annualized Lease Expense (14)	O&M Adjustment Advertising Expense (15)	Storm Damage Adjustment (16)	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$0	$0	$0	$0	$0	$0
2	Other Operating Revenues	$0	$0	$0	$0	$0	$0	$0
3	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0
	Operating Expenses							
4	Operation & Maintenance	$0	$48,576	$143,567	$12,404	($30,262)	$1,524,658	$1,698,943
5	Depreciation	$0	$0	$0	$0	$0	$0	$0
6	Taxes Other Than Income Taxes	$30,676	$0	$0	$0	$0	$0	$30,676
7	State Income Tax	($1,917)	($3,036)	($8,973)	($775)	$1,891	($95,291)	($108,101)
	Federal Income Tax:							
8	Current	($10,066)	($15,939)	($47,108)	($4,070)	$9,930	($500,278)	($567,531)
9	Deferred	$0	$0	$0	$0	$0	$0	$0
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$18,693	$29,601	$87,486	$7,559	($18,441)	$929,089	$1,053,987
12	Net Electric Operating Income (Lns 3-11)	($18,693)	($29,601)	($87,486)	($7,559)	$18,441	($929,089)	($1,053,987)
13	AFUDC Offset Adjustment	$0	$0	$0	$0	$0	$0	$0
14	Net Electric Operating Income - Adjusted	($18,693)	($29,601)	($87,486)	($7,559)	$18,441	($929,089)	($1,053,987)
	Rate Base							
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$0	$0	$0	$0	$0	$0	$0
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$0	$0
21	Material & Supplies	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	$0	$6,072	$17,946	$1,551	($3,783)	$190,582	$212,368
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$0	$6,072	$17,946	$1,551	($3,783)	$190,582	$212,368

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	O&M Expense Interest on Cust. Deposit (17)	Adjustment to Temp. Cash Investment (18)	AFUDC Offset Adjustment (19)	Adjustment Interest Synchronization (20)	Adjustment to Misc. Service Charges (21)	Adjustment to CATV Tariff (22)	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$0	$0	$0	$0	$0	$0
2	Other Operating Revenues	$0	$383,436	$0	$0	$455,973	$143,758	$983,167
3	Total Operating Revenues	$0	$383,436	$0	$0	$455,973	$143,758	$983,167
	Operating Expenses							
4	Operation & Maintenance	$632,477	$0	$0	$0	$0	$0	$632,477
5	Depreciation	$0	$0	$0	$0	$0	$0	$0
6	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
7	State Income Tax	($39,530)	$23,965	$0	$69,317	$28,498	$8,985	$91,235
	Federal Income Tax:							
8	Current	($207,531)	$125,815	$0	$363,916	$149,616	$47,171	$478,987
9	Deferred	$0	$0	$81,020	$0	$0	$0	$81,020
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$385,416	$149,780	$81,020	$433,233	$178,114	$56,156	$1,283,719
12	Net Electric Operating Income (Lns 3-11)	($385,416)	$233,656	($81,020)	($433,233)	$277,859	$87,602	($300,552)
13	AFUDC Offset Adjustment	$0	$0	$625,507	$0	$0	$0	$625,507
14	Net Electric Operating Income - Adjusted	($385,416)	$233,656	$544,487	($433,233)	$277,859	$87,602	$324,955
	Rate Base							
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$0	$0	$0	$0	$0	$0	$0
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$0	$0
21	Material & Supplies	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	$79,060	$0	$0	$0	$0	$0	$79,060
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$79,060	$0	$0	$0	$0	$0	$79,060

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Net Line of Credit Fee (23)	Revenue / Customer Annualization (24)	Customer Migration Adjustment (25)	Adjustment to System Sales (26)	Fuel Cost Recovery (27)	Adjustment to Fuel Stock Big Sandy Plt. (28)	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$195,124	$15,344	$0	($1,179,718)	$0	($969,250)
2	Other Operating Revenues	$0	$0	$0	$0	$0	$0	$0
3	Total Operating Revenues	$0	$195,124	$15,344	$0	($1,179,718)	$0	($969,250)
	Operating Expenses							
4	Operation & Maintenance	$378,305	$142,148	$0	$0	$0	$0	$520,453
5	Depreciation	$0	$0	$0	$0	$0	$0	$0
6	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
7	State Income Tax	($23,644)	$3,311	$959	$0	$0	$0	($19,374)
	Federal Income Tax:							
8	Current	($124,131)	$17,383	$5,035	$0	$0	$0	($101,713)
9	Deferred	$0	$0	$0	$0	($412,901)	$0	($412,901)
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$230,530	$162,842	$5,994	$0	($412,901)	$0	($13,535)
12	Net Electric Operating Income (Lns 3-11)	($230,530)	$32,282	$9,350	$0	($766,817)	$0	($955,715)
13	AFUDC Offset Adjustment	$0	$0	$0	$0	$0	$0	$0
14	Net Electric Operating Income - Adjusted	($230,530)	$32,282	$9,350	$0	($766,817)	$0	($955,715)
	Rate Base							
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant In Service - Net	$0	$0	$0	$0	$0	$0	$0
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$0	$0
21	Material & Supplies	$0	$0	$0	$0	$0	$3,542,537	$3,542,537
22	Cash Working Capital	$47,288	$17,769	$0	$0	$0	$0	$65,057
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$47,288	$17,769	$0	$0	$0	$3,542,537	$3,607,594

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Reliability Adjustment (29)	Adj. AEP Pool Capacity Cost for Changes (30)	Annualization of Vehicle Fuel Cost (31)	Normalization of PJM Revenues (32)	Normalize PJM Network Trans. Revenues (33)	Elimination of FERC Assessment Fee (34)	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$0	$0	$0	$0	$0	$0
2	Other Operating Revenues	$0	$0	$0	$2,774,645	$1,952,303	$0	$4,726,948
3	Total Operating Revenues	$0	$0	$0	$2,774,645	$1,952,303	$0	$4,726,948
	Operating Expenses							
4	Operation & Maintenance	$6,074,346	$8,992,705	$178,891	$0	$0	($28,063)	$15,217,879
5	Depreciation	$0	$0	$0	$0	$0	$0	$0
6	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
7	State Income Tax	($379,647)	($562,044)	($11,181)	$173,415	$122,019	$1,754	($655,684)
	Federal Income Tax:							
8	Current	($1,993,145)	($2,950,731)	($58,699)	$910,431	$640,599	$9,208	($3,442,337)
9	Deferred	$0	$0	$0	$0	$0	$0	$0
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
		($2,372,792)	($3,512,775)	($69,880)	$1,083,846	$762,618	$10,962	
11	Total Operating Expenses	$3,701,554	$5,479,930	$109,011	$1,083,846	$762,618	($17,101)	$11,119,858
12	Net Electric Operating Income (Lns 3-11)	($3,701,554)	($5,479,930)	($109,011)	$1,690,799	$1,189,685	$17,101	($6,392,910)
13	AFUDC Offset Adjustment	$0	$0	$0	$0	$0	$0	$0
14	Net Electric Operating Income - Adjusted	($3,701,554)	($5,479,930)	($109,011)	$1,690,799	$1,189,685	$17,101	($6,392,910)
	Rate Base							
15	Electric Plant in Service - Gross	$5,484,600	$0	$0	$0	$0	$0	$5,484,600
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$5,484,600	$0	$0	$0	$0	$0	$5,484,600
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$0	$0
21	Material & Supplies	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	$759,293	$1,124,088	$22,361	$0	$0	($3,508)	$1,902,234
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$6,243,893	$1,124,088	$22,361	$0	$0	($3,508)	$7,386,834

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Normalization of PJM Net Expansion Expenses (35)	Amortization of RTO Formation Costs (36)	Transmission Equalization Adjustment (37)	Big Sandy Plant Maintence Adjustment (38)	Normalization PJM PTP Trans. Revenues (39)	Prepayment Pension Adjustment (40)	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$0	$0	$0	$0	$0	$0
2	Other Operating Revenues	$0	$0	$272,404	$0	($9,557,784)	$0	($9,285,380)
3	Total Operating Revenues	$0	$0	$272,404	$0	($9,557,784)	$0	($9,285,380)
	Operating Expenses							
4	Operation & Maintenance	$75,402	$58,681	$0	$1,298,874	$0	$0	$1,432,957
5	Depreciation	$0	$0	$0	$0	$0	$0	$0
6	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
7	State Income Tax	($4,713)	($3,668)	$17,025	($81,180)	($597,362)	$0	($669,898)
	Federal Income Tax:							
8	Current	($24,741)	($19,255)	$89,383	($426,193)	($3,136,148)	$0	($3,516,954)
9	Deferred	$0	$0	$0	$0	$0	$0	$0
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$45,948	$35,758	$106,408	$791,501	($3,733,510)	$0	($2,753,895)
12	Net Electric Operating Income (Lns 3-11)	($45,948)	($35,758)	$165,996	($791,501)	($5,824,274)	$0	($6,531,485)
13	AFUDC Offset Adjustment	$0	$0	$0	$0	$0	$0	$0
14	Net Electric Operating Income - Adjusted	($45,948)	($35,758)	$165,996	($791,501)	($5,824,274)	$0	($6,531,485)
	Rate Base							
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$0	$0	$0	$0	$0	$0	$0
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$4,039,158	$4,039,158
21	Material & Supplies	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	$9,425	$7,335	$0	$162,359	$0	$0	$179,119
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$9,425	$7,335	$0	$162,359	$0	$4,039,158	$4,218,277

Kentucky Power Company
Rate Case Adjustments
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Normalization of PJM Admin. Costs (41)	0	0	0	0	0	Page Subtotal
	Operating Revenues							
1	Sales of Electricity	$0	$0	$0	$0	$0	$0	$0
2	Other Operating Revenues	$0	$0	$0	$0	$0	$0	$0
3	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0
	Operating Expenses							
4	Operation & Maintenance	$1,222,302	$0	$0	$0	$0	$0	$1,222,302
5	Depreciation	$0	$0	$0	$0	$0	$0	$0
6	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0
7	State Income Tax	($76,394)	$0	$0	$0	$0	$0	($76,394)
	Federal Income Tax:							
8	Current	($401,068)	$0	$0	$0	$0	$0	($401,068)
9	Deferred	$0	$0	$0	$0	$0	$0	$0
10	ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
11	Total Operating Expenses	$744,840	$0	$0	$0	$0	$0	$744,840
12	Net Electric Operating Income (Lns 3-11)	($744,840)	$0	$0	$0	$0	$0	($744,840)
13	AFUDC Offset Adjustment	$0	$0	$0	$0	$0	$0	$0
14	Net Electric Operating Income - Adjusted	($744,840)	$0	$0	$0	$0	$0	($744,840)
	Rate Base							
15	Electric Plant in Service - Gross	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Deperciation	$0	$0	$0	$0	$0	$0	$0
17	Electric Plant in Service - Net	$0	$0	$0	$0	$0	$0	$0
18	Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0
19	Dumont Test Site	$0	$0	$0	$0	$0	$0	$0
20	Prepayments	$0	$0	$0	$0	$0	$0	$0
21	Material & Supplies	$0	$0	$0	$0	$0	$0	$0
22	Cash Working Capital	$152,788	$0	$0	$0	$0	$0	$152,788
23	Construction Work in Progress	$0	$0	$0	$0	$0	$0	$0
	Less:							
24	Customer Advance & Deposits	$0	$0	$0	$0	$0	$0	$0
25	Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0
26	Total Rate Base	$152,788	$0	$0	$0	$0	$0	$152,788

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Kentucky Power Company
Adjustment for Postage Rate
Increase Effective January 1, 2006
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)		Amount (3)
1	Number of Bills, Notices and Letters Mailed in Test Year		2,384,132
2	Postage Rate Increase per Mailed Item	1/	$0.016
3	Adjustment to O&M for Postage Increase		$38,146
4	Allocation Factor - SPECIFIC		1.000
5	KPSC Juricdictional Amount (Ln 3 x Ln 4)		$38,146

1/ Effective Date of Postage Increase is January 1, 2006
Rate of Increase is 5.4%
Current Average Postage rate is $0.298
Increase Cost is $0.016

Witness: R. K. Wohnhas

Kentucky Power Company
Summary of Wage Related Adjustments
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Description (2)	Amount (3)
	O&M Expenses:	
1	Annualization of Wages & Salary Increase (Pg. 3, Ln 16)	$894,012
2	Annualization of Employee Benefit Plan Costs (Pg, 4, Ln 22)	$318,531
3	Annualization of Savings Plan Costs (Pg. 6 Ln 8)	$39,462
4	Adjustment to KPSC Jurisdictional Wage Related Expenses	$1,252,005
	Taxes Other:	
5	Annualization of FICA Expense (Pg. 5 Ln 16)	$66,919

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Wages and Salaries
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Month / Year (2)	Monthly Increase Granted (3)	Number Of Month Adjusted (4)	Total Adjustment Required to Annualize Test Year Increases (C 3 X C 4) (5)
1	Jul '04	$602	0	$0
2	Aug '04	$5,505	1	$5,505
3	Sep '04	$700	2	$1,400
4	Oct '04	$396	3	$1,188
5	Nov '04	$439	4	$1,756
6	Dec '04	$1,733	5	$8,665
7	Jan '05	$106,141	6	$636,846
8	Feb '05	$14,564	7	$101,948
9	Mar '05	$2,308	8	$18,464
10	Apr '05	$32,687	9	$294,183
11	May '05	$27,832	10	$278,320
12	Jun '05	$0	11	$0
13	Total Wage and Salary Annualization			$1,348,275
14	Increase Wages and Salaries Applicable to O&M (Ln 13 x 66.91%)			$902,131
15	Allocation Factor - OML			0.991
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$894,012

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Employee Benefit Plan Costs
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Amount (3)	Adjustment (4)
1	Annualization of June 2005 Monthly Medical Plan Costs ($279,891 x 12)	$3,358,692	
2	Medical Plan Costs for Twelve Months Ended 6/30/2005	$3,118,484	
3	Adjustment to Test Year Medical Plan Cost		$240,208
4	Annualization of June 2005 Life Insurance Cost ($9,893 x 12)	$118,716	
5	Life Insurance Cost for Twelve Months Ended 6/30/2005	$93,378	
6	Adjustment to Test Year Life Insurance Costs		$25,338
7	Annualization of June 2005 Dental Plan Costs ($16,831 x 12)	$201,972	
8	Dental Plan Costs for Twelve Months ended 6/30/2005	$184,881	
9	Adjustment to Test Year Dental Plan Costs		$17,091
10	Annualization of June 2005 Retirement Plan Costs ($125,499 x 12)	$1,505,988	
11	Retirement Plan Costs for Twelve Months Ended 6/30/2005	$1,038,398	
12	Adjustment to Test Year Retirement Plan Costs		$467,590
13	Annualization of June 2005 Long Term Disability Ins Cost ($16,390 X 12)	$196,680	
14	LTD Ins Prem Costs for Twelve Months Ended 6/30/2005	$118,480	
15	Adjustment to Test Year LTD Ins Prem Cost		$78,200
16	Annualization of June 2005 OPEB Costs ($183,668 x 12)	$2,204,016	
17	OPEB Costs for the Twelve Months Ended 6/30/2005	$2,552,060	
18	Adjustment to Test Year OPEB Cost		($348,044)
19	Total Employee Benefit Plan Cost Adjustments (Ln 3 + Ln 6 + Ln 9 + Ln 12 + Ln 15 + Ln 18)		$480,383
20	Employee Benefit Plan Applicable to O&M (Ln 19 x 66.91%)		$321,424
21	Allocation Factor - OML		0.991
22	KPSC Jurisdictional Amount (Ln 20 x Ln 21)		$318,531

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of FICA Expense for Test Year Ended 6/30/2005

Section V
Workpaper S-4
Page 5

Ln No (1)	Description (2)			Amount (3)
	Rate:			
1		OASDI	6.20%	
2		Medicare	1.45%	
3		Total	7.65%	
	New Subject Base:			
4		OASI	$90,000	
5		Medicare	No limit	
6	Annualized Wage and Salary Increase Paid Less Then $90,000			$1,312,453
7	June 30, 2005 FICA Rate			7.65%
8	Calculated FICA Tax on Line 6 above			$100,403
9	Annualized Wage & Salary Increase Paid above $90,000			$35,822
10	June 30,2005 FICA Rate for Wages Paid above $90,000			1.45%
11	Calculated FICA Tax on Line 9 above			$519
12	Total Calculated Increase in FICA Tax at June 30, 2005 Rate (Ln 8 + Ln 11)			$100,922
13	FICA Applicable to O&M			66.91%
14	Adjustment to FICA Expense			$67,527
15	Allocation Factor - OML			0.991
16	KPSC Jurisdictional Amount (Ln 14 x Ln 15)			$66,919

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Savings Plan Costs
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 6

Ln No (1)	Description (2)	Amount (3)
1	Base Payroll Test Year Ended 6/30/2005	$25,146,566
2	Contributions Test Year Ended 6/30/2005	$1,109,927
3	Percent of Contribution to Payroll (Ln 2 / Ln 1)	4.414%
4	Wage & Salary Annualization (WP S-4, P 3, Ln 13)	$1,348,275
5	Additional Contributions for Wage & Salary Annualized (Ln 3 x Ln 4)	$59,513
6	Increase Savings Plan Costs Applicable to O&M (Ln 5 x 66.91 %)	$39,820
7	Allocation Factor - OML	0.991
8	KPSC Jurisdictional Amount (Ln 6 x Ln 7)	$39,462

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Property Taxes
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 7

Ln No (1)	Description (2)	Amount (3)	Adjustment (4)
1	Estimated 2005 Property Taxes on Operating Property Based on December 31, 2004 Assessible Property Value and the Latest Actual Property	$7,224,392	
2	Less: Estimated Property Tax on Future Plant Site (Carrs Property)	$46,309	
3	Net Estimated Property Tax Based on December 31, 2004 Assessible Property Value and Latest Actual Property Rates (Ln 1 - Ln 2)		$7,178,083
4	Property Taxes Charged for the 12 Months Ended 6/30/2005	$7,058,826	
5	Less: Actual Property Tax on Future Plant Site (Carrs Property)	$44,743	
6	Net Property Tax Charged Accounts for the 12 Months Ended 6/30/2005 (Ln 4 - Ln 5)		$7,014,083
7	Adjustment to Property Tax Expense (Ln 3 - Ln 6)		$164,000
8	Allocation Factor - GP-TOT		0.990
9	KPSC Jurisdictional Amount (Ln 7 x Ln 8)		$162,360

Witness: R. K. Wohnhas

Section V
Workpaper S-4
Page 8

Kentucky Power Company
Adjustment/Annualized Depreciation Expense
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Electric Plant in Service as of June 30, 2005 (3)	New Annual Rate (4)	Annualized Depreciation on EPIS as of 6/30/05 (C3 x C4) (5)	Depreciation Expense 12 Months Ended 6/30/05 (6)	Adjusted Depreciation Expense (C5 - C6) (7)
1	Production Steam	$459,150,369	0.0351	$16,116,178	$17,906,864	($1,790,686)
2	Transmission	$385,378,899	0.0271	$10,443,768	$6,589,979	$3,853,789
3	Distribution	$445,002,421	0.0364	$16,198,088	$15,664,085	$534,003
4	General Plant	$29,575,208	0.0531	$1,570,444	$751,210	$819,234
5	Total	$1,319,106,897		$44,328,478	$40,912,138	$3,416,340
6	Allocation Factor - GP-TOT					0.990
7	KPSC Jurisdictional Amount (Ln 5 x Ln 6)					$3,382,177
8	Deferred Tax					($931,717)

Witness: J. E. Henderson / E. K. Wagner

Kentucky Power Company
Net Merger Savings Adjustment
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 9

Ln No (1)	Description (2)	Amount (3)
1	Add Back Customer's Test Year Merger Revenue Credit	$4,037,000
	Less:	
2	Add Back Year 5's Net Merger Savings [1/]	$7,385,000
3	State Income Tax at 6.25%	($209,250)
4	Federal; Income Tax	($1,098,563)
5	Net Electric Operating Income	($2,040,187)
6	Allocation Factor - SPECIFIC	1.000
7	KPSC Jurisdictional Amount (Ln 2 x Ln 3)	($2,040,187)

[1/] Pursuant to Commission's June 14, 1999
Order in Case No. 99-149, pg. 4 of Settlement Agreement

Witness: E. K. Wagner

Section V
Workpaper S-4
Page 10

Kentucky Power Company
Adjustment to Test Year Revenues to Remove
State Issues Settlement Revenues from
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Month / Year (2)	Per Book Revenue (3)	Adjustment (4)
1	July 04	$0	
2	Aug 04	$0	
3	Sept 04	$0	
4	Oct 04	$0	
5	Nov 04	$0	
6	Dec 04	$0	
7	Jan 05	$310,840	
8	Feb 05	$468,023	
9	Mar 05	$505,084	
10	Apr 05	$373,041	
11	May 05	$383,871	
12	June 05	$416,341	
13	Total		$2,457,200
14	Adjustment to Test Year Revenues to Remove Test Year State Issues Settlement Revenues *		($2,457,200)
15	Allocation Factor - SPECIFIC		1.000
16	KPSC Jurisdictional Amount (Ln 14 x Ln 15)		($2,457,200)

* Pursuant to Commission's Order Dated
December 14, 2004 in Case No. 2004-00420

Witness: E. K. Wagner

Kentucky Power Company
Annualization of Public Service Commission
Maintenance Assessment to Reflect Assessment for
PSC Fiscal Year July 1, 2005-2006
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 11

Ln No (1)	Month / Year (2)	Per Books Accrual (3)	Restatement of Charges To Reflect Monthly Cost To Fiscal Year 7/ 1, 2005 - 2006 (4)	Difference (C3 - C4) (5)
1	July 04	$42,035	$44,591	($2,556)
2	Aug 04	$42,035	$44,591	($2,556)
3	Sept 04	$42,035	$44,591	($2,556)
4	Oct 04	$42,035	$44,591	($2,556)
5	Nov 04	$42,035	$44,591	($2,556)
6	Dec 04	$42,035	$44,591	($2,556)
7	Jan 05	$42,035	$44,591	($2,556)
8	Feb 05	$42,035	$44,591	($2,556)
9	Mar 05	$42,035	$44,591	($2,556)
10	Apr 05	$42,035	$44,591	($2,556)
11	May 05	$42,035	$44,591	($2,556)
12	June 05	$42,030	$44,590	($2,560)
13	Total	$504,415	$535,091 *	($30,676)
14	Adjustment to Test Year Expense to Reflect Change in PSC Assessment			$30,676
15	Allocation Factor - SPECIFIC			1.000
16	KPSC Jurisdictional Amount (Ln 14 x Ln 15)			$30,676

* Per Department of Revenue Notice No. 10350079, dated June 14, 2005

Witness: E. K. Wagner

Kentucky Power Company
Recovery of Commission Mandated Consultants Costs
Pursuant to KRS 278.255 (3)
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 12

Ln No (1)	Description (2)	Amount (3)
1	Total Consultant Cost of 2002 KPSC Management Audit	$144,811
2	Total Consultant Cost of Assessment of Kentucky's Transmission System Vulnerability to Electrical Disturbances	$19,937
3	Total Consultant Cost of 161 Kv Transmission Line Estimate	$40,792
4	Total Consultants Cost (Ln 1 + Ln 2 + Ln 3)	$205,540
5	Annual Amortization (36 Month Period)	$68,513
6	Less: Consultants Costs in Test Year	$19,937
7	Adjustment to Test Year O&M Expense	$48,576
8	Allocation Factor - SPECIFIC	1.000
9	KPSC Jurisdictional Amount (Ln 7 x Ln 8)	$48,576

Witness: E. K. Wagner

Kentucky Power Company
Rate Case Expense Adjustment
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 13

Ln No (1)	Description (2)	Amount (3)
	Estimated Cost:	
1	Legal Expense	$250,000
2	Other Professional Services	$85,700
3	Publication of Notices	$75,000
4	KPCo Overtime Labor and Out-of-Pocket Expenses	$20,000
5	Total Estimated Cost	$430,700
6	Annual Amortization (36 month Amort. Period)	$143,567
7	Less: Rate Case Expense in Test Year	$0
8	Adjustment to Test Year O&M Expense (Ln 6 - Ln 7)	$143,567
9	Allocation Factor - SPECIFIC	1.000
10	KPSC Jurisdictional Amount (Ln 8 x Ln 9)	$143,567

Witness: E. K. Wagner

Kentucky Power Company
Annualized Lease Costs
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 14

Ln No (1)	Description (2)	Amount (3)
1	Annualization of June 2005 Monthly Costs ($277,873 x 12)	$3,334,476
2	Lease Expense in the Test Year 6/30/2005	$3,315,751
3	Adjustment to Test Year Lease Expense (Ln 1 - Ln 2)	$18,725
4	Adjustment Applicable to O&M (Ln 3 x 66.91%)	$12,529
5	Allocation Factor - GP-TOT	0.990
6	KPSC Jurisdictional Amount (Ln 4 x Ln 5)	$12,404

Witness: R. K. Wohnhas

Kentucky Power Company
Adjustment to Eliminate Advertising Expense
Pursuant to Commission Regulation 807 KAR 5:016 Section 4 (1)
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 15

Ln No (1)	Description (2)	Amount (3)
1	Test Year Advertising Expense	$250,136
2	Total Advertising Expense to Exclude	($30,262)
3	Allocation Factor	1.000
4	KPSC Jurisdictional Amount (Ln 2 x Ln 3)	($30,262)

Witness: R. K. Wohnhas

Kentucky Power Company
Normalization of Storm Damage Expense
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 16

Ln No (1)	Twelve Months Ended (2)	Storm Damage Expense Excl. In-House Labor (3)	Constant Dollar Index [1/] (4)	Expense in 2005 Dollars (5)
1	June 2003	$2,949,246	1.02	$3,022,067
2	June 2004	$2,751,725	1.00	$2,751,725
3	June 2005	$576,808	1.00	$576,808
4	3-Year Total Storm Damage			$6,350,600
5	3-year Average (Ln 4 / 3)			$2,116,867
6	Test Year Storm Damage Expense			$576,808
7	Adjustment to O&M for Storm Damage Normalization			$1,540,059
8	Allocation Factor - GP-TOT			0.99
9	KPSC Jurisdictional Amount (Ln 7 x Ln 8)			$1,524,658

[1/] Handy-Whitman Contract Labor Index
Reference E-2 Line 42

2003/Jan	324
2004/Jan	332
2005/Jan	332

Witness: E. Phillips / E. K. Wagner

Kentucky Power Company
Adjustment to Include in Test Year Operating Expense
the Interest Expense Associated with Customer Deposits
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 17

Ln No (1)	Description (2)	Amount (3)
1	Customer Deposits at 6/30/2005	$10,541,285
2	Interest at 6%	$632,477
3	Adjustment to O&M Expense	$632,477
4	Allocation Factor - SPECIFIC	1.000
5	KPSC Jurisdictional Amount Ln 3 X Ln 4)	$632,477

Witness: R. K. Wohnhas

Kentucky Power Company
Adjustment to Include Test Year
Interest Income on Temporary Investment
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 18

Ln No (1)	Description (2)	Amount (3)
1	Earnings on Temporary Cash Investment for Twelve Months Ending June 30, 2005	$386,918
2	Increase Other Operating Revenues	$386,918
3	Allocation Factor - OP-REV	0.991
4	KPSC Jurisdictional Amount (Ln 2 x Ln 3)	$383,436

Witness: E. K. Wagner

Kentucky Power Company
AFUDC Offset Adjustment
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 19

Ln No (1)	Description (2)	Total Amount (3)	Jurisdictional GP-TOT / .990 (4)
1	CWIP Balance at 6/30/2005 (WP S-16, P 1, C 3, Ln 5)	$19,336,201	
2	Portion of Line 1 Subject to AFUDC (WP S-16, P 1, C 4, Ln 5)	$15,798,401	
3	Overall Cost of Capital (WP S-2, P 1, C 6, Ln 5)	7.89%	
4	AFUDC Recalculation (Ln 2 x Ln 3)	$1,246,494	$1,234,029
5	Booked AFUDC in Test Year (Sch 16 Ln 10 Cols 3 & 4)	$615,862	$608,522
6	AFUDC Offset Adj. (Ln 4 - Ln 5)	$630,632	$625,507
7	Recalculated Deferred FIT on ABFUDC [1/]	$184,674	$182,827
8	Booked DFIT on ABFUDC (WP S-10, P 3A, Ln 111)	$102,835	$101,807
9	DFIT on ABFUDC Adj. (Ln 7 - Ln 8)	$81,839	$81,020

[1/] Deferred FIT Calculation:

$1,246,494 x 42.33% [(7.89% - 4.55%) / 7.89%]	=	$527,641	
		35%	FIT Rate
		$184,674	

Witness: R. K. Wohnhas

Kentucky Power Company
Interest Synchronization
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
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Ln No (1)	Description (2)	PSC Jurisdictional Amount (3)
1	LTD, per Capitalization (Sch 3, C 12, Ln 1)	$482,392,123
2	LTD Rate (WP S-2, P 1, C 5, Ln 1)	5.70%
3	Annualized LTD Interest	$27,496,351
4	STD, per Capitalization (Sch 3, C 12, Ln 2)	$3,340,763
5	STD Rate (WP S-2, P 1, C 5, Ln 2)	3.34%
6	Annualized STD Interest	$111,581
7	A/R Financing, per Capitalization (Sch3, C 11, Ln 2)	$30,052,250
8	A/R Finanicing Rate (WP S-2, P1, C 5, Ln 3)	2.99%
9	Annualized A/R Financing Interest	$898,562
10	Total Annualized Interest (Ln 3 + Ln 6 + 9)	$28,506,494
11	Interest per Books Net of ABFUDC	$29,914,717
12	Percent Retail (GP-TOT)	0.990
13	Retail Interest (Ln 8 x Ln 9)	$29,615,570
14	Decrease Interest Expense (Ln 7 - Ln 10)	($1,109,076)
15	SIT Rate	6.25%
16	SIT Adjustment (Ln 11 x Ln 12)	$69,317
17	Net Change for FIT (Ln 11 + Ln 13)	($1,039,759)
18	FIT Rate	35.00%
19	FIT Adjustment	$363,916

Witness: R. K. Wohnhas

Kentucky Power Company
Miscellaneous Service Charges
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 21

Ln No (1)	Description (2)	Amount (3)
1	Test Year Revenues From Miscellaneous Service Charges	$164,826
2	Revenue from Miscellanous Service Charges Adjusted from Increased Rates [1/]	$620,799
3	Increase Other Operating Revenue (Ln 2 - Ln 1)	$455,973
4	Allocation Factor - SPECIFIC	1.000
5	KPSC Jurisdictional Amount (Ln 3 x Ln 4)	$455,973

[1/] See Exhibit EKW- 7

Witness: E. K. Wagner

Kentucky Power Company
Annualized CATV Tariff Revenues
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 22

Ln No (1)	Description (2)		Amount (3)
1	Proposed Two User Pole Rate	$10.63	
2	Current Two User Pole Rate	$4.97	
3	Proposed Two-User Rate Increase (Ln 1 - Ln 2)		$5.66
4	Number of Two Users at June 30, 2005		12,435
5	Two User Increased Revenue (Ln 3 X Ln 5)		$70,382
6	Proposed Three User Pole Rate	$6.59	
7	Current Three User Pole Rate	$5.53	
8	Proposed Three-User Rate Increase (Ln 6 - Ln 7)		$1.06
9	Number of Three Users at June 30, 2005		69,223
10	Two User Increased Revenue (Ln 8 X Ln 9)		$73,376
11	KPSC Jurisdictional Amount (Ln 5 + Ln 10)		$143,758

(1) See Exhibit EKW- 10

Witness: E. K. Wagner

Kentucky Power Company
Net Line of Credit Fee
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Amount (3)
1	Actual Net Line of Credit Fee Recorded for 12 Mos. Ended 6/30/05	$382,126
2	Allocation Factor - GP-TOT	0.990
3	KPSC Jurisdictional Amount (Ln 1 x Ln 2)	$378,305

Witness: E. K. Wagner

Kentucky Power Company
Revenue Customer Annualization
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 24

Ln No (1)	Description (2)	Amount (3)
1	Electric Revenues	$195,124
	Less:	
2	Operation & Maintenance Expense *	$142,148
3	State Income Tax at 6.25%	$3,311
4	Federal Income Tax	$17,383
5	Net Electric Operating Income	$32,282
6	Allocation Factor - SPECIFIC	1.000
7	KPSC Jurisdictional Amount (Ln 5 x Ln 6)	$32,282

* Test Year O&M Expenses were 72.85% of the test year revenues.

Witness: D. M. Roush

Kentucky Power Company
Customer Migration Adjustment
Test Year Twelve Months Ended 6/30/2005

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Workpaper S-4
Page 25

Ln No (1)	Decription (2)	Amount (3)
1	Annualized Revenue Based on Billing Tariff at 6/30/2005	$337,148,564
2	Test Year Revenues - Sales of Electricity (Section V, Sch. 5, C6, Ln 1)	$336,751,863
	Less:	
3	Test Year State Issues Settlement Revenues	$2,457,200
	Test Year Merger Revenue Credit	($4,018,275)
4	Sub Total	$338,312,938
5	Over/(Under) Recovery of Fuel Adjustment (Section V, WP S-4, P 27 Ln 8)	($1,179,718)
6	Adjusted Test Year Revenues (Ln 4 + Ln 5)	$337,133,220
7	KPSC Jurisdictional Revenue Adjustment (Ln 1 - Ln 7)	$15,344

Witness: D. M. Roush

Kentucky Power Company
System Sales Adjustment
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 26

Ln No (1)	Month (2)	Test Year System Sales Profit Level (3)	Adjustment to Reflect Enviro. Costs Allocated to Sys Sales (4)	Adjusted Test Year System Sales Profit Level (5)	New System Sales Tariff Base (6)	Adjustment to Test Year Level (7) = (6) - (3)
1	July 2004	$4,068,332	$605,999	$3,462,333	$2,658,364	
2	August 2004	$2,871,664	$485,338	$2,386,326	$1,660,434	
3	September 2004	$1,922,864	$572,105	$1,350,759	$1,497,772	
4	October 2004	$67,121	$388,837	-$321,716	$950,190	
5	November 2004	$1,000,703	$0	$1,000,703	$1,258,779	
6	December 2004	$1,743,635	$0	$1,743,635	$2,025,256	
7	January 2005	$3,674,868	$0	$3,674,868	$2,661,693	
8	February 2005	$1,840,112	$0	$1,840,112	$2,236,268	
9	March 2005	($389,264)	$0	-$389,264	$1,732,591	
10	April 2005	$3,333,982	$0	$3,333,982	$2,706,860	
11	May 2005	$3,622,195	$0	$3,622,195	$2,365,563	
12	June 2005	$3,151,393	$0	$3,151,393	$3,101,556	
13	Total	$26,907,605	$2,052,279	$24,855,326	$24,855,326	
14	Allocation Factor - EAF					0.987
15	KPSC Jurisdictional O&M Adjustment (Ln 13 x Ln 14)					$0

Witness : E. K. Wagner

Kentucky Power Company
Over/(Under) Recovery of Fuel
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 27

Ln No (1)	Description (2)	Amount (3)
1	Fuel Revenue (Per Exhibit EKW-4, Col 16, Ln 15)	$113,164,488
2	Fuel Cost per Monthly F. A. C. Filings (Per Exhibit EKW-4, Col 7, Ln 15)	$116,757,583
3	Deferred Fuel Cost (Per Exhibit EKW-4, Col 8, Ln 15)	($4,772,813)
4	Total Fuel Cost (Ln 2 + Ln 3)	$111,984,770
5	Over/(Under) Recovery of Fuel (Ln 1 - Ln 4)	$1,179,718
6	Adjustment to Operating Revenue	($1,179,718)
7	Allocation Factor - SPECIFIC	1.000
8	KPSC Jurisdictional Amount (Ln 6 x Ln 7)	($1,179,718)
9	Deferred Tax	($412,901)

Witness: E. K. Wagner

Kentucky Power Company
Coal Stock Adjustment
Big Sandy Plant
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 28

Ln No (1)	Description (2)	Tons (3)	Average $/Ton (4)	Amount (5)
1	Balance End of Test Year	207,146	$49.32	$10,216,763
2	Daily Burn Rate	8,000		
3	Days Suppy on Hand (Ln1/Ln2)	26		
4	Day Supply Requested	35		
5	Fuel Stock Level (Ln 4 x Ln 2)	280,000	$49.32	$13,809,600
6	Adjustment to Test Year End Coal Stock (Ln 5 - Ln 1)	72,854		3,592,837
7	Allocation Factor - PDAF			0.986
8	KPSC Jurisdictional Amount (Ln 6 x Ln 7)			$3,542,537

Witness: E. K.Wagner

Kentucky Power Company
Reliability Adjustment
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Annual Expense (3)		Amount (4)
1	Year One O&M Expenditures	$5,750,000		
2	Year Two O&M Expenditures	$6,120,000		
3	Year Three O&M Expenditures	$6,500,000		
4	Total Expenditures	$18,370,000		
5	Three Year Average (Ln 4 / 3)			$6,123,333
6	Allocation Factor - GP - T&D			0.992
7	KPSC Jurisdictional Amount (Ln 5 x Ln 6)			$6,074,346
		Expenditure	Average Amount Invested	
8	Year One Associated Capital	$3,600,000	$1,800,000	
9	Year Two Associated Capital	$3,770,000	$5,485,000	
10	Year Three Associated Capital	$3,930,000	$9,335,000	
11	Total	$11,300,000	$16,620,000	
12	Three Year Average (Ln 11 / 3)			$5,540,000
13	Allocation Factor - GP-TOT			0.990
14	KPSC Jurisdictional Amount (Ln 12 X Ln 13)			$5,484,600

Witness: E Phillips / E. K. Wagner

Kentucky Power Company
AEP Pool Capacity Adjustment for Known Additions
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Month (2)	Year (3)	Test Year AEP Pool Capacity Cost (4)	Effect of the Addition of CSP's 830 MW Generation Unit (5)	Effect of the Addition of APCo's 481 MW Generation Unit (6)	Net Effect of the Addition of 289 MW of Load to CSP's System (7)	Effect of Removing 250 MW from CSP's Capacity (8)	Annualize Load Changes (9)	Adjusted Test Year AEP Pool Capacity Costs (10)	AEP Pool Capacity Costs Test Year Adjustment (Col 10 - Col 4) (11)
1	July	2004	$1,538,912	$442,108	$233,201	($21,937)	($118,135)	$1,189,905	$3,264,054	$1,725,142
2	August	2004	$1,459,267	$414,197	$216,250	($20,244)	($109,394)	$1,145,432	$3,105,508	$1,646,241
3	September	2004	$1,831,044	$438,137	$232,251	($25,553)	($117,822)	$775,087	$3,133,144	$1,302,100
4	October	2004	$1,857,139	$441,859	$234,595	($25,924)	($119,019)	$772,411	$3,161,061	$1,303,922
5	November	2004	$1,793,310	$424,546	$224,542	($24,769)	($113,867)	$750,626	$3,054,388	$1,261,078
6	December	2004	$1,864,356	$425,591	$218,676	($23,796)	($110,502)	$815,697	$3,190,022	$1,325,666
7	January	2005	$2,484,659	$462,828	$250,542	($20,589)	($127,300)	$14,153	$3,064,293	$579,634
8	February	2005	$3,034,222	$480,368	$263,193	($21,171)	($133,939)	($594,507)	$3,028,166	($6,056)
9	March	2005	$3,178,613	$507,372	$279,203	($22,501)	($142,174)	($626,910)	$3,173,603	($5,010)
10	April	2005	$3,240,968	$515,256	$282,941	($22,782)	($144,034)	($637,156)	$3,235,193	($5,775)
11	May	2005	$3,249,662	$524,540	$290,344	($23,458)	($147,968)	($646,705)	$3,246,415	($3,247)
12	June	2005	$3,218,782	$519,284	$287,357	($23,214)	($146,441)	($640,291)	$3,215,477	($3,305)
13	Total		$28,750,934	$5,596,086	$3,013,095	($275,938)	($1,530,595)	$2,317,742	$37,871,324	$9,120,390
14	Allocation Factor - PDAF									0.986
15	KPSC Jurisdictional Amount (Ln 13 x Ln 14)									$8,992,705

Note:

Column 4 Source: July 2004 through June 2005 Interchange Power Statement
Column 5 Incremental Effect of adding CSP's 830 MW Generating Unit for the entire test year
Column 6 Incremental Effect of adding APCo's 481 MW Generating Unit for the entire test year
Column 7 Incremental Effect of adding 289 MW of load to the CSP's System for the entire test year
Column 8 Incremental Effect of Removing 250 MW from CSP Member Primary Capacity for the entirs year
Column 9 Incremental Effect of current and Future Load Changes on Member Load Ratio for the entire year (annualized)
Column 10 The Adjusted Test Year AEP Pool Capacity Charge Refelcting the Interaction of all Changes

Witness: E. K. Wagner

Kentucky Power Company
Annualization of Vehicle Fuel Costs
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Amount (3)	Total (4)
1	Vehicle Fuel Cost for June 2005	$83,708	
2	Number of Months	12	
3	Annualized Vehicle Fuel Cost (Ln 1 X Ln 2)		$1,004,496
4	Vehicle Fuel Cost Twelve Months ending June 30, 2005		$733,888
5	Increase Vehicle Fuel Cost (Ln 3 - Ln 4)		$270,608
6	Increase Vehicle Fuel Cost Applicable to O&M (Ln 4 X 66.91)		$181,064
7	Allocation Factor - O&M		0.988
8	KPSC Jurisdictional Amount		$178,891

Witness: R. K. Wohnhas

Kentucky Power Company
Normalization of Net PJM (Revenues) and Expenses
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Month / Year (2)	Test Year Actual Amount (3)	Monthly 2006 Forecasted Amount * (4)	Adjustment Required (5)
1	July 2004	$0	($84,179)	($84,179)
2	August 2004	$0	($84,179)	($84,179)
3	September 2004	$0	($84,179)	($84,179)
4	October 2004	$201,445	($84,179)	($285,624)
5	November 2004	($133,116)	($84,179)	$48,937
6	December 2004	$793,440	($84,179)	($877,619)
7	January 2005	$614,445	($84,179)	($698,624)
8	February 2005	($71,303)	($84,179)	($12,876)
9	March 2005	$451,388	($84,179)	($535,567)
10	April 2005	$118,429	($84,179)	($202,608)
11	May 2005	$205,097	($84,179)	($289,276)
12	June 2005	($375,931)	($84,179)	$291,752
13	Total	$1,803,894	($1,010,148)	
14	Total Normalization of Net PJM (Revenues) and Expenses			($2,814,042)
15	Allocation Factor PDAF			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			($2,774,645)

* Does Not Include PJM Adminstrative Costs

Witness: R. W. Bradish

Kentucky Power Company
Normalize PJM Network Transmission Revenues
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Month / Year (2)	Test Year Amount (3)	Going Forward Normalized Twelve Month Amount (4)	Adjustment Amount (5)
1	July 2004	$230,202	$406,236	$176,034
2	August 2004	$197,834	$397,972	$200,138
3	September 2004	$220,085	$386,331	$166,246
4	October 2004	$232,977	$399,209	$166,232
5	November 2004	$220,658	$386,331	$165,673
6	December 2004	$239,934	$399,209	$159,275
7	January 2005	$221,995	$419,167	$197,172
8	February 2005	$221,356	$367,025	$145,669
9	March 2005	$242,978	$406,349	$163,371
10	April 2005	$270,947	$393,241	$122,294
11	May 2005	$243,452	$406,349	$162,897
12	June 2005	$238,219	$393,241	$155,022
13	Total	$2,780,637	$4,760,660	
14	Adj. to Normalize PJM NTS Revenues			$1,980,023
15	Allocation Factor GP - TRANS			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$1,952,303

Witness: D. W. Bethel

Kentucky Power Company
Elimination of FERC Assement Fees
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Month / Year (2)	Test Year Amount (3)	Adjustment Required (4)
1	July 2004	$20,790	($20,790)
2	August 2004	$3,836	($3,836)
3	September 2004	$3,835	($3,835)
4	October 2004	$0	$0
5	November 2004	$0	$0
6	December 2004	$0	$0
7	January 2005	$0	$0
8	February 2005	$0	$0
9	March 2005	$0	$0
10	April 2005	$0	$0
11	May 2005	$0	$0
12	June 2005	$0	$0
13	Total	$28,461	
14	Adj. Required to Remove FERC Fees from Test Year		($28,461)
15	Allocation Factor GP - TRANS		0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)		($28,063)

Witness: E. K. Wagner

Kentucky Power Company
Adjustment to Reflect Normalization of
PJM Net Expansion Expenses
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Month / Year (2)	Amortization of PJM Integration Test Year Amount (3)	Going Forward Monthly Normalized Amount (4)	Adjustment Required (5)=(Col 4 - 3)
1	July 2004	$0	$12,761	$12,761
2	August 2004	$0	$12,793	$12,793
3	September 2004	$0	$13,242	$13,242
4	October 2004	$0	$13,601	$13,601
5	November 2004	$0	$13,735	$13,735
6	December 2004	$0	$13,924	$13,924
7	January 2005	$14,161	$13,695	($466)
8	February 2005	$14,161	$13,649	($512)
9	March 2005	$14,173	$13,719	($454)
10	April 2005	$14,173	$13,605	($568)
11	May 2005	$14,173	$13,553	($620)
12	June 2005	$14,173	$13,210	($963)
13	Total	$85,014	$161,487	$76,473
14	Adj. To Reflect Normalization of PJM Net Expansion Exp. in Test Year			$76,473
15	Allocation Factor GP - TRANS			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$75,402

Witness: D. W. Bethel

Kentucky Power Company
Adjustment to Reflect RTO Formation Costs
Over a Fifteen Year Period
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Month / Year (2)	Test Year Amount (3)	Monthly Amortization Amount (4)	Adjustment Required (5)
1	July 2004	$0	$10,134	$10,134
2	August 2004	$0	$10,134	$10,134
3	September 2004	$0	$10,134	$10,134
4	October 2004	$0	$10,134	$10,134
5	November 2004	$0	$10,134	$10,134
6	December 2004	$0	$10,134	$10,134
7	January 2005	$10,456	$10,134	($322)
8	February 2005	$10,259	$10,134	($125)
9	March 2005	$10,260	$10,134	($126)
10	April 2005	$10,261	$10,134	($127)
11	May 2005	$10,261	$10,134	($127)
12	June 2005	$10,597	$10,134	($463)
13	Total	$62,094	$121,608	$59,514
14	Adj. Req. to Reflect Amort. RTO Formation Costs in Test Year			$59,514
15	Allocation Factor GP - TRANS			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$58,681

Witness: D. W. Bethel

Kentucky Power Company
Transmission Equalization Revenue Adjustment
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Month / Year (2)	Transmission Equalization Revenue Amount (3)	Adjusted Transmission Equalization Revenue Amount (4)	Adjustment Required (5)
1	July 2004	$535,374	$383,218	($152,156)
2	August 2004	$535,374	$383,218	($152,156)
3	September 2004	$467,895	$383,218	($84,677)
4	October 2004	$465,887	$383,218	($82,669)
5	November 2004	$465,887	$383,218	($82,669)
6	December 2004	$465,887	$383,218	($82,669)
7	January 2005	$333,010	$383,218	$50,208
8	February 2005	$210,490	$383,218	$172,728
9	March 2005	$210,635	$383,218	$172,583
10	April 2005	$210,635	$383,218	$172,583
11	May 2005	$210,635	$383,218	$172,583
12	June 2005	$210,635	$383,218	$172,583
13	Total	$4,322,344	$4,598,616	$276,272
14	Adj. Req. to Transmission Equalization Revenues Reflect MLR Change			$276,272
15	Allocation Factor GP - TRANS			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$272,404

Witness: E. K. Wagner

Kentucky Power Company
Big Sandy Plant Maintenance Normalization
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Twelve Month Steam Power Maintenance Expense (2)	Expense Amount (3)	Constant Dollar Index 1/ (4)	Expense in 2005 Dollars (5)
1	June 30, 2005	$12,392,698	1.000	$12,392,698
2	June 30, 2004	$11,187,582	1.000	$11,187,582
3	June 30, 2003	$17,222,534	1.019	$17,549,762
4	3 - Year Total			$41,130,042
5	Three Year Average (Ln 4 / 3)			$13,710,014
6	Test Year Steam Power Maintenance Expense			$12,392,698
7	Adjustment to Test Year Steam Power Maintenance Expense			$1,317,316
8	Allocation Factor - PDAF			0.986
9	KPSC Jurisdictional Amount (Ln 7 X Ln 8)			$1,298,874

1/ Handy-Whitman Total Steam Production Plant
Reference E-2 Line 6

2005/Jan	420
2004/Jan	420
2003/Jan	412

Witness: E. K. Wagner

Kentucky Power Company
Normalization of PJM Point-to-Point Transmission Revenues
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Month / Year (2)	Test Year Amount (3)	Monthly 2006 Forecast Amount (4)	Adjustment Amount (Col 4 - 3) (5)
1	July 2004	$772,048	$47,340	($724,708)
2	August 2004	$748,065	$51,619	($696,446)
3	September 2004	$594,551	$40,322	($554,229)
4	October 2004	$478,327	$43,050	($435,277)
5	November 2004	$361,378	$41,089	($320,289)
6	December 2004	$1,051,751	$41,089	($1,010,662)
7	January 2005	$1,086,668	$49,934	($1,036,734)
8	February 2005	$871,050	$32,250	($838,800)
9	March 2005	$977,031	$35,649	($941,382)
10	April 2005	$1,068,716	$32,797	($1,035,919)
11	May 2005	$1,177,662	$36,810	($1,140,852)
12	June 2005	$996,585	$38,390	($958,195)
13	Total	$10,183,832	$490,339	
14	Adj. to Normalize PJM PTP Revenues			($9,693,493)
15	Allocation Factor - GP - TRANS			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			($9,557,784)

Witness: D. W. Bethel

Kentucky Power Company
Prepaymant of Pension Funding In Excess of O & M Expense
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Expense Amount (3)
1	March 2005 Contribution	$3,045,764
2	June 2005 Contribution	$3,045,764
3	Total Contribution	$6,091,528
4	Pension Funding Applicaple to O&M (Ln 3 X 66.91%)	$4,075,841
5	Allocation Factor - OML	0.991
6	KPSC Jurisdictional Amount (Ln 4 X Ln 5)	$4,039,158

Witness: E. K. Wagner

Kentucky Power Company
Normalization of PJM Adminstrative Charges
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Month / Year (2)	Test Year Amount (3)	2006 Monthly Forecast Amount (4)	Required Adjustment (5)
1	July 2004	$0	$287,934	$287,934
2	August 2004	$0	$287,934	$287,934
3	September 2004	$0	$287,934	$287,934
4	October 2004	$225,924	$287,934	$62,010
5	November 2004	$230,904	$287,934	$57,030
6	December 2004	$243,851	$287,934	$44,083
7	January 2005	$260,773	$287,934	$27,161
8	February 2005	$252,236	$287,934	$35,698
9	March 2005	$311,050	$287,934	($23,116)
10	April 2005	$234,611	$287,934	$53,323
11	May 2005	$228,439	$287,934	$59,495
12	June 2005	$227,763	$287,934	$60,171
13	Total	$2,215,551	$3,455,208	
14	Adj. Required to Normalize Test Year PJM Charges			$1,239,657
15	Allocation Factor GP-TRANS			0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$1,222,302

Witness: R. W. Bradish

Kentucky Power Company
Base Case Summary
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 5

Ln No (1)	Description (2)	Total Company Per Books (3)	Eliminations/ Adjustments (4)	Electric Utility (5)	Kentucky P.S.C. Juricdiction (6)	Schedule Reference (7)
	Operating Revenues					
1	Sales of Electricity	$453,714,323	($113,745,108)	$339,969,215	$336,751,863	WP S-6 P3
2	Other Operating Revenues	$24,395,038	($11,332,321)	$13,062,717	$12,983,134	WP S-6 P1
3	Total Operating Revenues	$478,109,361	($125,077,429)	$353,031,932	$349,734,997	Sch 6
	Operating Expenses					
4	Operation & Maintenance	$365,416,246	($127,146,896)	$238,269,350	$235,483,553	Sch 7
5	Depreciation	$44,459,757	$0	$44,459,757	$44,043,880	Sch 8
6	Taxes Other Than Income Tax	$9,065,939	($44,743)	$9,021,196	$8,937,315	Sch 9
7	Gain From Disposition of Utility Plant	($1,190)	$1,190	$0	$0	SPECIFIC
8	Factored Cust A/R Expense	$1,087,761	($1,087,761)	$0	$0	SPECIFIC
9	Factored Cust A/R Bad Debts	$1,625,430	($1,625,430)	$0	$0	SPECIFIC
10	State Income Tax	($539,882)	$1,536,828	$996,946	$922,665	Sch 10
	Federal Income Tax					
11	Current	($4,344,492)	$8,863,601	$4,519,109	$4,705,661	Sch 10
12	Deferred	$11,845,697	($6,895,884)	$4,949,813	$4,900,291	Sch 10
13	ITC Adjustment	($1,232,876)	$64,192	($1,168,684)	($1,156,997)	Sch 10
14	Total Operating Expenses	$427,382,390	($126,334,903)	$301,047,487	$297,836,368	
15	Net Electric Operating Income (Lns. 3 - 14)	$50,726,971	$1,257,474	$51,984,445	$51,898,629	
16	AFUDC Offset Adjustment	$615,862	$0	$615,862	$608,522	Sch 16
17	Net Electric Operating Income - Adjusted	$51,342,833	$1,257,474	$52,600,307	$52,507,151	
	Rate Base					
18	Electric Plant in Service - Gross	$1,353,341,211	($8,658,419)	$1,344,682,792	$1,331,453,536	Sch 11
19	Accum. Prov. for Depreciation	$443,489,466	($5,995,664)	$437,493,802	$432,998,450	Sch 12
20	Electric Plant In Service - Net	$909,851,745	($2,662,755)	$907,188,990	$898,455,086	Sch 13
21	Plant Held for Future Use	$6,862,819	($6,778,355)	$84,464	$83,282	Sch 14
22	Prepayments	$661,934	$0	$661,934	$655,315	Sch 15
23	Materials & Supplies	$16,720,225	$0	$16,720,225	$16,502,178	Sch 15
24	Cash Working Capital	$45,677,031	$0	$45,677,031	$45,119,645	Sch 15
25	Construction Work in Progress	$19,336,201	$0	$19,336,201	$19,159,718	Sch 16
	Less:					
26	Customer Advances & Deposits	$10,598,069	$0	$10,598,069	$10,598,069	Sch 17
27	Accumulated Deferred Income Taxes	$129,276,197	$0	$129,276,197	$127,983,435	Sch 17
28	Total Rate Base	$859,235,689	($9,441,110)	$849,794,579	$841,393,720	

Kentucky Power Company
Electric Operating Revenues
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 6

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky P. S. C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Sales of Electricity	$339,969,215	$336,751,863		WP S-6 P3
	Other Operating Revenues				
2	Production	$5,933,656	$5,856,518		WP S-6 P1
3	Transmission	$174,664	$172,219		WP S-6 P1
4	Distribution	$6,954,397	$6,954,397		WP S-6 P1
5	General	$0	$0		WP S-6 P1
6	Total (Lns 2 through 5)	$13,062,717	$12,983,134	0.994	OP-REV-O
7	Total (Lns 1+6)	$353,031,932	$349,734,997	0.991	OP-REV
	Reconcile:				
8	Line No. 7	$353,031,932			
9	System Sales	$113,745,108			
10	Various Trans. Agreement	$13,401,788			
11	Sub-Total	$480,178,828			
	Less:				
12	DSM Activity Acct No 4560007	$2,069,467			
13	Total Operating Revenue	$478,109,361			

Kentucky Power Company
Analysis of Accounts 450, 451, 454 & 456
Other Operating Revenues
Summary
Test Year Twelve Months Ended 6/30/2005

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Ln No (1)	Description (2)	Total (3)	Adjustment (4)	Total Electric Utility (5)	Kentucky P. S. C. Jurisdiction (6)	Percent Retail (7)	Allocation Factor (8)
1	Production Plant	$5,933,656	$0	$5,933,656	$5,856,518	0.987	EAF
2	Transmission Plant	$174,664	$0	$174,664	$172,219	0.986	GP-TRANS
3	Distribution Plant	$4,884,930	$2,069,467	$6,954,397	$6,954,397	1.000	SPECIFIC
4	General Plant	$0	$0	$0	$0	0.991	OML
5	Various Trans. Agreement	$13,401,788	($13,401,788)	$0	$0		
6	Total	$24,395,038	($11,332,321)	$13,062,717	$12,983,134		

Kentucky Power Company
Analysis of Accounts 411, 450, 451, 454 & 456
Other Operating Revenues
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Account No. (2)	Description (3)	Total (4)
1	411	Gain on Disposition of Allowances (Production)	$5,690,490
2	450	Forfeited Discounts (Distribution)	$1,476,289
3	451	Misc. Service Revenues (Distribution)	$250,274
4	4540001	Rental from Electric Property Affilated (Distribution)	$353,341
5	4540002	Pole Attachment Rental (Distribution)	$2,602,948
6	4540004	Rent from Electric Property ABD Non Affilated (Dist)	$82,202
7	4560007	DSM Activity (Distribution)	($2,069,467)
8	4560012	Other Electric Revenue Non Affiliated (Production)	$14,812
9	4560013	Transmission Services Charge EKPC (Transmission)	$45,672
10	4560013	Transmission Services (Various Trans. Agreement)	$2,789,481
11	4560014	Transmission Services (Various Trans. Agreement)	$264,010
12	4560015	Other Electric Revenue ABD (Distribution)	$2,189,343
13	4560041	Misc. Revenues Non Affiliated (Transmission)	$42,771
14	4560049	Merchant Generation Finanical Realized (Production)	$143,261
15	4560050	Other Electric Rev. Coal Trading Realized (Production)	$2,476,387
16	4560058	PJM NITS Revenues Non Affiliated (Various Trans. Agreement)	$2,412,597
17	4560060	PJM Point to Point Trans. Rev. Non Affiliates (Various Trans. Agreement)	$1,448,788
18	4560062	PJM to Admin Revenues Non Affiliated (Various Trans. Agreement)	$182,784
19	4560064	Buckeye Admin. Fee Revenues (Transmission)	$86,221
20	4560067	Physical Coal Purchase Expense (Production)	($2,391,294)
21	4560068	SECA Transmission Revenues (Various Trans. Agreement)	$6,304,128
22		Total Other Operating Revenues	$24,395,038

Kentucky Power Company
Electric Revenues
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	Total (3)
1	Total Sales (WP S-6 Pg 4, Col 3, Ln 14)	$453,714,323
2	Less: System Pool (WP S-6 Pg 4, Col 3, Ln 8)	$113,745,108
3	Total Kentucky Sales	$339,969,215
4	Less: Kentucky Wholesale Sales (WP S-6 Pg 4, Col 3, Ln 5)	$3,217,352
5	Kentucky Retail Sales (WP S-6 Pg 4, Col 3, Ln 13)	$336,751,863

Kentucky Power Company
Electric Revenues
Test Year Twelve Months Ended 6/30/2005

Ln No. (1)	Jurisdiction (2)	Revenues (3)	Total Revenue Excluding Fuel Adjustment Clause (4)	Fuel Adjustment Clause (5)
	FERC:			
	Olive Hill:			
1	Billed	$1,035,482	$938,747	$96,735
2	Accrued	$1,258	$439	$819
	Vanceburg:			
3	Billed	$2,180,612	$1,972,365	$208,247
4	Accrued	$0	$0	$0
5	FERC Total	$3,217,352	$2,911,551	$305,801
	System Pool:			
6	System Sales	$122,392,276	$122,392,276	$0
7	System Sales Clause	($8,647,168)	($8,647,168)	$0
8	System Pool Total	$113,745,108	$113,745,108	$0
	Kentucky PSC:			
9	Billed	$328,346,558	$306,067,715	$22,278,843
10	Accrued	($241,863)	($286,523)	$44,660
11	Total PSC Billed and Accrued	$328,104,695	$305,781,192	$22,323,503
	Less:			
12	System Sales Clause	($8,647,168)	$0	($8,647,168)
13	Sub-Total (Lines 11-12)	$336,751,863	$305,781,192	$30,970,671
14	Total Sales (Lines 5+8+13)	$453,714,323	$422,437,851	$31,276,472

Section V
Schedule 7

Kentucky Power Company
Electric Operation and Maintenance Expense
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Description (2)	Total Electric Utility (3)	Kentucky P. S. C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
	Power Production Expense				
1	Demand Related	$81,174,494	$80,038,051	0.986	PDAF
2	Energy Related	$120,317,311	$118,753,186	0.987	EAF
3	Deferred Fuel	($4,502,865)	($4,502,865)	1.000	SPECIFIC
4	Total Power Production Expense	$196,988,940	$194,288,372		
5	Transmission Expense	$2,314,666	$2,282,261	0.986	GP-TRANS
6	Distribution Expense	$26,303,569	$26,250,962	0.998	GP-DIST
7	Cust. Acct/Cust. Service Expense	$12,631,964	$12,631,747	$217	* SPECIFIC
8	A&G Regulatory	$30,211	$30,211	1.000	SPECIFIC
9	Total Operation and Maintenance Expense	$238,269,350	$235,483,553	0.988	O&M
	Purchased Power & System Sales				
10	Demand Related	$50,867,314	$50,155,172	0.986	PDAF
11	Energy Related	($9,314,337)	($9,193,251)	0.987	EAF
12	Fuel Delivered (Act. 50110)	$94,700,565	$93,469,458	0.987	EAF
13	Total Purchased Power and Fuel	$136,253,542	$134,431,379		
14	Total O&M Less Total Purchased Power and Fuel	$102,015,808	$101,052,174	0.991	OML

Reconcile:

15	Line 9	$238,269,350
	Add:	
16	System Sales	$113,745,108
17	Various Trans. Agreements	$13,401,788
18	Sub-Total	$365,416,246
19	Gain from Disposition of Utility Plant	($1,190)
20	Factored Cust A/R Expense	$1,087,761
21	Factored Cust A/R Bad Debt	$1,625,430
22	Total O&M Per Books	$368,128,247

* $12,631,964/Year End No. of Customers 174,926 X 3 = $217

Kentucky Power Company
Electric O&M Expenses - Assignment of A&G
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Acct No (2)	Expense (3)	Total O&M Expense (4)	Total O&M Payroll (5)	A&G 1/ Excluding Regulation (6)	Restated Expense (4 + 6) (7)	Expense Allocation: Demand Related (8)	Expense Allocation: Energy Related (9)
		Power Production Expense						
		Steam Power Operation						
1	500	Supervision & Engineering	$4,007,829	$3,554,452	$4,661,926	$8,669,755	$8,669,755	$0
2	501	Fuel	$116,424,364	$224,007	$293,802	$116,718,166	$0	$116,718,166
3	50199	Fuel Exp. Deferred	($4,502,865)	$0	$0	($4,502,865)	$0	($4,502,865)
4	502	Steam Expense	$2,115,484	$433,795	$568,954	$2,684,438	$433,795	$2,250,643 2/
5	505	Electric Expense	$78,426	$12,931	$16,960	$95,386	$12,931	$82,455 2/
6	506	Misc. Steam Power Exp.	$2,893,753	$1,434,170	$1,881,020	$4,774,773	$4,774,773	$0
7	507	Rents	$0	$0	$0	$0	$0	$0
8	509	Allowances	$3,285,510	$0	$0	$3,285,510		$3,285,510
9		Total Steam Power-Operation	$124,302,501	$5,659,355	$7,422,662	$131,725,163	$13,891,254	$117,833,909
		Steam Power Maintenance						
10	510	Supervision & Engineering	$1,295,525	$639,731	$839,054	$2,134,579	$2,134,579	$0
11	511	Maint. of Structure	$471,513	$159,289	$208,919	$680,432	$680,432	$0
12	512	Maint of Boiler Plant	$8,158,660	$2,206,647	$2,894,180	$11,052,840	$3,757,966	$7,294,874 3/
13	513	Maint of Electric Plant	$1,949,978	$558,011	$731,873	$2,681,851	$2,681,851	$0
14	514&15	Maint of Misc. Steam	$516,962	$151,820	$199,123	$716,085	$716,085	$0
15		Total Steam Power-Maintenance	$12,392,638	$3,715,498	$4,873,149	$17,265,787	$9,970,913	$7,294,874
16		Total Steam Power & O&M (Lns 9+15)	$136,695,139	$9,374,853	$12,295,811	$148,990,950	$23,862,167	$125,128,783
		Other Power Supply Expense						
[illegible]	555	Purchased Power - Net	$168,699,873	$0	$0	$168,699,873	$71,246,758	$97,453,115
[illegible]	556	Sys. Control & Load Dispatching	$2,808,317	$0	$0	$2,808,317	$2,808,317	$0
	557	Other Expenses	$3,636,696	$0	$0	$3,636,696	$3,636,696	$0
19		Total-Other Power Supply Exp.	$175,144,886	$0	$0	$175,144,886	$77,691,771	$97,453,115
20		Various Trans. Agreements	($13,401,788)	$0	$0	($13,401,788)	($13,401,788)	
21		System Sales	($113,745,108)	$0	$0	($113,745,108)	($6,977,656)	($106,767,452)
22		Total Power Production	$184,693,129	$9,374,853	$12,295,811	$196,988,940	$81,174,494	$115,814,446
23		Transmission Expense	$522,098	$1,366,731	$1,792,568	$2,314,666		
24		Distribution Expense	$19,598,900	$5,111,927	$6,704,669	$26,303,569		
25		Customer Account Exp.	$8,267,013	$1,775,971	$2,329,317	$10,596,330		
26		Customer Services	$1,368,380	$508,743	$667,254	$2,035,634		
27		A&G Regulatory	$30,211	$0	$0	$30,211		
28		A&G Other	$23,789,619	$1,777,602	($23,789,619)	$0		
29		Total Operation & Maintenance Exp.	$238,269,350	$19,915,827	$0	$238,269,350		
		Reconcile:						
30		Total O&M Expense	$238,269,350					
31		System Sales	$113,745,108					
32		Various Trans. Agreement	$13,401,788					
		Sub-Total	$365,416,246					
		Factored Cust A/R Expense	$1,087,761					
		Factored Cust A/R Bad Debt	$1,625,430					
		Gain from Disposition Utility Plant	($1,190)					
33		Total Per Books	$368,128,247					

1/ Allocated on the basis of Payroll
Alloc. on the bases of Labor Exp., Demand Related; Material Exp., Energy Related (NARUC Cost Alloc. Pgs 37 & 39)
Allocated on the Basis of 34% Demand; 66% Energy

Kentucky Power Company
Payroll Labor by Function
(By Account Number for Production Only)
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Production (2)	Total Amount (3)
	Operation	
1	Account 500	$3,554,452
2	Account 501	$224,007
3	Account 502	$433,795
4	Account 505	$12,931
5	Account 506	$1,434,170
6	Account 507	$0
7	Total Operation	$5,659,355
	Maintenance	
8	Account 510	$639,731
9	Account 511	$159,289
10	Account 512	$2,206,647
11	Account 513	$558,011
12	Account 514	$151,820
13	Account 515	$0
14	Account 555	$0
15	Account 556	$0
16	Account 557	$0
17	Total Maintenance	$3,715,498
18	Total Production (Lines 7 + 17)	$9,374,853
	Transmission	
19	Operation	$445,048
20	Maintenance	$921,683
21	Total Transmission	$1,366,731
	Distribution	
22	Operation	$824,942
23	Maintenance	$4,286,985
24	Total Distribution	$5,111,927
25	Total Customer Accounts	$1,775,971
26	Total Customer Service & Informational	$508,743
	Adminstrative & General	
27	Operation	$1,042,879
28	Maintenance	$734,723
29	Total Adminstrative & General	$1,777,602
30	Grand Total (Lns 18 + 21 + 24 + 25 + 26 + 29)	$19,915,827

Kentucky Power Company
Direct and Allocated Payroll Distribution
Function Percentage
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Function (2)	Total (3)	Percent * (4)
1	Operation and Maintenance (WP S-7 Page 4 Ln 19)	$19,915,827	66.91%
2	Construction (WP S-7 Page 4 Ln 20)	$8,221,792	27.62%
3	Retirements (WP S-7 Page 4 Ln 21)	$1,570,099	5.27%
4	All Other (WP S-7 Page 4 Ln 31)	$59,282	0.20%
5	Total (WP S-7 Page 4 Ln 32)	$29,767,000	100.00%

* Total May Not Foot Due To Rounding

Kentucky Power Company
Direct and Allocated Payroll Distribution
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Function (2)	Direct Payroll Distribution (3)	Allocation of Payroll Charges For Clearing Accounts (4)	Total (5)
	Operation			
1	Production	$4,355,237	$1,304,118	$5,659,355
2	Transmission	$406,059	$38,989	$445,048
3	Distribution	$752,671	$72,271	$824,942
4	Customer Accounts	$1,620,383	$155,588	$1,775,971
5	Customer Services and Informational	$464,174	$44,569	$508,743
6	Administrative and General	$951,515	$91,364	$1,042,879
7	Total Operation	$8,550,039	$1,706,899	$10,256,938
	Maintenance			
8	Production	$3,398,792	$316,706	$3,715,498
9	Transmission	$840,937	$80,746	$921,683
10	Distribution	$3,911,414	$375,571	$4,286,985
11	Administrative and General	$670,357	$64,366	$734,723
12	Total Maintenance	$8,821,500	$837,389	$9,658,889
	Total Operation & Maintenance			
13	Production (Lns 1 + 8)	$7,754,029	$1,620,824	$9,374,853
14	Transmission (Lns 2 + 9)	$1,246,996	$119,735	$1,366,731
15	Distribution (Lns 3 + 10)	$4,664,085	$447,842	$5,111,927
16	Customer Accounts (Ln 4)	$1,620,383	$155,588	$1,775,971
17	Customer Services and Informational (Ln 5)	$464,174	$44,569	$508,743
18	Administrative and General (Lns 6 + 11)	$1,621,872	$155,730	$1,777,602
19	Total Operation & Maintenance	$17,371,539	$2,544,288	$19,915,827
20	Construction	$7,501,864	$719,928	$8,221,792
21	Plant Removal (Retirement)	$1,432,616	$137,483	$1,570,099
	Other Accounts			
22	Fuel Stock Expense Undistributed	$898,288	($898,288)	$0
23	Stores Exp. Undistributed-T&D	$1,122,693	($1,122,693)	$0
24	Clearing Accounts	$748,059	($748,059)	$0
25	ODD Temporary Facilities	$29,250	$0	$29,250
26	Miscellaneous Deferred Debits	$653,745	($653,745)	$0
27	Research and Development	$914	($914)	$0
28	Miscellaneous Current and Accrued Liabilities	($22,000)	$22,000	$0
29	Donations	$30,032	$0	$30,032
30	All Other General Ledger (GL)	$0	$0	$0
31	Total Other Accounts	$3,460,981	($3,401,699)	$59,282
32	Total Salaries & Wages (Lines 19+20+21+31)	$29,767,000	$0	$29,767,000
33	Operation and Maintenance		$19,915,827	66.91%
34	Construction		$8,221,792	27.62%
35	Retirements		$1,570,099	5.27%
36	All Other		$59,282	0.20%
37	Total		$29,767,000	100.00%

Kentucky Power Company
Energy and Capacity Charges
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Purchased Power (2)	Energy (3)	Capacity (4)	Total (5)
1	Purchased	$44,363,358	$42,162,555	$86,525,913
2	System Pool	$53,014,256	$29,084,203	$82,098,459
3	Loop, Interchange Cash and Interchange Suspense	$75,501	$0	$75,501
4	Total Purchased Power	$97,453,115	$71,246,758	$168,699,873
	Less:			
5	System Sales/Resale	$67,964,292	$6,930,521	$74,894,813
6	Sys Sales/Resale Assoc. Company	$47,450,328	$47,135	$47,497,463
7	Transmission Charges	$0	$0	$0
8	System Sales Clause	($8,647,168)	$0	($8,647,168)
9	Total System Sales	$106,767,452	$6,977,656	$113,745,108
10	Backup Energy	$0	$0	$0
11	Transmission Service Charges	$0	$13,401,788	$13,401,788
12	Total (Ln 4 - Lns 9, 10 and 11)	($9,314,337)	$50,867,314	$41,552,977

Kentucky Power Company
Depreciation, Depletion and Amortization Expense
Test Year Twelve Months Ended 6/30/2005

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Ln. No. (1)	Description (2)	Total Electric Utility (3)	Kentucky P. S. C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Production Plant	$17,573,542	$17,327,512	0.986	PDAF
2	Transmission Plant	$6,785,651	$6,690,652	0.986	GP-TRANS
3	Distribution Plant	$15,769,731	$15,738,192	0.998	GP-DIST
4	General Plant	$743,961	$736,521	0.990	GP-PTD
5	Intangible Plant	$3,586,872	$3,551,003	0.990	GP-PTD
6	Total Depreciation, Depletion and Amortization Expense	$44,459,757	$44,043,880		

Kentucky Power Company
Taxes Other Than Income Taxes
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 9

Ln. No. (1)	Description (2)	Total Electric Utility (3)	Kentucky P. S. C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Federal Insurance Contribution Excise	$2,171,663	$2,152,118	0.991	OML
2	Federal Unemployment Excise	$25,964	$25,730	0.991	OML
3	Kentucky Sales & Use	$214	$212	0.992	GP-T&D
4	Kentucky Personalty and Franchise	$7,054,932	$6,984,383	0.990	GP-TOT
5	Louisiana Real & Personal Property	$590	$584	0.990	GP-TOT
6	Kentucky Unemployment Insurance	$17,416	$17,259	0.991	OML
7	Kentucky PSC Maintenance	$504,415	$504,415	1.000	SPECIFIC
8	Kentucky License	$100	$99	0.990	GP-TOT
9	Ohio Franchise	$91,080	$89,805	0.986	PDAF
10	West Virginia Real & Personal Property	$3,304	$3,271	0.990	GP-TOT
11	West Virginia Unemployment Insurance	$2,973	$2,973	1.000	SPECIFIC
12	West Virginia Franchise	$23,533	$23,533	1.000	SPECIFIC
13	West Virginia License	$275	$275	1.000	SPECIFIC
14	Wyoming License	$50	$49	0.986	PDAF
15	Fringe Benefit Loading - FICA	($812,853)	($805,537)	0.991	OML
16	Fringe Benefit Loading - FUT	($12,362)	($12,251)	0.991	OML
17	Fringe Benefit Loading - SUT	($5,355)	($5,307)	0.991	OML
18	Total Taxes Other Than Income Taxes	$9,065,939	$8,981,611		
	Less:				
19	Carrs Site Kentucky Personalty and Franchise Tax	$44,743	$44,296	0.990	GP-TOT
20	Net Taxes Other Than Income Taxes	$9,021,196	$8,937,315		

Kentucky Power Company
Federal and State Income Taxes - Separate Return
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 10

Ln. No. (1)	Description (2)	Electric Utility (3)	Kentucky Jurisdiction (4)
1	Total Federal Income Tax Payable	$4,519,109	$4,705,661
2	Total Deferred Federal Income Tax	$4,949,813	$4,900,291
3	Total Deferred Investment Tax Credit	($1,168,684)	($1,156,997)
4	Total Current & Deferred Federal Income Taxes	$8,300,238	$8,448,955
5	State Income Tax	$996,946	$922,665

Section V
Schedule 11

Kentucky Power Company
Original Cost - Electric Plant In Service
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Description (2)	Total Electric Utility (3)	Kentucky P. S. C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
	Production Plant				
1	Land	$5,420	$5,344	0.986	PDAF
2	Land Rights	$1,071,126	$1,056,130	0.986	PDAF
3	All Other	$458,079,243	$451,666,134	0.986	PDAF
4	Total	$459,155,789	$452,727,608		
	Transmission Plant				
5	Land	$2,446,404	$2,412,154	0.986	TDAF
6	Land Rights	$23,311,444	$22,985,084	0.986	TDAF
7	Subs-Structures & Equipment	$129,671,286	$127,855,888	0.986	TDAF
8	All Other	$232,396,169	$229,142,623	0.986	TDAF
9	Total	$387,825,303	$382,395,749	0.986	GP-TRANS
	Distribution Plant				
10	Land	$1,446,548	$1,437,079		WP S-11 P1
11	Land Rights	$3,691,802	$3,691,802	1.000	SPECIFIC
12	Subs-Structures & Equipment	$46,885,675	$46,047,768		WP S-11 P1
13	Meters	$20,941,912	$20,937,281	($4,631)	WP S-11 P1
14	All Other	$373,483,032	$373,483,032	1.000	SPECIFIC
15	Total	$446,448,969	$445,596,962	0.998	GP-DIST
16	Total Transmission and Distribution (Lines 9+15)	$834,274,272	$827,992,711	0.992	GP - T&D
17	Total Production, Transmission and Distribution (Lines 4+16)	$1,293,430,061	$1,280,720,319	0.990	GP - PTD
	General Plant				
18	Land	$1,447,689	$1,433,212	0.990	GP - PTD
19	All Other	$29,575,208	$29,279,456	0.990	GP - PTD
20	Total	$31,022,897	$30,712,668		
21	Intangible Plant	$18,483,199	$18,298,367	0.990	GP - PTD
22	Electric Plant In Service (EPIS)	$1,342,936,157	$1,329,731,354		
23	EPIS-Capital Leases	$10,405,054	$10,301,003	0.990	GP - PTD
24	Total EPIS Original Cost (Lines 17+18)	$1,353,341,211	$1,340,032,357		
	Plus:				
25	Post In Service AFUDC HR-J	$1,603,846	$1,581,392	0.986	GP - TRANS
26	Deferred Depreciation HR-J	$142,789	$140,790	0.986	GP - TRANS
	Less:				
27	EPIS - Capital Leases	$10,405,054	$10,301,003	0.990	GP - PTD
28	Total EPIS-Original Cost with HR-J Post in Service AFUDC	$1,344,682,792	$1,331,453,536	0.990	GP - TOT

Kentucky Power Company
Analysis of Distribution Plant-Substations
Test Year Twelve Months Ended 6/30/2005

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Ln. No. (1)	Description (2)	360 Land (3)	361 Structures (4)	362 Station Equipment (5)	Total (6)
	City of Olive Hill Station:				
1	Olive Hill Station	$9,469	$44,907	$793,000	$847,376
2	All Other Distrubtion Stations	$1,437,079	$4,186,156	$41,861,612	$47,484,847
3	Total Distrubtion Stations	$1,446,548	$4,231,063	$42,654,612	$48,332,223

	Distrubtion:	
4	Total Substations	$48,332,223
5	Land	($1,446,548)
6	Structures and Equipment	$46,885,675
7	Total Distrubtion Plant	$446,448,969
	Less:	
8	Land	$1,446,548
9	Land Rights	$3,691,802
10	Structures and Equipment	$46,885,675
11	Meters	$20,941,912
12	All Other	$373,483,032

Kentucky Power Company
Distribution Plant - Analysis of Meters
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Description (2)	Total (3)
1	Olive Hill 4 kV	$2,102
2	Olive Hill 12 kV	$2,529
3	Sub-Total	$4,631
3	Vanceburg	$0
4	Total	$4,631

Section V
Schedule 12

Kentucky Power Company
Accumulated Provision for Depreciation, Depletion and Amortization of Electric Plant in Service
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Description (2)	Total Electric Utility (3)	Kentucky P. S. C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Production Plant Total	$175,291,580	$172,837,498	0.986	PDAF
2	Transmission Plant Total	$115,819,826	$114,198,348	0.986	GP-TRANS
3	Distribution Plant Total	$130,847,900	$130,586,204	0.998	GP-DIST
4	Total Production, Transmission and Distribution	$421,959,306	$417,622,050		
5	General Plant Total	$6,085,151	$6,024,299	0.990	GP-PTD
6	Intangible Plant Total	$8,761,699	$8,674,082	0.990	GP-PTD
7	Capital Leases	$6,683,310	$6,616,477	0.990	GP-PTD
8	Total Accumulated Provision for Depreciation	$443,489,466	$438,936,908		
	Plus:				
9	HR-J Post in Service AFUDC	$687,646	$678,019	0.986	GP-TRANS
	Less:				
10	Capital Leases	$6,683,310	$6,616,477	0.990	GP-PTD
11	Depreciation and Amortization Including HR-J Post in Service AFUDC	$437,493,802	$432,998,450		

Kentucky Power Company
Accumulated Provision for Depreciation,
Retirements and Easements Allocation
Test Year Twelve Months Ended 6/30/2005

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Workpaper S-12
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Ln. No. (1)	Description (2)	Electric Utility (3)	Percent * (4)	Retirements (5)	Total (6)
1	Production	$174,169,109	40.82%	$0	$174,169,109
2	Transmission	$115,819,826	27.14%	$0	$115,819,826
3	Distribution	$130,847,900	30.66%	$0	$130,847,900
4	General	$5,882,628	1.38%	$0	$5,882,628
5	Total	$426,719,463	100.00%	$0	$426,719,463

* Total May Not Foot Due To Rounding.

Kentucky Power Company
Net Electric Plant In Service
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 13

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky P.S.C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Production Plant	$283,864,209	$279,890,110		Sch 11-12
2	Transmission Plant	$272,005,477	$268,197,401		Sch 11-12
3	Distribution Plant	$315,601,069	$315,010,758		Sch 11-12
4	Total Production, Transmission and Distribution	$871,470,755	$863,098,269		
5	General Plant	$24,937,746	$24,688,369		Sch 11-12
6	Intangible Plant	$9,721,500	$9,624,285		Sch 11-12
7	Capital Leases	$3,721,744	$3,684,526		Sch 11-12
8	Total Electric Plant In Service - Net	$909,851,745	$901,095,449		
	Plus:				
9	HR-J Post In Service AFUDC	$916,200	$903,373		Sch 11-12
10	Deferred Depreciation HR-J	$142,789	$140,790		Sch 11-12
	Less:				
11	Capital Leases	$3,721,744	$3,684,526		Sch 11-12
12	Total EPIS - Net with HR-J Post In Service AFUDC	$907,188,990	$898,455,086	0.990	NP

Kentucky Power Company
Electric Plant Held for Future Use
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 14

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky P.S.C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Production Plant	$6,778,355	$6,683,458	0.986	PDAF
2	Transmission Plant	$84,464	$83,282	0.986	GP - TRANS
3	General Plant	$0	$0	0.990	GP - PTD
4	Total	$6,862,819	$6,766,740		
	Less:				
5	Carrs Site	$6,778,355	$6,683,458	0.986	PDAF
6	Net Plant Held For Future Use	$84,464	$83,282		

Kentucky Power Company
Working Capital Requirement
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 15

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky P.S.C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Materials & Supplies	$16,720,225	$16,502,178		WP S-15
2	Prepayments	$661,934	$655,315	0.990	GP-TOT
	Cash Working Capital:				
3	O & M Expense Restated	$238,269,350	$235,483,553		Sch 7
	Add Back System Sales: *				
4	Demand Related	$20,379,444	$20,094,132	0.986	PDAF
5	Energy Related	$106,767,452	$105,379,475	0.987	EAF
6	Total	$365,416,246	$360,957,160		
	Cash Working Capital				
7	1/8 of Line 6	$45,677,031	$45,119,645		
	Total Working Capital				
8	Sum of Lines 1, 2, & 7	$63,059,190	$62,277,138		

* Includes Various Transmission Agreements

Kentucky Power Company
Summary of Materials and Supplies
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-15
Page 1 of 1

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky P.S.C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
	M & S - Fuel :				
1	Fuel Stock - Coal	$10,216,763			
2	Fuel Stock - In Transit	$0			
3	Fuel Stock - Oil	$290,749			
4	Fuel Stock - Undist.	$155,721			
5	Total M & S - Fuel	$10,663,233	$10,524,611	0.987	EAF
	M & S - Other:				
6	Power Plant	$4,903,238	$4,834,593	0.986	PDAF
7	Urea	$258,284	$254,668	0.986	PDAF
8	T&D	$838,974	$832,262	0.992	GP - T&D
9	Transportation Inventory	$56,496	$56,044	0.992	GP - T&D
10	Total M&S - Other	$6,056,992	$5,977,567		
11	Total M & S (Lns 5+10)	$16,720,225	$16,502,178		

Kentucky Power Company
Construction Work In Progress (CWIP) - AFUDC
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 16

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky PSC Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
	CWIP:				
1	Production	$9,638,901	$9,503,956	0.986	PDAF
2	Transmission	$1,221,382	$1,204,283	0.986	GP-TRANS
3	Distribution	$7,540,011	$7,524,931	0.998	GP-DIST
4	General	$935,907	$926,548	0.990	GP-PTD
5	Total CWIP	$19,336,201	$19,159,718		
	AFUDC:				
6	Production	$405,997	$400,313	0.986	PDAF
7	Transmission	$91,999	$90,711	0.986	GP-TRANS
8	Distribution	$101,245	$101,043	0.998	GP-DIST
9	General	$16,621	$16,455	0.990	GP-PTD
10	Total AFUDC	$615,862	$608,522		

Kentucky Power Company
Functionalization of Construction Work In Progress
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Description (2)	CWIP Per Books (3)	Less Portion subject to AFUDC (4)	Not Subject To AFUDC (Col 3- Col 4) (5)
1	Production	$9,638,901	$9,635,152	$3,749
2	Transmission	$1,221,382	$1,126,955	$94,427
3	Distribution	$7,540,011	$4,254,755	$3,285,256
4	General	$935,907	$781,539	$154,368
5	Total CWIP	$19,336,201	$15,798,401	$3,537,800

Kentucky Power Company
Monthly Book Credits
Allowance for Funds Used During Construction (AFUDC) - Credit
Test Year Twelve Months Ended 6/30/2005

		Production		Transmission		Distribution		General Plant		Total			Monthly	Monthly
Ln No (1)	Month (2)	432 Borrowed (3)	419 Other (4)	432 Borrowed (5)	419 Other (6)	432 Borrowed (7)	419 Other (8)	432 Borrowed (9)	419 Other (10)	432 Borrowed (11)	419 Other (12)	Total AFUDC (13)	Debt Rate (14)	Equity Rate (15)
1	July 2004	$14,425	$13,124	$2,133	$1,666	$5,244	$4,919	$744	$677	$22,546	$20,386	$42,932	0.2285%	0.2079%
2	August 2004	$16,526	$17,846	$4,529	$4,911	$6,714	$7,248	$779	$841	$28,548	$30,846	$59,394	0.2686%	0.2899%
3	September 2004	$15,806	$17,260	$4,424	$4,850	$4,946	$6,293	$805	$882	$25,981	$29,285	$55,266	0.2690%	0.2946%
4	October 2004	$14,437	$15,817	($4,552)	($3,638)	($5,074)	($4,399)	$1,049	$1,150	$5,860	$8,930	$14,790	0.2684%	0.2941%
5	November 2004	$16,464	$17,971	$3,581	$4,390	$5,960	$6,505	$1,390	$1,517	$27,395	$30,383	$57,778	0.2689%	0.2935%
6	December 2004	$19,005	$20,736	$4,665	$5,089	$5,495	$5,996	($1,840)	($1,958)	$27,325	$29,863	$57,188	0.2678%	0.2921%
7	January 2005	$21,439	$23,098	$5,530	$5,956	$1,198	$1,333	$395	$435	$28,562	$30,822	$59,384	0.2703%	0.2911%
8	February 2005	$18,819	$20,177	$6,795	$7,176	$4,007	$4,296	$502	$539	$30,123	$32,188	$62,311	0.2732%	0.2930%
9	March 2005	$14,287	$15,540	$7,102	$7,725	$4,647	$5,055	$869	$946	$26,905	$29,266	$56,171	0.2717%	0.2955%
10	April 2005	$8,841	$9,734	$938	$1,252	$3,350	$3,674	$908	$991	$14,037	$15,651	$29,688	0.2715%	0.2963%
11	May 2005	$16,299	$18,325	$3,958	$4,462	$4,986	$5,667	$1,151	$1,294	$26,394	$29,748	$56,142	0.2643%	0.2972%
12	June 2005	$18,642	$21,379	$4,217	$4,840	$6,090	$7,095	$1,190	$1,365	$30,139	$34,679	$64,818	0.2658%	0.3049%
13	Total	$194,990	$211,007	$43,320	$48,679	$47,563	$53,682	$7,942	$8,679	$293,815	$322,047	$615,862		

Kentucky Power Company
Customer Advances for Construction, Customer Deposit
and Accumulated Deferred Income Taxes
Test Year Twelve Months Ended 6/30/2005

Section V
Schedule 17

Ln No (1)	Description (2)	Total Electric Utility (3)	Kentucky P.S.C. Jurisdiction (4)	Percent Retail (5)	Allocation Factor (6)
1	Customer Advances	$56,784	$56,784	1.000	SPECIFIC
2	Customer Deposits	$10,541,285	$10,541,285	1.000	SPECIFIC
3	Total	$10,598,069	$10,598,069		
4	Total Accumulated Deferred Income Tax	$129,276,197	$127,983,435	0.990	GP - TOT

Kentucky Power Company
Demand Allocation Factors
Test Year Twelve Months Ended 6/30/2005

Ln No	Description	Column (1)	Column (2)	Column (3)	Column (4)	Column (5)	Column (6)	Column (7)	Column (8)	Column (9)	Column (10)	Column (11)	Column (12)	Column (13) Total / Average
1	Date of MW Peak	Jul -13 - 04	Aug - 3 - 04	Sep - 1 - 04	Oct - 18 - 04	Nov - 15 - 04	Dec - 20 - 04	Jan - 24 -05	Feb - 2 - 05	Mar - 3 - 05	Apr - 2 - 05	May - 3 - 05	Jun - 14 - 05	
2	Hour of MW Peak	1500	1600	1700	0800	0900	0900	0800	0800	0800	2000	0800	1500	
3	KPCo's Peaks - Max. Load (MW) *	1,558.000	1,572.000	1,506.000	1,188.000	1,659.000	1,888.000	2,079.000	1,569.000	1,728.000	1,227.000	1,264.000	1,369.000	18,607.000
4														1,550.583
5	System Sales Excluding Losses	349.000	344.000	446.000	238.000	439.000	273.000	394.000	250.000	299.000	152.000	152.000	133.000	
6	Loss Percentage	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	
7	System Sales Including Losses	361.390	356.212	461.833	246.449	454.585	282.692	407.987	258.875	309.615	157.396	157.396	137.722	3,592.152
8														299.346
9	KPCo's Internal Maximum Load	1,196.610	1,215.788	1,044.167	941.551	1,204.415	1,605.308	1,671.013	1,310.125	1,418.385	1,069.604	1,106.604	1,231.278	15,014.848
10														1251.237
	Municipals (FERC Jurisdiction)													
11	Vanceburg, Excluding Losses	11.672	11.542	10.22	8.808	10.458	14.842	14.828	12.242	12.88	9.128	9.726	12.062	138.408
12	Loss Percentage	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	1.0355	
13	Vanceburg, Including Losses	12.086	11.952	10.583	9.121	10.829	15.369	15.354	12.677	13.337	9.452	10.071	12.49	143.321
14														11.943
15	Olive Hill, Excluding Losses	5.229	5.250	4.734	4.260	4.438	5.966	6.224	5.243	5.606	4.260	4.330	5.117	60.657
16	Loss Percenage	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	
17	Olive Hill, Including Losses	5.554	5.576	5.028	4.525	4.714	6.336	6.611	5.569	5.954	4.525	4.599	5.435	64.426
18														5.369
19	Total Municipals, Including Losses	17.64	17.528	15.611	13.646	15.543	21.705	21.965	18.246	19.291	13.977	14.67	17.925	207.747
20														17.312
21	Allocation Factor (FERC Jurisdiction)					17.312 /	1251.237 =	0.014						
22	Retail (KPSC Jurisdiction) Load	1178.97	1198.26	1028.556	927.905	1188.872	1583.603	1649.048	1291.879	1399.094	1055.827	1091.934	1213.353	14807.101
23														1233.925
24	Allocation Factor (KY Jurisdiction)					1233.925 /	1251.237 =	0.986						

*KPCo Internal Load plus System Sales at Time of Internal Peak

Kentucky Power Company
Energy Allocation Factors
Test Year Twelve Months Ended 6/30/2005

Ln No (1)	Energy Loss Calculations (2)	MWHs (3)	% Loss Factor (4)	MWH Losses (5)	MWH w/ Losses (6)
	Transmission				
1	St., Lt., Unit Power	4,728,554	2.87%	135,709	4,864,263
2	Firm Sales Vanceburg	66,480	2.87%	1,908	68,388
	Distribution				
3	Firm Sales Olive Hill	27,223	4.97%	1,353	28,576

Ln No		Total Company (3)	Elimination (4)	Total Company Adjusted (5)	City of Olive Hill (6)	City of Vanceburg (7)	Total Sales Municipal (8)	Total Retail (9)
	Source of Energy							
4	Generation	6,550,509	0	6,550,509				
5	Purchases	5,943,392	0	5,943,392				
6	Net Interchange	-604	0	-604				
7	Total Sources	12,493,297	0	12,493,297				
	Disposition of Energy							
8	Sales/Ultimate Customers	6,976,594	0	6,976,594	0	0	0	6,976,594
9	Energy w/o Charge	0		0				0
10	Sales for Resale	4,728,554	4,728,554	0				0
	Firm Sales (Mun.)							
11	Vanceburg	66,480		66,480		66,480	66,480	0
12	Olive Hill	27,223		27,223	27,223		27,223	0
13	Total Sales for Resale	4,822,257	4,728,554	93,703	27,223	66,480	93,703	6,976,594
14	Energy Losses	693,213	135,709	557,504	1,353	1,908	3,261	554,243
15	Total Disposition	12,492,064	4,864,263	7,627,801	28,576	68,388	96,964	7,530,837
16	Allocation Factor			1			0.013	0.987

Kentucky Power Company
Jurisdictional Allocation Factors
Test Year Twelve Months Ended 6/30/2005

Ln. No. (1)	Description (2)	Factor (3)	Retail (4)	Source (5)
1	Production Demand	PDAF	0.986	Schedule 18
2	Transmission Demand	TDAF	0.986	Schedule 18
3	Energy	EAF	0.987	Schedule 19
4	Gross Plant Transmission	GP-TRANS	0.986	Schedule 11
5	Gross Plant Distribution	GP-DIST	0.998	Schedule 11
6	Gross Plant - T&D	GP-T&D	0.992	Schedule 11
7	Gross Plant - PTD	GP-PTD	0.990	Schedule 11
8	Gross Plant - Total	GP-TOT	0.990	Schedule 11
9	Net Plant	NP	0.990	Schedule 13
10	O&M Expense	O&M	0.988	Schedule 7
11	O&M Expense - Labor	OML	0.991	Schedule 7
12	Operating Revenue	OP-REV	0.991	Schedule 6
13	Operating Revenue - Other	OP-REV-O	0.994	Schedule 6

Kentucky Power Company
Revenue Requirement
Test Year Twelve Months Ended 06/30/2005

Section V
Schedule 2
Revised 02/02/06

Line No. (1)	Description (2)	As Filed (3)	As Adjusted (4)	Difference (5)
1	Capitalization (Per Sch 3, L 7, Col 12)	$853,082,950	$853,082,950	$0
2	Rate of Return (WP S-2, Pg 1, L 5, Col 6)	7.89%	7.89%	$0
3	Required Net Electric Operating Income (L 1 X L 2)	$67,308,245	$67,308,245	$0
4	Test Year Net Electric Operating Income (Per Sch 4, L 14, Col 5)	$28,406,655	$30,239,264	$1,832,609
5	Net Electric Operating Income Change (L 3 - L 4)	$38,901,590	$37,068,981	($1,832,609)
6	Gross Revenue Conversion Factor (Per WP S-2, Pg 2, L 8)	1.6656	1.6488	
7	Change in Revenue Requirement (L 5 X L 6) Increase / (Decrease)	$64,796,239	$61,119,336	($3,676,903)
8	Operating Revenues	100.00%	100.00%	
9	Less: Uncollectible Accounts Expense	0.47%	0.47%	
10	Income Before income Taxes	99.53%	99.53%	
11	Less: State Income Taxes (L 10 X 7.20%)	7.16%		
12A	Less: State Income Taxes (L 10 X 6.25%) 1/		6.22%	
12B	Income Before Federal Income Taxes	92.37%	93.31%	
13	Less: Federal income Taxes (L 12 X 35.00%)	32.33%	32.66%	
14	Operating Income Percentage (Ln 12 - L 13)	60.04%	60.65%	
15	Gross Revenue Conversion Factor (100% / L 14)	1.6656	1.6488	

1/ 9 Months at 7% and 27 months at 6% — 6.25%

KENTUKY POWER COMPANY
ADJUSTMENTS SUMMARY
TWELVE MONTHS ENDED 06/30/2005

LINE NO. (1)	DESCRIPTION (2)	BASE CASE PSC JURISDICTION (3)	Sch 7 & Sch 10 Adjustments (4)	REVISED BASE CASE PSC JURISDICTION (5)	RATE CASE ADJUSTMENTS (6)	ADJUSTED PSC JURISDICTION (7)	02/02/06 ADJUSTMENTS (8)	ADJUSTMENTS FOR CHANGE IN KY INCOME TAX RATE FROM 7.20% TO 6.25% (9)	REVISED ADJUSTED PSC JURISDICTION (10)
	Operating Revenues								
1	Sales Of Electricity	$336,751,863	$0	$336,751,863	$591,825	$337,343,688	$18,725	$0	$337,362,413
2	Other Operating Revenues	12,983,134	0	12,983,134	(4,270,069)	8,713,065	694,804	0	9,407,869
3	Total Operating Revenues	$349,734,997	$0	$349,734,997	($3,678,244)	$346,056,753	$713,529	$0	$346,770,282
	Operating Expenses								
4	Operation & Maintenance	$235,489,125	($5,572)	$235,483,553	$31,506,995	$266,990,548	($2,106,833)	$0	$264,883,715
5	Depreciation	44,043,880	0	44,043,880	3,654,912	47,698,792	(272,735)	0	47,426,057
6	Taxes Other Than Income Taxes	8,937,315	0	8,937,315	260,696	9,198,011	(741)	0	9,197,270
7	State Income Tax	1,030,001	(107,336)	922,665	(2,378,229)	(1,455,564)	189,600	292,623	(973,341)
	Federal Income Tax :								
8	Current	4,668,094	37,567	4,705,661	(10,733,225)	(6,027,564)	942,933	(163,719)	(5,248,350)
9	Deferred	4,900,291	0	4,900,291	(1,338,731)	3,561,560	75,133	0	3,636,693
10	ITC Adjustment	(1,156,997)	0	(1,156,997)	0	(1,156,997)	0	0	(1,156,997)
11	Total Operating Expenses	$297,911,709	($75,341)	$297,836,368	$20,972,418	$318,808,786	($1,172,643)	$128,904	$317,765,047
12	Net Electric Operating Income (LINE 3 - LINE 11)	$51,823,288	$75,341	$51,898,629	($24,650,662)	$27,247,967	$1,886,172	($128,904)	$29,005,235
13	AFUDC Offset Adjustment / Deferred Income	608,522	0	608,522	625,507	1,234,029	0	0	1,234,029
14	Net Electric Operating Income - Adjusted	$52,431,810	$75,341	$52,507,151	($24,025,155)	$28,481,996	$1,886,172	($128,904)	$30,239,264
	Rate Base								
15	Electric Plant In Service - Gross	$1,331,453,536	$0	$1,331,453,536	$5,484,600	$1,336,938,136	$0	$0	$1,336,938,136
16	Accum. Prov. For Depreciation	432,998,450	0	432,998,450	0	432,998,450	0	0	432,998,450
17	Electric Plant In Service - Net	$898,455,086	$0	$898,455,086	$5,484,600	$903,939,686	$0	$0	$903,939,686
18	Plant Held For Future Use	83,282	0	83,282	0	83,282	0	0	83,282
19	Prepayments	655,315	0	655,315	4,083,831	4,739,146	(44,673)	0	4,694,473
20	Materials & Supplies	16,502,178	0	16,502,178	3,542,537	20,044,715	0	0	20,044,715
21	Cash Working Capital	45,120,342	(698)	45,119,644	3,938,375	49,058,019	(263,354)	0	48,794,665
22	Construction Work In Progress	19,159,718	0	19,159,718	0	19,159,718	0	0	19,159,718
	Less:								
23	Customer Advances & Deposits	10,598,069	0	10,598,069	0	10,598,069	0	0	10,598,069
24	Accumulated Deferred Income Taxes	127,983,435	0	127,983,435	0	127,983,435	0	0	127,983,435
25	Total Rate Base	$841,394,417	($698)	$841,393,719	$17,049,343	$858,443,062	($308,027)	$0	$858,135,035

KENTUCKY POWER COMPANY
REVISED - ADJUSTMENTS SUMMARY
TWELVE MONTHS ENDED 06/30/2005

LINE NO (1)	DESCRIPTION (2)	Annualization Postage Increase (1)	Annualization Emp. Related Expense (2 - 6)	Depreciation Adjustment (8)	Net Merger Savings Adjustment (9)	Annualized Lease Expense (14)	Adjustment Interest Synchronization (20)	Adjustment to System Sales (28)	Annualized of Vehicle Fuel Cost (31)	Adjustment to Reflect Normalization of PJM (Revenues) and Expenses (32)	Adjustment Normal PJM Network Transmission Revenues (33)	Adjustment to Reflect RTO Formation Costs (36)	Adjustment Normalization of PJM PTP Transmission Revenues (39)	Prepayment Pension Adjustment (40)	Adjustment Normalization of PJM Admin Costs (41)	Page Total
	Operating Revenues															
1	Sales Of Electricity	$0	$0	$0	$18,725	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,725
2	Other Operating Revenues	0	0	0	0	0	0	0	0	350,558	314,786	0	29,480	0	0	694,804
3	Total Operating Revenues	$0	$0	$0	$18,725	$0	$0	$0	$0	$350,558	$314,786	$0	$29,480	$0	$0	$713,529
	Operating Expenses															
4	Operation & Maintenance	($48)	($13,647)	$0	$0	($138)	$0	($2,025,599)	$45,710	$0	$0	($39,320)	$0	$0	($73,595)	($2,106,833)
5	Depreciation	0	0	(272,735)	0	0	0	0	0	0	0	0	0	0	0	(272,735)
6	Taxes Other Than Income Taxes	0	(741)	0	0	0	0	0	0	0	0	0	0	0	0	(741)
7	State Income Tax	3	912	0	33,054	8	(18,604)	126,600	(2,857)	21,910	19,674	2,458	1,841	0	4,600	189,600
	Federal Income Tax :															
8	Current	16	5,106	0	(5,016)	48	(32,883)	708,960	(15,999)	122,895	110,175	13,762	10,311	0	25,758	942,933
9	Deferred	0	0	75,133	0	0	0	0	0	0	0	0	0	0	0	75,133
10	ITC Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total Operating Expenses	($27)	($8,570)	($197,602)	$28,038	($78)	($51,487)	($1,190,039)	$26,854	$144,805	$129,849	($23,100)	$12,152	$0	($43,237)	($1,172,643)
12	Net Electric Operating Income (L3 - L11)	$27	$8,570	$197,602	($9,313)	$78	$51,487	$1,190,039	($26,854)	$205,953	$184,937	$23,100	$17,308	$0	$43,237	($459,114)
13	AFUDC Offset Adjustment / Deferred Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Net Electric Operating Income - Adjusted	$27	$8,570	$197,602	($9,313)	$78	$51,487	$1,190,039	($26,854)	$205,953	$184,937	$23,100	$17,308	$0	$43,237	($459,114)
	Rate Base															
15	Electric Plant In Service - Gross	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Accum. Prov. For Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Electric Plant In Service - Net	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Plant Held For Future Use	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Prepayments	0	0	0	0	0	0	0	0	0	0	0	0	(44,873)	0	(44,873)
20	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Cash Working Capital	(8)	(1,731)	0	0	(17)	0	(253,200)	5,714	0	0	(4,915)	0	0	(9,199)	(263,354)
22	Construction Work In Progress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Less:															0
23	Customer Advances & Deposits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Total Rate Base	($8)	($1,731)	$0	$0	($17)	$0	($253,200)	$5,714	$0	$0	($4,915)	$0	($44,873)	($9,199)	($306,027)

State Income Tax Rate - Revised	6.25%
Federal Income Tax Rate	35.00%

Kentucky Power Company
Adjustment for Postage Rate
Increase Effective January 1, 2006
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	DESCRIPTION (2)	As Filed Amount (3)	Revised Amount 2/ (4)	Difference (Col 4 - Col 3) (5)
1	Number of Bills, Notices and Lettters Mailed in Test Year	2,387,000	2,384,132	
2	Postage Rate Increase per Mailed Item 1/	$0.016	$0.016	
3	Adjustment to O&M for Postage Increase	$38,192	$38,146	
4	Allocation Factor - SPECIFIC	1.000	1.000	
5	KPSC Jurisdictional Amount (Ln 3 X Ln 4)	$38,192	$38,146	($46)

1/ Effective Date of Postage Increase is January 1, 2006
Rate of Increase is 5.4%
Current Average Postage Rate is $0.298
Increase Cost is $0.016

2/ Per Staff 3rd Set Item No. 6 Page 4

Witness: R. K. Wohnhas

Kentucky Power Company
Summary of Wage Related Adjustments
Increase Effective January 1, 2006
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)	Original Filed Amount (3)	Revised Amount (4)	Difference (5)
	O & M Expenses:			
1	Annualization of Wages & Salary Increase (Pg 3, Col 7, Ln 16)	$903,899	$894,012	($9,887)
2	Annualization of Insurance Costs (Pg 4, Col 6, Ln 22)	$322,054	$318,531	($3,523)
3	Annualization of Savings Plan Costs (Pg 6, Col 5, Ln 8)	$39,899	$39,462	($437)
4	Adjustment to KPCS Jurisdictional Wage Related Expenses	$1,265,852	$1,252,005	($13,847)
	Taxes Other:			
5	Annualization of FICA Expense (Pg 5, Col 5, Ln 16)	$67,660	$66,919	($741)

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Wages and Salaries
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Month / Year (2)	Monthly Increase Granted (3)	Number Of Month Adjusted (4)	Total Adjustment Required to Annualize Test Year Increases (C 3 X C 4) (5)	Revised Total Adjustment (6)	Difference (7)
1	Jul 04	$602	0	$0	$0	
2	Aug 04	$5,505	1	$5,505	$5,505	
3	Sep 04	$700	2	$1,400	$1,400	
4	Oct 04	$396	3	$1,188	$1,188	
5	Nov 04	$439	4	$1,756	$1,756	
6	Dec 04	$1,733	5	$8,665	$8,665	
7	Jan 05	$106,141	6	$636,846	$636,846	
8	Feb 05	$14,564	7	$101,948	$101,948	
9	Mar 05	$2,308	8	$18,464	$18,464	
10	Apr 05	$32,687	9	$294,183	$294,183	
11	May 05	$27,832	10	$278,320	$278,320	
12	Jun 05	$0	11	$0	$0	
13	Total Wage and Salary Annualization			$1,348,275	$1,348,275	
14A	Increase Wages and Salaries Applicable to O&M (Ln 13 X 67.65%)			$912,108		
14B	Increase Wages and Salaries Applicable to O&M (Ln 13 X 66.91%)				$902,131	
15	Allocation Factor - OML			0.991	0.991	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$903,899	$894,012	($9,887)

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Insurance Costs
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Description (2)	Amount (3)	Adjustment Amount As Filed (4)	Revised Adjustment Amount (5)	Difference (6)
1	Annualization of June 2005 Monthly Medical Plan Costs ($279,891 X 12)	$3,358,692			
2	Medical Plan Costs for the Twelve Months Ended 06/30/2005	$3,118,484			
3	Adjustment to Test Year Medical Plan Cost		$240,208	$240,208	
4	Annualization of June 2005 Life Insurance Costs ($9,893 X 12)	$118,716			
5	Life Insurance Costs for the Twelve Months Ended 06/30/2005	$93,378			
6	Adjustment to Test Year Life Insurance Costs		$25,338	$25,338	
7	Annualization of June 2005 Dental Plan Costs ($16,831 X 12)	$201,972			
8	Dental Plan Costs for the Twelve Months Ended 06/30/2005	$184,881			
9	Adjustment to Test Year Dental Plan Costs		$17,091	$17,091	
10	Annualization of June 2005 Retirement Plan Costs ($125,499 X 12)	$1,505,988			
11	Retirement Plan Costs for the Twelve Months Ended 06/30/2005	$1,038,398			
12	Adjustment to Test Year Retirement Plan Costs		$467,590	$467,590	
13	Annualization of June 2005 Long Term Disability Ins Costs ($16,390 X 12)	$196,680			
14	Long Term Disability Ins Costs for the Twelve Months Ended 06/30/2005	$118,480			
15	Adjustment to Test Year Long Term Disability Insurance Premium Cost		$78,200	$78,200	
16	Annualization of June 2005 OPEB Costs ($171,462 X 12)	$2,204,016			
17	Adjustment to Test year OPEB Cost	$2,552,060			
18	Adjustment to Test Year OPEB Cost		($348,044)	($348,044)	
19	Total Employee Benefit Plan Cost Adjustments (Ln 3 + Ln 6 + Ln 9 + Ln 12 + Ln 15 + Ln 18)		$480,383	$480,383	
20A	Employee Benefit Plan Applicable to O&M (Ln 19 X 67.65%)		$324,979		
20B	Employee Benefit Plan Applicable to O&M (Ln 19 X 66.91%)			$321,424	
21	Allocation Factor - OML		0.991	0.991	
22	KPSC Jurisdictional Amount (Ln 20 X Ln 21)		$322,054	$318,531	($3,523)

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of FICA Expense for Test Year Ended 06/30/2005

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LINE NO. (1)	Description (2)			Original Filed Amount (3)	Revised Amount (4)	Difference (5)
1	New Rate:					
2		OASI	6.20%			
3		Medicare	1.45%			
		Total	7.65%			
	New Subject Rate:					
4		OASI	$53,400			
5		Medicare	$125,000			
6	Annualized 06/30/2005 Wages Paid $90,000 and Less			$1,312,453	$1,312,453	
7	June 30, 2005 FICA Rate			7.65%	7.65%	
8	Calculated FICA Tax on Wages Paid $53,400 and Less at 2005 Rate			$100,403	$100,403	
9	Annualized FICA Tax on Wages Paid $53,400 to $125,000			$35,822	$35,822	
10	2005 FICA Rate for Wages Paid $53,400 to $125,000			1.45%	1.45%	
11	Calculated FICA Tax on Wages Paid $53,400 to $125,000 at 2005 Rate			$519	$519	
12	Total Calculated FICA Tax at 2005 Rate (ln 8 + Ln 11)			$100,922	$100,922	
13A	FICA Applicable to O&M - 67.65%			67.65%		
13B	FICA Applicable to O&M - 66.91%				66.91%	
14	Adjustment to FICA Expense			$68,274	$67,527	
15	Allocation Factor - OML			0.991	0.991	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$67,660	$66,919	($741)

Witness: R. K. Wohnhas

Kentucky Power Company
Annualization of Savings Plan Costs
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Description (2)	Original Filed Amount (3)	Revised Amount (4)	Difference (5)
1	Base Payroll Test Year Ended 06/30/2005	$25,146,566	$25,146,566	
2	Contributions Test Year Ended 06/30/2005	$1,109,927	$1,109,927	
3	Percent of Contributions to Payroll (Ln 2 / Ln 3)	4.414%	4.414%	
4	Wages & Salary Annualization (WP S-4, Pg 3, Ln 13)	$1,348,275	$1,348,275	
5	Additional Contributions for Wages & Salary	$59,513	$59,513	
6A	Increase Savings Plan Costs Applicable to O&M (L X 67.65%)	$40,261		
6B	Increase Savings Plan Costs Applicable to O&M (L X 66.91%)		$39,820	
7	Allocation Factor - OML	0.991	0.991	
8	KPSC Jurisdictional Amount (Ln 6 X Ln 7)	$39,899	$39,462	($437)

Witness: R. K. Wohnhas

Kentucky Power Company
Adjustment / Annualization of Depreciation Expense
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)		Electric Plant in Service as of June 30, 2005 (3)	New Annual Rate (4)	Annualized Depreciation on EPIS as of 06/30/2005 (C3 X C4) (5)	Depreciation Expense 12 Months Ended 06/30/2005 (6)	Depreciation Expense 12 Months Ended 06/30/2005 (7)	Adjustment (8)
1	Production Plant		$459,150,369	0.0351	$16,116,178	$17,906,864	($1,790,686)	($275,490)
2	Transmission Plant		$385,378,899	0.0271	$10,443,768	$6,589,979	$3,853,789	0
3	Distribution Plant		$445,002,421	0.0364	$16,198,088	$15,664,085	$534,003	0
4	General Plant		$29,575,208	0.0531	$1,570,444	$751,210	$819,234	0
5	Total		$1,319,106,897		$44,328,478	$40,912,138	$3,416,340	($275,490)
6	Allocation Factor - GP-TOT						0.990	0.990
7	KPSC Jurisdictional Amount	(Ln 5 X Ln 6)					$3,382,177	($272,735)
8	Production Plant @ 3.51%						$16,116,178	
9	Production Plant @ 3.57%						16,391,668	
10	Difference						($275,490)	
11	Deferred Tax @ 3.51% (Production Plant)						($931,717)	
12	Deferred Tax @ 3.57% (Production Plant)						($1,006,850)	
13	Difference						$75,133	

Kentucky Power Company
Net Merger Savings Adjustment
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)	Original Filed Amount (3)	Revised Amount (4)	Difference (C4 - C3) (5)
1	Add Back Customer's Test Year Merger Revenue Credit	$4,018,275	$4,037,000	$18,725
	Less:			
2	Add Back Year 5's Net Merger Savings 1/	$7,385,000	$7,385,000	$0
3A	State Income Tax - 7.19702812%	($242,304)		
3B	State Income Tax - 6.25%		($209,250)	$33,054
4	Federal Income Tax - 35.00%	($1,093,547)	($1,098,563)	($5,016)
5	Net Electric Operating Income	($2,030,874)	($2,040,187)	($9,313)
6	Allocation Factor - SPECIFIC	1.000	1.000	1.000
7	KPSC Jurisdictional Amount (Ln 2 X Ln 3)	($2,030,874)	($2,040,187)	($9,313)

1/ Pursuant to Commission's June 14, 1999 Order in Case No. 99-149, pg. 4 of the Settlement Agreement

Witness: E. K. Wagner

Kentucky Power Company
Annualized Lease Cost
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)	Original Filed Amount (3)	Revised Amount (4)	Difference (5)
1	Annualization of June 2005 Monthly Lease Costs	$3,334,476	$3,334,476	
2	Lease Expense in the Test Year 06/30/2005	$3,315,751	$3,315,751	
3	Adjustment to Test Year Lease Expense (Ln 1 - Ln 2)	$18,725	$18,725	
4A	Adjustment Applicable to O&M (Ln 3 X 67.65%)	$12,667		
4B	Adjustment Applicable to O&M (Ln 3 X 66.91%)		$12,529	
5	Allocation Factor - GP-TOT	0.990	0.990	
6	KPSC Jurisdictional Amount (Ln 4 X Ln 5)	$12,540	$12,404	($136)

Witness: R. K. Wohnhas

Kentucky Power Company
Interest Synchronization
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)	PSC Jurisdictional Amount (3)	PSC Jurisdictional Amount 1/ (4)	PSC Jurisdictional Amount 2/ (5)	Difference (Col 5 - Col 3) (6)
1	LTD per Captilaization (Sch 3, C 11, Ln 1)	$482,392,123	$482,392,123	$482,392,123	
2	LTD Rate (WP S-3, P 1, C 5, Ln 12)	5.70%	5.70%	5.70%	
3	Annualized LTD Interest	$27,496,351	$27,496,351	$27,496,351	
4	STD per Captilaization (Sch 3, C 11, Ln 2)	$3,340,763	$3,340,763	$3,340,763	
5	STD Rate (WP S-2, P 2, C 4, Ln 17)	3.34%	3.34%	3.34%	
6	Annualized STD Interest	$111,581	$111,581	$111,581	
7	A/R Financing, per Capitalization (Sch 3, C 12, Ln 3)		$30,052,250	$30,052,250	
8	A/R Financing Rate (WP S-2, P 1, C 5, Ln 3)		2.99%	2.99%	
9	Annualized A/R Financing Interest		$898,562	$898,562	
10	Total Annualized Interest (Ln 3 + Ln 6 + Ln 9)	$27,607,932	$28,506,494	$28,506,494	
11	Total Interest Charges per Books Net of ABFUDC	$29,120,772	$29,914,717	$29,914,717	
12	Percent Retail (GP-TOT)	0.990	0.990	0.990	
13	Retail Interest (Ln 11 X Ln 12)	$28,829,564	$29,615,570	$29,615,570	
14	Interest Expense Adjustment (Ln 10 - Ln 13)	($1,221,632)	($1,109,076)	($1,109,076)	
15	SIT Rate	7.20%	7.20%	6.25%	
16	SIT Adjustment (Ln 14 X Ln 15)	$87,921	$79,853	$69,317	($18,604)
17	Net Change for FIT (Ln 14 + Ln 16)	($1,133,711)	($1,029,223)	($1,039,759)	
18	FIT Rate	35.00%	35.00%	35.00%	
19	FIT Adjustment (Ln 17 X Ln 18)	$396,799	$360,228	$363,916	($32,883)

1/ Per AG 1st Set Item No. 19

2/ Per the Change in State Tax Rate from 7.20% to 6.15%

Witness: R. K. Wohnhas

Kentucky Power Company
System Sales Adjustment
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Month (2)	Year (3)	Test Year Base System Sales Profit Level (4)	Adjustment to Reflect Environ. Costs Allocated to System Sales (5)	Adjustment to Test Year System Sales Profit Level (6)	New System Sales Tariff Base (7)	Adjustment to Test Year Level (8) = (7) - (4)	Revised Amount (9)	Adjustment to Test Year Level (10) = (9) - (8)
1	July	2004	$4,068,332	$605,999	$3,462,333	$2,658,364	($1,409,968)	$0	$1,409,968
2	August	2004	$2,871,664	$485,338	$2,386,326	$1,660,434	($1,211,230)	$0	$1,211,230
3	September	2004	$1,922,864	$572,105	$1,350,759	$1,497,772	($425,092)	$0	$425,092
4	October	2004	$67,121	$388,837	($321,716)	$950,190	$883,069	$0	($883,069)
5	November	2004	$1,000,703	$0	$1,000,703	$1,258,779	$258,076	$0	($258,076)
6	December	2004	$1,743,635	$0	$1,743,635	$2,025,256	$281,621	$0	($281,621)
7	January	2005	$3,674,868	$0	$3,674,868	$2,661,693	($1,013,175)	$0	$1,013,175
8	February	2005	$1,840,112	$0	$1,840,112	$2,236,268	$396,156	$0	($396,156)
9	March	2005	($389,264)	$0	($389,264)	$1,732,591	$2,121,855	$0	($2,121,855)
10	April	2005	$3,333,982	$0	$3,333,982	$2,706,860	($627,122)	$0	$627,122
11	May	2005	$3,622,195	$0	$3,622,195	$2,365,563	($1,256,632)	$0	$1,256,632
12	June	2005	$3,151,393	$0	$3,151,393	$3,101,556	($49,837)	$0	$49,837
13	Total		$26,907,605	$2,052,279	$24,855,326	$24,855,326	($2,052,279)	$0	$2,052,279
14	Allocation Factor - EAF						0.987		0.987
15	KPSC Jurisdictional O&M Adjustment (Ln 13 X Ln 14)						$2,025,599		($2,025,599)

Witness: E. K. Wagner

Kentucky Power Company
Annualization of Vehicle Fuel Costs
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)	Amount (3)	Original Filed Total (4)	Amount (5)	Commission Staff 2nd Set Requests Order Dated November 10, 2005 Item No. 18 (6)	Revised Total (7)	Difference (Col 7 - Col 3) (8)
1	Vehicle Fuel Cost for June 2005	$88,488		$83,708			
2	Number of Months	12		12			
3	Annualized Vehicle Fuel Cost (Ln 1 X Ln 2)		$1,061,856		$1,004,496	$1,004,496	
4	Vehicle Fuel Cost Twelve Months Ending June 30, 2005		862,596		733,888	733,888	
5	Increase Vehicle Fuel Cost (Ln 3 - Ln 4)		$199,260		$270,608	$270,608	
6A	Increase Vehicle Fuel Cost Applicable to O&M (Ln 4 X 67.65%)		$134,799		$183,066		
6B	Increase Vehicle Fuel Cost Applicable to O&M (Ln 4 X 66.91%)					$181,064	
7	Allocation Factor - O&M		0.988		0.988	0.988	
8	KPSC Jurisdictional Amount (Ln 6 X Ln 7)		$133,181		$180,869	$178,891	$45,710

Witness: R. K. Wohnhas

Kentucky Power Company
Normalization of Net PJM (Revenues) and Expenses
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Month / Year (2)	Test Year Amount (3)	Monthly 2006 Forecasted Amount * (4)	Adjustment Required (5) = (4) - (3)	Revised Monthly 2006 Forecasted Amount ** (6)	Adjustment Required (7) = (6) - (3)	Difference (Col 7 - Col 5) (8)
1	Jul 04	$0	($54,551)	($54,551)	($84,179)	($84,179)	
2	Aug 04	$0	($54,551)	($54,551)	($84,179)	($84,179)	
3	Sep 04	$0	($54,551)	($54,551)	($84,179)	($84,179)	
4	Oct 04	$201,445	($54,551)	($255,996)	($84,179)	($285,624)	
5	Nov 04	($133,116)	($54,551)	$78,565	($84,179)	$48,937	
6	Dec 04	$793,440	($54,551)	($847,991)	($84,179)	($877,619)	
7	Jan 05	$614,445	($54,551)	($668,996)	($84,179)	($698,624)	
8	Feb 05	($71,303)	($54,551)	$16,752	($84,179)	($12,876)	
9	Mar 05	$451,388	($54,551)	($505,939)	($84,179)	($535,567)	
10	Apr 05	$118,429	($54,551)	($172,980)	($84,179)	($202,608)	
11	May 05	$205,097	($54,551)	($259,648)	($84,179)	($289,276)	
12	Jun 05	($375,931)	($54,551)	$321,380	($84,179)	$291,752	
13	Total	$1,803,894	($654,612)		($1,010,148)		
14	Adj., Required to Reflect Amort. RTO Fromation Costs in Test Year			($2,458,506)		($2,814,042)	
15	Allocation Factor - PDAF			0.986		0.986	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			($2,424,087)		($2,774,645)	($350,558)

* Does Not Include PJM Administrative Costs

** Does Not Include PJM Administrative Costs
and the Source is AG 1st Set Data Requests Item No. 65-d Page 3 of 3

Witness: R. W. Bradish

Kentucky Power Company
Normalization of PJM Network Transmission Expenses
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Month / Year (2)	Test Year Amount (3)	Monthly 2006 Forecasted Amount * (4)	Adjusted Amount As Filed (5) = (4) - (3)	Revised Forecasted Amount (6)	Adjusted Amount As Revised (7) = (6) - (3)	Difference (8)
1	Jul 04	$230,202	$381,011	$150,809	$406,236	$176,034	
2	Aug 04	$197,834	$371,810	$173,976	$397,972	$200,138	
3	Sep 04	$220,085	$358,329	$138,244	$386,331	$166,246	
4	Oct 04	$232,977	$370,273	$137,296	$399,209	$166,232	
5	Nov 04	$220,658	$358,329	$137,671	$386,331	$165,673	
6	Dec 04	$239,934	$370,273	$130,339	$399,209	$159,275	
7	Jan 05	$221,995	$388,536	$166,541	$419,167	$197,172	
8	Feb 05	$221,356	$343,998	$122,642	$367,025	$145,669	
9	Mar 05	$242,978	$380,854	$137,876	$406,349	$163,371	
10	Apr 05	$270,947	$368,569	$97,622	$393,241	$122,294	
11	May 05	$243,452	$380,854	$137,402	$406,349	$162,897	
12	Jun 05	$238,219	$368,569	$130,350	$393,241	$155,022	
13	Total	$2,780,637	$4,441,405		$4,760,660		
14	Adj., Required to Reflect Amort. RTO Fromation Costs in Test Year			$1,660,768		$1,980,023	
15	Allocation Factor - PDAF			0.986		0.986	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$1,637,517		$1,952,303	$314,786

* Does Not Include PJM Administrative Costs

Witness: D. W. Bethel

Kentucky Power Company
Adjustment to Reflect RTO Formation Costs
Over a Fifteen Year Period
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Month / Year (2)	Test Year Amount (3)	Monthly Amortization Amount (4)	Adjustment Required (5) = (4) - (3)	Revised Forecasted Amount (6)	Adjusted Amount As Revised (7) = (6) - (3)	Difference (8)
1	Jul 04	$0	$12,761	$12,761	$10,134	$10,134	
2	Aug 04	$0	$12,793	$12,793	$10,134	$10,134	
3	Sep 04	$0	$13,242	$13,242	$10,134	$10,134	
4	Oct 04	$0	$13,601	$13,601	$10,134	$10,134	
5	Nov 04	$0	$13,735	$13,735	$10,134	$10,134	
6	Dec 04	$0	$13,924	$13,924	$10,134	$10,134	
7	Jan 05	$10,456	$13,695	$3,239	$10,134	($322)	
8	Feb 05	$10,259	$13,649	$3,390	$10,134	($125)	
9	Mar 05	$10,260	$13,719	$3,459	$10,134	($126)	
10	Apr 05	$10,261	$13,605	$3,344	$10,134	($127)	
11	May 05	$10,261	$13,553	$3,292	$10,134	($127)	
12	Jun 05	$10,597	$13,210	$2,613	$10,134	($463)	
13	Total	$62,094	$161,487	$99,393	$121,608		
14	Adj., Required to Reflect Amort. RTO Fromation Costs in Test Year			$99,393		$59,514	
15	Allocation Factor - GP-TRANS			0.986		0.986	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$98,001		$58,681	($39,320)

Witness: D. W. Bethel

Kentucky Power Company
Normalization of PJM Point to Point Transmission Revenues
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Month / Year (2)	Transmission Equalization Revenue Amount (3)	Adjusted Transmission Equalization Revenue Amount (4)	Adjustment Required (5) = (4) - (3)	Revised Forecasted Amount (6)	Adjusted Amount As Revised (7) = (6) - (3)	Difference (8)
1	Jul 04	$772,048	$49,156	($722,892)	$47,340	($724,708)	
2	Aug 04	$748,065	$38,840	($709,225)	$51,619	($696,446)	
3	Sep 04	$594,551	$37,109	($557,442)	$40,322	($554,229)	
4	Oct 04	$478,327	$33,068	($445,259)	$43,050	($435,277)	
5	Nov 04	$361,378	$35,970	($325,408)	$41,089	($320,289)	
6	Dec 04	$1,051,751	$32,565	($1,019,186)	$41,089	($1,010,662)	
7	Jan 05	$1,086,668	$51,292	($1,035,376)	$49,934	($1,036,734)	
8	Feb 05	$871,050	$33,495	($837,555)	$32,250	($838,800)	
9	Mar 05	$977,031	$36,998	($940,033)	$35,649	($941,382)	
10	Apr 05	$1,068,716	$34,013	($1,034,703)	$32,797	($1,035,919)	
11	May 05	$1,177,662	$38,170	($1,139,492)	$36,810	($1,140,852)	
12	Jun 05	$996,585	$39,785	($956,800)	$38,390	($958,195)	
13	Total	$10,183,832	$460,461		$490,339		
14	Adj., Required to Reflect Amort. RTO Fromation Costs in Test Year			($9,723,371)		($9,693,493)	
15	Allocation Factor - GP-TRANS			0.986		0.986	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			($9,587,244)		($9,557,784)	$29,460

Witness: D. W. Bethel

Kentucky Power Company
Prepayment of Pension Funding in Excess O&M Expense
Test Year Twelve Months Ended 06/30/2005

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Line No. (1)	Description (2)	Original Filed Amount (3)	Revised Amount (4)	Difference (5)
1	March 2005 Contribution	$3,045,764	$3,045,764	
2	June 2005 Contribution	$3,045,764	$3,045,764	
3	Total Contribution	$6,091,528	$6,091,528	
4A	Pension Funding Applicable to O&M (Ln 3 X 67.65%)	$4,120,919		
4B	Pension Funding Applicable to O&M (Ln 3 X 66.91%)		$4,075,841	
5	Allocation Factor - OML	0.991	0.991	
6	KPSC Jurisdictional Amount (Ln 4 X Ln 5)	$4,083,831	$4,039,158	($44,673)

Witness: E. K. Wagner

Kentucky Power Company
Normalization of PJM Administration Charges
Test Year Twelve Months Ended 06/30/2005

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LINE NO. (1)	Month / Year (2)	Test Year Amount (3)	2006 Monthly Forecast Amount (4)	Adjustment Required (5) = (4) - (3)	Revised 2006 Monthly Forecast Amount (6)	Revised Adjustment Required (7) = (6) - (3)	Difference (8)
1	Jul 04	$0	$294,154	$294,154	$287,934	$287,934	
2	Aug 04	$0	$294,154	$294,154	$287,934	$287,934	
3	Sep 04	$0	$294,154	$294,154	$287,934	$287,934	
4	Oct 04	$225,924	$294,154	$68,230	$287,934	$62,010	
5	Nov 04	$230,904	$294,154	$63,250	$287,934	$57,030	
6	Dec 04	$243,851	$294,154	$50,303	$287,934	$44,083	
7	Jan 05	$260,773	$294,154	$33,381	$287,934	$27,161	
8	Feb 05	$252,236	$294,154	$41,918	$287,934	$35,698	
9	Mar 05	$311,050	$294,154	($16,896)	$287,934	($23,116)	
10	Apr 05	$234,611	$294,154	$59,543	$287,934	$53,323	
11	May 05	$228,439	$294,154	$65,715	$287,934	$59,495	
12	Jun 05	$227,763	$294,154	$66,391	$287,934	$60,171	
13	Total	$2,215,551	$3,529,848		$3,455,208		
14	Adj., Required to Reflect Amort. RTO Fromation Costs in Test Year			$1,314,297		$1,239,657	
15	Allocation Factor - GP-TRANS			0.986		0.986	
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)			$1,295,897		$1,222,302	($73,595)

Kentucky Power Company
Change State Tax Rate from
7.20% to 6.25%

Section V
Workpaper S-4
Tax No. 1
Revised 02/02/06

Line No. (1)	DESCRIPTION (2)	Kentucky Jurisdiction As Filed at 7.20% Sch 10 (3)	Kentucky Jurisdiction Changed to 6.25% (4)	Difference (Col 4 - Col 3) (5)
1	State Income Tax	$1,030,001	$922,665	($107,336)
2	Federal Income Tax Payable	$4,668,094	$4,705,661	$37,567

3	Total Operating Expenses			($69,769)
				==========

Witness: E. K. Wagner

Kentucky Power Company
Adjusted Summary
Change in State Tax Rate
from 7.20% to 6.25%

Section V
Workpaper S-4
Tax No. 2
Revised 02/02/06

Line No. (1)	DESCRIPTION (2)	PSC Jurisdiction with Proposed Changes As Filed at 7.20% (3)	PSC Jurisdiction with Proposed Changes As Filed at 6.25% (4)	Difference (Col 4 - Col 3) (5)	
1	State Income Tax	($1,348,228)	($973,341)	$374,887	1/
2	Federal Income Tax Payable	($6,065,131)	($5,248,350)	$816,781	2/
3	Total Operating Expenses			$1,191,668	

Source:

Section V
Schedule 4
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	State Income Tax 1/	Federal Income Tax: Current 2/
Sch 7 & Sch 10 Adjustments Column 4	($107,336)	$37,567
02/02/06 Adjustments	189,600	942,933
ADJUSTMENTS FOR CHANGE IN KY INCOME TAX RATE FROM 7.20% TO 6.25%	292,623	(163,719)
Total	$374,887	$816,781

Witness: E. K. Wagner

Infrastructure Deployment Options
Kentucky Power Company – CATV

Option	Annual Cost Per Mile
1. Pole Attachment	CATV @ $164.75 (3-party) and $265.75 (2-party)
2. 30' Communications Pole	35 poles x $500/pole x 20% carrying charge = $3500
3. Underground service	5,280' x $1.50/foot x 20% carrying charge = $1584
4. Joint trench with electric	5,280' x $1.00/foot x 20% carrying charge = $1056

Notes:

1. **Assumes 25 40' poles required per mile for electric service (200' spans) and 35 30' poles/mile for CATVs**
2. **Installation costs for a 30' communication pole is $500**
3. **Underground direct bury cost of $1.50 per foot**
4. **Joint trench costs typically are based on shared trench costs that range from $1 - $6 per foot**
5. **Annual carrying charge rate for return on investment, depreciation, taxes and O&M assumed to be 20%**