COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	Case No. 2014-00396
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

KENTUCKY OFFICE OF ATTORNEY GENERAL

MARCH 23, 2015

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Appendix and Exhibits

Appendix A – Ralph C. Smith, Educational Background and Qualifications

I. STATEMENT OF QUALIFICATIONS

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan.[1] I am also a

[1] My testimony in this proceeding is as a Senior Regulatory Consultant, and I am not offering any legal opinions.

Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association. I have been a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"), and the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 35 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you previously testified before the Kentucky Public Service Commission ("PSC" or "Commission")?

A. Yes, in a Kentucky American Water Company rate case, Case No. 2010-00036.

Q. Have you previously performed analysis on rate case issues where testimony was submitted by other members of Larkin & Associates before the Kentucky Public Service Commission?

A. Yes. Several years ago, I worked on various Kentucky rate cases as a regulatory analyst where testimony was submitted before the Commission by other Larkin & Associates professionals, such as Hugh Larkin, Jr.

Q. Have you previously testified before other state public utility regulatory commissions?

A. Yes, I have testified before other state public utility regulatory commissions on many occasions.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Appendix A provides details concerning my experience and qualifications.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I have prepared Exhibits RCS-1 through RCS-29.

Q. Please briefly explain what is contained in each of those exhibits.

A. Exhibit RCS-1 presents Accounting and Revenue Requirement Schedules.

Exhibit RCS-2 presents a Revenue Requirement Schedule Associated with the Proposed Big Sandy Retirement Rider.

Exhibit RCS-3 presents a Revenue Requirement Schedule associated with the proposed Big Sandy Unit 1 Operation Rider.

Exhibit RCS-4 presents a Recalculation of proposed Revenue Requirement associated with the flue gas desulfurization system at the Mitchell Plant through the Environmental Surcharge.

Exhibit RCS-5 presents Kentucky Power's responses to data requests referenced in testimony related to the impact on Accumulated Deferred Income Taxes (a rate base offset) for 50 percent Bonus Tax Depreciation for 2014.

Exhibit RCS-6 presents Kentucky Power's responses to data requests referenced in testimony related to Contributions in Aid of Construction.

Exhibit RCS-7 presents Kentucky Power's responses to data requests referenced in testimony related to Cash Working Capital.

Exhibit RCS-8 presents Kentucky Power's responses to data requests referenced in testimony related to Commercial and Industrial Customer Revenue.

Exhibit RCS-9 presents Kentucky Power's responses to data requests referenced in testimony related to Amortization of Deferred IGCC Costs.

Exhibit RCS-10 presents Kentucky Power's responses to data requests referenced in testimony related to Amortization of Deferred CCS FEED Study Costs.

Exhibit RCS-11 presents Kentucky Power's responses to data requests referenced in testimony related to Amortization of Deferred CARRS Site Costs.

Exhibit RCS-12 presents Kentucky Power's responses to data requests referenced in testimony related to Amortization of Deferred Big Sandy FGD Costs.

Exhibit RCS-13 presents Kentucky Power's responses to data requests referenced in testimony related to Parent Company Loss Allocation.

Exhibit RCS-14 presents Kentucky Power's responses to data requests referenced in testimony related to Incentive Compensation.

Exhibit RCS-15 presents Kentucky Power's responses to data requests referenced in testimony related to Stock-Based Compensation.

Exhibit RCS-16 presents Kentucky Power's responses to data requests referenced in testimony related to Engage to Gain Program Costs.

Exhibit RCS-17 presents Kentucky Power's responses to data requests referenced in testimony related to PJM Charges and Credit Related to Big Sandy Unit 1.

Exhibit RCS-18 presents Kentucky Power's responses to data requests referenced in testimony related to Miscellaneous Expense.

Exhibit RCS-19 presents Kentucky Power's responses to data requests referenced in testimony related to Interest Synchronization and the Company's inadvertent omission of the Interest on Accounts Receivable Financing from the Interest Synchronization Calculation in a prior Company rate case.

Exhibit RCS-20 presents Kentucky Power's responses to data requests referenced in testimony related to Jurisdictional Capitalization.

Exhibit RCS-21 presents Kentucky Power's responses to data requests referenced in testimony related to the Big Sandy Unit 1 O&M Rider (BS1OR).

Exhibit RCS-22 presents Kentucky Power's responses to data requests referenced in testimony related to the Company's proposed Kentucky Economic Development Surcharge (KEDS).

Exhibit RCS-23 presents Kentucky Power's responses to data requests referenced in testimony related to the Company's Transmission Adjustment.

Exhibit RCS-24 presents information referenced in testimony related to the transfer of the 50 percent interest in Plant Mitchell and the Liability for Costs related to the Ash Pond.

Exhibit RCS-25 presents Kentucky Power's responses to data requests referenced in testimony related to Off System Sales Margins and the Sharing Ratio.

Exhibit RCS-26 presents Kentucky Power's responses to data requests referenced in testimony related to Affiliated Charges to Kentucky Power from AEP Generation Company for Rockport Unit Power Sale.

Exhibit RCS-27 presents Calculations of Test Year Billings to Kentucky Power from AEP Generation Company for Rockport Unit Power Sale and estimated savings from reducing return from 12.16 Percent.

Exhibit RCS-28 presents Invoice Pages Showing Affiliate Charges to Kentucky Power Kentucky Power from AEP Generation Company for Rockport Unit Power Sale

Exhibit RCS-29 presents Kentucky Power's response to data request AG 1-20 concerning Mitchell Plant maintenance expense normalization.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. Please discuss the Stipulation and Settlement Agreement dated July 2, 2013 as background for Kentucky Power Company's current rate case.

A. Pursuant to a Stipulation and Settlement Agreement ("Stipulation") dated July 2, 2013, between Kentucky Power Company ("Kentucky Power", "KPCo", or "Company"), Kentucky Industrial Utility Customers, Inc. ("KIUC") and the Sierra Club, and which was approved with modifications by the Commission in its Order dated October 7, 2013, in Case No. 2012-00578, KPCo acquired an undivided 50 percent interest in the Mitchell Generating Station ("Mitchell Transfer"), located in Moundsville, West Virginia, on December 31, 2013. On June 28, 2013, KPCo had filed base rate Case No. 2013-00197 in which the Company had requested full recovery through rates, the costs associated with the Mitchell Plant transfer during an interim period beginning January 1, 2014 and ending May 31, 2015[2]. However, under the terms of the Stipulation, on November 18, 2013, KPCo filed a motion to withdraw Case No. 2013-00197, which was granted by the

[2] January 1, 2014 was the effective date of the Mitchell Transfer and May 31, 2015 is the planned retirement date of Big Sandy Unit 2. Both of these events are discussed in further detail in a later section of this testimony.

Commission on November 22, 2013. In addition, as part of the Stipulation, the Company had agreed to re-file its base rate case no later than December 29, 2014 and to utilize the test year ended September 30, 2014.

Q. What amount of revenue increase is the Company requesting?

A. In reference to the aforementioned terms of the Stipulation, on December 23, 2014, KPCo filed its application in the current proceeding, which requested an increase in its base rates through the development of its revenue requirement as well as the implementation of several surcharges for electric utility service. Specifically, the Company calculated that the proposed adjustment to electric rates will result in an overall revenue increase of $69,977,002 over the test year adjusted revenues of $560,593,075, and resulting in total annual Company revenues of $630,570,077, for an increase of approximately 12.48%. These amounts reflect the Company's proposed transmission adjustment[3]. Absent the proposed transmission adjustment, the Company's annual revenue requirement would be $70,103,910, or an increase of 12.51%. KPCo's requested revenue increase is based on operating results for the 12-month period ended September 30, 2014, with adjustments and a proposed return on equity ("ROE") of 10.62%.

As noted above, the Company's requested revenue increase is predicated on its requested base rate revenue requirement as well as the following proposed surcharges:

- Big Sandy Retirement Rider
- Big Sandy Unit 1 Operation Rider
- Environmental Surcharge Related to Mitchell FGD

[3] As discussed in the Direct Testimony of Company witness Alex E. Vaughn, the embedded cost of transmission service and the PJM OATT transmission owner revenues would be removed from cost of service.

- Kentucky Economic Development Surcharge

In addition, the Company is proposing that its transmission costs should be based on charges it incurs as a load serving entity ("LSE") under PJM's Open Access Transmission Tariff ("OATT"). According to KPCo, the net effect of this proposed treatment results in a $126,908 reduction of transmission costs to ratepayers, which is reflected in the Company's overall requested revenue increase.

The table below provides a summary of the six components that comprise the Company's requested revenue increase:

Description	Combined Amount
Base Revenue Decrease	$ (4,696,331)
Big Sandy Retirement Rider	$ 21,855,982
Big Sandy Unit 1 Operation Rider	$ 18,245,413
Environmental Surcharge Related to Mitchell FGD	$ 34,391,339
Kentucky Economic Development Surcharge	$ 307,506
Transmission Adjustment from CCOS Study	$ (126,908)
Total Requested Increase	$ 69,977,002

I discuss each of the proposed surcharges and the transmission adjustment in further detail in later sections of my testimony.

Q. What is the purpose and scope of your testimony?

A. Larkin & Associates was engaged by the Office of Rate Intervention of the Kentucky Office of Attorney General (“AG”) to conduct a review and analysis and present testimony regarding rate base, operating income and revenue requirement aspects of the filing.

The purpose of my testimony is to present to the PSC the appropriate test period rate base, overall rate of return and utility operating income, as well as the appropriate overall revenue requirement and rate increase for the Company in this proceeding.

In the determination of the AG's recommended overall revenue requirement and revenue increase, I have relied on and incorporated the recommendations of AG witness Dr. J. Randall Woolridge concerning the appropriate capital structure ratios, cost rates for short and long term debt, and common equity, and the resulting overall rate of return for the Company in this proceeding.

In developing this testimony, I have reviewed and analyzed the Company's December 23, 2014 filing, supporting testimonies, exhibits, filing requirements and workpapers; the Company's responses to initial and follow-up data requests by the PSC Staff, AG and other intervenors; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. Please summarize your findings and conclusions in this case.

A. I have reached the following findings and conclusions in this case:

1. The appropriate jurisdictional capitalization in this proceeding amounts to $1.124 billion, which is approximately $23.4 million lower than the Company's proposed capitalization of $1.147 billion, as shown on Exhibit RCS-1, Schedule A, line 1 and on Schedule D.

2. The appropriate jurisdictional test period rate base amounts to approximately $1.134 billion, which is approximately $24.1 million lower than the Company's proposed test period rate base of $1.158 billion, as shown on Exhibit RCS-1, Schedule B, line 21.

3. The AG's expert rate of return witness, Dr. Woolridge, has recommended a return on equity of 8.65%, and an overall rate of return of 6.63%. In contrast, KPCo has requested an overall rate of return of 7.71%, including a return on equity of 10.62%, as shown on Exhibit RCS-1, Schedule A, line 2 and on Schedule D.

4. The appropriate test period utility operating income amounts to approximately $95.5 million, which is approximately $4.2 million higher than the Company's proposed test period utility operating income of $91.3 million, as shown on Exhibit RCS-1, Schedule A, line 4 and on Schedule C.

5. To calculate the base rate revenue increase, I used a gross revenue conversion factor ("GRCF") of 1.6402, which is the same factor used by KPCo, as shown on Exhibit RCS-1, Schedule A-1.

6. The application of the recommended overall rate of return of 6.63% to the recommended capitalization of approximately $1.124 billion produces a required return of approximately $74.6 million, as shown on Exhibit RCS-1, Schedule A, column B, line 3. Compared to the adjusted net operating income of approximately $95.5 million, this represents a sufficiency of approximately $20.9 million, as shown on Exhibit RCS-1, Schedule A, column B, line 5. Applying the GRCF of 1.6402 indicates that the Company has an annual base rate revenue requirement excess of approximately $34.3 million, as shown on Exhibit RCS-1, Schedule A, column B, line 7. As shown on Exhibit RCS-1, Schedule A, column C, line 7, this represents a difference of approximately $29.6 million versus the Company's proposed annual base rate revenue sufficiency of $4.7 million.

7. For the Big Sandy Retirement Rider, as shown on Exhibit RCS-1, Schedule A, column B, line 8, I recommend an initial revenue requirement of $11.1 million versus the

approximately $21.9 million requested by KPCo. Additional details are discussed in Section IX of my testimony and as shown on Exhibit RCS-2.

8. For the Big Sandy Unit 1 Operation Rider, as shown on Exhibit RCS-1, Schedule A, column B, line 9, I recommend a revenue requirement of $12.6 million versus the approximately $18.2 million requested by KPCo. Additional details are discussed in Section X of my testimony and as shown on Exhibit RCS-3.

9. For the Environmental Surcharge Related to the Mitchell FGD, as shown on Exhibit RCS-1, Schedule A, column B, line 10, I recommend a revenue requirement of $31.1 million versus the approximately $34.4 million requested by KPCo. Additional details are discussed in Section XI of my testimony and as shown on Exhibit RCS-4.

10. I recommend rejection of KPCo's requested Kentucky Economic Development Surcharge. As shown on Exhibit RCS-1, Schedule A, column B, line 11, the $307,506 requested by KPCo for this Rider have been removed, as discussed in Section XII of my testimony.

11. KPCo's proposed reduction of $126,908 for a transmission adjustment is removed, and KPCo's transmission costs remain in base rates, as discussed in Section XIII of my testimony.

12. The total base rate and surcharge revenue increases of approximately $20.5 million is an overall increase of 3.64 percent over adjusted revenue at current rates of approximately $561.6 million, as shown on Exhibit RCS-1, Schedule A, lines 13-16.

13. The off-systems sales margin sharing should be adjusted to 90%/10% ratepayers/KPCo, as described in Section XV of my testimony.

14. Safeguards to protect Kentucky ratepayers should be placed upon KPCo's Vegetation Management expenditures, including annual reporting, and tracking in a one-way balancing account, as described in Section XVI of my testimony.

15. The Rockport Plant Unit Power Sales Agreement is an affiliated contract between KPCo and AEP Generating Company, with a 12.16 percent return on equity that, on its face, appears excessive, and should be challenged at FERC, as described in Section XVII of my testimony.

IV. ORGANIZATION OF ACCOUNTING SCHEDULES FOR BASE RATE REVENUE REQUIREMENT (EXHIBIT RCS-1)

Q. How are the AG's accounting schedules organized?

A. The AG's accounting schedules used to determine KPCo's base rate revenue requirement are presented in Exhibit RCS-1. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Exhibit RCS-1 also contains rate base adjustment Schedules B-1 through B-3 and net operating income adjustment Schedules C-1 through C-13.

Q. What is shown on Schedule A, page 1, of Exhibit RCS-1?

A. Exhibit RCS-1 presents the AG Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn the AG's recommended rate of return on the adjusted rate base. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on rate base of 6.63 percent, as presented in the direct testimony of AG witness Woolridge, is provided on Exhibit RCS-1, Schedule D for convenience.

Column A of Schedule A replicates KPCo's proposed calculations of its overall revenue deficiency, consisting of (1) the base rate revenue sufficiency; (2) the revenue requirement for each of the Company's proposed surcharges; and (3) the Company's proposed treatment of transmission revenues and expenses in base rates. Column B of Schedule A presents the AG's determination of the base rate revenue sufficiency, the revenue requirement for each Company-proposed surcharge and the transmission adjustment. Column C shows the differences between KPCo's request and the AG's recommendation.

The operating income sufficiency shown on line 5 of Schedule A is obtained by subtracting the adjusted operating income on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income sufficiency by the GRCF.

Q. What is shown on Exhibit RCS-1, Schedule A, page 2?

A. Exhibit RCS-1, Schedule A, page 2, presents a reconciliation of the base rate revenue requirement and shows the approximate impact of each adjustment.

Q. What is shown on Schedule A-1 of Exhibit RCS-1?

A. Schedule A-1 shows the GRCF that I used to convert the net operating income sufficiency into a revenue sufficiency amount. For purposes of this case, I used the same GRCF that was used in KPCo's filing.

Q. What is shown on Exhibit RCS-1, Schedule B, page 1?

A. Schedule B presents KPCo's proposed adjusted test year rate base and the AG's proposed adjusted test year rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically Section V, Exhibit 1, Schedule 4. My recommended adjustments to rate base are summarized on Schedule B.1, and are shown on Schedule B, page 1, column B. My adjusted rate base for KPCo is shown on Schedule B, page 1, column C.

Q. What is shown on Exhibit RCS-1, Schedule B, page 2?

A. Exhibit RCS-1, Schedule B, page 2, replicates the Company's reconciliation of its proposed rate base and jurisdictional capitalization that was used to determine its proposed revenue requirement[4].

Q. What is shown on Schedule B.1 and Schedules B-1 through B-3?

A. Exhibit RCS-1, Schedule B.1 presents a summary of recommended rate base adjustments. Schedules B-1 through B-3 provide further support and calculations for the rate base adjustments I am recommending.

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[4] KPCo presented this reconciliation in Filing Requirement 807 KAR 5:001, Section 16 (4)(i) from Section II of its Application.

Q. What is shown on Exhibit RCS-1, Schedule C?

A. The starting point on Schedule C is KPCo's adjusted test year net operating income, as provided on Schedule 1 from Section V, Exhibit 1 from the Company's filing. My recommended adjustments to KPCo's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments is discussed in my testimony.

Schedules C-1 through C-13 provide further support and calculations for the net operating income adjustments I am recommending.

Q. What is shown on Exhibit RCS-1, Schedule D?

A. Schedule D, page 1, summarizes the capital structure and cost of capital that is being proposed by KPCo and the capital structure and cost of capital that is recommended by AG witness Woolridge. Schedule D also shows, in column E, the GRCFs reflected on Company Exhibit AJE-5 that the Company used to calculate the pre-tax weighted average cost of capital ("WACC") in its proposed revenue requirement related to the Mitchell FGD costs, which KPCo proposes to recover through the Environmental Surcharge. Column F of Schedule D reflects the Company's proposed pre-tax WACC, which included using its requested ROE of 10.62% as well as the AG's proposed pre-tax WACC using AG witness Woolridge's recommended capital structure and his recommended ROE of 8.65%.

Q. What is shown on Schedule D, pages 2 and 3?

A. Schedule D, page 2, replicates the Company's calculation of its proposed jurisdictional capitalization.[5] Schedule D, page 3, also presents the derivation of the AG's adjusted

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[5] KPCo's proposed jurisdictional capitalization is reflected in Section V, Exhibit 1, Schedule 3 from its filing.

capitalization for the same items without the negative short term debt that KPCo proposes. Page 3 of Schedule D reflects the impacts of my recommended rate base adjustments on the Company's jurisdictional capitalization.

V. OTHER EXHIBITS

Q. What is shown on Exhibit RCS-2?

A. Exhibit RCS-2 is a schedule which reflects the calculation of the Company's proposed revenue requirement associated with its proposed Big Sandy Retirement Rider ("BSRR"). In addition, this exhibit reflects my recommended adjustments to the BSRR as well as my overall adjusted initial BSRR revenue requirement.

Q. What is shown on Exhibit RCS-3?

A. Exhibit RCS-3 is a schedule which reflects the calculation of the Company's proposed revenue requirement associated with its proposed Big Sandy Unit 1 Operation Rider ("BS1OR"). In addition, this exhibit reflects my recommended adjustments to the BS1OR as well as my overall adjusted BS1OR revenue requirement.

Q. What is shown on Exhibit RCS-4?

A. Exhibit RCS-4 is a schedule which reflects my re-calculation of the Company's proposed revenue requirement that is associated with collecting the capital and O&M costs associated with the flue gas desulfurization ("FGD") system at the Mitchell Plant through the Environmental Surcharge using the WACC that is calculated by incorporating AG witness Woolridge's recommended capital structure and his recommended ROE of 8.65%.

Q. Should the revised cost of capital rate that the Commission finds appropriate in this case also be applied to the Company's Environmental Surcharge?

A. Yes. In this base rate case, the Company's cost of capital is being determined based upon all relevant information known at this time. Consequently, the same ROE that the Commission authorizes in the current KPCo rate case should also be applied for purposes of determining the charges under KPCo's Environmental Surcharge.

Q. What is shown on Exhibit RCS-5?

A. Exhibit RCS-5 includes KPCo’s responses to discovery referenced in my testimony related to the issue of Accumulated Deferred Income Taxes and the 50% Bonus Depreciation that was extended in December 2014 to apply to tax year 2014.

Q. What is shown on Exhibit RCS-6?

A. Exhibit RCS-6 includes KPCo’s responses to discovery referenced in my testimony related to the issue of Contributions in Aid of Construction.

Q. What is shown on Exhibit RCS-7?

A. Exhibit RCS-7 includes KPCo’s responses to discovery referenced in my testimony related to the issue of Cash Working Capital.

Q. What is shown on Exhibit RCS-8?

A. Exhibit RCS-8 includes KPCo's responses to discovery referenced in my testimony related to the issue of known changes in Commercial and Industrial Customer Revenue.

Q. What is shown on Exhibit RCS-9?

A. Exhibit RCS-9 includes KPCo's responses to discovery referenced in my testimony related to the issue of Amortization of Deferred IGCC Costs.

Q. What is shown on Exhibit RCS-10?

A. Exhibit RCS-10 includes KPCo's responses to discovery referenced in my testimony related to the issue of Amortization of Deferred CCS FEED Study Costs.

Q. What is shown on Exhibit RCS-11?

A. Exhibit RCS-11 includes KPCo's responses to discovery referenced in my testimony related to the issue of Amortization of Deferred CARRS Site Costs.

Q. What is shown on Exhibit RCS-12?

A. Exhibit RCS-12 includes KPCo's responses to discovery referenced in my testimony related to the issue of Amortization of Deferred Big Sandy FGD Costs.

Q. What is shown on Exhibit RCS-13?

A. Exhibit RCS-13 includes KPCo's responses to discovery referenced in my testimony related to the issue of Income Tax Expense savings related to the Parent Company Loss Allocation.

Q. What is shown on Exhibit RCS-14?

A. Exhibit RCS-14 includes KPCo's responses to discovery referenced in my testimony related to the issue of Incentive Compensation.

Q. What is shown on Exhibit RCS-15?

A. Exhibit RCS-15 includes KPCo's responses to discovery referenced in my testimony related to the issue of Stock-Based Compensation.

Q. What is shown on Exhibit RCS-16?

A. Exhibit RCS-16 includes KPCo's responses to discovery referenced in my testimony related to the issue of Engage to Gain Program Costs.

Q. What is shown on Exhibit RCS-17?

A. Exhibit RCS-17 includes KPCo's responses to discovery referenced in my testimony related to the issue of PJM Charges and Credits related to Big Sandy Unit 1.

Q. What is shown on Exhibit RCS-18?

A. Exhibit RCS-18 includes KPCo's responses to discovery referenced in my testimony related to the issue of Miscellaneous Expenses.

Q. What is shown on Exhibit RCS-19?

A. Exhibit RCS-19 includes KPCo’s response to discovery referenced in my testimony related to the issue of Interest Synchronization and the Company's inadvertent omission of the Interest on Accounts Receivable Financing from the Interest Synchronization Calculation in a prior Company rate case.

Q. What is shown on Exhibit RCS-20?

A. Exhibit RCS-20 includes KPCo’s responses to discovery referenced in my testimony related to the issue of Jurisdictional Capitalization.

Q. What is shown on Exhibit RCS-21?

A. Exhibit RCS-21 includes KPCo’s responses to discovery referenced in my testimony related to the issue of the Big Sandy Unit 1 O&M Expense Rider (BS1OR).

Q. What is shown on Exhibit RCS-22?

A. Exhibit RCS-22 includes KPCo’s responses to discovery referenced in my testimony related to the issue of the Company's proposed Kentucky Economic Development Surcharge.

Q. What is shown on Exhibit RCS-23?

A. Exhibit RCS-23 includes KPCo’s responses to discovery referenced in my testimony related to the issue of the Company's proposed Transmission Adjustment.

Q. What is shown on Exhibit RCS-24?

A. Exhibit RCS-24 presents information referenced in my testimony related to the issue of Mitchell Transfer/Ash Pond Costs.

Q. What is shown on Exhibit RCS-25?

A. Exhibit RCS-25 includes KPCo's responses to discovery referenced in my testimony related to the issue of Off System Sales Margin Sharing.

Q. What is shown on Exhibit RCS-26?

A. Exhibit RCS-26 includes KPCo's responses to discovery referenced in my testimony related to the issue of the affiliated company charges to KPCo related to the Rockport Plant Unit Power Sales Agreement.

Q. What is shown on Exhibit RCS-27?

A. Exhibit RCS-27 presents a summary of the affiliated charges to KPCo from AEP Generating Company for the 12 months ending September 30, 2014 related to the Rockport Unit Power Sales Agreement dated October 1, 1984 (As Amended), including the charges to KPCo related to the12.16 percent ROE provided for in that affiliated contract, and the potential savings that could result from reducing that affiliate-charged ROE.

Q. What is shown on Exhibit RCS-28?

A. Exhibit RCS-28 presents information concerning the affiliated charges to KPCo from AEP Generating Company for the 12 months ending September 30, 2014 related to the

Rockport Unit Power Sale Agreement based on excerpts from the AEP Generating Company invoices to KPCo for the twelve months ending September 30, 2014.

Q. What is shown on Exhibit RCS-29?

A. Exhibit RCS-29 includes KPCo's responses to discovery referenced in my testimony related to the issue of Mitchell Plant Maintenance Expense Normalization.

VI. JURISDICTIONAL CAPITALIZATION

Q. Have you prepared a schedule that summarizes the AG's recommended adjustments to KPCo's jurisdictional capitalization?

A. Yes. Exhibit RCS-1, Schedule D, pages 2 and 3 summarize the AG's adjustments to the Company's jurisdictional capitalization.

Q. Does the Company have short term debt at September 30, 2014, the end of the test year?

A. No, the Company's per book balances from Section V, Exhibit 1, Schedule 3, of its filing show that the Company has zero short term debt. The zero short term debt balance is also shown on Exhibit RCS-1, Schedule D, page 2, column A, line 2.

Q. Has KPCo attempted to include a <u>negative</u> balance for short term debt in its proposed capitalization?

A. Yes. KPCo has proposed a negative short-term debt balance for inclusion in its adjusted jurisdictional capitalization, as shown in the Company's filing at Section V, Exhibit 1, Schedule 3. The Company's proposed jurisdictional capitalization derivation is reproduced on Exhibit RCS-1, Schedule D, page 2, lines 1-7, and the Company's creation of the negative short-term debt balance is shown there on line 2.

Q. How did the Company produce a negative balance for short-term debt?

A. As shown on Exhibit RCS-1, Schedule D, page 2, column C, line 2, when the Company attempted to reflect the impact on its jurisdictional capitalization of its adjustment to remove Big Sandy Coal Stock, it put that adjustment on the line for Short Term Debt. This created a negative balance of short term debt in the Company's presentation. Then, as shown on Exhibit RCS-1, Schedule D, page 2, line 2, whenever the Company had other adjustments to its jurisdictional capitalization, it further adjusted the short term debt, ultimately getting the negative balance of short term debt up to $30.9 million.

Q. Has KPCo justified reflecting a <u>negative</u> balance for short term debt in its proposed capitalization?

A. No. KPCo has a zero balance for short term debt. KPCo has effectively created this **<u>negative</u>** balance for short term debt in its proposed capitalization by its attempt to reflect rate base adjustments, such as for Big Sandy Coal Inventory, by removing short-term debt amounts from its capitalization that did not exist. A negative balance for short term debt is unreasonable, and should not be permitted in this rate case.

Q. What capitalization was proposed by KPCo and by the AG in KPCo's 2005 rate case?

A. The following capitalization was proposed by KPCo and the AG in KPCo's 2005 rate case[6]:

KPC PROPOSED:

	Capitalization (1)	Ratios (1)	Cost Rates (1)	Weighted Cost Rates (1)
Long Term Debt	$ 482,392,123	56.55%	5.70%	3.22%
Short Term Debt	3,340,763	0.39%	3.34%	0.01%
A/R Financing	30,052,250	3.52%	2.99%	0.11%
Common Equity	337,297,815	39.54%	11.50%	4.55%
Total	$ 853,082,951	100.00%		7.89%

AG RECOMMENDED:

	Capitalization [Sch. RJH-3]	Ratios	Cost Rates (2)	Weighted Cost Rates
Long Term Debt	$ 479,249,392	56.66%	5.70%	3.23%
Short Term Debt	1,293,426	0.15%	3.34%	0.01%
A/R Financing	30,054,116	3.55%	2.99%	0.11%
Common Equity	335,163,238	39.63%	8.75%	3.47%
Total	$ 845,760,172	100.00%		6.81%

As shown in the above tables, the balance for short term debt was positive in both KPCo's proposed and the AG's recommended capitalization.

Q. What capitalization was used by the Commission in KPCo's 2005 rate case?

A. As summarized in Appendix C to the Commission's March 14, 2006 Order, the following capitalization was used:

[6] See Case No. 2005-00341, Testimony of Robert Henkes, Schedule RJH-2, which provided both KPCo's and the AG's recommended capitalization.

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2005-00341 DATED March 14, 2006.

Capital Structure and Weighted Average Cost of Capital

Component of Capitalization	Test-Year-End Per Book Balances	Capital Structure	Annual Cost Rate	Weighted Aver. Cost of Capital
Long-Term Debt	$487,716,122	57.43%	5.70%	3.27%
Short-Term Debt	0	0.00%	3.34%	0.00%
Accounts Receivable Financing	30,139,598	3.55%	2.99%	0.11%
Common Equity	331,354,481	39.02%	10.50%	4.10%
Totals	$849,210,201	100.00%		7.48%

Note: Test-Year-End Per Book Balances taken from the Application, Section V, Schedule 3.

As indicated in the Appendix C note, the capitalization used was based on the end of test period per book balances, which reflected a zero balance from short term debt.

Q. Does it make sense to have either a positive short term debt balance or a zero short term debt balance in the utility's capitalization?

A. Yes. A positive balance makes sense if short-term debt is being used to finance a portion of the assets which are used and useful in providing utility service and which are included in rate base. A zero balance would make sense if the utility does not have short term debt, and thus there would be no short term debt use for financing the utility's rate base.

Q. Is it reasonable to have a negative short term debt in a utility's capital structure or jurisdictional capitalization?

A. No, in my professional opinion, it is not. The AG's cost of capital witness, Dr. Randall Woolridge, has reached a similar conclusion. For purposes of determining the utility's capital structure and capitalization, either the utility has a positive balance of short term debt or it has a zero balance.

Q. How would a negative balance for short term debt be affecting the Company's revenue requirement?

A. Having a negative balance for short term debt included in the Company's jurisdictional capitalization would be similar to having a bank savings account that is earning a very low rate of interest - in this case 0.25% - be credited against the revenue requirement while charging ratepayers for higher amounts of the other capitalization components, each of which carries a cost rate that is much higher than the 0.25%. In short, including a negative balance for short term debt in the Company's capitalization is both unreasonable and a way to increase the revenue requirement by overstating the cost of capital.

Q. How have you reflected the impact of rate base adjustments on KPCo's jurisdictional capitalization?

A. As shown on Exhibit RCS-1, Schedule D, page 2, lines 8-14, each rate base adjustment has been reflected proportionally to the Company's per-book balances of long-term debt and common equity. This results in maintaining the per-book balance of the Accounts Receivable Financing, and also maintains the short-term debt balance at zero. The same approach was used for the impact on jurisdictional capitalization for the rate base adjustments I am recommending, as shown on Exhibit RCS-1, Schedule D, page 3.

VII. RATE BASE

Q. What adjustments are you recommending to KPCo's requested rate base?

A. I am recommending three adjustments to KPCo's rate base, as discussed below.

B-1, Accumulated Deferred Income Taxes – 2014 Bonus Tax Depreciation

Q. Please discuss the extension of 50% bonus tax depreciation for calendar year 2014.

A. House Bill H.R. 5771 was introduced to Congress on December 1, 2014 and on December 19, 2014, President Obama signed the Tax Increase Prevention Act of 2014 ("TIPA") into law. Section 125 of the TIPA addresses the extension of bonus depreciation whereby property acquired and placed into service during 2014 is eligible for 50% bonus depreciation retroactive to the beginning of calendar year 2014.

Q. Please briefly explain the circumstances which led to the Company's Application being filed in the instant proceeding.

A. Pursuant to the Stipulation dated July 2, 2013 in Case No. 2012-00578, which was approved by the Commission in its Order dated October 7, 2013, the Company agreed to file its base rate proceeding no later than December 29, 2014, which reflected the test year ended September 30, 2014. KPCo officially filed its Application for a base rate increase on December 23, 2014.

Q. Does the Company's filing reflect the impacts of 2014 50% bonus depreciation in its test year accumulated deferred income taxes ("ADIT")?

A. No. In response to KIUC 1-28, the Company stated that it did not consider the extension of 50% bonus depreciation into 2014 or later years.

Q. Was the Company's omission of the impacts of 2014 bonus depreciation from its filing merely a matter of timing?

A. It appears so. In response to KIUC 1-30, which asked KPCo to confirm that it agrees that the additional ADIT resulting from extension of bonus depreciation should be reflected as an adjustment to its filing, the Company stated:

> If the retroactive 50% bonus depreciation extension had been signed into law in time to include it in the rate filing, the Company would have included its impacts on the ADIT balances as of September 30, 2014.

Q. Has the Company quantified what the impact of the 2014 bonus depreciation would be on test year ADIT?

A. Yes. In response to KIUC 1-29, KPCo stated that it estimates that it would have recorded an additional $23.6 million of ADIT through September 2014 had the retroactive 50% bonus depreciation been enacted during the test year, or had been a known and measurable change at the time of filing its Application. In addition, in response to KPSC 3-50, KPCo provided updated income tax workpapers which reflected the impacts of the 50% bonus depreciation.

Q. Has KPCo confirmed that test year ADIT should be increased by the $23.6 million in order to reflect the impacts associated with the 2014 bonus depreciation?

A. Yes. In response to AG 2-79, KPCo confirmed that test year ADIT should be increased by the $23.6 million to reflect the impacts associated with the passage of the TIPA.

Q. Are you recommending an adjustment to increase ADIT in order to reflect the impact of the 50% bonus depreciation on the Company's rate base?

A. Yes. As shown on Exhibit RCS-1, Schedule B-1, I have reflected the $23.6 million increase to ADIT, which results in a reduction to rate base in the amount of $23.3 million on a Kentucky jurisdictional basis. In addition, I have allocated the $23.3 million ratably between the Company's long-term debt and common equity, thus reducing KPCo's capitalization as shown on Exhibit RCS-1, Schedule D, page 3.

B-2, Contributions in Aid of Construction

Q. Please explain AG Adjustment B-2.

A. This adjustment corrects an error in the Company's filing. Specifically, data request AG 2-51 asked the Company whether Contributions in Aid of Construction ("CIAC") collected during the test year, was reflected as a rate base deduction in its filing. In response, the Company stated that the CIAC collected during the test year totaled $947,995. However, of this amount, only $909,674 was reflected as a rate base deduction in Accounts 101 - Plant-in-Service and 107 - Construction Work in Progress ("CWIP"). KPCo stated that the $38,321 difference was recorded in Account No. 253 - Deferred Credits and was not reflected as a rate base deduction. Furthermore, the Company stated that not reflecting the $38,321 as a rate base reduction was an oversight. Therefore, I have made an adjustment to reflect the remaining $38,321 as a reduction to rate base. As shown Exhibit RCS-1, Schedule B-2, this adjustment reduces rate base by $37,899 on a Kentucky jurisdictional basis. In addition, I have allocated the $37,899 ratably between the Company's long-term debt and common equity, thus reducing KPCo's capitalization as shown on Exhibit RCS-1, Schedule D, page 3.

B-3, Cash Working Capital

Q. What is Cash Working Capital ("CWC")?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company’s cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when cash expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is an increase to rate base as ratepayers are essentially supplying these funds.

Q. How has KPCo determined CWC?

A. KPCo has determined its proposed test year CWC requirement of $43.6 million using the "1/8th formula" method. By using this method, the Company assumes that 1/8th of the going-level O&M expenses reflects a reasonable level of cash working capital.

Q. Do you agree with the Company's use of the "1/8th Formula" method in its determination of going-level CWC?

A. No, I do not. In my opinion, an accurate level of a utility's CWC can only be obtained through the use of a detailed lead-lag study. However, it is my understanding that the Commission has established a long-standing precedent whereby a utility's CWC can be calculated using the 1/8th formula. Therefore, I am not challenging the method by which the Company has calculated CWC in this proceeding.

Q. Although you are not challenging the Company's use of the 1/8th formula in its CWC determination, have you made any adjustments to KPCo's CWC requirement?

A. Yes. As shown on Exhibit RCS-1, Schedule B-3, I have reflected the impacts of my adjustments to O&M expenses to KPCo's CWC requirement. Specifically, reflecting the impact of my recommended adjustments to KPCo's operating expenses would reduce KPCo's CWC allowance to $42.8 million, which is about $726,000 lower than KPCo's proposed CWC requirement of $43.6 million.

Q. Do you have any other comments regarding the Company's CWC requirement?

A. Yes. If CWC is to be calculated using the 1/8th formula, then the proper level of CWC reflected for ratemaking purposes should ultimately be based on the pro forma O&M expenses allowed by the Commission versus the $43.6 million proposed by the Company in this proceeding.

Q. Has your adjustment to CWC impacted the base rate revenue requirement?

A. No. Since KPCo's revenue requirement is calculated based upon the Company's jurisdictional capitalization rather than its adjusted jurisdictional rate base, it appears that my recommended adjustments to CWC would have no impact on KPCo's revenue requirement. In its response to AG 2-110, which asked KPCo to explain the criteria by which an adjustment to rate base results in a corresponding capitalization adjustment, the Company stated:

> With the exception of adjustments for cash working capital, the Company generally adjusts capitalization for rate base adjustments. For example, the exclusion of non-utility property and adjustments to coal stock. With respect to rate base adjustments for cash working capital, the Company has consistently not adjusted capitalization as a conservative approach that those funds are already included in our total capitalization. If the Company were to adjust capitalization for cash working capital, it would most of the time increase the level of capitalization.

Based on the foregoing passage from AG 2-110, I have reflected my CWC adjustments for illustrative purposes on Exhibit RCS-1, Schedule B-3, but have not reflected the reduction in CWC as a reduction to KPCo's jurisdictional capitalization on Exhibit RCS-1, Schedule D, page 3.

VIII. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized the AG's proposed adjustments to operating income.

A. Schedule C summarizes the AG's recommended net operating income. Schedule C.1 presents the AG's recommended adjustments to test year revenues and expenses. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income is also reflected on Schedule C.1. KPCo's proposed adjusted test year net operating income is $91.3 million, whereas the AG's recommended adjusted net operating income is $95.5 million, as shown on Exhibit RCS-1, Schedule C, line 16. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1, Commercial and Industrial Revenue

Q. Please explain the AG's inquiry with respect to commercial and industrial customers.

A. The AG had requested whether any of KPCo's commercial and/or industrial customers had informed the Company about expanding operations or increasing electricity purchases since September 30, 2014. In response to AG 1-331, KPCo provided a list which summarized actual and anticipated expansions, reductions, or closures from certain of the Company's commercial and industrial customers as well as the actual or anticipated effective date of each such expansion, reduction, or closure. As part of its response to AG 1-331, the Company stated:

> The attached list includes information from customers who have informed the Company of plans to expand operations. The additional load may or may not actually materialize on the effective date. Because of the advanced start date, the specific rate code has not been determined yet, so it is not possible to provide the amount of revenue associated with each project.

Q. Have any of the effective dates related to the commercial and industrial customer expansions, reductions and closures already occurred?

A. Yes. As previously noted, the attachment provided with the response to AG 1-331 included the actual or anticipated effective date of each project listed. Of the 14 projects included on the list, nine projects had effective dates occurring in 2014 and three other projects had effective dates occurring between January 1 and March 1, 2015. The two remaining projects listed anticipated effective dates of June 1, 2015 and January 1, 2016.

Q. Since the effective dates of the majority of the projects listed in AG 1-331 have already occurred, did you request that KPCo provide additional information related to these projects?

A. Yes. Since the effective dates for the majority of these projects have already occurred, I requested that KPCo provide its best estimates for the increased and decreased revenues associated with each project, depending on whether the project has been expanded, reduced, or closed. In response to AG 2-112, the Company provided a list similar to the one previously provided, but updated it to include the tariff rate code and estimated monthly revenue change associated with each project. For those projects in which the effective date has already occurred, such monthly revenues netted to $88,636. The estimated monthly revenues for the two projects with anticipated effective dates in the future totaled $50,485.

Q. Please explain your adjustment on Exhibit RCS-1, Schedule C-1.

A. Since the majority of the projects have already occurred, based on the effective dates provided, such amounts are known and measurable. Therefore, as shown on Exhibit RCS-1, Schedule C-1, I have taken the total estimated monthly revenues of $88,636 related to those projects for which the effective date has already occurred, and then annualized that amount, resulting in annual revenues totaling $1,063,638. I then applied the operating revenue related Kentucky jurisdictional factor to this amount which results in an increase to Kentucky jurisdictional revenue of $1,051,938.

C-2, Amortization of Deferred IGCC Costs

Q. Please explain the issue associated with deferred IGCC costs and the Company's proposed treatment of such costs.

A. As discussed in the Direct Testimony of Company witness Wohnhas, the Company incurred preliminary engineering and development costs related to the potential construction and operation of an integrated gasification combined cycle ("IGCC") generation facility. A feasibility study was conducted and this study was the basis for whether the Kentucky General Assembly would adopt legislation that would support recovery of the proposed IGCC facility's costs through rates. However, the General Assembly failed to adopt such legislation, at which time, the proposed IGCC facility became uneconomic to construct. In the instant proceeding, the Company is proposing to recover the IGCC related preliminary engineering and development costs, which total $1,331,254, by amortizing such costs over a 25 year period, or an increase to O&M expense of $52,505 on a Kentucky jurisdictional basis.

Q. Did the Company explain why the Kentucky General Assembly failed to adopt legislation which would have supported recovery of the IGCC related costs through base rates?

A. No. In response to AG 1-302, the Company stated that it cannot speculate as to why the General Assembly failed to adopt such legislation.

Q. Did KPCo provide information related to whether other jurisdictions have addressed the ratemaking treatment associated with IGCC costs?

A. Yes. In response to AG 1-301, KPCo cited the following proceedings in other jurisdictions:

- In Case No. 05-00376-EL-UNC, the Public Utilities Commission of Ohio ("PUCO") approved a surcharge to collect the preconstruction costs associated with an IGCC plant. However, this case is pending before the PUCO pursuant to a remand from the Ohio Supreme Court.

- On March 6, 2008, the Public Service Commission of West Virginia granted Appalachian Power Company ("APCo") a CPCN to construct an IGCC facility pursuant to Case No. 06-0033-E-CN. In Case No. 14-1152-E-42T, APCo currently has a case pending before the Public Service Commission of West Virginia in which it is seeking recovery of the costs associated with the FEED study.

- In Case No. PUE-2014-00026, the Virginia State Corporation Commission issued an Order dated November 26, 2014, in which it rejected APCo's request to amortize and recover IGCC study costs.

In addition, KPCo stated that it is unaware of any prior KPSC Orders addressing the ratemaking treatment associated with IGCC costs.

Q. Do you believe that Kentucky ratepayers should be responsible for costs associated with a facility that was never constructed and therefore not used and useful in the provision of electric service?

A. No. The Company has not constructed an IGCC facility and these costs are not related to an asset that is used and useful in the provision of electric service to Kentucky ratepayers.

Therefore, the Company's proposed amortization should be rejected. These costs should be written off by KPCo as not allowable.

Q. Please explain the adjustment to remove the deferred IGCC cost amortization from O&M expense.

A. As shown on Exhibit RCS-1, Schedule C-2, I have removed the Company's proposed amortization of $52,505 from operating expenses.

C-3, Amortization of Deferred CCS FEED Study Costs

Q. Please explain the issue associated with deferred CCS FEED study costs and the Company's proposed treatment of such costs.

A. As discussed in the Direct Testimony of Company witness Wohnhas, as part of an investigation to address environmental regulations, American Electric Power ("AEP")[7] conducted a carbon capture and sequestration ("CCS") study at its Mountaineer generation station located in West Virginia. AEP allocated the costs of this study among each of its operating companies with coal-fired generation, including KPCo based on the notion that each such operating company would benefit from the study. In the instant proceeding, the Company is proposing to recover the CCS FEED study costs allocated to KPCo, which total $872,858, by amortizing such costs over a 25 year period, or an increase to O&M expense of $34,425 on a Kentucky jurisdictional basis.

Q. What were the results and/or conclusions of AEP's CCS FEED study?

[7] AEP is KPCo's parent company.

A. KPCo provided a copy of AEP's CCS FEED study report dated January 30, 2012 in response to AG 1-304. As stated in the Abstract section of AEP's report, the report was based on the preliminary design information that was developed during Phase I - Project Definition Stage and covered the period February 1, 2010 through September 30, 2011. The Executive Summary indicates that AEP had originally planned to conduct the CCS FEED study in three additional phases, including Phase II - Detailed Engineering/Design & Permitting; Phase III - Construction and Start-Up; and Phase IV - Operations. However, AEP stated in part the following:

> As the commercial scale project was drawing near to the end of Phase I, AEP communicated to the DOE its plans to dissolve the existing cooperative agreement and postpone project activities following the completion of Phase I.

As indicated in the above passage, AEP did not complete the remaining three phases of the CCS FEED study.

Q. What is the Company's reasoning for why Kentucky ratepayers should be responsible for costs associated with a study performed at the Mountaineer generating station in West Virginia?

A. In response to AG 1-304, the Company stated that although the CCS FEED study was performed at the Mountaineer facility, the study could benefit any of the AEP companies that own coal-fired generating capacity and because KPCo owns such facilities, AEP allocated a share of the study's costs to KPCo.

Q. Do you agree with the Company's position that KPCo's ratepayers should be responsible for a portion of the CCS FEED study's costs?

A. No. I disagree that KPCo ratepayers should be responsible for the CCS FEED study costs for a number of reasons, including (1) the costs associated with the CCS FEED study were incurred prior to the test year; (2) the CCS study was conducted at the Mountaineer facility located in West Virginia, which is not owned by KPCo; and (3) AEP did not complete the full CCS FEED study that was originally intended. In addition to those reasons, in response to AG 1-304, the Company stated that none of the generating plants owned by AEP and its subsidiaries, including KPCo, currently employ any form of CCS nor are there any plans to employ CCS. These costs should therefore be written off by KPCo as not allowable.

Q. Please explain the adjustment to remove the deferred CCS FEED study amortization from O&M expense.

A. As shown on Exhibit RCS-1, Schedule C-3, I have removed the Company's proposed amortization of $34,425 from operating expenses. These costs should therefore be written off by KPCo as not allowable.

C-4, Amortization of Deferred CARRS Site Costs

Q. Please explain the issue associated with deferred CARRS Site costs and the Company's proposed treatment of such costs.

A. As discussed in the Direct Testimony of Company witness Wohnhas, as part of its long term planning, the Company had purchased property in Lewis County, Kentucky as a potential site for a new generation facility. Pursuant to this purchase, KPCo conducted preliminary site design and engineering work to support developing the site. However, KPCo ultimately decided not to construct a new generating facility at the CARRS Site and therefore removed the land-related costs of the site from rate base. In the instant proceeding, the Company is proposing to recover the CARRS Site costs, which total $2,619,935, by amortizing such costs over a 25 year period, or an increase to O&M expense of $103,330 on a Kentucky jurisdictional basis.

Q. Why did KPCo ultimately elect not to pursue constructing a new generating facility at the CARRS site?

A. In response to AG 1-307, the Company stated the following:

> Kentucky Power acquired the site to permit the Company to satisfy its obligations to provide capacity and energy under the AEP-East Interconnection Agreement through Company owned generation. The generation resources were not constructed at the CARRS site because Kentucky Power was never required under the AEP-East Interconnection Agreement to provide additional Company-owned generation.

Q. Has the Company submitted any filings with the Commission seeking approval of a new generation facility on the CARRS site, or a certificate of need for a new generation facility?

A. No. In response to AG 1-308, the Company stated that the CARRS site is raw land that was acquired for the possible construction of a generating facility, but that since KPCo has not begun construction of any plant, equipment, property, or facility, an application for the CARRS site was neither submitted nor required.

Q. When did KPCo incur the CARRS site costs which totaled $2,619,935?

A. According to the response to AG 1-307, the Company's best estimate is that the majority of such costs were incurred prior to 1980. In addition, the Company stated that since the journal entries to record the CARRS site costs were made "decades ago", they are not available. Moreover, KPCo stated that it does not have records available to determine whether the CARRS site costs were incurred by KPCo, AEPSC or another affiliate.[8]

Q. What is your conclusion regarding whether the proposed amortization of CARRS site costs should be included in the Company's cost of service?

A. The Company's proposed amortization of the CARRS site costs should be removed from cost of service. As noted above, by the Company's estimates, these costs were incurred over 30 years ago and there are evidently no records available from that time that support these costs nor is it clear whether it was actually KPCo that incurred the costs. In addition, the Company has not constructed a generating facility at the CARRS site and these costs are not related to an asset that is used and useful in the provision of electric service to Kentucky ratepayers. Moreover, the land, which is not being used to provide electric utility service, may have value and KPCo could sell it. Therefore, the Company's proposed amortization should be rejected.

Q. Please explain the adjustment to remove the deferred CARRS site amortization from O&M expense.

A. As shown on Exhibit RCS-1, Schedule C-4, I have removed the Company's proposed amortization of $103,330 from operating expenses.

[8] See the response to AG 1-308.

C-5, Amortization of Deferred Preliminary Big Sandy FGD Costs

Q. Please explain the issue associated with deferred Preliminary Big Sandy FGD costs and the Company's proposed treatment of such costs.

A. As discussed in the Direct Testimony of Company witness Wohnhas, beginning in 2004, KPCo began evaluating potential alternatives to comply with increasing environmental regulations pursuant to the Clean Air Act. This included engineering and design work related to potentially installing flue gas desulfurization (FGD) systems at the Big Sandy plant. However, the Kentucky Public Service Commission ultimately concluded that the transfer of the 50% interest in Mitchell Plant, which already has a FGD system, was the least cost alternative.[9] However, in the instant proceeding, the Company is proposing to recover the preliminary Big Sandy FGD costs, which total $28,024,682, by amortizing such costs over a 25 year period, or an increase to O&M expense of $1,105,293 on a Kentucky jurisdictional basis.

Q. Were these costs previously disallowed by the Commission in a prior proceeding?

A. Yes. The Company had sought recovery of the Big Sandy FGD costs in Case No. 2012-00578 but the Company's request was denied by the Commission. Specifically, paragraph 8 from the Stipulation and Settlement Agreement from that prior proceeding stated:

> The Company shall be authorized to in accordance with Financial Accounting Standards Board Standards Codification 980-340-25-1 to accumulate and defer for review and recovery in the Base Rate Case the $28,113,304 of costs incurred from 2004 through 2012 in

[9] The Attorney General has appealed the Commission’s Final Order that was issued in Case No. 2012-00578.

> connection with the Company's ongoing efforts to meet Federal Clean Air Act and other environmental requirements with respect to Big Sandy Unit 2. The Company shall be authorized to amortize and recover the regulatory asset over a five-year period commencing with the implementation of the base rates established in the Base Rate Case. The Company will be authorized to apply carrying costs to the unamortized asset at a long-term debt rate of 6.48%.

The Commission's Order in Case No. 2012-00578 (October 7, 2013), which approved the Stipulation and Settlement Agreement, did so contingent on certain modifications. Among these modifications was the following:

> Paragraph 8 of the Stipulation allowing Kentucky Power to accumulate and defer for review and recovery in a future base rate case the $28,113,304 Scrubber Study Costs shall be stricken and removed from the Stipulation.

As acknowledged by Mr. Wohnhas on page 19 of his testimony, the Company filed its written acceptance of the Commission's modifications on October 14, 2013[10].

Q. Should the Company be able to recover the Big Sandy FGD costs in the instant proceeding?

A. No. The Commission removed the Stipulation provision that would have allowed KPCo to accumulate and defer Big Sandy FGD study costs, leaving KPCo with no authorization to defer them. Moreover, recovery of these costs is not reasonable, especially since the study in question did not result in the addition of a FGD system being installed at Big Sandy Unit 2. Therefore, the Company's proposed amortization should be rejected. These costs should therefore be written off by KPCo as not allowable.

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[10] KPCo provided a copy of this written acceptance in response to KIUC 1-52.

Q. Please explain the adjustment to remove the deferred Big Sandy FGD costs amortization from O&M expense.

A. As shown on Exhibit RCS-1, Schedule C-5, I have removed the Company's proposed amortization of $1,105,293 from operating expenses.

C-6, Parent Company Loss Allocation

Q. Please explain the Parent Company Loss Allocation (PCLA).

A. As discussed in the response to KIUC 1-21, the PCLA occurs when the income tax savings benefit of the tax loss of AEP (KPCo's parent company) is allocated to the companies with positive taxable income which participate in the AEP consolidated tax return. The result of the PCLA is a reduction to the Company's current federal income tax expense.

Q. Did the Company reflect a PCLA in its filing?

A. Yes; however, the PCLA is reflected on a total Company basis and it does not flow through as a reduction to the Company's Kentucky jurisdictional federal income tax expense.

Q. What was the Company's explanation for not flowing the PCLA through to KPCo's Kentucky jurisdictional federal income tax expense?

A. In response to KIUC 1-21(c), the Company stated:

> The PCLA adjustment has been included in Federal income tax expense and approved by the West Virginia Commission in West

> Virginia rate cases since the early 1990's. In this filing, however, the Company followed past precedent in Company Case Nos. 2005-00341 and 2009-00459 and did not include the PCLA in the determination of income tax expense. Should the Kentucky Commission determine that it would now be appropriate to include the PCLA adjustment as a reduction to income tax expense in this proceeding, the Company would comply.

Q. Was the PCLA endorsed by Company witnesses in the recent West Virginia proceeding involving Appalachian Power Company and Wheeling Power Company as an appropriate adjustment to federal income tax expense for utility ratemaking purposes?

A. Yes. The PCLA was recommended by KPCo's affiliates in Case No. 14-1152-E-42T, which involved Appalachian Power Company and Wheeling Power Company ("APCo" and "WPCo" or "Companies"), and which is currently pending before the Public Service Commission of West Virginia. The PCLA adjustment was endorsed by Company witnesses, including Mr. Bartsch, as an appropriate adjustment to federal income tax expense for utility ratemaking purposes, and is consistent with the Company's tax sharing agreement. At the hearing in Case No. 14-1152-E-42T (specifically on January 21, 2015), Mr. Bartsch (also a witness in the instant proceeding), in response to the Chairman's question regarding the Companies' recommended use of the PCLA, stated that the PCLA is recorded on the Companies' pursuant to their tax sharing agreement and complies with SEC guidance:

> That's what we record on the books and records of the Companies because that was in our tax allocation agreement and that's what the

> SEC requires to do back in the day when they were, you know, monitoring and making sure we're following that agreement[11].

Q. Do you believe it is appropriate for KPCo to reflect the PCLA in Kentucky jurisdictional federal income tax expense?

A. Yes. In my opinion, the Company has not demonstrated a good reason why the PCLA should be excluded from the determination of Kentucky jurisdictional federal income tax expense.

Q. Please explain your adjustment to reflect the PCLA as a reduction to current federal income tax expense.

A. The Company has quantified the KPCo allocated portion of the PCLA for the test year ended September 30, 2014 in its response to KIUC 1-21(e). As shown on Exhibit RCS-1, Schedule C-6, I have reduced current federal income tax expense by $314,997 on a Kentucky jurisdictional basis.

C-7, Incentive Compensation Expense

Q. Does the Company have an incentive compensation plan available to its employees?

A. Yes. The Company has an annual incentive compensation ("AIP") plan available to its employees. KPCo provided copies of AEP's 2013 and 2014 AIP plans in response to KIUC 1-31. The AG had also requested the 2015 AIP plan, but in response to AG 2-38, the Company stated that its 2015 AIP plan has not yet been finalized or approved and that

[11] See, e.g., pages 59-60 from the transcript for the hearing held by the Public Service Commission of West Virginia on January 21, 2015 in Case No. 14-1152-E-42T.

it is expected that it will be finalized and approved by the second quarter of 2015. Since the 2015 AIP plan is not available, I used the 2014 AIP plan as the basis for my analysis, as it is the most recent.

Q. What are the AIP plan's stated objectives?

A. The stated objectives of AEP's AIP plan are to:

- Attract, retain, and motivate employees to further the objectives of the Company, its customers and the communities it serves.
- Enable high performance by establishing, communicating, and aligning employee efforts with the plan's performance objectives.
- Foster the creation of sustainable shareholder value through achievement of AEP's goals.

Q. Please briefly describe the AIP plan.

A. As discussed in the 2014 AIP plan, the plan provides annual incentive compensation to motivate and reward employees based on AEP's performance, business unit performance (if applicable) and to those employees whose payout is discretionary, based on their individual performance. In addition, the funding measures for the plan are tied to AEP's operating earnings per share (75% weight), safety (10% weight), and strategic initiatives (15% weight)[12]. The AIP plan states that all staff groups participate in the AIP plan based on the aforementioned funding measures and do not have separate function level incentive goals. In response to AG 2-38, KPCo stated that the funding measures associated with the incentive compensation costs included in the Company's filing reflect the performance measure percentages discussed above.

[12] The plan has two extra credit measures, which are the Zero Fatality Adjustment (7.5%) and a Culture and Employee Engagement measure (5%).

Q. Has KPCo included incentive compensation expense in its test year cost of service?

A. Yes. The response to AG 1-369 included an attachment which indicated that the Company included direct charged O&M incentive compensation expense totaling $3,579,033 in the test year. In addition, the response to AG 2-112 included Attachment 5, which indicated that the Company included O&M incentive compensation billed to KPCo from affiliates other than AEPSC of $99,763 in test year cost of service. In addition, this response also included Attachment 6, which indicated that the Company included O&M incentive compensation billed to KPCo by AEPSC of $3,510,392 in test year cost of service.

Q. Are you recommending an adjustment to the level of incentive compensation that is included in test year cost of service?

A. Yes. I recommend that 75% of the direct charged incentive compensation included in the test year be charged to shareholders. Similarly, I recommend that 75% of the incentive compensation allocated to KPCo from AEPSC as well as the affiliates other than AEPSC also be charged to the Company's shareholders.

Q. What is the basis for your recommendation?

A. The basis for my recommendation is the 75% funding measure previously discussed. The AIP plan states the following with respect to the 75% funding measure:

- AEP is committed to generating sustainable value for its shareholders through its earnings and growth. Therefore 75% of annual incentive funding is tied to AEP's Operating Earnings Per Share. This ensures that funding is commensurate with the Company's earnings and the extent to which the company can afford to pay annual

> incentive compensation while also serving the interests of its shareholders, customers and other stakeholders. It also:
>
> - Further aligns the financial interests of all AEP employees with those of AEP's shareholders;
> - Ensures adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before employees are rewarded with annual incentive compensation; and
> - Aligns employee interests with those of regulated and other customers by strongly encouraging expense discipline.

Since the Company's shareholders are the main beneficiaries of the 75% funding measure for earnings per share, then ratepayers should not be responsible for the incentive compensation that is tied to the 75% funding measure.

Q. Has the Commission previously disallowed incentive compensation expense that is tied to a utility's financial performance?

A. Yes. For example, in its Order dated December 14, 2010 in Case No. 2010-00036 in a proceeding involving Kentucky-American Water Company, the Commission stated in part the following with regard to incentive compensation:

> We remain unconvinced that Kentucky-American's ratepayers receive any benefit from the AIP program to support the recovery of AIP's costs through rates. While some consideration is given to non-financial criteria, the AIP appears weighted to financial goals that primarily benefit shareholders. If these goals are not met, the program is unfunded and no Kentucky-American employee receives an incentive award regardless of how well he or she meets the customer satisfaction or service quality goals. Accordingly, we find that forecasted labor expense should be decreased by an additional $349,529 to eliminate the ICP.

In addition, in its Order dated April 22, 2014 in Case No. 2013-00148 in a proceeding involving Atmos Energy Corporation, the Commission stated in part the following with regard to incentive compensation:

> Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As noted in the hearing on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans...It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find Atmos-Ky's argument to the contrary unpersuasive.

Q. Does the Company's filing reflect an adjustment to incentive compensation expense?

A. Yes. As discussed in the Direct Testimony of Company witness Yoder and shown on Section V, Exhibit 2, page 25, the Company's adjustment to incentive compensation reflects the annual level of incentive compensation expense at a base payout level of one times the incentive target paid to the Company's employees.

Q. Please explain your recommended adjustment for KPCo's Incentive Compensation expense.

A. As shown on Exhibit RCS-1, Schedule C-7, this adjustment decreases test year expense by $4,607,841 on a Kentucky jurisdictional basis to reflect the removal of 75% of (1) KPCo's test year direct charged incentive compensation of $3,579,033; (2) test year AEPSC incentive compensation allocated to KPCo of $3,510,392; and (3) test year incentive compensation billed to KPCo from affiliates other than AEPSC of $99,763. My recommended adjustment also takes into account the Company's aforementioned adjustment to transmission and distribution related incentive compensation reflected on Company Adjustment No. 25 and shown on lines 6 and 7 of Schedule C-7. As it relates to generation related incentive compensation, on page 6 of his testimony Mr. Yoder stated:

> Generation was excluded from this adjustment because I sponsor an adjustment to remove Big Sandy Plant expenses and an adjustment to annualize Mitchell Plant expenses in total.

In addition, as it relates to incentive compensation, the response to AG 1-369 states that the requested amount included in the test year revenue requirement has not been calculated since the adjustments for the removal of Big Sandy costs and the annualization of Mitchell Plant costs were prepared at the account number level and not by the types of costs within the account numbers. Based on the foregoing, I was unable to determine the generation related incentive compensation that relates to the removal of Big Sandy costs or the annualization of Mitchell Plant costs.

C-8, Stock-Based Compensation Expense

Q. Does the Company have stock-based compensation plans available to its employees?

A. Yes. The Company's stock-based compensation plans include Restricted Stock Units and Performance Units[13]. These plans are briefly described below.

> Restricted Stock Units ("RSU") - RSU's are a type of variable long-term compensation, which represent shares of common stock that are issued subject to restrictions on transfer and other incidents of ownership and forfeiture conditions as the Human Resources Committee may determine. RSU's have no voting rights and are not entitled to receive any dividend declared on AEP common stock. However, RSU's are entitled to additional RSU's (Dividend Equivalent RSU's) of an equal value to dividends paid on AEP common stock.

> Performance Units ("PU") - PU's are a type of variable long-term compensation, which do not convey to employees any voting,

[13] See the response to AG 1-86.

> dividend, or other rights associated with shares of AEP common stock. However, they do accrue dividend credits that are generally equal to the value of dividends paid on share of AEP common stock. The overall performance score is based on the achievement of the performance measures established by the Human Resources Committee Board of Directors.

Q. Has KPCo included stock-based compensation expense in its test year cost of service?

A. Yes. The response to KIUC 1-32 included an attachment which indicated that the Company included O&M related RSU's and PU's totaling $215,336 and $37,806, respectively, for a total of $253,142 in the test year. In addition, the response to KPSC 2-112 included Attachment 5, which indicated that the Company included O&M stock-based compensation billed to KPCo from affiliates other than AEPSC of $15,939 in test year cost of service. In addition, this response included Attachment 6, which indicated that the Company also included O&M stock-based compensation billed to KPCo by AEPSC of $2,372,183 in test year cost of service. These amounts should be removed from cost of service in their entirety.

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive or director compensation that is based on the performance of the Company’s (or its parent company’s) stock price, or which has the primary purpose of benefitting the parent company’s stockholders and aligning the interests of participants with those of such stockholders.

Additionally, prior to being required to expense stock options for financial reporting purposes under ASC 718 (formerly SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders’ investments, i.e., it was a cost borne by shareholders. While ASC 718 now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock-based compensation from shareholders to utility ratepayers.

Q. Has the Commission previously disallowed stock-based compensation expense that is tied to a utility's financial performance?

A. Yes. For example, in its Order on Rehearing dated February 2, 2006 in a proceeding involving Union Light Heat & Power Company ("ULH&P), the Commission stated in part the following with regard to stock-based compensation:

> After reexamining the components and component goals of the AIP, we agree with the AG that 100 percent of the expense for the Corporate Goals component should be borne by shareholders rather than allocated 50 percent to shareholders and 50 percent to ratepayers as directed in our Order of December 22, 2005. As noted by the AG, this conclusion is consistent with our treatment of the corporate financial performance goals in the LTIP.

In addition, in its Order dated December 14, 2010 in Case No. 2010-00036 in a proceeding involving Kentucky-American Water Company, the Commission stated in part the following with regard to stock-based compensation:

> The Commission finds that, based upon the stated purpose of the program, the program primarily benefits shareholders. In the absence of clear and definitive quantitative evidence demonstrating a benefit to the utility's ratepayers, the ratepayers should not be required to bear the program's costs. Accordingly, we find that forecasted labor expense should be reduced by $27,288 to eliminate the stock-based compensation plan.

Q. Please explain your recommended adjustment for KPCo's Stock-Based Compensation expense.

A. As shown on Exhibit RCS-1, Schedule C-8, this adjustment decreases test year expense by $2,614,851 to reflect the removal of (1) KPCo's test year direct charged stock-based compensation of $253,142; (2) test year AEPSC stock-based compensation allocated to KPCo of $2,372,183; and (3) test year stock-based compensation billed to KPCo from affiliates other than AEPSC of $15,938. The expense of providing stock options and other stock-based compensation to officers and employees beyond their other compensation should be borne by shareholders and not by ratepayers.

C-9, Engage to Gain Program Costs

Q. Please explain your adjustment on Exhibit RCS-1, Schedule C-9.

A. As stated in the Company's response to AG 2-32, the objectives of the Engage to Gain Program were to (1) align and create an avenue for all employees to contribute to the sustainable savings target; (2) create an environment that is not just about cutting O&M costs, but focused on new ideas and on working differently in the future that will lead to savings; and (3) create a line of sight for each employee to contribute to the generation of innovative or money saving ideas that result in a direct benefit for AEP in 2013[14]. However, the response to AG 2-32 also stated that the Engage to Gain Program was only in effect for one year and ended in December 2013. Since there will be no more Engage to Gain costs going forward, I have removed the test year amount of these costs from O&M expense. Therefore, as shown on Exhibit RCS-1, Schedule C-9, my adjustment reduces O&M expense by $145,421 on a Kentucky jurisdictional basis.

[14] See AG 2-32, Attachment 1.

C-10, PJM Charges and Credits to Reflect Removal of Big Sandy

Q. Please explain your adjustment on Exhibit RCS-1, Schedule C-10.

A. As discussed in further detail in a later section of my testimony, KPCo is proposing to remove all Big Sandy Unit 1 costs from base rates to be recovered through the BS1OR pursuant to the Stipulation and Settlement Agreement that was approved by the Commission in Case No. 2012-00578. Among the costs that KPCo has removed from base rates to be recovered in the BS1OR are PJM charges totaling $4,300,110, which were incurred during the period January through September 2014. For purposes of including the PJM charges in the BS1OR, the Company annualized these costs.[15] I am recommending that the PJM charges remain in base rates and have therefore, removed the annualized amount of PJM charges from the BS1OR. I have added the $4,300,110 of PJM charges incurred from January through September 2014 back into base rates. The AG had requested that KPCo provide the PJM charges it incurred during calendar year 2014 in AG 1-338, which was not provided. In response to AG follow-up data request AG 2-114, KPCo stated the following with respect to the AG's request for calendar year 2014 PJM fees:

> Item d from Company Exhibit AEV-4, page 1 of 3 was not included in the Company's response to AG 1-338 because the requested analysis has not been performed for 2009-2014, only for the historic test year in this proceeding.

Since the Company did not provide the actual calendar year 2014 PJM charges, my adjustment reflects only the PJM charges incurred from January through September 2014. In addition, my adjustment reflects the correction of an error that the Company identified

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[15] As shown on Exhibit AEV-4, the Company's annualized amount of PJM charges totals $5,653,211.

in response to KIUC 1-90.[16] As shown on Exhibit RCS-1, Schedule C-10, my adjustment increases O&M expense by $4,221,140 on a Kentucky jurisdictional basis.

C-11, Miscellaneous Expenses

Q. Please explain your adjustment on Exhibit RCS-1, Schedule C-11.

A. This adjustment removes from cost of service expenses for items such as the lobbying portion of Messrs. Pauley and Hall's salaries, tickets to sporting events, employee gifts and awards, membership dues, charitable contributions and public relations. As shown on Exhibit RCS-1, Schedule C-11, my adjustment reduces O&M expense by $365,132 on a Kentucky jurisdictional basis.

C-12, Mitchell Plant Maintenance Expense

Q. Please explain the Company's proposed adjustment to Mitchell Plant maintenance expense.

A. As discussed in the Direct Testimony of Company witness Wohnhas, the Company is proposing to normalize maintenance expense for the Mitchell Plant by calculating a three-year average of the Mitchell Plant maintenance expense using the 12 months ended September 30, 2012, 2013 and an annualized amount for 2014, resulting in Mitchell Plant maintenance expense totaling $15,744,373, that when compared to the test year level of

[16] See Exhibit RCS-17 for a copy of the referenced responses.

$12,474,790, resulted in an increase to O&M expense of $3,223,809 on a Kentucky jurisdictional basis[17].

Q. Do you agree with the Company's adjustment?

A. Partially. While I agree that normalizing plant maintenance expense is an appropriate method for smoothing out any abnormally high or low plant maintenance costs in a specific period (i.e., the test year), I believe that normalizing such maintenance costs over a period greater than three years provides a better measure for smoothing out any abnormal plant maintenance costs incurred in a particular year.

Q. What normalization period do you recommend as it relates to the Mitchell Plant's maintenance expense?

A. Normalizing Mitchell Plant maintenance expense over a longer period, such as five years, should be a more accurate methodology for smoothing out any abnormal plant maintenance costs that have been incurred in a particular year. Therefore, I have calculated an adjustment similar to the Company's except that I have a reflected a five-year normalization period using the periods September 30, 2010 through September 30, 2014.

Q. What adjustment do you recommend?

A. As shown on Exhibit RCS-1, Schedule C-12, my recommended adjustment to normalize Mitchell Plant maintenance expense using a five-year average results in a decrease from

[17] See Section V, Exhibit 2, page 34 from the Company's filing.

the Company's proposed going-level amount by $998,577 on a Kentucky jurisdictional basis.

C-13, Interest Synchronization

Q. Please explain the adjustment on Exhibit RCS-1, Schedule C-13.

A. This adjustment modified the Company's interest synchronization adjustment to reflect (1) my recommended capitalization; and (2) including the tax-deductible interest related to the Company's accounts receivable financing, which the Company appears to have inadvertently omitted from its calculation. As shown on Exhibit RCS-1, Schedule C-13, the result of this adjustment is to increase state and federal income tax by $54,320 and $312,504, respectively.

Q. Has the Company agreed in a prior rate case that the interest expense on the Accounts Receivable Financing is tax deductible and should therefore be included in the interest synchronization adjustment?

A. Yes. The Company's response provided in a prior KPCo rate case about this issue, which is presented in Exhibit RCS-19, indicates that the Company had inadvertently omitted the tax-deductible interest related to the Company's accounts receivable financing from its interest synchronization calculation in that case, and agreed that this tax-deductible interest should be included.

IX. BIG SANDY RETIREMENT RIDER

Q. Please explain the Company's proposed Big Sandy Retirement Rider ("BSRR").

A. As discussed in the Direct Testimony of Company witness Wohnhas, pursuant to the Stipulation and Settlement Agreement ("Stipulation") in Case No. 2012-00578[18], the Commission authorized KPCo to recover the Big Sandy Unit 1 coal related retirement costs as well as the Big Sandy Unit 2 retirement costs on a levelized basis, which includes carrying costs based on the WACC and which are subject to an accumulated deferred income tax ("ADIT") offset, through the BSRR over a 25 year period.

Q. Is the rider discussed in the Stipulation referred to as the Big Sandy Retirement Rider or BSRR?

A. No. The rider discussed in the Stipulation is referred to as the Asset Transfer Rider-2 ("A.T.R.-2"). The A.T.R.-2, which was effective January 1, 2014, was designed to collect $44 million annually and also included a true-up mechanism and, pursuant to the Stipulation, is to remain in place until the Commission sets new rates in the instant proceeding. Specifically, paragraph 4 of the Stipulation states in part:

> After new base rates are established, the Asset Transfer Rider will be reset to remove the $44 million by substituting Asset Transfer Rider-2 (Tariff A.T.R.-2), attached hereto as **<u>Exhibit 1-A</u>**, which thereafter will be used to recover the Big Sandy 1 and Big Sandy 2 retirement costs as described in Paragraph 14.

Q. What does Paragraph 14 from the Stipulation state with respect to Big Sandy Units 1 and 2?

A. Paragraph 14 states the following with respect to Big Sandy Units 1 and 2:

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[18] The Commission's Order approving the Stipulation and Settlement Agreement (subject to certain modification) was issued on October 7, 2013.

> The Company shall be authorized to recover the coal-related retirement costs Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs that will not continue in use. The costs shall be recovered on a levelized basis, including a weighted average cost of capital (WACC) carrying cost, over a 25 year period beginning when base rates are set in the Base Rate Case. The term "Retirement Costs" as used in this agreement are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses. **The Company will use its best efforts to minimize the cost of dismantling and to maximize salvage credits.** Such retirement credits will be recovered in the Asset Transfer Rider-2.
>
> (Emphasis supplied.)

As discussed on page 7 of his Direct Testimony, Mr. Wohnhas stated that the Company is proposing to change the name of the A.T.R.-2 to the BSRR in order to avoid any ratepayer confusion as it relates to specific line items on their bills. The Company's proposed annual revenue requirement for the BSRR is $21,855,982 on a Kentucky jurisdictional basis.

Q. Please describe the components of the proposed BSRR from which the annual revenue requirement of $21,855,982 is derived.

A. As discussed in the Direct Testimony of Company witness Yoder, the components of the proposed BSRR from which the annual revenue requirement of $21,855,982 is derived are reflected in the table below.

BSRR Component	Amount
Net Book Value	$ 201,911,435
Unusable Materials & Supplies	$ 4,342,987
Removal Costs and Salvage	$ 43,797,850
Ongoing Big Sandy Unit 2 Expense	$ 6,058,782
ARO Costs	$ 56,025,824
Less: ADIT	$ (72,189,048)
Net Retirement Costs	$ 239,947,830
Carrying Costs	$ 314,209,917
Total Retirement Costs	$ 554,157,747
Total Retirement Costs / 25 Years	$ 22,166,310
Kentucky Jurisdictional Allocation Factor	0.986
Kentucky Jurisdictional BSSR Revenue Requirement	$ 21,855,982

Q. Are the amounts reflected in the BSRR revenue requirement calculation estimates?

A. Yes. As discussed in Mr. Yoder's testimony, the components of the proposed BSRR are comprised of a combination of estimated balances as of June 30, 2015 as well as estimated "future costs".

Q. Do you agree with the estimated future costs in KPCo's requested rider?

A. No. There is no need for the initial Rider to include estimates of future costs of removal or dismantling that have not yet occurred and which could be subject to substantial mis-estimations. Additionally, the Company's requested carrying costs of over $314 million are excessive.

Q. What adjustments do you recommend?

A. As shown on Exhibit RCS-2, I have removed the estimated future costs for removal, operating expenses and Asset Retirement Obligation (ARO) from the initial BSRR costs. This produces a net book value, net of ADIT, of $134 million, as shown on Exhibit RCS-2, line 11, column E.

Q. Please explain how you have adjusted the amount of carrying costs.

A. As shown on Exhibit RCS-2, lines 17 through 25, I adjusted KPCo's requested carrying costs in two steps.

First, as shown on lines 17 through 20, I adjusted carrying costs using the ratio of AG-adjusted to Company-proposed net book value. This resulted in adjusted carrying costs of $175.6 million, a $138.7 million reduction from KPCo's requested amount of $314.2 million. The $175.6 million effectively reflects KPCo's requested cost of capital over the 25 year period.

Second, I adjusted the $175.6 million to $147.7 million, as shown on Exhibit RCS-2, lines 21 through 25, based on the ratio of the AG's adjusted pre-tax cost of capital, 9.08 percent, to KPCo's request of 10.79 percent. Multiplying the $175.6 million by 0.8415199 based on this ratio, as shown on Exhibit RCS-2, line 21, produced the $147.7 million of carrying costs for the initial rider.

Q. How does your recommendation compare with KPCo's request?

A. As shown on Exhibit RCS-2, line 16, my recommendation would set the initial BSRR to recover an annual amount of $11.114 million versus KPCo's requested amount of $21.856 million.

Q. How would the removal costs/ARO and other variances in the net book value be addressed in your recommendation?

A. Such estimated future costs would not be included in the initial BSRR, but as the actual expenditures were made, the costs would be tracked in a deferral account, and would be reviewed in KPCo's next base rate case. The BSRR revenue requirement would be adjusted accordingly at that time, after such costs were reviewed in the KPCo rate case.

X. BIG SANDY UNIT 1 OPERATION RIDER ("BS1OR")

Q. Please explain the Company's proposed BS1OR.

A. As discussed in the Direct Testimony of Company witness Wohnhas, the Company is proposing the BS1OR, which would be a new rider from which KPCo would recover (1) the non-fuel costs of operating Big Sandy Unit 1 as a coal facility until its conversion to natural gas; (2) the non-fuel costs of operating Big Sandy Unit 1 as a natural gas-fired generating station; and (3) the return of and on the capital investment required for the conversion of Big Sandy Unit 1 from coal to natural gas. In addition, the Company proposes that the BS1OR remain in place until the rates established in KPCo's next rate base case are implemented at which time, the BS1OR will be discontinued. Upon the BS1OR being discontinued, all operational costs associated with Big Sandy Unit 1 will again be recovered through base rates. Furthermore, Mr. Wohnhas stated that the annual revenue requirement associated with the proposed BS1OR is $18,245,413.

Q. Please describe the components of the proposed BS1OR from which the annual revenue requirement of $18,245,413 is derived.

A. As discussed in the Direct Testimony of Company witness Vaughn and reflected on his Exhibit AEV-4, the components of the proposed BS1OR from which the annual revenue requirement of $18,245,413 is derived are reflected in the table below.

BS1OR Component	Kentucky Jurisdictional Amount
Non-Fuel Plant O&M - Demand	$ 9,150,077
Non-Fuel Plant O&M - Energy	$ 3,351,767
KPCo Cost of Service Study for Big Sandy Unit 1 Non-Fuel O&M Expense	$ 12,501,844
Add: Annualized PJM Charges	$ 5,653,211
Total BS1 Operational Expense	$ 18,155,055
Gross Up Factor	1.004977
Kentucky Retail Total	$ 18,245,413
Demand Total	$ 9,195,617
Energy Total	$ 9,049,796
Total	$ 18,245,413

As shown in the above table, and explained in KPCo witness Vaughan's direct testimony at page 19, he performed a cost of service study for Big Sandy Unit 1 to separate expenses for each of the plant's units. KPCo identified the test year operating expenses attributable to the Big Sandy plant and then either direct charged or allocated a portion of such expenses to Big Sandy Unit 1. Mr. Vaughan states that: "The study results in $12.5 million of test year non-fuel operations and maintenance expense that is attributable to Big Sandy Unit 1."[19]

On top of that $12.5 million, KPCo has also attempted to include in its proposed BS1OR approximately $5.65 million of net PJM charges. That amount is based on nine months of 2014 net PJM charges, which Mr. Vaughan attributes to Big Sandy Unit 1, annualized.

[19] KPCo witness Vaughan's direct testimony at page 19.

Q. What is the Company's rationale for proposing that the costs shown in the table above be recovered through the proposed BS1OR and did KPCo consider other options for recovery of these costs?

A. In response to AG 1-287[20], in which the AG requested the Company's rationale for proposing the BS1OR, KPCo referred to the response to KPSC 2-86, which stated:

> Pursuant to the Stipulation Agreement approved in Case No. 2012-00578, paragraph 3, "The Company agrees to remove all coal-related operating expenses related to Big Sandy 1..." With the one year extension to operate Big Sandy Unit 1 as coal leading up to the conversion to gas, the rider was the only option available that would keep the Company compliant with the Stipulation and Settlement Agreement. The rider gives transparency of the operating costs to all parties during the one year extension, during the conversion of the unit to gas, and through its operation as a gas-fired unit up until the next base rate filing after its conversion to gas.

In addition, on pages 18 and 19 of his Direct Testimony, Company witness Vaughn stated in part the following with respect to the proposed BS1OR:

> In order to comply with the Stipulation and Settlement Agreement, the Company is proposing to remove all Big Sandy Unit 1 operating expenses from base rates in this case and recover them through the BS1OR. This is because Big Sandy Unit 1 will continue to operate as a coal fired generating plant for a period of time before it is converted to a natural gas fired generating plant...the BS1OR will recover all operating expenses of Big Sandy Unit 1 that are not otherwise included in the Company's fuel adjustment clause or the system sales clause.
>
> The BS1OR revenue requirement and rates will be trued up to actual costs so that customers pay no more or no less than the actual cost to operate Big Sandy Unit 1 as described in the Company's proposed BS1OR tariff.

Q. When will Big Sandy Unit 1 be converted to a natural gas fired facility?

[20] See Exhibit RCS-21 for this and other KPCo responses to discovery on the BS1OR issues.

A. According to the Direct Testimony of Company witness LaFleur[21] and the response to AG 1-338, KPCo plans to complete the conversion to natural gas by June 30, 2016.

Q. Are you recommending any adjustments to KPCo's proposed rider?

A. Yes. KPCo has proposed to include not only Big Sandy Unit 1 non-fuel O&M expense in the rider, but has also included estimated PJM costs. As shown on Exhibit RCS-3, my recommended adjustment removes the estimated PJM costs from this Rider.

Q. Why should the estimated PJM charges be removed?

A. KPCo has not justified inclusion of estimated PJM charges in this Rider. Inclusion of PJM charges in the BS1OR could also lead to abuse, as the PJM invoices can be quite complicated, and KPCo has not provided a clear audit trail of which exact PJM charges would be included in the Rider versus PJM charges that are recovered elsewhere, such as in base rates. The inclusion of PJM charges introduces an unneeded complication and could make auditing the BS1OR costs more difficult. Therefore, I recommend excluding PJM charges from the BS1OR and instead providing recovery of test year PJM charges in KPCo's base rates.[22] As shown on Exhibit RCS-3, without the inclusion of the PJM charges, the BS1OR would recover an annual revenue requirement of $12.6 million.

XI. ENVIRONMENTAL SURCHARGE RELATED TO MITCHELL FGD

Q. Please explain the provision in the Stipulation and Settlement Agreement dated July 2, 2013 and approved by the Commission in its Order dated October 7, 2013 in Case

[21] See the Direct Testimony of Jeffery D. LaFleur at page 9 (lines 3-4).
[22] See discussion in my testimony in conjunction with AG Adjustment C-10.

No. 2012-00578, that relates to the treatment of the Mitchell Units 1 and 2 Flue Gas Desulfurization costs.

A. Paragraph 6 from the Stipulation states the following with respect to Mitchell Units 1 and 2 flue gas desulfurization ("FGD") costs:

> When base rates are set in the Base Rate Case, all costs associated with the Mitchell Units 1 and 2 Flue Gas Desulfurization (FGD) equipment will be recovered through the environmental surcharge (Tariff E.S.) approved in the Base Rate Case, and excluded from base rates in the Base Rate Case. This collection mechanism shall continue at least until the Commission sets new base rates for a period commencing after June 30, 2020 that include these costs. The charges payable under the Environmental Surcharge to be submitted for approval in the Base Rate Case will be determined by first allocating the revenue requirement between full requirements wholesale customers and retail customers in the same manner that it is presently allocated. The retail share of the revenue requirement will then be allocated between residential and non-residential retail customers based upon their respective total revenues. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

As stated in the passage above, all costs associated with the Mitchell FGD system are to be recovered through the environmental surcharge and excluded from base rates. This mechanism is to remain in place until the Commission sets new base rates for a period commencing after June 30, 2020 at a minimum.

Q. Has the Company made any adjustments to remove from base rates, costs associated with the Mitchell FGD system?

A. Yes. As discussed in the Direct Testimony of KPCo witness Elliott, the Company removed $14.879 million of annualized O&M expenses associated with the Mitchell FGD system.[23] In addition, KPCo made an adjustment to remove the Mitchell FGD costs from rate base which netted to $223.1 million.[24]

Q. Did the Company calculate an annual revenue requirement pursuant to including the Mitchell FGD system costs in the Environmental Surcharge?

A. Yes. As shown on Company Exhibit AJE-4, which was filed in conjunction with Ms. Elliott's Direct Testimony, the Company calculated an annual revenue requirement related to the Mitchell FGD system in the amount of $34.391 million and which reflects the period from July 2015 through June 2016. On page 17 of her testimony, Ms. Elliott stated that the July 2015 through June 2016 period was used because it is the first 12 month period following the date in which the rates proposed in this proceeding will go into effect.

Q. Did KPCo's Mitchell FGD revenue requirement calculation include rate of return on equity?

A. Yes. The proposed Mitchell FGD revenue requirement calculation is based on the Company's requested ROE of 10.62%. Use of the Company's proposed ROE of 10.62% results in a WACC of 10.79%.

Q. Are you recommending any adjustments to the Company's requested annual revenue requirement of $34.391 million for the Mitchell FGD?

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[23] See Section V, Exhibit 2, W35 from KPCo's filing.
[24] See Section V, Exhibit 2, W53 from KPCo's filing.

A. Yes. As shown on Exhibit RCS-4, which essentially replicates Company Exhibit AJE-4, I adjusted the WACC component of the revenue requirement calculation to reflect AG witness Woolridge's recommended ROE of 8.65% and the AG's adjusted jurisdictional capitalization. As shown on Exhibit RCS-1, Schedule D, page 1, column E, and in Column G of Exhibit RCS-4, using Dr. Woolridge's recommended ROE of 8.65% and the AG's recommended capital structure (which does not contain negative short-term debt), results in a WACC of 9.08%[25] versus the WACC of 10.79% proposed by KPCo[26] in its Mitchell FGD revenue requirement calculation on Exhibit AJE-4. As shown in Column N of Exhibit RCS-4, the impact of using the 9.08% WACC reduces the Mitchell FGD revenue requirement by $3.280 million.

XII. KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE

Q. What has KPCo requested for a new Kentucky Economic Development Surcharge (KEDS)

A. KPCo witness Rogness's direct testimony at page 16 describes the KEDS as a monthly surcharge of $0.15 to be applied to each customer account (except outdoor lighting) for the purpose of funding economic development initiatives. KPCo proposes to match ratepayer funds with shareholder funds. KPCo is requesting an additional revenue requirement of $307,507 for the KEDS.

Q. What is your recommendation for KPCo's proposed KEDS?

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[25] The derivation of the 9.08 WACC is also reflected on Exhibit RCS-1, Schedule D.
[26] KPCo's proposed cost of capital rate is also reproduced on Exhibit RCS-1, Schedule D, page 1. Schedule D, pages 1 and 2 shows in detail how KPCo has attempted to include negative short-term debt in its proposed capitalization.

A. A new surcharge for Kentucky Economic Development is not needed and has not been adequately justified and is therefore being removed. As shown on Exhibit RCS-1, Schedule A, page 1, line 11, I have removed the additional revenue requirement of $307,506 that KPCo proposes to collect from this surcharge. As indicated in the response to AG 2-105[27], KPCo has not identified specific projects to be funded through the $307,506. Moreover, KPCo has previously committed to continue shareholder-provided funding via the KPCo Economic Advancement Program through 2018, as described in the responses to AG 1-8 and AG 2-101, but has not made a decision concerning shareholder economic funding of that Program beyond 2018. As described in KPCo witness Rogness' direct testimony at page 21, as a result of the Settlement Agreement in Case No. 2012-00578 dated July 2, 2013, the Company is contributing $200,000 per year through 2018 toward economic development in Lawrence County and the surrounding contiguous counties.

Q. Has KPCo indicated whether surcharges similar to its proposed KEDS are common in other jurisdictions?

A. According to KPCo's response Staff 2-51 and Staff 3-20, there is a similar program in Ohio, which has enabling legislation providing for the cost of economic development programs to be recovered from utility customers. However, as stated in response to Staff 2-51(b): "The Company is not aware of any other utility in any other jurisdiction having similar charges approved to support and promote economic development."

[27] See Exhibit RCS-22 for copies of the referenced responses concerning the KEDS.

Q. Should KPCo's proposed economic development expenditures receive special piecemeal ratemaking treatment?

A. No. As noted above, the Company's shareholders are already committed to providing economic development related funding through 2018. KPCo has not shown that its proposed additional costs that it proposed to include in the KEDS is significantly material (similar to fuel costs or other large costs that may be singled out for surcharge treatment), volatile or beyond the ability of management to control.

XIII. TRANSMISSION ADJUSTMENT

Q. KPCo's proposed revenue deficiency, including the Company quantified revenue requirements related to the surcharges that are listed on your Exhibit RCS-1, include a subtraction for a transmission adjustment. How have you reflected that?

A. As shown on Exhibit RCS-1, Schedule A, line 12, I have removed KPCo's proposed Transmission Adjustment from CCOS Study of $126,908, which apparently relates to a proposal by KPCo to remove transmission costs from base rates and have recovery occur in a transmission rider.[28] Transmission cost recovery should continue in KPCo's base rates, and this KPCo proposed adjustment, which reduced KPCo's requested revenue requirement by the $126,908, is not needed.

[28] See, e.g., KPCo's Exhibit JMS-3 and KPCo's response to AG 1-335 which indicates that eliminating the adjustment would keep the transmission function revenue requirement in base rates which would result in the KY retail jurisdictional revenue requirement increasing by $126,908. Also, see, e.g., KPCo's responses to Staff 2-101, and to KIUC 1-81, 1-82 and 1-84. These responses are presented in Exhibit RCS-23.

XIV. MITCHELL PLANT TRANSFER/ASH POND COSTS

Q. Are you familiar with the transfer of a 50 percent interest in the Mitchell Plant to KPCo's affiliate in West Virginia?

A. Yes, to some extent, as costs related to that Mitchell plant interest transfer were an issue in the most recent West Virginia rate case involving Appalachian Power Company (“APCo”) and Wheeling Power Company (“WPCo”).

Q. Please provide some background on the transfer of that other 50 percent interest in the Mitchell Plant.

A. KPCo's affiliate, APCo had originally requested in Virginia and West Virginia that the other 50 percent interest in the Mitchell Plant be transferred to APCo. The Virginia Commission rejected that transfer, based on various concerns, including that the Virginia Commission was not convinced that the plant would be economical. Because of that Virginia decision rejecting the proposed transfer of the Mitchell plant to APCo, AEP Generation ("AEPGR") took over the 50 percent interest from Ohio Power Company. A proposed merger of APCo and WPCo that was pending approval in West Virginia was put on hold. The West Virginia Commission ultimately approved the transfer of the Mitchell plant to WPCo, subject to certain restrictions on the amounts and portions of plant costs that could be included in WPCo's base rate revenue requirement. Also, the transfer of the 50 percent interest in the Mitchell plant that was approved by the West Virginia Commission specifically singled out liability for and ownership of the Mitchell plant ash pond as something that was not being transferred to WPCo.

Q. Was the liability for the Mitchell Plant ash pond future cost increases transferred to the utility affiliate in West Virginia?

A. It is my understanding that it was not. The liability for the Mitchell plant ash pond was effectively eliminated from the transfer of Mitchell related assets and costs to WPCo. As explained in the KPCo's response to AG 2-36, the West Virginia Commission approved transfer to WPCo excluded the transfer of a 50 percent interest of the Connor Run Impoundment (ash pond) facility, and WPCo remitted a $20 million payment to AEPGR as a regulatory adjustment. The West Virginia Commission stated that it "views the $20 million payment as a form of consideration for eliminating the Connor Run Impoundment and any future costs and liabilities related to the Connor Run Impoundment from the Mitchell Settlement Interest."[29] This effectively limits the exposure of WPCo ratepayers to future large costs associated with accidents at the Mitchell ash pond.

Q. Has the potential for large costs to a utility of spillage from an ash pond at a generating unit been highlighted based on an incident involving a Duke-owned unit in North Carolina?

A. Yes. News articles, copies of which are included in Exhibit RCS-24, discuss Duke's ash pond spill into the Dan River, as well as some of the fines imposed and the potential cost Duke is facing for remediation.[30]

[29] See, WV Commission Order in Case No. 14-0546-E-PC dated December 30, 2014, as quoted in KPCo's response to AG 2-36(b).
[30] See, e.g., Exhibit RCS-24.

Q. Should KPCo's ratepayers be responsible for the cost if an incident occurs at the Mitchell plant ash pond?

A. No. While KPCo ratepayers are paying for the cost of the Mitchell ash pond, which is part of the cost of KPCo's 50 percent interest in the Mitchell plant, if a serious ash pond spill should occur there, similar to the one that occurred at Duke's North Carolina plant, it should be understood that KPCo's shareholders, and not the Kentucky ratepayers, would be responsible for the related fines and remediation cost.

XV. OFF SYSTEM SALES MARGIN SHARING

Q. What has KPCo proposed for off system sales margins sharing?

A. As described in the testimony of KPCo witness Wohnas at pages 23-24, the Company proposes a 60/40 customer sharing that was found in its System Sales Clause (Tariff S.S.C.) that were in place prior to the changes that were instituted in accordance with the Stipulation and Settlement Agreement approved as modified by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578.

Q. What explanations did KPCo provide for the 60/40 sharing ratio?

A. The Company's responses to KIUC 1-54 and AG 2-90 provide some explanations of the Company's rationale. The Company believes that a mechanism that allows the Company to retain 40 percent of all margins above the amount included in base rates and to absorb 40 percent of the margins below the amount included in base rates provides a reasonable balance between the Company's incentive to maximize OSS margins while sharing a large portion with customers. The Company claims that assigning the Company less than 40 percent of the OSS margins above the amount built into base rates would unreasonably saddle KPCo with a disproportionate risk of any shortfall without providing the Company with adequate compensation for that risk through a reasonable sharing of OSS margins above the amount built into base rates.

Q. Do you agree with that off system margin sharing percentage going-forward?

A. No. With the cessation of the AEP East Power Pool arrangement, KPCo's generation should be dispatched under normal operating conditions based on economic dispatch in the PJM interconnection. This dispatch will impact the amount of off-system sales. KPCo, after acquiring the 50 percent interest in the Mitchell plant, has abundant generation, more than sufficient to serve its own load. KPCo's ratepayers are paying for the fixed cost of KPCo's generation. Consequently, ratepayers should receive a larger share of any off-system sales margins that occur.

Q. What off-system sales margin sharing do you recommend?

A. I recommend a ratepayer/Company sharing ratio of 90%/10% for off system sales margins.

Q. What amount of OSS margins did KPCo realize during the test year?

A. According to KPCo witness Vaughan's testimony at pages 31-32, KPCo realized OSS margins during the test year of $76.09 million.

Q. What amount of OSS margins does KPCo propose to credit against base rates in the current case?

A. According to KPCo witness Vaughan's testimony at pages 31-32, KPCo proposes to credit OSS margins based on a "going level amount" of only $14.3 million on a Kentucky jurisdictional basis.

Q. If the bar had been set at $14.3 million and KPCo realized $76.09 million with a 40 percent Company sharing percentage, how much would KPCo have retained?

A. The following calculation shows that, if the threshold for sharing had been set at $14.3 million and KPCo realized $76.09 million with a 40 percent Company sharing percentage, KPCo would have retained $24.64 million:

Illustrative Example of OSS Margin Sharing Retainage Proposed by KPCo		
	$Millions	
OSS Margins in test year	76.09	
Margin credited to base rates	$ 14.3	
Above KPCo proposed sharing threshold	$ 61.79	[1]
Above KPCo proposed sharing threshold	$ 61.59	[1]
40 Percent KPCo retention	40%	
Retained by KPCo	$ 24.64	
Notes		
[1] Vaughan direct testimony page 32 shows $61.59 million		

Q. Using this same scenario, what would be KPCo's retention under a 90%/10% sharing ratio?

A. Under a 90%/10% sharing arrangement, with KPCo receiving a 10 percent retention incentive, using the same hypothetical to illustrate the impact, KPCo would have retained $6.159 million on a Kentucky jurisdictional basis.[31]

XVI. VEGETATION MANAGEMENT

Q. Have you made any adjustment to KPCo's requested Vegetation Management expenses in this proceeding?

A. No. For purposes of this case, the Company's selection of option 2 has been accepted for the cost level and no adjustment to the Company's requested amount is being proposed. However, in conjunction with accepting that Company requested amount, some safeguards and reporting requirements are needed.

Q. What reporting requirements and safeguards to you recommend?

A. I recommend that KPCo be required to continue to file annual vegetation management work plans and reliability reports with the Commission and with the AG.

Additionally, KPCo should track its actual Vegetation Management spending versus the amount allowed for base rate inclusion in a one-way balancing account that would be reviewed in KPCo's next rate case. If the balance in that account shows that KPCo has under-spent the amounts allowed for Vegetation Management, then the amount of under-spending would be refunded to ratepayers annually as a bill credit or used to reduce KPCo's revenue requirement in that base rate case. On the other hand, because spending on Vegetation Management can be subject to management influence and control,

[31] 10% x $61.59 million.

if KPCo over-spends the allowed amounts, the amount of excess spending would be borne by KPCo's shareholders. KPCo should also be required to report to the Commission on the amounts tracked in the one-way balancing account annually.

XVII. ROCKPORT PLANT UNIT POWER SALES AGREEMENT - RETURN ON EQUITY OF 12.16 PERCENT

Q. Is KPCo being charged from an affiliate with respect to a Unit Power Sales agreement related to the Rockport Plant?

A. Yes. KPCo is charged from AEP Generating Company[32] ("AEGCO") under a Unit Power Sales agreement related to the Rockport Plant. Under this arrangement, AEGCO charges KPCo for 30 percent of the costs of the Rockport Plant that are covered in the Unit Power Sales agreement and charges the other 70 percent to another affiliate, Indiana and Michigan Power Company ("IMPC" or "I&M").

Q. Approximately how much were the Rockport Plant UPA related charges to KPCo for the 12 months ending September 30, 2014?

A. An Excel file was provided by KPCo in response to AG 2-5, showing the charges for the Rockport UPA from AEGCO to KPCo by unit and by account. The total charges for the 12 months ending September 30, 2014 were approximately $118.2 million, including $68.8 million for fuel (account 5550046) and $43.4 million for non-fuel (account 5550027) charges.

[32] See, e.g., Exhibit RCS-28 for copies of invoice excerpts, Exhibit RCS-27 for a summary of charges from AEP Generating Company to KPCo, and Exhibit RCS-26 for copies of selected responses to discovery.

Q. Do the charges to KPCo under this affiliated contract include a return on equity component?

A. Yes, the non-fuel charges from AEP Generating Company to KPCo (and to I&M) include a return on equity component that is based on a 12.16 percent ROE.

Q. Have you adjusted those charges that are related to the 12.16 percent ROE?

A. No, not in the current case. It appears that an adjustment of the ROE included in that affiliated unit power sales contract must be addressed at the Federal Energy Regulatory Commission ("FERC")[33]. A provision in the agreement addressing this provides as follows[34]:

> 1. Return on Equity
>
> The return on common equity allowance shall be based upon a rate of return of 12.16% as set forth in sub-paragraph (a) above.
>
> In October of 1988, and every October thereafter for the effective duration of AEGCO's formula rate, **any purchaser under AEGCO's two unit power agreements, any state regulatory commission having jurisdiction over the retail rates of purchasers under these agreements, or any other entity representing customers' interest, may file a complaint with the Commission with respect to the specified rate of return on common equity. If the Commission, in response to such a complaint, or on its own motion, institutes an investigation into the reasonableness of the specified return on common equity, such investigation shall be pursued under the special procedures set forth as follows:**
>
> **A. The only issue to be addressed under these special procedures shall be the continued collection of the return on equity as incorporated in the formula rate; and**

[33] The FERC is referred to as "the Commission" in the following quoted passage.
[34] See, e.g., KPCo's response to AG 1-394, Attachment 1, page 226 of 253.

> **<u>B. Refund will be due, should the return on equity, specified in the formula be found not just and reasonable, dating from the first day of January immediately following the date the complaint is filed or an investigation is instituted by the Commission on its own motion, calculated on the resulting difference in rates due to the application of the return found to be just and reasonable and the return stated in the formula.</u>** The first such effective date for the calculation of refunds shall be January 1, 1989.
>
> Any other complaint which challenges the justness and reasonableness of any other component of the filed formula rate or any other complaint filed at any other time which challenges the justness and reasonableness of the specified rate of return on common equity and which is set for investigation by the Commission shall be pursued under Section 206 of the Federal Power Act.
>
> (Emphasis supplied.)

Q. How much were the return on equity charges from AEPCO to KPCo for the 12 months ending September 30, 2014?

A. As summarized on Exhibit RCS-27 and shown on the excerpts of the AEPCO invoices to KPCo, which are reproduced in Exhibit RCS-28, the affiliated charges to KPCo for Return on Equity for this period were approximately $3.0 million for unit 1 and $2.359 million for units one and two combined.[35]

Q. Do you also show the potential annual and total savings, if the affiliate-charged ROE of 12.16% was reduced?

A. Yes. Exhibit RCS-27 also includes illustrative estimates of the annual and total savings if the affiliate-charged ROE of 12.16% in the Rockport UPA was reduced to each of these:

(1) KPCo's requested ROE of 10.62%.

[35] For the 12 month period ending September 30, 2014, the Return on Equity charges billed by AEPCO to KPCo for Rockport Unit 2 were negative.

(2) KPCo's currently authorized ROE of 10.5%.

(3) The AG's recommended ROE of 8.65%

Q. What do you recommend?

A. I recommend that the Commission and any other parties that are concerned that the 12.16 percent ROE being used as the basis for charges to KPCo in this affiliated contract is excessive address the matter before FERC as soon as possible. The Commission should also consider establishing an Affiliate Charge ROE-Reduction Rider for KPCo in order to flow back to ratepayers the impact of the cost reductions to KPCo that could be achieved by having the 12.16 percent ROE in this affiliated contract reduced by the FERC, and requiring KPCo to present an accounting of the Return on Common Equity portion of the AEP Generating Company charges to KPCo that are related to an ROE reduction and to report on any refunds from AEPCO to KPCo relating to such a reduced affiliated contract ROE.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For:	)	
(1) A General Adjustment Of Its Rates;	)	
(2) Approval of Its 2014 Environmental Compliance	)	Case No. 2014-00396
Plan; (3) Approval of Tariffs And Riders; and (4)	)	
An Order Granting All Other Required Approvals	)	
and Relief	)	

AFFIDAVIT of Ralph C. Smith

State of Michigan)

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

Ralph C. Smith

Ralph C. Smith

SUBSCRIBED AND SWORN to before me this 23rd day of March, 2015.

Kathleen K. Niemiec

NOTARY PUBLIC

My Commission Expires: July 31, 2015

KATHLEEN K. NIEMIEC
NOTARY PUBLIC, STATE OF MI
COUNTY OF WAYNE
MY COMMISSION EXPIRES Jul 31, 2015
ACTING IN COUNTY OF WAYNE