COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVINGS ITS 2014 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; AND (4) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))	**CASE NO. 2014-00396**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 2015

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

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

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration degree in accounting and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, and a Certified Management Accountant ("CMA").

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on nearly two hundred occasions.

I have testified before the Kentucky Public Service Commission on numerous occasions, including Kentucky Power Company ("KPC" or "Company") base rate proceedings, Case Nos. 2009-00459 and 2005-00341; the Mitchell acquisition proceeding, Case No. 2012-00578; a biomass proceeding, Case No. 2013-00144; the Big Sandy 2 environmental retrofit proceeding, Case No. 2011-00401; a wind power proceeding, Case No. 2009-00545; various Company Environmental Surcharge ("ES") proceedings and Fuel Adjustment Clause ("FAC") proceedings; numerous Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") base rate proceedings; numerous LG&E and KU ES and FAC proceedings; and other proceedings involving Big Rivers Electric Corporation and East Kentucky

Power Cooperative, Inc. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service on the KPC system. The members of KIUC participating in this proceeding are: Air Products and Chemicals, Inc., Air Liquide Industrial U.S. LP, AK Steel Corporation, EQT Corporation, and Marathon Petroleum Company LP.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) summarize the KIUC revenue requirement recommendations, 2) address specific issues that affect the Company's revenue requirement, 3) quantify the effect on the revenue requirement of the return on equity recommendation provided by KIUC witness Mr. Richard Baudino, 4) address the costs included in the Big Sandy Retirement Rider ("BSRR"), 5) address the costs included in the Big Sandy 1 Operation Rider ("BS1OR"), 6) address the sharing of off-system sales ("OSS") margins reflected in the System Sales Clause ("SSC") included in the Company's fuel adjustment clause, and 7) address the Company's proposal for a new NERC Compliance and Cybersecurity Rider ("NCCR").

Q. Please summarize your testimony.

A. The Company's rates charged to customers already have increased 73% over the last ten years. The Company seeks additional increases of 12.5% in this proceeding. The Commission should carefully scrutinize the Company's requests in this proceeding in order to limit the increases to just and reasonable amounts and to minimize the effects on customers.

I recommend that the Commission increase the Company's rates by no more than $25.814 million compared to the Company's proposed increase of $69.977 million. The following table provides a summary of the KIUC recommendations compared to the all of Company's requests for various forms of rate recovery, including the base revenue requirement, the Mitchell FGD included in the ES revenue requirement, the BSRR revenue requirement, the BS1OR revenue requirement, the PJM rider revenue requirement, and the economic development rider revenue requirement.

Kentucky Power Company Revenue Requirement
Summary of KIUC Recommendations
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

Increase Requested by Company	
Change in Base Rates Without Proposed Transmission Adjustment	(4.696)
Proposed Transmission Adjustment - Base Rates	(0.127)
Big Sandy Retirement Rider ("BSRR")	21.856
Big Sandy Unit 1 Operation Rider ("BS1OR")	18.245
Mitchell FGD Recovered Through Environmental Surcharge	34.391
Kentucky Economic Development Surcharge ("KEDS")	0.308
Total Increase Requested by Company	**69.977**
Increase Recommended by KIUC	
Change in Base Rates With Proposed Transmission Adjustment	(36.670)
Proposed Transmission Adjustment - Base Rates	-
Big Sandy Retirement Rider ("BSRR")	13.282
Big Sandy Unit 1 Operation Rider ("BS1OR")	18.245
Mitchell FGD Recovered Through Environmental Surcharge	30.649
Kentucky Economic Development Surcharge ("KEDS")	0.308
Total Increase Recommended by KIUC	**25.814**

The following tables summarize the KIUC adjustments to the Company's proposed net rate increase and the effect on the Company's claimed revenue surplus or deficiency separately for the base revenue requirement, the Mitchell FGD in the ES, and the BSRR. The amounts on the following tables are Kentucky retail jurisdictional. The amounts on the base revenue requirement table are slightly greater than the expense amounts cited in my testimony due to the gross-up for bad debt expense and the PSC assessment included in the revenue requirement.

Kentucky Power Company Revenue Requirement
Summary of KIUC Recommendations
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

BASE RATES	
Company Proposed Decrease Without Proposed Transmission Adjustment	**(4.696)**
Operating Income Issues	
Remove Incentive Compensation Expense Tied to Financial Performance	(2.612)
Correct Interest Synchronization Deduction Error in Income Tax Expense	(0.350)
Include PCLA in Income Tax Expense	(0.516)
Include Section 199 Deduction in Gross Revenue Conversion Factor	(2.116)
Reject Company Adjustment to Reduce Removal Costs on Schedule M Based on 3-Yr Avg.	(0.206)
Remove Amortization Expense for Deferred Big Sandy 2 FGD Costs	(1.111)
Remove Amortization Expense for Deferred IGCC Costs	(0.053)
Remove Amortization Expense for Deferred CCS/FEED Costs	(0.035)
Remove Amortization Expense for Deferred Carr Site Costs	(0.104)
Shorten Amortization of OH State ADIT to Three Years Rather than Life of the Unit	(1.362)
Reduce Depreciation Expense to Remove Escalation on Terminal Net Salvage	(0.766)
Increase Off-System Sales Margins	(0.836)
Cost of Capital Issues	
Reject Proforma Adjustments Resulting in Negative Short Term Debt	(3.307)
Remove Non-Utility Investment in AEP Utility Money Pool	(1.037)
Reflect Increase in ADIT Due to Bonus Depreciation Extension in 2014	(2.557)
Reflect Return on Equity of 8.75%	(15.006)
Total KIUC Adjustments to KPCo Request - BASE RATES	**(31.973)**
KIUC Recommended Decrease - BASE RATES	**(36.670)**

Kentucky Power Company Revenue Requirement
Summary of KIUC Recommendations
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

Big Sandy Retirement Rider ("BSRR")	
Company Proposed Initial BSRR Revenue Requirement	**21.856**
Operating Income Issues	
Include Section 199 Deduction in Gross Revenue Conversion Factor	(0.409)
Cost of Capital Issues	
Reject Proforma Adjustments Resulting in Negative Short Term Debt	(0.389)
Remove Non-Utility Investment in AEP Utility Money Pool	(0.005)
Reflect Increase in ADIT Due to Bonus Depreciation Extension in 2014	(0.013)
Reflect Return on Equity of 8.75%	(1.826)
Remove Levelized Return Of and On Future Cost Additions Until Incurred	(5.933)
Total KIUC Adjustments to KPCO Request - BSRR	**(8.574)**
KIUC Recommended Increase - BSRR	**13.282**

Kentucky Power Company Revenue Requirement
Summary of KIUC Recommendations
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

Mitchell FGD Recovered Through Environmental Surcharge ("ES")	
Company Proposed Mitchell FGD Recovered Through Environmental Surcharge	**34.391**
Operating Income Issues	
Include Section 199 Deduction in Gross Revenue Conversion Factor	(0.591)
Cost of Capital Issues	
Reject Proforma Adjustments Resulting in Negative Short Term Debt	(0.544)
Remove Non-Utility Investment in AEP Utility Money Pool	(0.007)
Reflect Increase in ADIT Due to Bonus Depreciation Extension in 2014	(0.018)
Reflect Return on Equity of 8.75%	(2.582)
Total KIUC Adjustments to KPCO Request - Mitchell FGD in ES	**(3.742)**
KIUC Recommended Increase - Mitchell FGD in ES	**30.649**

Although there is no immediate effect on the Company's ES revenue requirement, except for the effects of the Mitchell FGD included in rate base in the ES, several of the KIUC recommendations will affect the rate of return and income tax expense on all other investments that are included in the Company's ES revenue starting in June 2015. These include the KIUC recommendations for the capital structure, cost of debt, return on equity, and the gross revenue conversion factor ("GRCF").

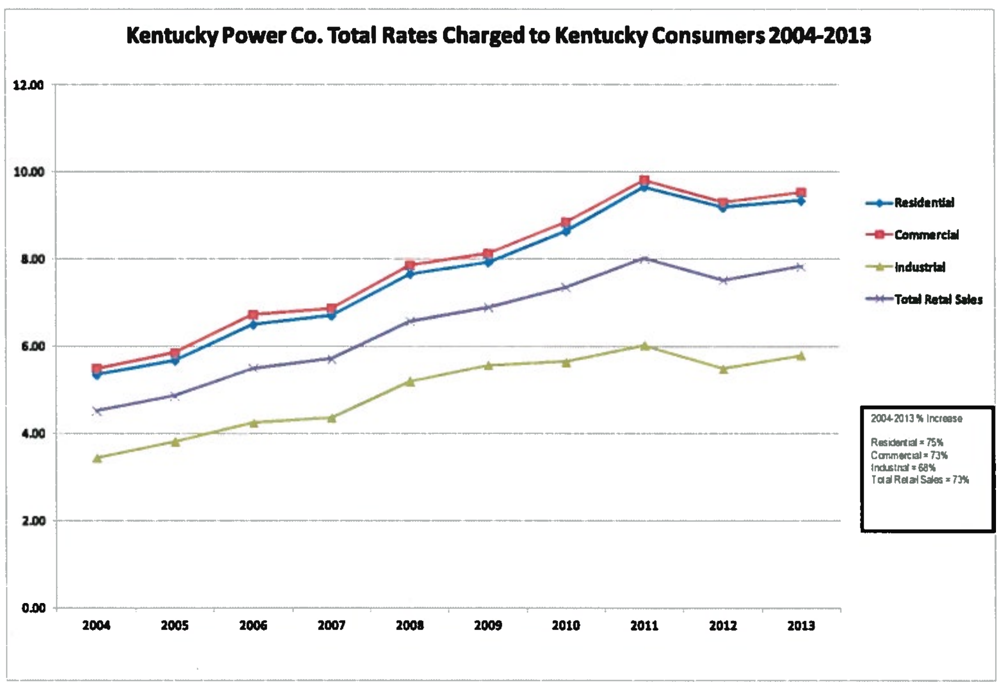
In addition to the revenue requirement issues identified on the preceding tables, I recommend that the Commission adopt a sharing of 90% to customers and 10% to the Company for the SSC rather than the 60%/40% proposed by the Company. I also recommend that the Commission reject the Company's proposal for an NCCR. KIUC witness Mr. Stephen Baron recommends that the Commission reject the Company's proposed PJM rider.

The remainder of my testimony is structured to address each of the issues on the preceding table and the Company's various surcharge requests. Amounts cited throughout the testimony are Kentucky retail-jurisdictional ("jurisdictional") unless otherwise indicated as "total Company."

II. SIGNIFICANT INCREASES IN CUSTOMER RATES

Q. Please describe the significant increases in customer rates over the last ten years.

A. The Company's rates have increased steadily and significantly over the last ten years. The Company's rates have increased an average of 73% over all customer classes. The following chart graphically portrays these increases for each customer class and in total from 2004 through 2013.



Q. Why are the historic increases in customer rates relevant in this proceeding?

A. First, they provide context for the increases that the Company seeks in this proceeding. These rate increases impact real customers in residential households, schools and other government agencies, and small and large businesses. These customers need electric service and generally do not have economically realistic alternatives.

Second, these increases affect household budgets/expenses, government budgets/expenses, and business budgets/expenses, as well as business competitiveness and viability. Each of these customers must manage their income and expenses efficiently. The Commission should insist that the Companies are managed and operated efficiently to minimize their costs and that the costs allowed recovery reflect the least reasonable cost.

III. OPERATING INCOME ISSUES

<u>Remove Incentive Compensation Expense Tied to Financial Performance</u>

Q. Please describe the Company's request for recovery of incentive compensation expense tied to AEP financial performance.

A. The Company included $2.625 million in incentive compensation expense tied to AEP financial performance pursuant to the AEP Long Term Incentive Plan ("LTIP").[1,2] This amount is comprised of $0.253 million in expense (total Company) incurred directly by KPC and $2.372 million in expense (total Company) allocated from AEPSC.[3]

Q. Please describe the AEP LTIP.

A. The primary purpose of the AEP LTIP is to motivate AEP executives and managers to maximize shareholder value by linking a portion of their compensation directly to

---

[1] Company's response to KIUC 1-32. The Company provided the incentive compensation cost incurred during the test year by FERC account (for CWIP and other balance sheet accounts and for O&M and A&G accounts). In this response, the Company states that a portion of this expense was removed from the base revenue requirement for the BSRR and BS1OR and there were additional amounts included due to the annualization of the Mitchell acquisition, but it declined to provide these quantifications. Consequently, I have used what the Company provided as a reasonable proxy and have assumed that the entirety of the expense was included in the base revenue requirement. The actual amount in the test year may be more or less and it may be allocated among the base, BSRR, and BS1OR revenue requirements. I have attached a copy of this response as my Exhibit___(LK-2).

[2] Company's response to KIUC 1-32. I summed the amounts charged to expense during the test year. To determine the amount included in the revenue requirement, I summed the expense amounts incurred directly by KPCo and that were allocated from AEPSC to KPCo. I then multiplied the sum times the Kentucky jurisdictional factor. The calculations are shown on my Exhibit___(LK-3).

[3] *Id.*

shareholder returns and earnings. The LTIP provides grants or awards in the form of performance units and restricted stock units (units are similar to shares of AEP common stock, but have no voting rights). The LTIP payouts are based on a three year performance and vesting period beginning January 1st of each year. Performance units are earned based on the achievement of two equally weighted performance measures compared to the target: three-year total shareholder return measured relative to the S&P Utilities and three-year cumulative earnings per share measured relative to a Board approved target.[4]

Q. **Should the Commission include the AEP LTIP incentive compensation expense in the Company's revenue requirement?**

A. No. The Commission precedent is to remove incentive compensation expenses from the revenue requirement if the expenses incentivize financial performance to achieve shareholder goals, not customer goals. The AEP LTIP incentive compensation expense is incurred to achieve shareholder goals and is not directly tied to the achievement of regulated utility service requirements. In fact, the AEP LTIP benefits shareholders to the detriment of customers in rate proceedings such as this.

In its order in Kentucky-American Water Company Case No. 2010-00036, the Commission disallowed incentive compensation expense tied to "financial goals

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[4] Company's response to KIUC 1-33. I have attached a copy of this response as my Exhibit___(LK-4).

that primarily benefited shareholders."[5] This expense falls clearly within that category and should be a shareholder cost, not a customer cost.

Similarly, in its order in Atmos Energy Corporation Case No. 2013-00148, the Commission stated "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 plants. . . 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."[6] Thus, the cost should be borne by shareholders, not customers.

In addition, this form of profit-maximizing incentive compensation incentivizes the Companies to seek greater rate increases from customers to improve AEP total shareholder return and earnings per share. The greater the rate increases and revenues, the greater the AEP total shareholder return and earnings per share and the greater the incentive compensation expense. There is an inherent conflict between lower rates to customers and greater financial performance for shareholders and incentive compensation for executives and other employees. This expense should be a shareholder cost.

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[5] Order in Kentucky American Water Company Case No. 2010-00036 at 14.

[6] Order in Atmos Energy Corporation Case No. 2013-00148 at 9.

Finally, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling because it provides additional earnings to ensure the achievement of the shareholder objectives, all else equal. Thus, the expense should be directly assigned to AEP shareholders, not customers.

Correct Interest Synchronization Deduction Error in Income Tax Expense

Q. Please describe the Company's calculation of the interest synchronization deduction used in the calculation of income tax expense.

A. The Company's calculation of the interest synchronization deduction is detailed on Section V Exhibit 2 W48. The Company calculated the interest synchronization adjustment using the interest expense on its adjusted long-term debt less the negative interest expense on its adjusted negative short term debt.

Q. Is this calculation correct?

A. No. The Company failed to include the $0.561 million in interest on the receivables financing. This interest is deductible for income tax purposes and should not have been excluded.

Q. What is your recommendation?

A. I recommend that the Commission include the $0.561 million in interest on the receivables financing.

Q. What is the effect of your recommendation?

A. The effect of including the interest on the receivables financing is a reduction of $0.217 million in income tax expense and a reduction of $0.350 million in the base revenue requirement.[7]

<u>Include Parent Company Loss Allocation in Income Tax Expense</u>

Q. Please describe the parent company loss allocation and how it affects the Company's income tax expense.

A. The parent company loss allocation ("PCLA") is a reduction in the Company's income tax expense recorded in its accounting books pursuant to the AEP Tax Allocation Agreement. In response to discovery, the Company described the Parent Company Loss Allocation as follows:

> The PCLA refers to the Parent Company Loss Allocation in which the tax benefit of the tax loss of American Electric Power Company, Inc. (Parent Company) is allocated prorata to those companies that participate in the AEP Consolidated Tax Return that have positive taxable income.
>
> ***
>
> The PCLA results in a reduction to the Company's income tax expense assuming that the Company has positive taxable income. The amount of the reduction is depend[e]nt on the actual amount of the parent company loss and the Company's relative taxable income as compared to the other companies in the consolidated group having taxable income.[8]

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[7] The calculations are shown on my Exhibit___(LK-5).

[8] Company's response to KIUC 1-21(a) and (b). I have attached a copy of the entire response to KIUC 1-21, including attachments as my Exhibit___(LK-6).

Q. Did the Company reflect the PCLA in the income tax expense included in its proposed revenue requirement?

A. No. The Company failed to reflect this component of its income tax expense, thus overstating it.

Q. Has the Commission historically included the PCLA in the calculation of income tax expense?

A. Yes. In response to discovery in this proceeding, the Company acknowledged that the Commission precedent was to include the PCLA as a reduction to income tax expense. The Company stated:

> The Company now understands that the Commission had historically required that the Company's portion of the parent company tax loss be included in the operating income tax expense for cost of service purposes. Based on the Commission's previous Orders, the Company should have included the PCLA as a reduction to income tax expense in this filing.[9]

Q. Aside from the Company's acknowledgement regarding Commission precedent to include the PCLA in income tax expense, does AEP actually agree that the PCLA should be reflected in income tax expense for ratemaking purposes?

A. Yes. AEP believes that the PCLA should be included in the calculation of income tax expense as a matter of principle, i.e., it is not merely a concession in recognition of the Commission's precedent on this issue.

[9] Company's response to KIUC 2-2. I have attached a copy of this response as my Exhibit___(LK-7).

Mr. Bartsch, the Company's witness on tax issues in this proceeding, was also a witness for Appalachian Power Company in West Virginia Case No. 14-1152-E-42T. In that proceeding, Mr. Bartsch testified that "the [West Virginia Public Service] Commission should adopt the Parent Company Loss Allocation Methodology, which is determined in accordance with the AEP Tax Allocation Agreement and is the approach recommended by Company witness Highlander."[10]

Q. What is the effect of reflecting the PCLA in income tax expense?

A. The effect is a reduction in income tax expense of $0.319 million and a reduction of $0.516 million in the base revenue requirement.[11]

<u>Include §199 Tax Deduction in Gross-Up Factor Used for Income Tax Expense</u>

Q. What is the §199 deduction?

A. §199 of the Internal Revenue Code ("IRC") allows a deduction against taxable income for qualified domestic production (manufacturing) activities. The §199 deduction is calculated by applying a 9% rate against qualified domestic production income for federal income tax expense and a 6% rate for state income tax expense.

[10] Direct Testimony of Jeffrey B. Bartsch in WV Case No. 14-1152-E-42T at 17.

[11] The Company provided the quantification of the effect on income tax expense in the test year in response to KIUC 1-21, a copy of which I have attached as my Exhibit___(LK-6). I grossed-up this adjustment to income tax expense to determine the effect on the revenue requirement using the gross-up factor that I subsequently recommend, which includes the effect of the Section 199 deduction. The effect on the revenue requirement will be greater if the Commission uses the Company's proposed gross-up factor, which does not include the effect of the Section 199 deduction.

This requires an allocation of the Company's taxable income to production (or generation) activities, not only for the calculation of the §199 deduction in the test year income tax expense, but also for the calculation of the gross revenue conversion factor. Kentucky Utilities Company and Louisville Gas and Electric Company use a production rate base allocation factor to allocate taxable income for this purpose in their base rate proceedings.

Q. Did the Company include a §199 deduction in the calculation of income tax expense?

A. Yes. The Company used a three year historic average of the §199 deduction in the calculation of income tax expense under the assumption that it had filed a standalone income tax return in those years.[12]

Q. Do you agree that it is appropriate to include a §199 deduction in the calculation of income tax expense and that the Company's methodology is reasonable for this purpose?

A. Yes.

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[12] Bartsch Direct at 12.

Q. Did the Company also include the §199 deduction in the calculation of the gross revenue conversion factor?

A. No. In contrast to its use of the §199 deduction in the calculation of income tax expense, the Company excluded the §199 deduction from the GRCF as shown in Section V, Workpaper S-2, Page 2.[13] In other words, the Company incorporated the §199 deduction in the calculation of income tax expense, but then unreasonably assumed that the increase in taxable income arising from its proposed rate increase would not result in an additional §199 deduction.

Q. What is the Commission precedent for the §199 deduction in prior KPCo proceedings?

A. The Commission first incorporated this deduction in the computation of the Company's gross conversion factor in all ES surcharge proceedings in Case No. 2005-00068, despite the Company's strong opposition in that proceeding. The Company appealed the Commission's decision in Case No. 2005-00068 to the Franklin Circuit Court, which affirmed the Commission. The Company then appealed it to the Kentucky Court of Appeals, which also affirmed the Commission.[14] The Commission has incorporated this deduction in the GRCF in all

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[13] *Id.*, 4.

[14] *Commonwealth ex rel. Stumbo v. Kentucky Public Service Comm'n*. 243 S.W.3d 374, 383 (Ky. App. 2007).

subsequent ES surcharge proceedings.

Q. In contrast to the Company's opposition to reflecting the § 199 deduction in the GRCF in this base rate proceeding, have KU and LG&E reflected the § 199 deduction in all of their recent base rate case filings?

A. Yes. KU and LG&E both reflected this deduction in the calculation of income tax expense and in the calculation of the GRCF in pending Case Nos. 2014-00371 and 2014-00372, respectively.[15] KU and LG&E also reflected this deduction in Case Nos. 2008-00251 and 2008-00252, 2009-00548 and 2009-00549, and 2012-00221 and 2012-00222.

Q. How do KU and LG&E incorporate the §199 deduction in their calculations of the GRCF?

A. In their base rate case filings, KU and LG&E use the percentage of production plant to total plant included in rate base as the allocator to calculate the percentage of taxable income considered as qualified domestic production activities income. They multiply the resulting production percentage times the 9% rate to determine the weighted §199 deduction percentage for federal income tax expense and times the 6% rate for state income tax expense.

[15] I have attached a copy of KU's and LG&E's calculation of the GRCF in their pending cases as my Exhibit___(LK-8).

In their ES filings, like the Company, KU and LG&E correctly assume that the entirety of the environmental investment is production, so there is no need to allocate the deduction to production.

Q. Do you agree with the KU and LG&E methodology for the base revenue requirement?

A. Yes. This same methodology should be used for the Company's base revenue requirement. The income tax expense is a function of the weighted equity return applied to capitalization. Only the income tax expense due to the equity return on the production portion of the capitalization is eligible for the §199 deduction.

Q. Should there be any change in the present methodology for the Company's Mitchell FGD or any other ES revenue requirement?

A. No. The Company applied the same GCRF for the base revenue requirement, the Mitchell FGD revenue requirement, and the BSRR revenue requirement. Even if the Commission adopts the Company's proposal for the base revenue requirement, it should not do so for the Mitchell FGD or any other ES revenue requirement, or for the BSRR revenue requirement.

Q. Does that mean that there will be two separate GCRFs?

A. Yes. That is the case with KU and LG&E. I have reflected separate GCRFs in my quantifications of this issue for the base revenue requirement on the one hand and for the Mitchell FGD and the BSRR revenue requirements on the other hand. The GRCF will be slightly more for the base revenue requirement to reflect the allocation of the §199 deduction to production than it is for the Mitchell FGD and BSRR revenue requirements, which require no allocation because they are 100% production.

Q. The Company argues that the Commission should not include the §199 deduction in GRCF because it assumes that the Company always will be able to claim the deduction.[16] Please respond.

A. This argument is logically flawed. First, the Company's argument is negated by the very fact that it included the §199 deduction in the income tax expense calculation. If anything, that fact supports reflecting the §199 deduction in the GRCF, not excluding it.

Second, the Commission is limited to the facts and circumstances of the historic test year unless there are known and measurable changes and these changes are considered on a consistent and comprehensive basis. The Company has offered no projections of its taxable income in future years and has provided no evidence that it will be unable to take the §199 deduction in future years. Although it is true

[16] Bartsch Direct at 5.

that taxable income varies from year to year, that is due, at least in part, to the fact that revenues vary from year to year and expenses vary from year to year. Yet, the Commission determines the reasonable level of such revenues and expenses for the test year in order to quantify the revenue requirement; it doesn't simply ignore certain revenues or expenses because they might vary in future years.

Q. Why is it unreasonable to exclude the §199 deduction from the GRCF?

A. The rate increase sought in this proceeding, if granted or granted at a lesser amount, will increase taxable income and thus, the amount of the §199 deduction reflected in the Company's calculation of income tax expense, all else equal. The concept of the GRCF is to allow the Company to recover the incremental income tax expense resulting from the rate increase, not something more.

The income tax rates that are used in the GRCF generally assume that the income from the rate increase will be taxed at the Company's maximum incremental income tax rate on a standalone basis. That maximum incremental income tax rate should reflect all reductions that are available. However, the Company's proposal incorrectly assumes that the §199 deduction does not apply to the additional taxable income, which is not true given that the Company agrees that the §199 deduction does apply in the historic test year even with no rate increase. Consequently, the Company's proposal overstates the incremental income tax rate and the resulting increase in income tax expense resulting from the rate increase, thus transferring this tax benefit from customers to the Company's shareholder. The Commission should reject this windfall to the Company's shareholder.

Q. What are the effects of including the §199 deduction in the Company's revenue requirements?

A. The effects are reductions of $2.116 million in the Company's base revenue requirement, $0.591 million in the Mitchell FGD revenue requirement, and $0.409 million in the BSRR. I calculated the effect on the base revenue requirement using the KU and LG&E methodology that I previously described and the effects on the Mitchell FGD and BSRR revenue requirements using the present methodology for the ES.[17] I quantified these adjustments after all other KIUC adjustments to the capital structure and costs of capital were incorporated into the revenue requirement. I note this because the sequence in which the adjustments are made affects their quantification.

Reject Proforma Adjustment to Reduce Removal Cost Schedule M

Q. Please describe the removal cost deduction.

A. The Company is allowed to deduct removal costs on its income tax returns. This results in a reduction in current income tax expense and total income tax expense.

[17] The calculations for the effects on base rates are shown on my Exhibit___(LK-9) at Section VI and page 3. See Exhibit___(LK-17) page 6 for the reduction in the Mitchell FGD revenue requirement. Likewise, see Exhibit___(LK-18) page 6 for the reduction in the BSRR revenue requirement.

There is no offsetting increase in deferred income tax expense because the removal cost deduction is treated as flow-through for Kentucky retail ratemaking purposes.[18] Thus, a reduction in the test year removal cost deduction directly increases taxable income and income tax expense for ratemaking purposes.

Q. Please describe the Company's proposed adjustment to the removal cost deduction in the test year.

A. The Company proposes an adjustment to reduce the test year deduction by $0.326 million from $8.300 million (total Company) to $7.970 million (total Company) to reflect the average of the deductions for the years 2011-2013.[19] Mr. Bartsch claims that a three year average is "more representative of a normal annual Schedule M Adjustment."[20]

Q. Is such an adjustment appropriate?

A. No. The Company has not demonstrated that there is significant variability in the deduction, other than a spike upward in calendar year 2012, which appears to be an anomaly and is outside the test year. The removal deduction has been trending

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[18] Company's response to KIUC 1-26, a copy of which I have attached as my Exhibit___(LK-10).

[19] Section V Exhibit 2 Tab W49.

[20] Bartsch Direct at 10.

steadily upward since 2009. The actual deduction was $8.045 million (total Company) for 2014 compared to the actual deduction of $7.376 million in 2013.[21]

Q. If the Commission determines that it is appropriate to use a three year average of the removal cost deduction, then should it update the Company's calculation to reflect the three year period 2012-2014?

A. Yes. The adjustment would change from a reduction in the removal cost deduction of $0.326, as proposed by the Company, to an increase in the deduction of $0.619 million.[22] The effect of this alternative would be to reduce the Company's base revenue requirement by $0.590 million.

<u>**Remove Amortization Expense for Deferred Big Sandy 2 FGD Costs**</u>

Q. Please describe the Company's request for recovery of the Big Sandy 2 FGD study costs.

A. The Company seeks recovery of the $28.025 million in preliminary Big Sandy 2 FGD study costs incurred in two separate time periods, one that addressed the wet FGD technology and ended in 2006 and another that addressed the dry FGD technology and ended in 2011. The Company included $1.105 million in

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[21] Response to KIUC 1-26 showing the actual annual removal cost deductions for the years 2009 through 2014.

[22] The calculations are shown on my Exhibit___(LK-11).

amortization expense based on the expected 25 years remaining life of the Mitchell units.[23]

Q. Has the Commission previously addressed this issue?

A. Yes. The Commission denied the recovery of these costs in Case No. 2012-00578. In its Order in that proceeding, the Commission stated:

> While studies or evaluations relating to major multi-year capital asset projects are generally considered necessary and recovery of the cost of such studies and evaluations through rate is generally considered reasonable, given the uniqueness of the situation as presented herein, the Commission finds that this provision of the Stipulation is not reasonable and should be stricken.
>
> ***
>
> The Commission finds that the potential imposition of the $28 million Scrubber Study Costs, in addition to the costs associated with the Mitchell acquisition, is not reasonable, particularly when the Scrubber Study Costs, although spanning a significant period of time, did not result in a formal Kentucky Power proposal upon which the Commission rendered a decision based on its merits. The Commission likewise finds the potential imposition of the Scrubber Study Costs on ratepayers not reasonable due to the fact that a study of this magnitude did not result in the addition of a scrubber or other pollution control facilities at Big Sandy Unit 2.[24]

Q. Did the Company accept and agree to be bound by the Commission's decision to deny recovery of the Big Sandy 2 FGD study costs?

A. Yes. The President of the Company agreed to accept this decision in a letter to the Commission dated October 14, 2013. In his letter, Mr. Pauley stated:

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[23] Wohnhas Direct at 20.

[24] Order in Case No. 2012-00578 at 38-39.

> Pursuant to ordering paragraph 4 of the Commission's October 7, 2013 Order in Case No. 2012-00578 I write to notify the Commission that Kentucky Power Company accepts and agrees to be bound by the modifications to the July 2. 2013 Stipulation and Settlement Agreement set forth in Appendix 13 to the Commission's Order.[25]

After the Commission's decision in Case No. 2012-00578 denying recovery of the Big Sandy 2 FGD study costs and the Company's agreement to accept and be "bound" by this decision, it is surprising, to say the least, that the Company would again seek recovery of these costs. The Company's letter to the Commission did not condition its agreement on the ability to seek recovery in a subsequent proceeding or state that it was temporary or limited to Case No. 2012-00578.

Q. Did the Company write off the Big Sandy 2 FGD study costs in 2013 after the Commission issued its Order in Case No. 2012-00578?

A. Yes. It wrote off the deferred costs through the income statement, but created a contra-asset (negative asset) on the balance sheet equal to the deferred cost. The net amount remaining on its accounting books is $0.[26]

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[25] Company's response to KIUC 1-52, which included a copy of the Company's filing accepting the modifications filed by its counsel, including the letter from Mr. Pauley. I have attached a copy of this response as my Exhibit___(LK-12).

[26] Company's responses to KIUC 1-49, 1-50, and 1-51. In response to KIUC 1-49, the Company confirmed that it had written off the Big Sandy 2 FGD study costs. In response to KIUC 1-50, the Company referred to the accounting journal entries, which it provided in response to KIUC 1-51. In response to KIUC 1-51, the Company provided its internal accounting memorandum analyzing the Commission's decision to deny recovery of the costs ("The Commission denied deferral for future recovery in a future base case the $28,113,304 FGD costs") and describing the basis for the writeoff of the Big Sandy 2 FGD study costs as well

Q. Should the Commission to reverse its prior determination in Case No. 2012-00578?

A. No. The Commission's Order in Case No. 2012-00578 is final. The Company did not seek rehearing and it wrote-off the deferred cost.

The Company now argues that recovery should be allowed because the Mitchell acquisition was less expensive than retrofitting Big Sandy 2 with an FGD. However, that conclusion was fully vetted and formed the basis for the Commission's Order in Case No. 2012-00578; it is not a valid reason now to revisit or reverse the decision made in that proceeding.

The Company also now argues that denying recovery "discourages the sort of open-minded investigation that yielded the Mitchell transfer." Whether that is true or not, it is irrelevant to the issue of the Big Sandy FGD study costs. The Commission already decided this issue.

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as the IGCC, CCS/FEED, and Carrs Site costs. I have attached a copy of the responses to KIUC 1-49, 1-50, and 1-51 as my Exhibit___(LK-13).

Remove Amortization Expense for Deferred IGCC Costs

Q. Please describe the Companies' request for recovery of IGCC costs.

A. The Company requests recovery of $0.053 million in annual amortization expense over 25 years (a total of $1.313 million) incurred for a potential Integrated Gasification Combined Cycle ("IGCC") generating plant that no longer is under consideration or development.[27] These costs were incurred for engineering, design, and other pre-construction costs incurred in 2007 and 2008.[28] The Company determined that it would not proceed with construction of the IGCC facility unless the Kentucky General Assembly adopted legislation to support the recovery of the IGCC's costs through rates. The Assembly never adopted this legislation.[29] KIUC actively opposed this legislation because it was uneconomic and would negatively impact the Kentucky economy.

Q. Did the Company write off the IGCCC costs in 2013 after the Commission issued its Order in Case No. 2012-00578?

A. Yes. It wrote off the deferred costs through the income statement, but created a contra-asset (negative asset) on the balance sheet equal to the deferred cost. The net

[27] Yoder Direct at 5.

[28] Wohnhas Direct at 16.

[29] Wohnhas Direct at 16.

amount remaining on its accounting books is \$0.[30]

Q. Should the Commission authorize recovery of the IGCC costs?

A. No. The Company has failed to justify recovery of these costs. The Company never sought a CPCN and the Commission never certified the project. The Company never sought and the Commission never authorized the deferral of these costs for subsequent ratemaking recovery. The Company incurred the costs at its own risk. Finally, the Company has already written off the costs.

<u>Remove Amortization Expense for Deferred CCS/FEED Costs</u>

Q. Please describe the Companies' request for recovery of deferred CCS/FEED costs.

A. The Company requests recovery of \$0.034 million in annual amortization expense over 25 years (a total of \$0.850 million) incurred for carbon capture and sequestration ("CCS") by Appalachian Power Company at it Mountaineer generating station in West Virginia.[31] After the Virginia and West Virginia Commissions denied recovery of these costs, AEP allocated a portion of the costs to other AEP utilities, including the Company.

[30] Company's response to KIUC 1-51.

[31] Yoder Direct at 5.

Q. Did the Company write off the deferred CCS/FEED costs in 2013 after the Commission issued its Order in Case No. 2012-00578?

A. Yes. It wrote off the deferred costs through the income statement, but created a contra-asset (negative asset) on the balance sheet equal to the deferred cost. The net amount remaining on its accounting books is $0.[32]

Q. Should the Commission authorize recovery of the CCS/FEED costs?

A. No. The Company has failed to justify recovery of these costs. These costs were incurred by Appalachian Power Company and were not allocated to the Company until after the Virginia and West Virginia Commissions denied ratemaking recovery. The Company never sought and the Commission never certified the project. The Company never sought and the Commission never authorized the deferral of these costs for subsequent ratemaking recovery. The Company incurred the costs at its own risk. Finally, the Company has already written off the costs.

<u>Remove Amortization Expense for Deferred CARR Site Costs</u>

Q. Please describe the Companies' request for recovery of deferred CARR site costs.

A. The Company requests recovery of $0.103 million in annual amortization expense over 25 years (a total of $2.575 million) for preliminary site design and engineering

[32] Company's response to KIUC 1-51.

costs incurred for a potential new generation facility at the CARRS site in Lewis County, Kentucky. The Company did not include the cost of purchasing the CARRS site in either capitalization or amortization expense. The Company has decided not to proceed with the construction of new generation at the site.[33]

Q. Did the Company write off the deferred CARRS site costs in 2013 after the Commission issued its Order in Case No. 2012-00578?

A. Yes. It wrote off the deferred costs through the income statement, but created a contra-asset (negative asset) on the balance sheet equal to the deferred cost. The net amount remaining on its accounting books is $0.[34]

Q. Should the Commission authorize recovery of the deferred CARRS site costs?

A. No. The Company has failed to justify recovery of these costs. The Company never sought a CPCN and the Commission never certified the project. The Company never sought and the Commission never authorized the deferral of these costs for subsequent ratemaking recovery. The Company incurred the costs at its own risk. Finally, the Company has already written off the costs.

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[33] Yoder Direct at 5 and Wohnhas Direct at 17.

[34] Company's response to KIUC 1-51.

Shorten Amortization of The Mitchell Ohio State ADIT to Three Years Rather than Life of Units

Q. Please describe the Company's proposal to amortize the Ohio state ADIT related to the Mitchell acquisition.

A. The Company proposes to amortize the Ohio state ADIT related to the Mitchell acquisition over the lives of the Mitchell units.[35] On December 31, 2013, in conjunction with the Mitchell acquisition, the Company recorded $4.724 million in Ohio state ADIT and proposes to amortization this amount to expense over the remaining book life of the Mitchell units of 23.59 years.[36]

Q. Is this reasonable?

A. No. The Ohio state ADIT is not a KPCo deferred income tax liability. It never will be paid to Ohio, Kentucky, or any other tax authority.[37] It is more akin to a regulatory liability, which means that it is simply an amount due to the Company's customers. In response to discovery, the Company agreed with this assessment.[38]

[35] Bartsch Direct at 11.

[36] *Id.*

[37] Company's response to KIUC 1-22. In that response, the Company stated "The deferred state income taxes that were transferred from Ohio Power Company to Kentucky Power Company related to the Mitchell Plant is not a direct future state income tax obligation of the Company." I have attached a copy of this response as my Exhibit___(LK-14).

[38] Company's response to KIUC 1-24. In that response, the Company stated "Since the Company has never recorded Deferred SIT for ratemaking purposes, in this special situation it could be deemed to be more akin to a regulatory liability.

As a regulatory liability, this amount is no longer tethered to the service lives of the Mitchell units and the Commission has the discretion to amortize the amount over a shorter period than proposed by the Company.

Q. What is your recommendation?

A. I recommend that the Commission amortize this regulatory liability over three years in order to reduce the immediate rate impact of fully including the Mitchell units in the revenue requirement in this proceeding.

Q. What is the effect of your recommendation on the revenue requirement?

A. The effect is a reduction in the expense of $1.355 million and a reduction in the revenue requirement of $1.362.[39]

<u>**Reduce Terminal Net Salvage in Proposed Mitchell Depreciation Rates**</u>

Q. Please describe the terminal net salvage reflected in the Company's proposed Mitchell depreciation rates.

A. The Company relied on the results of a "conceptual dismantling cost estimate" performed by Sargent & Lundy to develop the terminal net salvage. This study

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[39] The calculations are shown on my Exhibit___(LK-15). The effect of my recommendation is the difference between the Company's proposed amortization over the service lives of the units and my recommendation for a three year amortization period.

provided estimated removal cost and salvage amounts specific to the Mitchell plant. The costs and salvage income were stated in 2013 dollars.[40]

The Company then escalated the 2013 dollars to 2040 dollars using a 2.35% annual escalator to restate the cost estimate in 2040 dollars. The Company then calculated the proposed negative 5% terminal net salvage using the 2040 dollars as a percentage of terminal retirements.[41]

Q. Should the Commission escalate the terminal net salvage to 2040 dollars to determine the Mitchell depreciation rates in this proceeding?

A. No. This overstates the effect on depreciation rates and expense by frontloading a future cost. The Commission should be careful that it does not impose an unnecessary cost on the Company's customers.

If the Commission includes terminal net salvage in the depreciation rates, then it should minimize the amount recovered. As a foundational matter, there is no certainty that the Mitchell plant actually will dismantled or when. The Company will have to seek and obtain a CPCN for that purpose. It may be more economical to retire the plant in place, in which case the plant will not be dismantled and the cost

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[40] Kentucky Power Company Depreciation Study Report (Exhibit DAD-2 at 17 attached to Davis Direct.

[41] The total net salvage used in Exhibit DAD-2 is negative 7%.

will not be incurred. However, the Commission should not predetermine a decision that is not required at this time.

In addition, there is uncertainty on the cost that will be incurred, even in today's dollars. The Company's proposed escalation compounds the uncertainty of the cost estimate.

Finally, the use of 2040 dollars for 2015 ratemaking purposes is an inherent mismatch and forces today's customers to subsidize future customers. If the cost estimate or actual cost escalates in future years, then the increases, to the extent they are reasonable and prudent, can be reflected in periodic revisions and updates to depreciation rates and expense.

Q. If the escalation is removed, what effect does that have on the negative terminal net salvage as a percentage of terminal plant retirements?

A. It reduces the terminal net salvage to negative 3%.

Q. What is your recommendation?

A. I recommend that the Commission deny the proposed escalation of the Mitchell plant dismantlement cost estimate to 2040 dollars and limit the terminal net salvage to the Sargent & Lundy conceptual cost estimate in 2013 dollars.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $0.761 million in depreciation expense.[42]

__Increase Off-System Sales Margins__

Q. Please describe the OSS margins included by the Company in the base revenue requirement.

A. The Company included $14.300 million in OSS margins in the base revenue requirement compared to the actual $76.088 million in the test year. The Company made the following adjustments to the actual test year amount:

- Removed test year OSS margins associated with the AEP East Pool that ceased to exist on January 1, 2014.

- Removed test year OSS margins from Big Sandy 2 to reflect its retirement no later than May 31, 2015.

- Annualized test year OSS margins from the Mitchell plant. The Company owned 50% of the Mitchell plant for only nine months during the test year.

- Removed test year margins for the effects of the Polar Vortex in January and February 2014.

Q. Are the first three of these adjustments reasonable given the changes in the Company's generating unit portfolio?

A. Yes. The adjustments are consistent with the termination of the AEP East Pool

[42] The calculations are shown on my Exhibit___(LK-16).

Agreement and the changes in the Company's generating unit portfolio.

Q. Is the adjustment for the effects of the Polar Vortex reasonable?

A. No. I agree that it is reasonable to adjust the OSS margins to normalize the extreme weather event that occurred in January and February 2014, but I disagree with the methodology the Company used for the adjustment.

Q. Please describe how the Company calculated the adjustments to the per books OSS margins for the test year.

A. The Company adjusted the OSS margins based on an analysis that reconstructed the hourly margins for the test year using a model that it developed to restack its resources.[43] The model sold all generation in excess of native load into the PJM market at the Day Ahead spot market price. The OSS margins were calculated as the difference between the revenue received and the fuel cost incurred in each hour.

Q. Please describe the Company's Polar Vortex adjustment.

A. Mr. Vaughan compared market prices during the 2008 to 2013 period to the market prices during the 2014 period and concluded that the 2014 period was not representative of market prices that had occurred previously. As a result, Mr. Vaughan's replaced the actual January and February 2014 PJM market prices in the

[43] Vaughn Direct at 29.

test year with an average of the actual PJM market prices during January and February during the six years from 2008 through 2013.

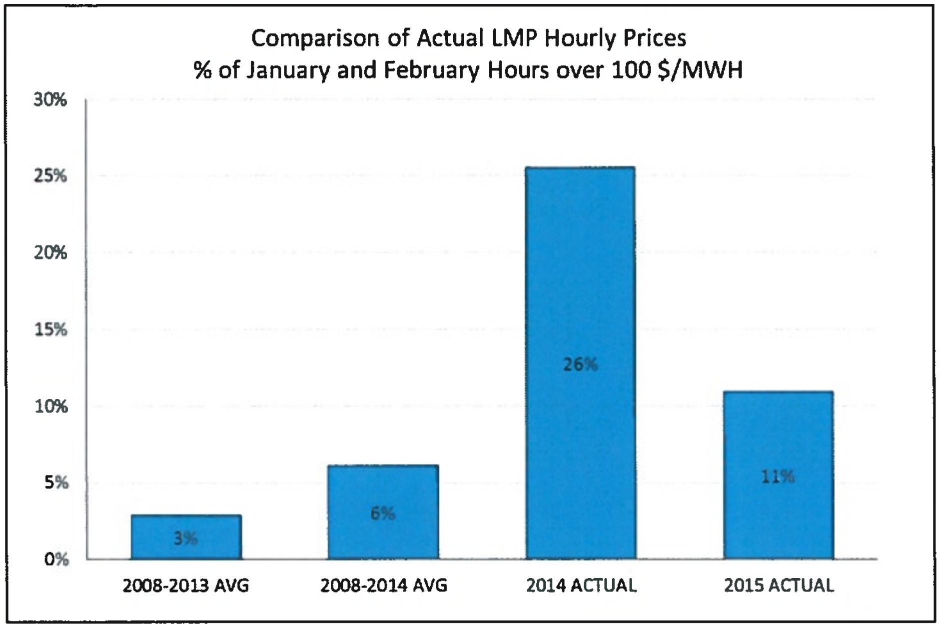
Q. Do you agree that the 2008-2013 period is representative of current or future conditions?

A. No. Mr. Vaughan presented no evidence to support his contention that 2008 – 2013 is representative of current or future conditions. He merely demonstrated that 2014 was different than the average for the 2008 – 2013 period. While I agree that 2014 was different than the average for the 2008 – 2013 period, that does not mean that 2008 – 2013 necessarily is representative of conditions that will exist once Big Sandy 2 is retired. A further assessment is necessary. First, for portions of the 2008 to 2013 period, the U.S. was recovering from a major recession. Economic growth has since rebounded, which may lead to higher market prices. Second, some of the coal units that were operating during the 2008 – 2013 period already have been or will be shut down in the near future due to environmental regulations (Big Sandy 2 among others). That most likely will lead to higher market prices. Finally, it is possible that cold weather patterns will occur again in the future. In fact, in January and February 2015 there were times that the weather was bitterly cold in parts of the U.S. and parts of the country suffered through multiple snowstorms, and in some cases record snowfall.

Q. Do you recommend an alternative that builds on and improves the Company's proposed Polar Vortex adjustment?

A. Yes. I recommend that 2014 data be included in the calculation of average LMP prices instead of removing it entirely as the Company proposes. In other words, instead of averaging together only the 2008 – 2013 LMP prices, I recommend that the Commission use an average of the 2008 – 2014 LMP prices.

The following chart demonstrates that it is reasonable to include 2014 in the average compared to the most recent actual experience. The chart shows the percentage of hours during the specified periods that LMP prices exceeded $100/MWH. Although there were substantially more hours at this level in 2014 than on average over the 2008 – 2013 period, the 2015 results are nearly four times the average for the 2008 – 2013 period. The chart shows that a better representation of 2015 would be to use an average over a 7 year period, instead of the six years the Company used. The 2015 results still are nearly twice the average over the 2008 – 2014 period.



Thus, including 2014 in the average results in a more representative approximation for the current and future periods.

Q. What is the effect of your recommendation on the base revenue requirement?.

A. It increases the OSS margins by $0.832 million and reduces the Company's base revenue requirement by $0.836 million.

IV. COST OF CAPITAL ISSUES

<u>Reallocate Company's Proforma Adjustments That Result In Negative Short-Term Debt to Long-Term Debt and Common Equity</u>

Q. Did the Company have a per books balance of short-term debt at the end of the test year?

A. No. The per books balance of short-term debt at the end of the test year was $0.

Q. Why is this significant?

A. It is significant because the Company made a series of adjustments to reduce the short term debt balance below $0 to a negative balance for its proposed cost of capital. These adjustments are shown on Section V Exhibit 1 Schedule 3. The first of these adjustments was to remove the Big Sandy coal stock pile. The Company removed the entire balance from short-term debt, which reduced the per books short-term debt from $0 to negative $18.709 million.

The second adjustment was to remove a prorata share of the Big Sandy coal-related assets. The Company determined the adjusted capital structure after the first adjustment, which resulted in negative short-term debt and then allocated the Big Sandy coal-related assets to short-term debt, long-term debt, and common equity in proportion to the adjusted capitalization ratios. Because short-term debt had a negative capital ratio, the Company reduced it by another $4.945 million.

The third and fourth adjustments were to remove prorata shares of the Big

Sandy M&S and Big Sandy CWIP, respectively. As it did with the second adjustment, the Company allocated these two Big Sandy adjustments to short-term debt, long-term debt, and common equity in proportion to the adjusted capitalization ratios after the first adjustment. The Company reduced the short-term debt by another $0.209 million and $0.177 million for the third and fourth adjustments, respectively.

The fifth adjustment was to remove the Mitchell FGD from the base rate capitalization. Using the same methodology, the Company reduced short-term debt by another $7.458 million.

The sixth adjustment was to increase the Mitchell coal stock, which increased (made it less negative) the short term debt by $0.664 million.

The seventh, eight, and ninth tenth adjustments were to remove the FRECO, Carrs site, and other non-utility property, respectively. These adjustments reduced short-term debt by $0.152 million, $0.227 million, and $0.033 million, respectively.

Q. Are any adjustments that result in negative short-term debt appropriate?

A. No. As a fundamental matter, you cannot reduce something that does not exist to something that does not exist even more. If there was no short-term debt outstanding, then it cannot be used to finance anything. It cannot be reduced to negative balances because such a condition cannot and does not exist. It cannot be reduced to a short-term investment.

In addition, it generally has been the Commission's historic practice to adjust capitalization proportionately across all components for which there is a per books balance, except for non-utility investments, which the Commission has on occasion removed directly from common equity. The reason for this ratemaking practice is based on the premise that all capitalization components are used to finance all utility rate base investment and cannot be tied to specific assets.[44]

Finally, the Company's methodology essentially assumes that the Company financed excessive amounts of long-term debt and common equity in order to finance negative short-term debt. If the negative short-term debt were not reflected, then the adjusted long-term debt and common equity capitalization necessarily would be less in order for the total capitalization to remain the same. In other words, the Company's methodology assumes that it would borrow long-term debt at 5.41% and that AEP would invest additional common equity at 10.62% in order for the Company to earn 0.25% on its short-term investments. This assumption is not consistent with reality and imposes a cost on customers that the Company does not actually incur to finance utility rate base investment.

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[44] For example, in its Order in Case No. 2000-00386, the Commission found that "a reasonable return on the capital expenditures included in the [environmental] surcharge constitutes part of the total actual costs incurred by the utility. Concerning the financing of utility plant, it has long been recognized in the utility industry that capital expenditures are financed by numerous sources of capital, and that it is generally not possible to match a capital expenditure with a specific source of capital. KIUC has acknowledged that neither it nor LG&E stated that the 2001 Plan capital expenditures will be financed exclusively with short-term debt. Absent such evidence, the Commission cannot find it reasonable or appropriate to set the rate of return on the 2001 Plan rate base at the cost of LG&E's short-term debt, either during the CWIP phase or after the facilities are in service."

Q. **Should the Commission reject the Company's proposed nine adjustments to short-term debt?**

A. Yes. The Commission instead should reflect all nine of these adjustments as reductions to long-term debt and common equity on a per books prorata basis to reflect the fact that there was no short-term debt at the end of the test year.

Q. **What are the effects of your recommendation?**

A. Yes. The effects are a reduction of $3.307 million in the base revenue requirement, a reduction of $0.544 million in the Mitchell FGD revenue requirement, and a reduction of $0.389 million in the BSRR revenue requirement.[45]

Reduce Capitalization for Non-Utility Short-Term Investments in AEP Money Pool

Q. **Please describe the Company's investment in the AEP Money Pool at the end of the test year.**

A. The Company had a net investment of $9.577 million in the AEP Money Pool on September 30, 2014.[46]

Q. **Is the investment in the AEP Money Pool a non-utility investment?**

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[45] Refer to Section II on Exhibit___(LK-9) for the effect on the base rate revenue requirement. Refer to page 2 on Exhibit___(LK-17) for the effects on the Mitchell FGD revenue requirement. Refer to page 2 on Exhibit___(LK-18) for the effects on the BSRR revenue requirement.

[46] Company's response to KIUC 1-41.

A. Yes. The investment in the AEP Money Pool is a financial investment. By definition, it was not invested in utility rate base investments. In fact, it was money loaned to other AEP Money Pool participants. The investment was financed with excessive amounts of long-term debt and common equity for ratemaking purposes.

Q. Should the Commission reduce the long-term debt and common equity by the amount of the investment in the AEP Money Pool loaned to other AEP Money Pool participants?

A. Yes. The Commission should not require the Company's customers to pay a return on capitalization that is not invested in utility rate base investment, but that rather is loaned to other AEP Money Pool participants.

Q. What are the effects of your recommendation?

A. The effects are reductions of $1.037 million in the base revenue requirement, $0.007 million in the Mitchell FGD revenue requirement, and $0.005 million in the BSRR revenue requirement.[47]

[47] Refer to Section III on Exhibit___(LK-9) for the effect on the base rate revenue requirement. Refer to page 3 on Exhibit___(LK-17) for the effects on the Mitchell FGD revenue requirement. Refer to page 3 on Exhibit___(LK-18) for the effects on the BSRR revenue requirement.

<u>Reduce Capitalization to Reflect the Extension of Bonus Depreciation Enacted Shortly Before The Company Made Its Filing</u>

Q. Please describe the "tax extender" bill passed by the U.S. Congress in December 2014.

A. In December 2014, the Congress passed Public Law No. 113-295, entitled "The Tax Increase Prevention Act of 2014" ("Act"). The Act provided for the extension of 50% bonus tax depreciation in 2014 for qualified property while also providing 50% bonus tax depreciation in 2015 for long-production-period property.

Q. What effect does the additional tax depreciation have on the Company's capitalization and rate base in the test year?

A. The additional tax depreciation results in a reduction in current income tax expense and income taxes payable and an increase in deferred income tax expense and accumulated deferred income taxes ("ADIT"). The reduction in current income tax expense and the increase in deferred income tax expense net to zero and thus, have no effect on the revenue requirement. However, the reduction in income taxes payable and increase in ADIT result in a reduction to the Company's capitalization and rate base.[48]

[48] The Company provided the accounting journal entries for December 2014 on Attachment 1 to its response to KIUC 2-3 showing the current income tax expense and deferred tax expense netting to zero, the reduction in the income taxes payable and the increase in the liability ADIT.

Q. Did the Company reflect the additional tax depreciation and ADIT as a reduction to capitalization in its filing?

A. No. The Company made its filing shortly after the Act was signed into law on December 19, 2014.

Q. Should the Commission reflect the effects of the Act in the revenue requirement?

A. Yes. The Commission should reflect the known and measurable effects of the Act in both the base revenue requirement and the ES revenue requirement. The Act resulted in a reduction in the Company's capitalization and revenue requirement. The Company made the accounting journal entries in December 2014 after the Act was signed into law, but the law applied retroactively for the entire calendar year 2014. In response to discovery, the Company confirmed that the law was applicable to the "entire" year.[49]

Q. What are the effects of your recommendation?

A. The effects are reductions of $2.557 million in the base revenue requirement, $0.018 million in the Mitchell FGD revenue requirement, and $0.013 million in the BSRR

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[49] Company's response to KIUC 1-27. In the response, it states: "In December 2014, the Federal 50% bonus tax depreciation deduction was extended for the entire 2014 year. I have attached a copy of this response as my Exhibit___(LK-19).

revenue requirement.[50] The additional tax depreciation resulted in an additional $23.606 million in ADIT (total Company) and an equivalent reduction in capitalization.[51]

There also will be an effect on the 2014 and 2015 property additions included in the Company's future ES filings and cannot be quantified at this time. The Company's ES is presently set at 0.00%, but will reflect the Mitchell FGD and the 2014 compliance plan costs on the effective date of the Commission's Order in this proceeding, which is likely to be on or about June 1, 2015.

Effect of Return on Common Equity Recommended by KIUC

Q. Have you quantified the effect on the Company's revenue requirement of the return on equity recommendation sponsored by KIUC witness Mr. Richard Baudino?

A. Yes. The effects are reductions of $15.006 million in the base revenue requirement, $2.582 million in the Mitchell FGD revenue requirement, and $1.826 million in the BSRR revenue requirement. These reductions are incremental to the reductions for

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[50] Refer to Section IV on Exhibit___(LK-9) for the effect on the base rate revenue requirement. Refer to page 4 on Exhibit___(LK-17) for the effects on the Mitchell FGD revenue requirement. Refer to page 4 on Exhibit___(LK-18) for the effects on the BSRR revenue requirement.

[51] Company's response to PSC 3-50 and KIUC 2-3. I have attached a copy of the narrative portion of the response to PSC 3-50 as my Exhibit___(LK-20) and KIUC 2-3 as my Exhibit___(LK-21).

the other cost of capital recommendations that I address.[52]

Q. What is the effect of each 1.0% return on common equity?

A. The effects of each 1.0% return on common equity are $8.024 million on the base revenue requirement, $1.381 million on the Mitchell FGD revenue requirement, and $0.976 million on the BSRR revenue requirement.

Q. What is the pretax return on common equity requested by the Company and that recommended by KIUC?

A. The pretax return on common equity requested by the Company is 17.42%. The pretax return recommended by KIUC is 13.92%. The pretax return is the return on common equity that must be recovered from ratepayers in the revenue requirement. It includes federal and state income taxes that must be recovered in the revenue requirement, but that are expensed by the Company in computing its earned return. For this purpose, I included not only the income tax gross-up to the return on common equity but also a gross-up for uncollectibles expense and the Commission maintenance fee.

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[52] Refer to Section V on Exhibit___(LK-9) for the effect on the base rate revenue requirement. Refer to page 5 on Exhibit___(LK-17) for the effects on the Mitchell FGD revenue requirement. Refer to page 5 on Exhibit___(LK-18) for the effects on the BSRR revenue requirement.

Q. Will there be an effect on the environmental surcharge revenue requirement in addition to the effect on the Mitchell FGD?

A. Yes. The Commission historically has used the return on common equity set in the utility's most recent base rate proceeding in the cost of capital applied in the environmental surcharge. Thus, the return on equity will apply to all rate base investment in the environmental surcharge in addition to the Mitchell FGD. However, the quantification will be dependent on the rate base included in the monthly environmental surcharge filings after the date rates are reset in this proceeding.[53]

[53] The Stipulation and Settlement Agreement in Case No. 2012-00578 set the ES rate at 0.00% until base rates are reset in this proceeding.

V. BIG SANDY RETIREMENT RIDER

Remove Projected ARO, Other Dismantling, and O&M Expense from BSRR

Q. Please describe the Company's proposed BSRR.

A. The Company proposes a BSRR to recover the net book value of Big Sandy 2 and the coal-related assets of Big Sandy 1 at May 31, 2015, the asset retirement obligation ("ARO") payments at May 31, 2015, projected ARO payments after May 31, 2015, projected dismantling costs in 2031, and projected operation and maintenance ("O&M") expenses after May 31, 2015. The Company developed an annuitized (levelized) revenue requirement using these actual and projected costs as well as a grossed-up rate of return applied to the unamortized balance each year.[54] Finally, the Company plans to true-up the projected costs in each subsequent base rate case filing and recalculate the BSRR revenue requirement to reflect actual costs incurred and revised projections of future costs, as well as "any over/under recovery during the current period base rates were in effect."[55]

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[54] The costs included in this calculation are summarized on the table on page 15 of Mr. Yoder's Direct Testimony. The Company provided additional detail in the table on page 16 of Mr. Yoder's Direct Testimony and his Exhibit JMY 1. Finally, the Company provided an electronic spreadsheet showing the projected amounts by year and the calculation of the annuitized expense.

[55] Wohnhas Direct at 25.

Q. Does the proposed BSRR comply with the terms of the Stipulation and Settlement Agreement approved by the Commission in Case No. 2012-00578 for this rider?

A. No. There are fundamental differences between the "retirement costs" eligible for recovery through this rider as set forth in the terms of the Stipulation and Settlement Agreement and the costs that the Company proposes to include in the BSRR. The terms of the Stipulation and Settlement Agreement do not authorize recovery of projected costs or O&M expenses. The relevant terms of the Stipulation and Settlement Agreement are as follows:

> 3. . . .The Company agrees to remove all coal-related operating expenses related to Big Sandy l, and all operating expenses related to Big Sandy Unit 2 from the
> cost of service study in the Base Rate Case. The Company further agrees to remove all coal-related plant and other capitalized costs, e.g., fuel inventories, materials and supplies inventories, etc., related to Big Sandy Unit 1, and all plant and other capitalized costs, e.g., fuel inventories, materials and supplies inventories, etc., related to Big Sandy Unit 2, from the cost of service study in the Base Rate Case, and instead recover these costs in the manner set forth in Paragraph 14 of this Settlement Agreement.
>
> ***
>
> 14. The Company shall be authorized to recover the coal-related retirement costs of 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 costs will be recovered in the Asset Transfer Rider-2.[56]

The Stipulation defines the "retirement costs" that the Company is authorized recover through the ATR-2 (renamed by the Company as the BSRR). These costs include actual costs for the net book value of the plant, including inventories and materials and supplies, and costs that are incurred for removal, net of salvage income. However, the Company's proposed BSRR includes *projected* costs for future ARO activities, other dismantling and site remediation activities, and O&M expenses. In other words, the Company seeks to modify the Stipulation without even acknowledging that it is doing so.

Q. Do you agree that the BSRR should be modified to include projected costs?

A. No. This was not authorized in the Stipulation and Settlement Agreement. If and when the ARO and other dismantling costs are authorized and the projected costs actually are incurred, then the Company can include them in the BSRR on a levelized basis over the remaining years of the 25 year amortization period, subject to the Commission's review and determination that they were reasonable and prudent.

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[56] The Asset-Transfer-2 Rider has been renamed by the Company as the BSRR.

The use of projected costs violates the matching principle given the use of the historic test year in this proceeding and is inconsistent with the Commission' historic reliance on actual costs for the Company's various riders.

It is unreasonable to use projected costs, particularly costs that are not approved and that will be incurred many years in the future. The Company should not recover any costs unless and until they are incurred. There is no reason to introduce the uncertainty resulting from projected costs, to incorporate the proposed after the fact true-up of the actual costs to the projected costs, or to prematurely recover costs that have not been and may not be incurred.

Q. Do you have additional concerns with including projected ARO costs?

A. Yes. The Company provided no support for these ARO costs in its filing other than the projected costs by year separated into asbestos removal and ash pond remediation. The Company failed to provide even a conceptual cost study similar to what it provided for the projected decommissioning cost.[57]

In addition, the Company has not filed a CPCN application for the ARO activities and has not indicated that it has any plans to do so, although it acknowledges that it plans to submit CPCN applications as required by KRS 278.020

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[57] Company's response to KIUC 1-60 and KIUC_1_17_Attachment 58 pages 44 and 51. In KIUC 1-60(b), the Company was asked to provide "the source documents for the amount [for the ARO] shown on the table [Yoder at 16]. The Company's response stated that the"source of the ARO costs is provided in KIUC_1_17_Attachment 58 pages 44 and 51." I have attached a copy of these responses as my Exhibit___(LK-22).

or otherwise to obtain approval for dismantling and site remediation plans for the Big Sandy site.[58] The ARO activities also fall within the scope of dismantling and site remediation, the only difference being that the ARO activities are a legally required subset of the dismantling and site remediation activities.

Q. Do you have additional concerns with including projected dismantling costs?

A. Yes. Fundamentally, the Company's proposal requires the Commission to prematurely decide the future disposition of the generation facilities after they are retired. Yet, the Commission has not yet had a chance to evaluate any alternatives to the proposed scope and cost set forth in the Sargent & Lundy conceptual estimate for dismantlement nor has the Company considered or provided any such alternatives. For example, the Company has not considered a "retirement in place" option, which would reduce or eliminate the projected dismantling costs.[59] The Commission normally would consider such options in a CPCN proceeding, a proceeding that is required pursuant to KRS 278.020, but which has not yet been opened and will not be opened for many years.

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[58] Company's response to KIUC 1-57. I have attached a copy of this response as my Exhibit___(LK-23).

[59] Response to KIUC 1-59(b), which asked the Company to provide "all cost/benefit studies of the Company's plans and alternatives for the removal of the Big Sandy facilities and remediation of the site, including a retirement in place alternative." The Company did not identify any alternatives and stated that it "did not consider a retirement in place option." I have attached a copy of this response as my Exhibit___(LK-24).

Q. Do you have additional comments regarding the projected O&M expenses?

A. Yes. The Company has unilaterally attempted to modify the Stipulation without explicitly requesting a modification. Although I do not agree with the Company's approach, it is reasonable to allow the Company recovery of O&M expenses that it actually incurs through the BSRR.

Q. What are your recommendations?

A. I recommend that the Commission remove all projected costs from the BSRR in this proceeding and exclude all projected costs from the BSRR in future proceedings. I recommend that the Commission include only actual costs that are incurred. I recommend that the Commission direct the Company to defer the actual costs that it incurs for approved ARO and other dismantling activities as well as actual O&M expenses and then update the BSRR revenue requirement in subsequent base rate proceedings to include the effects of these deferrals.

I recommend that the Commission review the scope and the cost of the ARO and dismantling activities as well as lower cost options in one or more CPCN proceedings before it allows recovery of any costs, projected or actual, for ARO and dismantling activities through the BSRR. If the Commission approves recovery of actual ARO and other dismantlement costs, then I recommend that the Company be allowed to defer the actual ARO and other dismantlement costs and then include the resulting amortization expense over the remaining years of the 25 year amortization period when it recalculates the BSRR revenue requirement in each future base rate proceeding.

Q. What is the effect of your recommendation to remove the projected costs from the BSRR revenue requirement?

A. The effect is a reduction of $5.933 million in the BSRR revenue requirement.[60]

Q. Is there another issue that the Commission should address that will affect the BSRR revenue requirement?

A. Yes. There is a methodological error in the Company's proposed BSRR. The Company failed to subtract the ADIT related to the deferrals of projected ARO and other dismantling costs and the projected O&M expenses reflected in the calculation of the BSRR annuitized or levelized revenue requirement as shown on Exhibit JMY 1. This overstates the "rate base" used for the carrying charge column.

Q. What is your recommendation to correct this methodological error?

A. I recommend that the Commission modify and correct the calculation so that the ADIT is properly subtracted from the "rate base" used for the carrying charge

[60] The calculations are shown on page 7 of my Exhibit___(LK-18). I note that the weighted cost of capital already reflects the KIUC cost of capital recommendations that I previously addressed and quantified. Thus, this reduction in the revenue requirement is sequential and incremental to those cost of capital recommendations.

column. The correction should be made regardless of whether the Commission allows recovery of projected costs or actual costs.

Q. Does this recommendation have an effect on the BSRR revenue requirement?

A. It does not have an effect on the BSRR revenue requirement in this proceeding if the Commission adopts my recommendation to remove all projected costs. However, it will affect the BSRR revenue requirement in future rate proceedings after actual costs are incurred. Alternatively, if the Commission rejects my recommendation in this proceeding, then it should recalculate the BSRR revenue requirement to reflect the ADIT for the deferred projected ARO, other dismantling, and O&M expenses.

Q. As one final BSRR concern, does the proposed BSRR describe how the Company will determine the over/under recovery?

A. No. The Commission should make it clear that the over/under recovery for this tariff is the difference between the revenues billed and the costs that were reflected in the revenue requirement.

If the Commission adopts my recommendation to set the BSRR revenue requirement using only actual costs rather than projected costs, then additional actual costs should be deferred and included when the Company recalculates the levelized annual revenue requirement in each base rate proceeding.

Alternatively, if the Commission does not adopt by recommendation and uses projected costs, then the true-up of actual to the projected costs should be deferred and included when the Company recalculates the levelized annual revenue requirement in each base rate proceeding. The over/under recovery should not be used for this purpose.

VI. BIG SANDY 1 OPERATION RIDER

Q. Please describe the Company's proposed BS1OR.

A. The Company proposes a new BS1OR to recover the "operational costs" of Big Sandy 1 as it transitions from a coal-fired unit to a natural gas-fired unit. This includes the non-fuel expenses of operating the Big Sandy 1 unit as a coal-fired unit until the conversion and the non-fuel expenses of operating Big Sandy 1 as a natural gas-fired unit after the conversion. It also includes the return on and of the capital investment required for the conversion of Big Sandy 1 once the unit is places in service.[61] In addition to the costs identified by Mr. Wohnhas, the Company's calculation of the BS1OR revenue requirement includes annualized non-OATT PJM charges and credits.[62]

Q. Was the proposed BS1OR addressed in the Stipulation or the Commission's Order in Case No. 2012-00578?

A. No. This is a new proposal.

Q. Do you agree with the proposal to recover Big Sandy 1 *operating expenses* in this manner?

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[61] Wohnhas Direct at 7.

[62] Vaughan Direct at 24 and Attachment 52 provided in response to KIUC 1-17 seeking the Company's workpapers. I have attached a copy of Attachment 52 to KIUC 1-17 as my Exhibit___(LK-25).

A. Yes. However, the Commission should impose two conditions. First, non-recurring O&M expenses such as severance expenses should be deferred and amortized over three years. Second, the annual revenue requirement should be capped at the $18.245 million quantified by the Company based on the test year in this proceeding.[63]

Q. Do you agree with the proposal to recover a *return on and of the capital cost of the conversion* once it is placed in-service?

A. No. This would represent a significant change in the Commission's ratemaking practice for capital investments of this nature and could be considered as precedent if adopted. The Company has provided no justification for such a change. The Company estimated the capital cost at approximately $60 million in Case No. 2012-00578, a relatively modest investment compared to the test year gross plant in service of $2,015.831 million. If the Company is underearning when the unit is returned to service after the conversion, then it should file for an increase in base rates so that the Commission can consider all revenues and costs on a comprehensive basis at that time.

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63 Id., 8.

Q. What is your recommendation?

A. I recommend that the Commission adopt the BS1OR for the *operating expenses,* but reject the return of and on the *capital cost of the conversion.* I also recommend that the Commission direct the Company to defer one-time O&M expenses, such as severance expense, and amortize them over three years.

Q. Does the proposed BS1OR describe how the Company will determine the over/under recovery?

A. No. The Commission should make it clear that the over/under recovery for this tariff is the difference between the revenues billed and the costs that were reflected in the revenue requirement.

If the Commission adopts my recommendations to defer and amortize one-time costs, then additional actual costs should be deferred and the amortization expense included when the Company recalculates the revenue requirement in each base rate proceeding until the BS1OR revenue requirement is rolled into base rates in a subsequent base rate proceeding. The over/under recovery should not be used for this purpose.

VII. SHARING OF OFF-SYSTEM SALES MARGINS THROUGH THE SYSTEM SALES CLAUSE

Commission Should Adopt a 90% to Customers and 10% to Company Sharing of Off-System Sales Margins in the System Sales Clause

Q. Please describe the Company's proposed sharing of OSS margins through the System Sales Clause.

A. The Company proposes a sharing of OSS margins that are above or below the amount included in the base revenue requirement of 60% to customers and 40% to the Company.

Q. What are the reasons cited by the Company's in support of its proposed sharing of OSS margins through the SSC?

A. The only reason cited by the Company is that there was a 60%/40% sharing in some prior versions of the SSC.[64] The Company offers no substantive reasons why its proposed sharing is reasonable.

Q. Is the proposed 60%/40% sharing reasonable?

A. No. The percentage to customers should be closer to 100%, not the almost equivalent sharing proposed by the Company for several reasons. First, the Company's customers, not its shareholders, provide the Company recovery of the

[64] Wohnhas Direct at 24.

entirety of the generation and transmission fixed costs necessary to supply and manage OSS revenues, expenses, and risks.

Second, the Company has offered no evidence whatsoever that greater sharing percentages to the Company have any effect on the Company's ability to mitigate costs associated with managing wholesale power risks. Those costs and risks exist independently of the retail ratemaking mechanisms that exist for the Company.

Third, the Company's generation is dispatched by PJM based on market clearing prices. The sharing margins in the SSC do not affect the dispatch of the Company's generating units.

Fourth, the greater the sharing to the customers, the less effect there is from disagreements over the methodologies used to allocate fuel costs between native load customers and OSS. For example, if all fuel costs were included in the fuel adjustment clause and all OSS revenues were credited against those fuel costs in the fuel adjustment clause, then there would be no disagreement whatsoever on the allocation of fuel costs between native load customers and OSS. Those disagreements are the direct result of the sharing provisions, which most recently have been 100% to the Company due to the Mitchell acquisition Stipulation and Settlement Agreement approved in Case No. 2012-00578.

Fourth, there is no empirical or other evidence that the Company, or its agent AEPSC, would act any differently in the bidding or dispatch process or that it would achieve more or less OSS margins if it were provided a greater or lesser "incentives" through the sharing of OSS margins.

Fifth, there is a wide variety of sharing that is recognized for retail ratemaking purposes among the AEP utilities, including some jurisdictions in which there is no sharing at all. For example, in West Virginia, Appalachian Power Company flows through 100% of the OSS margins to ratepayers.

Finally, the Company now recovers the entirety of the fixed costs associated with its purchased power through the PPA rider. There is no sharing of these costs or the risks.

Q. What is your recommendation regarding the SSC?

A. I recommend that the Commission adopt a sharing of 90% to customers and 10% to the Company for OSS margins above or below OSS margins that it reflects in the base revenue requirement in this proceeding.

VIII. NERC COMPLIANCE AND CYBERSECURITY RIDER

Q. **Please describe the NERC Compliance and Cybersecurity Rider proposed by the Company.**

A. The Company proposes to track, defer, and then recover through this proposed NCCR the capital and O&M expense associated with compliance and cybersecurity activities for new NERC requirements or new interpretations of existing requirements. The Company also proposes that it include carrying costs at its weighted cost of capital on the NERC capital-related costs.[65] Initially, all such costs would be deferred and then after review by the Commission in a subsequent proceeding, the costs would be recovered through the NCCR.[66]

Q. **Should the Commission adopt this proposal?**

A. No. Fundamentally, this is not the type of cost that should be recovered through a rider; these costs are appropriately recovered through the base revenue requirement. They are fixed in nature, even if they may increase over time, and are not particularly volatile. It is inappropriate and unnecessary to carve out this single category of costs from the base revenue requirement and include them in a separate rider.

Second, such a rider will only increase over time. It is designed to capture only increases in costs. It is not designed to capture decreases in costs. Such

[65] Wohnhas Direct at 27.

[66] *Id.*

decreases in costs may occur when NERC compliance and cybersecurity requirements are superseded by new requirements or new interpretations of existing requirements. Such decreases in costs also occur as plant depreciates for book and tax purposes.

Third, the costs eligible for deferral and recovery through the rider are not readily and objectively identified and quantified. The identification and quantification of the costs are extremely subjective and may require specialized expertise. The Company has provided no identification or baseline quantification of the NERC compliance and cybersecurity costs included in the revenue requirement in this proceeding, an essential starting point in measuring whether there has been an increase, let alone an increase due to new NERC requirements or new interpretations of existing requirements. For example, some costs may increase from the test year in this proceeding simply due to the purchase of new computers or payroll increases. It would be improper for the Company to identify these costs as caused by new NERC requirements or new interpretations of existing requirements, but this could easily occur.

Fourth, the costs of cybersecurity are not solely the result of NERC requirements. Although the Company claims that it will include only those costs resulting from new NERC requirements or new interpretations of existing requirements, there may be no realistic methodology to separate out the costs incurred due to NERC requirements versus those incurred due to other government or private industry requirements or those incurred for business reasons. For example, if the Company improves the physical security of its substations, it may not, as a practical matter, be able to allocate the cost between NERC requirements, if any, and the need to protect the substation as a general business matter or to reduce insurance premiums.

Finally, the proposed NCCR provides a disincentive to aggressively manage NERC compliance and cybersecurity costs.

Q. Is the better approach to continue to include all security costs in the base revenue requirement?

A. Yes. The Company will recover all security costs through the base revenue requirement in the same manner that it recovers almost all other non-fuel and non-environmental costs. There is no compelling reason to treat security costs differently than other costs included in base rates, all of which vary to some extent over time. There is no compelling reason to strip some or all of the Companies' security costs from base rates and to recover them through a surcharge or to allow deferral of costs. In fact, the primary effect of the Companies' proposal will be to provide the Companies with open-ended and real-time recovery (through deferral and surcharge) of their security costs.

The primary reason why it is better to continue to recover these costs in base rates is that it provides the Companies the right incentives to actively and aggressively manage these costs rather than simply deferring and recovery them through the NCCR regardless of the amounts. That incentive is due primarily to the regulatory delay in recovery of potential or actual cost increases.

Q. If the Commission adopts an NCCR and allows the Company to defer these costs, including a return on and of capital costs, how should it determine the rate base, return, depreciation, operating expenses, and income tax expense?

A. The Commission first should determine the methodology for the deferrals. As a starting point, if the Commission authorizes recovery of incremental plant (capital) costs and operating expenses, then it must establish a baseline and methodology for the calculation of incremental costs. It also should require that reductions in costs included in the base revenue requirement are used to offset these incremental costs. Administratively, the best way to accomplish this is to identify the NERC compliance and cybersecurity revenue requirement included in the revenue requirement in this case. This will require the Companies to identify and quantify all security rate base and expense components included in its revenue requirement in this proceeding in the same level of detail that it would track such costs in the future for deferral.

Thereafter, the Companies should quantify the total NERC compliance and cybersecurity revenue requirement each month, both for the rate base and expense components included in the revenue requirement in this proceeding and for the incremental rate base and expense. The rate base reflected in the revenue requirement in this proceeding will continue to decline each month due to book and tax depreciation. Then, the Companies should subtract the security revenue requirement allowed in this proceeding from the total security revenue requirement to determine the net amount that can be deferred and ultimately recovered through the NCCR.

Further, if there is a deferral and the Company is allowed to defer a return on the deferrals, the deferrals should be reduced by the related ADIT before the application of the rate of return. The Commission should require the Companies to use the same return, GRCF, and depreciation rates authorized in this proceeding and as revised in future base rate proceedings. This consistency is necessary to ensure that there are no differences in the calculation of the revenue requirement for base ratemaking, ECR, BSRR, and NCCR purposes.

Finally, if the deferrals are recovered through the NCCR, the Companies will need to allocate the revenue requirement to customer class and determine the Security Rider surcharge rates.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
23rd day of March 2015.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVINGS ITS 2014 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; AND (4) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))	CASE NO. 2014-00396

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 2015

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.**: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates**: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company**: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
as of March 2015**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

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5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.

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8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

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12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

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3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

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6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

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6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.

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4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.

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12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Healllthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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Date	Case	Jurisdict.	Party	Utility	Subject
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.

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04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.

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12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.

Expert Testimony Appearances
of
Lane Kollen
as of March 2015

Date	Case	Jurisdict.	Party	Utility	Subject
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

**Expert Testimony Appearances
of
Lane Kollen
as of March 2015**

Date	Case	Jurisdict.	Party	Utility	Subject
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

**Expert Testimony Appearances
of
Lane Kollen
as of March 2015**

Date	Case	Jurisdict.	Party	Utility	Subject
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recover Company LLC	Public Service Company of Colorado	Line extension policies and refunds.

Expert Testimony Appearances
of
Lane Kollen
as of March 2015

Date	Case	Jurisdict.	Party	Utility	Subject
01/15	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.

EXHIBIT ____ (LK-2)

Kentucky Power Company

REQUEST

Please provide the amount of incentive compensation expense pursuant to the Long Term Incentive Plan included in the test year revenue requirement for each target metric used for this plan during the test year. Separately provide the costs incurred directly by the Company and the costs incurred through AEPSC affiliate charges. In addition, please provide these amounts by FERC O&M and/or A&G expense account.

RESPONSE

For the Kentucky Power Company costs incurred directly see KIUC_1_32_Attachment1.xls for the total Company amount included in the test year.

Refer to KIUC_1_32_Attachment2.xls for the requested information related to AEPSC's long term incentive billed to KYPCo for the test year ended September 30, 2014 by FERC account.

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.

WITNESS: Andrew R Carlin

Kentucky Power Company Long Term Incentive Plan
12 Months Ending September 30, 2014

Row Labels	Performance Units	Restricted Stock Units	Grand Total
1070	115,526.72	16,636.51	132,163.23
1080	21,763.94	2,390.95	24,154.89
1520	14,110.15	2,502.05	16,612.20
1830	(30.47)	(14.40)	(44.87)
1840	(0.70)	(1.01)	(1.71)
1850	623.41	59.61	683.02
1860	10,643.07	402.87	11,045.94
1880	(0.20)		(0.20)
4264	659.74	57.15	716.89
4265	0.12		0.12
5000	2,541.40	379.10	2,920.50
5010	1,055.50	172.19	1,227.69
5020	5,613.30	1,006.48	6,619.78
5050	1,346.32	247.78	1,594.10
5060	7,732.46	1,925.02	9,657.48
5100	10,600.47	1,917.91	12,518.38
5110	1,108.04	162.97	1,271.01
5120	17,634.04	3,237.70	20,871.74
5130	3,133.96	588.65	3,722.61
5140	1,325.81	227.94	1,553.75
5530	0.32	0.39	0.71
5570	88.36	8.12	96.48
5700	0.21	0.34	0.55
5710	43.49	18.24	61.73
5800	1,970.00	259.32	2,229.32
5830	9,679.56	1,024.22	10,703.78
5840	311.37	4.00	315.37
5850	53.81		53.81
5860	12,121.61	1,338.25	13,459.86
5870	2,090.85	269.15	2,360.00
5880	26,506.49	4,933.47	31,439.96
5900	1.36		1.36
5930	49,825.29	11,771.81	61,597.10
5940	(27.77)	22.37	(5.40)
5950	418.82	11.70	430.52
5960	558.17	56.15	614.32
5970	976.04	69.78	1,045.82
5980	2,096.98	234.25	2,331.23
9010	3,740.06	605.98	4,346.04
9020	5,835.85	899.18	6,735.03
9030	11,160.75	1,697.51	12,858.26
9050	107.97		107.97
9070	1,086.37	95.82	1,182.19
9080	8,750.45	1,388.06	10,138.51
9100	60.60		60.60
9200	17,016.41	2,933.93	19,950.34
9210	1.86	0.28	2.14
9230	(0.33)	(0.12)	(0.45)
9250	152.77	35.41	188.18
9260	5,506.48		5,506.48
9280	2,922.99	243.83	3,166.82
9302	185.58	19.23	204.81
9350	1.88		1.88
Grand Total	378,631.73	59,840.14	438,471.87

Kentucky Power Company
AEPSC Billings to Kentucky Power Company
For Long Term Incentive
For the Test Year Ended September 2014

FERC Account	Total
1070	377,116
1080	31,836
1520	58,063
1630	85,170
1830	18,102
1840	0
1860	2,691
1880	3,990
4210	1,120
4264	12,474
4265	1,662
5000	210,696
5010	2,839
5020	1,706
5060	9,323
5100	13,069
5110	17,694
5120	32,125
5130	12,106
5140	2,134
5240	11
5280	83
5300	9
5550	887
5560	27,497
5570	113,116
5600	27,812
5611	167
5612	23,372
5615	2,478
5620	240
5630	104
5660	25,758
5680	2,059
5691	482
5692	4,548
5693	198
5700	4,740
5710	1,254
5730	1,456
5800	28,972
5810	90
5820	48
5840	369
5860	7,083
5880	30,966
5890	1

Kentucky Power Company
AEPSC Billings to Kentucky Power Company
For Long Term Incentive
For the Test Year Ended September 2014

FERC Account	Total
5900	183
5910	105
5920	4,178
5930	2,004
5970	269
5980	51
9010	1,399
9020	2,999
9030	192,441
9050	865
9070	5,040
9080	1,370
9100	8
9200	1,496,703
9210	0
9230	13,906
9250	409
9260	2,767
9280	25,670
9301	138
9302	11,124
9350	5,059
Grand Total	2,964,408

EXHIBIT ____ (LK-3)

Kentucky Power Company
KIUC Recommendation to Remove Incentive Compensation Tied to Financial Performance
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

Incentive Compensation-LTIP-Incurred by KPCo FERC Accounts 500-935	0.253
Incentive Compensation-LTIP-Allocated by AEPSC to KPCo FERC Accounts 500-935	2.372
Total LTIP Incentive Compensation in FERC Accounts 500-935	2.625
50% Tied to Total Shareholder Return and 50% Tied to Earnings Per Share	100%
Remove Total LTIP Incentive Compensation in FERC Accounts 500-935 - Tied to Financial Performance - Total Company	(2.625)
KY Jurisdictional Allocation Factor - O&M Labor	99.00%
Remove Total LTIP Incentive Compensation in FERC Accounts 500-935 - Tied to Financial Performance - KY Jurisdiction	(2.599)

Source: Responses to KIUC 1-32 and 1-33

EXHIBIT ____ (LK-4)

Kentucky Power Company

REQUEST

Please provide the LTIP target metrics for the Company and AEPSC applicable to the test year,describe how they are calculated and the source of the data used for the calculations, and provide the Company and AEPSC's actual performance against each of these metrics in the test year.

RESPONSE

The LTIP metrics for the 2013 test year are calculated based on of the Company Total Shareholder Return and Earnings Per Share scores (TSR and EPS, respectively). These benchmarks have an important long-term effect on the Company's cost of service and cost of raising equity and debt capital. Each of the two components makes up 50% of the score.

The TSR score is calculated by comparing the Company's stock return during a 3 year period to the return of a peer group and multiplying that result by a payout curve. The peer list and payout curve is provided by the Human Resources department annually for the new LTIP compensation. The 2011-2013 award peer list consists of 29 utility companies and is shown in KPSC_1_33_Attachment1.xlsx. If the Company's result is in the top 80% of its peers, the TSR score will be a 2.00. If the Company's result is in the bottom 20%, the score will be a 0.00. If the result falls between 20% and 80% then the TSR score will be found by taking the percentage ranking then subtracting 20% (since the bottom 20% results in a 0 score) and then multiplying it by 3.3333 (200/(80-20)).

The 2011-2013 TSR return for the Company and peers is calculated by taking 20 day average at the end of the three year award period plus the three years of dividends minus the beginning 20 day average. That sum is divided by the beginning 20 day average. (12/31/13 20 day average plus three years of dividends – 12/31/10 20 day average)/(12/31/10 20 day average). This formula provides the three year return for the company and peers. AEP's percentage return for 2011-2013 was 45.37%. The returns of all the companies are then ranked by a percentage and in 2013 AEP's percentage was 62%. The TSR score for AEP was 1.40 ((62%-20%)*3.333).

The Corporate Consolidation and Governance, Planning, Analysis Reporting group provides the EPS score which is a score based on the Company's earnings per share. The score for the 2011-2013 plan was 0.975. The final performance score for AEP was 1.188 which comes from 50% TSR score and 50% EPS score ((1.4+0.975)/2).

This component of employee compensation is only paid if employees in fact remain with the Company, resulting in stability and effective employee retention.

WITNESS: Andrew R Carlin

EXHIBIT ____ (LK-5)

Kentucky Power Company
KIUC Recommendation to Include A/R Financing Interest Expense in Interest Syncronization
To Determine Income Tax Expense
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

A/R Financing Included in Capitalization	52.412
Rate % as Filed	1.07%
Annualized Interest on A/R Financing Available as an Income Tax Deduction	0.561
Effective Combined Income Tax Rate	38.61%
KIUC Decrease in Income Tax Expense	(0.217)
KIUC Decrease in Income Tax Expense Grossed Up	(0.353)
KY Jurisdictional Allocation Factor - GP-TOT	0.989
Correct Interest Synchronization Deduction Error in Income Tax Expense - KY Juris	(0.349)

Source: See Adjustment WP 34 in Section V, Exhibit 2 Page 34
See Also Section V Exhibit 1 Schedule 3

EXHIBIT ____ (LK-6)

Kentucky Power Company

REQUEST

In a pending rate case before the West Virginia Public Service Commission Case No. 14-1152-E-42T, Appalachian Power Company proposed that income tax expense be reduced by the parent company loss adjustment ("PCLA").

a. Please describe the PCLA.

b. Please confirm that the PCLA is a reduction to the Company's income tax expense set forth in the AEP Tax Agreement.

c. Please confirm that the Company agrees that income tax expense should reflect a reduction for the PCLA. If the Company does not agree, then please provide all reasons why it does not agree and why the Company believes this Commission should treat it differently than Appalachian Power Company's proposal in West Virginia.

d. Please confirm that Mr. Bartsch is a witness in the Appalachian Power Company proceeding in West Virginia and is familiar with Appalachian Power Company's proposal in West Virginia.

e. Please provide a quantification of the PCLA for this proceeding, a description of the data and sources of data that were used, and a narrative description of each step in the calculation.

RESPONSE

a. The PCLA refers to the Parent Company Loss Allocation in which the tax benefit of the tax loss of American Electric Power Company, Inc. (Parent Company) is allocated prorata to those companies that participate in the AEP Consolidated Tax Return that have positive taxable income. Please see KIUC_1_21_Attachment1.pdf for a copy of the AEP Tax Allocation Agreement which was first approved by the IRS in 1955.

b. The PCLA results in a reduction to the Company's income tax expense assuming that the Company has positive taxable income. The amount of the reduction is dependant on the actual amount of the parent company loss and the Company's relative taxable income as compared to the other companies in the consolidated group having taxable income.

c. 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.

d. Mr. Bartsch is a witness in the Appalachian Power Company proceeding in West Virginia and is familiar with Appalachian Power Company's proposal related to the PCLA.

e. Please see KIUC_1_21_Attachment2.xlsx (Closing Tax Allocation for 2013) and KIUC_1_21_Attachment3.xlsx (Closing Tax Allocation for 2014) which show the estimated Parent Company Loss Allocations that were accrued for calendar years 2013 and 2014 using the process described in the AEP Tax Allocation Agreement. The 2014 amounts include the retroactive extension of bonus depreciation. The PCLA accrued for Kentucky Power was $293,000 in 2013 and $327,000 in 2014. A pro rata Kentucky Power PCLA adjustment for the 12 months ended September 30, 2014 Test Year would be $318,500.

WITNESS: Jeffrey B Bartsch

AMERICAN ELECTRIC POWER COMPANY, INC. AND ITS CONSOLIDATED AFFILIATES — 2013 TAX AGREEMENT REGARDING METHOD OF ALLOCATING CONSOLIDATED INCOME TAXES

The below listed affiliated companies, joining in the annual filing of a consolidated federal income tax return with American Electric Power Company, Inc., agree to allocate the consolidated annual net current federal income tax liability and/or benefit to the members of the consolidated group in accordance with the following procedures:

(1) The consolidated regular federal income tax, exclusive of capital gains and preference taxes and before the application of general business credits including foreign tax credits, shall be apportioned among the members of the consolidated group based on corporate taxable income. Loss companies shall be included in the allocation, receiving a negative tax allocation which is similar to a separate return carryback refund, before considering general business credits, which would have resulted had the loss company historically filed a separate return.

(2) The corporate taxable income of each member of the group shall be first reduced by its proportionate share of American Electric Power Company, Inc.'s (the holding company) tax loss (excluding the effects of extraordinary items which do not apply to the regulated business) in arriving at adjusted corporate taxable income for each member of the group with positive taxable income.

(3) To the extent that the consolidated and corporate taxable incomes include material items taxed at rates other than the statutory tax rate (such as capital gains and preference items), the portion of the consolidated tax attributable to these items shall be apportioned directly to the members of the group giving rise to such items.

(4) General business credits, other tax credits, and foreign tax credits shall be equitably allocated to those members whose investments or contributions generates the tax credit.

(5) If the tax credits can not be entirely utilized to offset the consolidated tax liability, the tax credit carryover shall be equitably allocated to those members whose investments or contributions generated the credit.

(6) Should the consolidated group generate a net operating tax loss for a calendar year, the tax benefits of any resultant carryback refund shall be allocated proportionately to member companies that generated corporate tax losses in the year the consolidated net operating loss was generated. Any related loss of general business credits, shall be allocated to the member companies that utilized the credits in the prior year in the same

proportion that the credit lost is to the total credit utilized in the prior year. A consolidated net operating tax loss carryfoward shall be allocated proportionately to member companies that generated the original tax losses that gave rise to the consolidated net operating tax loss carryforward.

(7) A member with a net positive tax allocation shall pay the holding company the net amount allocated, while a tax loss member with a net negative tax allocation shall receive current payment from the holding company in the amount of its negative allocation. The payment made to a member with a tax loss should equal the amount by which the consolidated tax is reduced by including the member's net corporate tax loss in the consolidated tax return. The holding company shall pay to the Internal Revenue Service the consolidated group's net current federal income tax liability from the net of the receipts and payments.

(8) No member of the consolidated group shall be allocated a federal income tax which is greater than the federal income tax computed as if such member had filed a separate return.

(9) In the event the consolidated tax liability is subsequently revised by Internal Revenue Service audit adjustments, amended returns, claims for refund, or otherwise, such changes shall be allocated in the same manner as though the adjustments on which they are based had formed part of the original consolidated return using the tax allocation agreement which was in effect at that time.

Any current state tax liability and/or benefit associated with a state tax return involving more than one member of the consolidated group, shall be allocated to such members following the principles set forth above for current federal income taxes. Due to certain states utilizing a unitary approach, the consolidated return liability may exceed the sum of the liabilities computed for each company on a separate return basis. If this occurs, the excess of the consolidated liability over the sum of the separate return liabilities shall be allocated proportionally based on each member's contribution to the consolidated apportionment percentage. If additional tax is attributable to a significant transaction or event, such additional tax shall be allocated directly to the members who are party to said transaction or event.

This agreement is subject to revision as a result of changes in federal and state tax law and relevant facts and circumstances.

The above procedures for apportioning the consolidated annual net current federal and state tax liabilities and expenses of American Electric Power Company, Inc. and its consolidating affiliates have been agreed to by each of the below listed members of the consolidated group as evidenced by the signature of an officer of each company.

COMPANY	OFFICER'S SIGNATURE
American Electric Power Company, Inc.	
American Electric Power Service Corporation	
AEP Appalachian Transmission Company, Inc.	
AEP C&I Company, LLC	
AEP Coal, Inc.	
AEP Credit, Inc.	
AEP Desert Sky GP, LLC	
AEP Desert Sky LP II, LLC	
AEP Elmwood LLC	
AEP Energy, Inc.	
AEP Energy Partners, Inc.	
AEP Energy Services, Inc.	
AEP Energy Services Gas Holding Company	
AEP Energy Supply LLC	

AEP Fiber Venture, LLC

AEP Generating Company

AEP Generation Resources, Inc.

AEP Indiana Michigan Transmission Company, Inc.

AEP Investments, Inc.

AEP Kentucky Coal, LLC

AEP Kentucky Transmission Company, Inc.

AEP Nonutility Funding, LLC

AEP Ohio Transmission Company, Inc.

AEP Oklahoma Transmission Company, Inc.

AEP Pro Serv, Inc.

AEP Properties, LLC

AEP Resources, Inc.

AEP Retail Energy Partners, LLC

AEP River Operations, LLC

AEP Southwestern Transmission Company, Inc.

AEP T & D Services, LLC

AEP Texas Central Company

AEP Texas Central Transition Funding, LLC

AEP Texas Central Transition Funding II, LLC

AEP Texas Central Transition Funding III, LLC

AEP Texas Commercial & Industrial Retail GP,LLC

AEP Texas Commercial & Industrial Retail Limited Partnership

AEP Texas North Company

AEP Texas North Generation Company, LLC

AEP Transmission Company, LLC

AEP Transmission Holding Company, LLC

AEP Transmission Partner, LLC

AEP Utilities, Inc

AEP Utility Funding, LLC

AEP West Virginia Transmission Company, Inc.

AEP Wind GP, LLC

AEP Wind Holding, LLC

AEP Wind LP II, LLC

Appalachian Consumer Rate Relief Funding LLC

Appalachian Power Company

Avigent

Blackhawk Coal Company

BlueStar Energy Holdings, Inc.

BSE Holdco, LLC

BSE Solutions, LLC

Cedar Coal Company

Central Appalachian Coal Company

Central Coal Company

Conesville Coal Preparation Company

Conlease, Inc.

CSW Energy, Inc.

CSW Energy Services, Inc.

Dolet Hills Lignite Company, LLC

Franklin Real Estate Company

Indiana Franklin Realty, Inc.

Indiana Michigan Power Company

Kentucky Power Company

Kingsport Power Company

Mutual Energy SWEPCO LP

Ohio Phase-In Recovery Funding LLC

Ohio Power Company

Price River Coal Company, Inc.

Public Service Company of Oklahoma

REP General Partner LLC

REP Holdco, LLC

Snowcap Coal Company, Inc.

Southern Appalachian Coal Company

Southwest Arkansas Utilities Corp.

Southwestern Electric Power Company

United Sciences Testing, Inc.

Wheeling Power Company

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2013

BU #	COMPANY NAME	ACTUAL Taxable Income (Loss) 11/30/13	Taxable Income (Loss) Adjustments	Taxable Income (Loss) Adjustments	Taxable Income (Loss) Adjustments	ADJUSTED ACTUAL Taxable Income (Loss) 11/30/13	Consolidated Taxable Income	Taxable Income Companies	INITIAL Allocation of Parent Company Loss	Unbundled Taxable Income Companies	REVISED Allocation of Parent Company Loss
100	AEP Company	(20,187,890)	0	0	0	(20,187,890)	(20,187,890)	0	20,187,890		20,187,890
203	AEP C&I Company, LLC	(503,619)	0	0	0	(503,619)	(503,619)	0	0		0
302	AEP Coal, Inc.	325,764	0	0	0	325,764	325,764	325,764	(10,732)		(10,732)
154	AEP Credit, Inc	4,435,556	0	0	0	4,435,556	4,435,556	4,435,556	(146,121)		(146,121)
315	AEP Desert Sky GP, LLC	17,840	0	0	0	17,840	17,840	17,840	(588)		(588)
341	AEP Desert Sky LP2, LLC	3,804,381	0	0	0	3,804,381	3,804,381	3,804,381	(125,328)		(125,328)
293	AEP Elmwood, LLC	540,041	0	0	0	540,041	540,041	540,041	(17,791)		(17,791)
175	AEP Energy Partners, Inc.	25,039,182	0	0	0	25,039,182	25,039,182	25,039,182	(824,867)		(824,867)
185	AEP Energy Services	(1,589,770)	0	0	0	(1,589,770)	(1,589,770)	0	0		0
102	AEP Energy Supply LLC	0	0	0	0	0	0	0	0		0
127	AEP Energy Srvcs Gas Holding	(148,716)	0	0	0	(148,716)	(148,716)	0	0		0
193	AEP Fiber Venture, LLC	(1,419,393)	0	0	0	(1,419,393)	(1,419,393)	0	0		0
181	AEP Generation Resources	0	0	0	0	0	0	0	0		0
174	AEP Holdco, Inc.	28,006	0	0	0	28,006	28,006	28,006	(923)		(923)
163	AEP Generating - Rockport	6,625,701	0	0	0	6,625,701				6,625,701	(218,271)
377	AEP Generating - Dresden	1,077,948	0	0	0	1,077,948				1,077,948	(35,511)
375	AEP Generating - Lawrenceburg	631,304	0	0	0	631,304				631,304	(20,797)
270	Cook Coal Terminal	0	0	0	0	0				0	0
	AEG - Consolidated						8,334,953	8,334,953	(274,579)	8,334,953	
196	AEP Investments	2,736,133	0	0	0	2,736,133	2,736,133	2,736,133	(90,137)		(90,137)
305	AEP Kentucky Coal, LLC	(654,963)	0	0	0	(654,963)	(654,963)	0	0		0
292	AEP Memco, LLC - Barges / Boats	(1,931,822)	0	0	0	(1,931,822)	(1,931,822)	0	0		0
364	AEP Non-Utility Funding, LLC	(131,556)	0	0	0	(131,556)	(131,556)	0	0		0
304	AEP Ohio Coal, LLC	0	0	0	0	0	0	0	0		0
373	AEP Partners	0	0	0	0	0	0	0	0		0
361	AEP Properties	140,780	0	0	0	140,780	140,780	140,780	(4,638)		(4,638)
143	AEP Pro Serv	298,711	0	0	0	298,711	298,711	298,711	(9,840)		(9,840)
172	AEP Resources	36,134,583	0	0	0	36,134,583	36,134,583	36,134,583	(1,190,384)		(1,190,384)
390	AEP Retail Energy Partners LLC	(242,814)	0	0	0	(242,814)	(242,814)	0	0		0
103	AEP Service Corp	(51,811,908)	0	0	0	(51,811,908)	(51,811,908)	0	0		0
204	AEP T&D Services, LLC	8,403,776	0	0	0	8,403,776	8,403,776	8,403,776	(276,846)		(276,846)
195	AEP Texas C&I Retail, LP	(98,976)	0	0	0	(98,976)	(98,976)	0	0		0
211	AEP Texas Central Co. - Dist	207,084,903	0	0	0	207,084,903				207,084,903	(5,652,935)
162	AEP Texas Central Co. - Securitization I	192,918	0	0	0	192,918				192,918	(5,266)
372	AEP Texas Central Co. - Securitization II	(5,757,463)	0	0	0	(5,757,463)				0	0
395	AEP Texas Central Co. - Securitization III	(5,929,823)	0	0	0	(5,929,823)				0	0
169	AEP Texas Central Co. - Trans	(23,833,531)	0	0	0	(23,833,531)				0	0
	TCC - Consolidated						171,757,004	171,757,004	(5,658,201)	207,277,821	
119	AEP Texas North Co. - Dist	(437,189)	0	0	0	(437,189)				0	0
166	AEP Texas North Co. - Gen	31,517,817	0	0	0	31,517,817				31,517,817	(786,265)
192	AEP Texas North Co. - Trans	(6,162,377)	0	0	0	(6,162,377)				0	0
371	Texas North Generation Co.	(1,050,863)	0	0	0	(1,050,863)				0	0
	TCN - Consolidated						23,867,388	23,867,388	(786,265)	31,517,817	
370	AEP Tranmission Company, LLC	(752,302)	0	0	0	(752,302)	(752,302)	0	0		0
369	AEP Transmission Holding Co.	(258,578,094)	0	0	0	(258,578,094)	(258,578,094)	0	0		0
393	AEP Transmission Partner LLC	(2,680,839)	0	0	0	(2,680,839)	(2,680,839)	0	0		0
365	AEP Transportation, LLC	0	0	0	0	0	0	0	0		0
216	AEP TX C&I Retail GP, LLC	(3,076)	0	0	0	(3,076)	(3,076)	0	0		0
101	AEP Utilities	6,616,826	0	0	0	6,616,826	6,616,826	6,616,826	(217,978)		(217,978)
353	AEP Utility Funding, LLC	(51,915)	0	0	0	(51,915)	(51,915)	0	0		0

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2013

BU #	COMPANY NAME	ACTUAL Taxable Income (Loss) 11/30/13	Taxable Income (Loss) Adjustments	Taxable Income (Loss) Adjustments	Taxable Income (Loss) Adjustments	ADJUSTED ACTUAL Taxable Income (Loss) 11/30/13	Consolidated Taxable Income	Taxable Income Companies	INITIAL Allocation of Parent Company Loss	Unbundled Taxable Income Companies	REVISED Allocation of Parent Company Loss
306	AEP West Virginia Coal, Inc.	0	0	0	0	0	0	0	0		0
277	AEP Wind GP	18,564	0	0	0	18,564	18,564	18,564	(612)		(612)
345	AEP Wind Holding Company	50,382	0	0	0	50,382	50,382	50,382	(1,660)		(1,660)
339	AEP Wind LP 2	5,580,560	0	0	0	5,580,560	5,580,560	5,580,560	(183,841)		(183,841)
140	Appalachian Power - Dist	(27,811,334)	0	0	0	(27,811,334)				0	0
215	Appalachian Power - Gen	(23,387,062)	0	0	0	(23,387,062)				0	0
150	Appalachian Power - Trans	59,360,511	0	0	0	59,360,511				59,360,511	(247,628)
410	Appalachian Power - Rate Relief Fund	(645,280)	0	0	0	(645,280)				0	0
	APCO - Consolidated						7,516,835	7,516,835	(247,628)	59,360,511	
202	Blackhawk Coal	7,838	0	0	0	7,838	7,838	7,838	(258)		(258)
398	BlueStar Energy Holdings, Inc.	(18,652)	0	0	0	(18,652)	(18,652)	0	0		0
400	AEP Energy, Inc.	15,722,984	0	0	0	15,722,984	15,722,984	15,722,984	(517,963)		(517,963)
401	BSE Solutions LLC	(134,463)	0	0	0	(134,463)	(134,463)	0	0		0
225	Cedar Coal	256,163	0	0	0	256,163	256,163	256,163	(8,439)		(8,439)
125	Central Appalachian Coal	(309,139)	0	0	0	(309,139)	(309,139)	0	0		0
189	Central Coal Co	(20,180)	0	0	0	(20,180)	(20,180)	0	0		0
290	Conesville Coal	1,240,827	0	0	0	1,240,827	1,240,827	1,240,827	(40,877)		(40,877)
176	CSW Energy Services, Inc.	35,171	0	0	0	35,171	35,171	35,171	(1,159)		(1,159)
171	CSW Energy, Inc	2,592,933	0	0	0	2,592,933	2,592,933	2,592,933	(85,419)		(85,419)
263	CSW Services International, Inc.	0	0	0	0	0	0	0	0		0
245	Dolet Hills Lignite Co., LLC	0	0	0	0	0	0	0	0		0
324	HPL Storage, Inc.	0	0	0	0	0	0	0	0		0
170	Indiana Michigan Power - Dist	(36,207,664)	0	0	0	(36,207,664)				0	0
132	Indiana Michigan Power - Gen	534,193,991	0	0	0	534,193,991				534,193,991	0
190	Indiana Michigan Power - Nucl	(653,212,283)	0	0	0	(653,212,283)				0	0
280	Indiana Michigan Power - RTD	5,293,421	0	0	0	5,293,421				5,293,421	0
120	Indiana Michigan Power - Trans	89,059,049	0	0	0	89,059,049				89,059,049	0
	I&M - Consolidated						(60,873,486)	0	0	628,546,461	
110	Kentucky Power - Dist	(3,293,176)	0	0	0	(3,293,176)				0	0
117	Kentucky Power - Gen	(3,051,654)	0	0	0	(3,051,654)				0	0
180	Kentucky Power - Trans	31,808,307	0	0	0	31,808,307				31,808,307	(838,845)
	KPCO - Consolidated						25,463,477	25,463,477	(838,845)	31,808,307	
230	Kingsport Power - Dist	(4,595,864)	0	0	0	(4,595,864)				0	0
260	Kingsport Power - Trans	3,150,603	0	0	0	3,150,603				3,150,603	0
	KGPRT - Consolidated						(1,445,261)	0	0	3,150,603	
250	Ohio Power - Dist	110,050,405	0	0	0	110,050,405				110,050,405	(2,794,290)
160	Ohio Power - Trans	(41,247,490)	0	0	0	(41,247,490)				0	0
181	Ohio Power - Gen	125,804,604	0	0	0	125,804,604				125,804,604	(3,194,305)
270	Cook Coal Terminal	(11,267,989)	0	0	0	(11,267,989)				0	0
404	AEP Generation Resources	(1,533,267)	0	0	0	(1,533,267)				0	0
408	Ohio Phase-In Recovery Funding	0	0	0	0	0				0	0
	OPCO - Consolidated						181,786,263	181,786,263	(5,988,595)	235,855,009	
167	Public Service Co. of Ok - Dist	1,274,987	0	0	0	1,274,987				1,274,987	(21,128)
198	Public Service Co. of Ok - Gen	(33,708,699)	0	0	0	(33,708,699)				0	0
114	Public Service Co. of Ok - Trans	66,552,868	0	0	0	66,552,868				66,552,868	(1,102,861)
	PSO - Consolidated						34,119,156	34,119,156	(1,123,989)	67,827,855	

AEP SYSTEM

FORECASTED SEC ALLOCATION

ESTIMATE AS OF DECEMBER 2013

BU #	COMPANY NAME	ACTUAL Taxable Income (Loss) 11/30/13	Taxable Income (Loss) Adjustments	Taxable Income (Loss) Adjustments	Taxable Income (Loss) Adjustments	ADJUSTED ACTUAL Taxable Income (Loss) 11/30/13	Consolidated Taxable Income	Taxable Income Companies	INITIAL Allocation of Parent Company Loss	Unbundled Taxable Income Companies	REVISED Allocation of Parent Company Loss
227	Rep General Partner LLC	(1,182)	0	0	0	(1,182)	(1,182)	0	0		0
303	Snowcap Coal Company, Inc.	(399,093)	0	0	0	(399,093)	(399,093)	0	0		0
217	Southern Appalachian Coal	(1,481)	0	0	0	(1,481)	(1,481)	0	0		0
159	Southwestern Electric Pwr - Dist	24,665,509	0	0	0	24,665,509				24,665,509	(43,578)
161	Southwestern Electric Pwr - Dist - TX	54,043,619	0	0	0	54,043,619				54,043,619	(95,482)
168	Southwestern Electric Pwr - Gen	(148,409,798)	0	0	0	(148,409,798)				0	0
194	Southwestern Electric Pwr - Trans	92,116,254	0	0	0	92,116,254				92,116,254	(162,747)
111	Southwestern Electric Pwr - Trans - TX	(8,969,747)	0	0	0	(8,969,747)				0	0
245	Dolet Hills Lignite Co., LLC	(4,284,356)	0	0	0	(4,284,356)				0	0
	SWEPCO - Consolidated						9,161,481	9,161,481	(301,807)	170,825,382	
319	United Sciences Testing, Inc.	(229,760)	0	0	0	(229,760)	(229,760)	0	0		0
210	Wheeling Power - Dist	27,543,209	0	0	0	27,543,209				27,543,209	(907,357)
200	Wheeling Power - Trans	8,974,965	0	0	0	8,974,965				8,974,965	(295,663)
200	Wheeling Power - Gen	0	0	0	0	0				0	0
	WPCO - Consolidated						36,518,174	36,518,174	(1,203,020)	36,518,174	
380	AEP Ohio Transmission Co.	(30,749,448)	0	0	0	(30,749,448)	(30,749,448)	0	0		0
382	AEP Appalachian Transmission Co.	(219,393)	0	0	0	(219,393)	(219,393)	0	0		0
383	AEP West Vrginia Transmission Co.	150,000	0	0	0	150,000	150,000	150,000	(4,941)		(4,941)
384	AEP Kentucky Transmission Co.	(13,276)	0	0	0	(13,276)	(13,276)	0	0		0
385	AEP Indiana Michigan Transmission Co.	(41,996,154)	0	0	0	(41,996,154)	(41,996,154)	0	0		0
386	AEP Oklahoma Transmission Co.	(11,349,021)	0	0	0	(11,349,021)	(11,349,021)	0	0		0
388	AEP Southwestern Transmission Co.	(214,794)	0	0	0	(214,794)	(214,794)	0	0		0
396	RITELine Indiana, LLC	(79,081)	0	0	0	(79,081)	(79,081)	0	0		0
397	AEP Retail Energy Partners	0	0	0	0	0	0	0	0		0
403	Transource Energy, LLC	0	0	0	0	0	0	0	0		0
407	Transource Missouri, LLC	109,951	0	0	0	109,951	109,951	109,951	(3,622)		(3,622)
	Other Companies - Non Allocated	0	0	0	0	0	0	0	0		0
	Total System	123,970,166	0	0	0	123,970,166	123,970,166	612,811,683	(3)		(3)
						OK					

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2013

BU #	COMPANY NAME	INITIAL Tax Effect of Parent Company Loss	Rounding Adjustments	Special Adjustments	FINAL Tax Effect of Parent Company Loss
160	AEP Company	[redacted]			
203	AEP C&I Company, LLC	0	0	0	0
302	AEP Coal, Inc.	(3,756)	756	0	(3,000)
154	AEP Credit, Inc	(51,142)	142	0	(51,000)
315	AEP Desert Sky GP, LLC	(206)	206	0	0
341	AEP Desert Sky LP2, LLC	(43,865)	865	0	(43,000)
293	AEP Elmwood, LLC	(6,227)	227	0	(6,000)
175	AEP Energy Partners, Inc.	(288,703)	703	0	(288,000)
185	AEP Energy Services	0	0	0	0
102	AEP Energy Supply LLC	0	0	0	0
127	AEP Energy Srvcs Gas Holding	0	0	0	0
193	AEP Fiber Venture, LLC	0	0	0	0
181	AEP Generation Resources	0	0	0	0
174	AEP Holdco, Inc.	(323)	323	0	0
153	AEP Generating - Rockport	(76,395)	395	0	(76,000)
377	AEP Generating - Dresden	(12,429)	429	0	(12,000)
375	AEP Generating - Lawrenceburg	(7,279)	279	0	(7,000)
270	Cook Coal Terminal	0	0	0	0
	AEG - Consolidated				
196	AEP Investments	(31,548)	548	0	(31,000)
305	AEP Kentucky Coal, LLC	0	0	0	0
292	AEP Memco, LLC - Barges / Boats	0	0	0	0
364	AEP Non-Utility Funding, LLC	0	0	0	0
304	AEP Ohio Coal, LLC	0	0	0	0
373	AEP Partners	0	0	0	0
361	AEP Properties	(1,623)	623	0	(1,000)
143	AEP Pro Serv	(3,444)	444	0	(3,000)
172	AEP Resources	(416,634)	634	0	(416,000)
390	AEP Retail Energy Partners LLC	0	0	0	0
103	AEP Service Corp	0	0	0	0
204	AEP T&D Services, LLC	(96,896)	896	0	(96,000)
195	AEP Texas C&I Retail, LP	0	0	0	0
211	AEP Texas Central Co. - Dist	(1,978,527)	527	0	(1,978,000)
162	AEP Texas Central Co. - Securitization I	(1,843)	843	0	(1,000)
372	AEP Texas Central Co. - Securitization II	0	0	0	0
395	AEP Texas Central Co. - Securitization III	0	0	0	0
169	AEP Texas Central Co. - Trans	0	0	0	0
	TCC - Consolidated				
119	AEP Texas North Co. - Dist	0	0	0	0
166	AEP Texas North Co. - Gen	(275,193)	193	0	(275,000)
192	AEP Texas North Co. - Trans	0	0	0	0
371	Texas North Generation Co.	0	0	0	0
	TCN - Consolidated				
370	AEP Tranmission Company, LLC	0	0	0	0
369	AEP Transmission Holding Co.	0	0	0	0
393	AEP Transmission Partner LLC	0	0	0	0
365	AEP Transportation, LLC	0	0	0	0
216	AEP TX C&I Retail GP, LLC	0	0	0	0
101	AEP Utilities	(76,292)	292	0	(76,000)
353	AEP Utility Funding, LLC	0	0	0	0

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2013

BU #	COMPANY NAME	INITIAL Tax Effect of Parent Company Loss	Rounding Adjustments	Special Adjustments	FINAL Tax Effect of Parent Company Loss
306	AEP West Virginia Coal, Inc.	0	0	0	0
277	AEP Wind GP	(214)	214	0	0
345	AEP Wind Holding Company	(581)	581	0	0
339	AEP Wind LP 2	(64,344)	344	0	(64,000)
140	Appalachian Power - Dist	0	0	0	0
215	Appalachian Power - Gen	0	0	0	0
150	Appalachian Power - Trans	(86,670)	670	0	(86,000)
410	Appalachian Power - Rate Relief Fund	0	0	0	0
	APCO - Consolidated				
202	Blackhawk Coal	(90)	90	0	0
398	BlueStar Energy Holdings, Inc.	0	0	0	0
400	AEP Energy, Inc.	(181,287)	287	0	(181,000)
401	BSE Solutions LLC	0	0	0	0
225	Cedar Coal	(2,954)	954	0	(2,000)
125	Central Appalachian Coal	0	0	0	0
189	Central Coal Co	0	0	0	0
290	Conesville Coal	(14,307)	307	0	(14,000)
176	CSW Energy Services, Inc.	(406)	406	0	0
171	CSW Energy, Inc	(29,897)	897	0	(29,000)
263	CSW Services International, Inc.	0	0	0	0
245	Dolet Hills Lignite Co., LLC	0	0	0	0
324	HPL Storage, Inc.	0	0	0	0
170	Indiana Michigan Power - Dist	0	0	0	0
132	Indiana Michigan Power - Gen	0	0	0	0
190	Indiana Michigan Power - Nucl	0	0	0	0
280	Indiana Michigan Power - RTD	0	0	0	0
120	Indiana Michigan Power - Trans	0	0	0	0
	I&M - Consolidated				
110	Kentucky Power - Dist	0	0	0	0
117	Kentucky Power - Gen	0	0	0	0
180	Kentucky Power - Trans	(293,596)	596	0	(293,000)
	KPCO - Consolidated				
230	Kingsport Power - Dist	0	0	0	0
260	Kingsport Power - Trans	0	0	0	0
	KGPRT - Consolidated				
250	Ohio Power - Dist	(978,002)	2	0	(978,000)
160	Ohio Power - Trans	0	0	0	0
181	Ohio Power - Gen	(1,118,007)	7	0	(1,118,000)
270	Cook Coal Terminal	0	0	0	0
404	AEP Generation Resources	0	0	0	0
408	Ohio Phase-In Recovery Funding	0	0	0	0
	OPCO - Consolidated				
167	Public Service Co. of Ok - Dist	(7,395)	395	0	(7,000)
198	Public Service Co. of Ok - Gen	0	0	0	0
114	Public Service Co. of Ok - Trans	(386,001)	1	0	(386,000)
	PSO - Consolidated				

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2013

BU #	COMPANY NAME	INITIAL Tax Effect of Parent Company Loss	Rounding Adjustments	Special Adjustments	FINAL Tax Effect of Parent Company Loss
227	Rep General Partner LLC	0	0	0	0
303	Snowcap Coal Company, Inc.	0	0	0	0
217	Southern Appalachian Coal	0	0	0	0
159	Southwestern Electric Pwr - Dist	(15,252)	252	0	(15,000)
161	Southwestern Electric Pwr - Dist - TX	(33,419)	419	0	(33,000)
168	Southwestern Electric Pwr - Gen	0	0	0	0
194	Southwestern Electric Pwr - Trans	(56,961)	961	0	(56,000)
111	Southwestern Electric Pwr - Trans - TX	0	0	0	0
245	Dolet Hills Lignite Co., LLC	0	0	0	0
	SWEPCO - Consolidated				
319	United Sciences Testing, Inc.	0	0	0	0
210	Wheeling Power - Dist	(317,575)	575	0	(317,000)
200	Wheeling Power - Trans	(103,482)	482	0	(103,000)
200	Wheeling Power - Gen	0	0	0	0
	WPCO - Consolidated				
380	AEP Ohio Transmission Co.	0	0	0	0
382	AEP Appalachian Transmission Co.	0	0	0	0
383	AEP West Vrginia Transmission Co.	(1,729)	729	0	(1,000)
384	AEP Kentucky Transmission Co.	0	0	0	0
385	AEP Indiana Michigan Transmission Co.	0	0	0	0
386	AEP Oklahoma Transmission Co.	0	0	0	0
388	AEP Southwestern Transmission Co.	0	0	0	0
396	RITELine Indiana, LLC	0	0	0	0
397	AEP Retail Energy Partners	0	0	0	0
403	Transource Energy, LLC	0	0	0	0
407	Transource Missouri, LLC	(1,268)	268	0	(1,000)
	Other Companies - Non Allocated	0	0	0	0
	Total System	(7,065,762)	18,762	0	(7,047,000)
					OK

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2014

BU #	COMPANY NAME	ACTUAL Taxable Income (Loss) 11/30/14	Taxable Income (Loss) Adjustments BONUS DEPR	Taxable Income (Loss) Adjustments §199 DEDUCT	Taxable Income (Loss) Adjustments Charitable Adj	ADJUSTED ACTUAL Taxable Income (Loss) 11/30/14	Consolidated Taxable Income	Taxable Income Companies	INITIAL Allocation of Parent Company Loss	Unbundled Taxable Income Companies	REVISED Allocation of Parent Company Loss
100	AEP Company	(48,264,343)	0	0	11,336,911	(36,927,432)	(36,927,432)	0	36,927,432		36,927,432
203	AEP C&I Company, LLC	(463,553)	0	0	14	(463,539)	(463,539)	0	0		0
302	AEP Coal, Inc.	(184,368)	0	0	0	(184,368)	(184,368)	0	0		0
154	AEP Credit, Inc	11,593,888	0	0	0	11,593,888	11,593,888	11,593,888	(340,817)		(340,817)
315	AEP Desert Sky GP, LLC	22,530	0	3,300	0	25,830	25,830	25,830	(759)		(759)
341	AEP Desert Sky LP2, LLC	4,260,498	0	330,000	0	4,590,498	4,590,498	4,590,498	(134,943)		(134,943)
293	AEP Elmwood, LLC	(767,702)	(252,000)	0	501,662	(518,040)	(518,040)	0	0		0
175	AEP Energy Partners, Inc.	81,874,782	(3,768,000)	3,025,000	6,524	81,138,306	81,138,306	81,138,306	(2,385,160)		(2,385,160)
185	AEP Energy Services	(1,235,700)	0	0	580	(1,235,120)	(1,235,120)	0	0		0
102	AEP Energy Supply LLC	(990,152)	0	0	0	(990,152)	(990,152)	0	0		0
127	AEP Energy Srvcs Gas Holding	(3,414)	0	0	0	(3,414)	(3,414)	0	0		0
193	AEP Fiber Venture, LLC	(1,449,424)	0	0	0	(1,449,424)	(1,449,424)	0	0		0
181	AEP Generation Resources	579,905,290	(71,509,200)	23,100,000	8,163,723	539,659,813	539,659,813	539,659,813	(15,863,961)		(15,863,961)
174	AEP Holdco, Inc.	24,502	0	0	0	24,502	24,502	24,502	(720)		(720)
153	AEP Generating - Rockport	28,836,684	(1,776,000)	2,860,000	728,123	30,648,807				30,648,807	(900,959)
377	AEP Generating - Dresden	722,386	0	0	12,971	735,357				735,357	(21,617)
375	AEP Generating - Lawrenceburg	10,825,947	(3,660,000)	0	18,681	7,184,628				7,184,628	(211,201)
270	Cook Coal Terminal	7,514,258	(45,000)	0	76,445	7,545,703				7,545,703	(221,815)
	AEG - Consolidated						46,114,495	46,114,495	(1,355,592)	46,114,495	
196	AEP Investments	1,933,551	0	0	17	1,933,568	1,933,568	1,933,568	(56,840)		(56,840)
305	AEP Kentucky Coal, LLC	(586,824)	0	0	0	(586,824)	(586,824)	0	0		0
292	AEP Memco, LLC - Barges / Boats	82,396,747	(1,764,000)	0	1,271,431	81,904,178	81,904,178	81,904,178	(2,407,674)		(2,407,674)
384	AEP Non-Utility Funding, LLC	(99,307)	0	0	0	(99,307)	(99,307)	0	0		0
304	AEP Ohio Coal, LLC	0	0	0	0	0	0	0	0		0
373	AEP Partners	0	0	0	0	0	0	0	0		0
361	AEP Properties	103,980	0	0	0	103,980	103,980	103,980	(3,057)		(3,057)
143	AEP Pro Serv	212,340	0	0	1	212,341	212,341	212,341	(6,242)		(6,242)
172	AEP Resources	1,250,381	0	0	18	1,250,399	1,250,399	1,250,399	(36,757)		(36,757)
390	AEP Retail Energy Partners LLC	0	0	0	0	0	0	0	0		0
103	AEP Service Corp	(1,487,207)	(15,796,800)	0	3,989,484	(13,294,523)	(13,294,523)	0	0		0
204	AEP T&D Services, LLC	1,406,723	0	0	0	1,406,723	1,406,723	1,406,723	(41,352)		(41,352)
195	AEP Texas C&I Retail, LP	(8,101)	0	0	0	(8,101)	(8,101)	0	0		0
211	AEP Texas Central Co. - Dist	351,864,259	(96,132,000)	0	1,908,804	257,641,063				257,641,063	(5,668,697)
162	AEP Texas Central Co. - Securitization I	7,112,584	0	0	0	7,112,584				7,112,584	(156,493)
372	AEP Texas Central Co. - Securitization II	5,097,030	0	0	0	5,097,030				5,097,030	(112,146)
395	AEP Texas Central Co. - Securitization III	3,234,604	0	0	0	3,234,604				3,234,604	(71,169)
169	AEP Texas Central Co. - Trans	33,396,029	(103,200,000)	0	1,115,853	(68,688,118)				0	0
	TCC - Consolidated						204,397,163	204,397,163	(6,008,505)	273,085,281	
119	AEP Texas North Co. - Dist	28,484,261	(28,248,000)	0	463,287	699,548				699,548	(4,469)
166	AEP Texas North Co. - Gen	15,684,465	0	0	12,828	15,697,293				15,697,293	(100,275)
192	AEP Texas North Co. - Trans	13,177,614	(25,788,000)	0	456,632	(12,153,754)				0	0
371	Texas North Generation Co.	(679,895)	0	0	0	(679,895)				0	0
	TCN - Consolidated						3,563,192	3,563,192	(104,744)	16,396,841	
370	AEP Tranmission Company, LLC	(324,601)	0	0	1,684	(322,917)	(322,917)	0	0		0
369	AEP Transmission Holding Co.	50,948,540	0	0	5,231	50,953,771	50,953,771	50,953,771	(1,497,848)		(1,497,848)
393	AEP Transmission Partner LLC	492,086	0	0	0	492,086	492,086	492,086	(14,465)		(14,465)
365	AEP Transportation, LLC	0	0	0	0	0	0	0	0		0
216	AEP TX C&I Retail GP, LLC	(3,434)	0	0	0	(3,434)	(3,434)	0	0		0
101	AEP Utilities	(1,395,976)	0	0	284,790	(1,111,186)	(1,111,186)	0	0		0
353	AEP Utility Funding, LLC	(57,056)	0	0	0	(57,056)	(57,056)	0	0		0

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2014

BU #	COMPANY NAME	ACTUAL Taxable Income (Loss) 11/30/14	Taxable Income (Loss) Adjustments BONUS DEPR	Taxable Income (Loss) Adjustments §199 DEDUCT	Taxable Income (Loss) Adjustments Charitable Adj	ADJUSTED ACTUAL Taxable Income (Loss) 11/30/14	Consolidated Taxable Income	Taxable Income Companies	INITIAL Allocation of Parent Company Loss	Unbundled Taxable Income Companies	REVISED Allocation of Parent Company Loss
306	AEP West Virginia Coal, Inc.	0	0	0	0	0	0	0	0		0
277	AEP Wind GP	15,621	0	5,500	0	21,121	21,121	21,121	(621)		(621)
345	AEP Wind Holding Company	(83,462)	0	0	113	(83,349)	(83,349)	0	0		0
339	AEP Wind LP 2	4,975,503	0	495,000	0	5,470,503	5,470,503	5,470,503	(160,812)		(160,812)
140	Appalachian Power - Dist	19,461,639	(75,816,000)	0	7,252,698	(49,101,663)				0	0
215	Appalachian Power - Gen	32,374,868	(38,736,000)	6,435,000	16,652,286	16,726,154				16,726,154	(103,665)
150	Appalachian Power - Trans	108,674,494	(63,660,000)	0	479,207	45,493,701				45,493,701	(281,960)
410	Appalachian Power - Rate Relief Fund	0	0	0	0	0				0	0
	APCO - Consolidated						13,118,192	13,118,192	(385,625)	62,219,855	
202	Blackhawk Coal	7,277	0	0	0	7,277	7,277	7,277	(214)		(214)
398	BlueStar Energy Holdings, Inc.	(12,807)	0	0	0	(12,807)	(12,807)	0	0		0
400	AEP Energy, Inc.	17,504,340	(888,000)	0	20,476	16,636,816	16,636,816	16,636,816	(489,060)		(489,060)
401	BSE Solutions LLC	(1,308,987)	0	0	714	(1,308,273)	(1,308,273)	0	0		0
225	Cedar Coal	24,782	0	0	0	24,782	24,782	24,782	(728)		(728)
125	Central Appalachian Coal	(227,614)	0	0	0	(227,614)	(227,614)	0	0		0
189	Central Coal Co	(36,384)	0	0	0	(36,384)	(36,384)	0	0		0
290	Conesville Coal	106,502	0	0	779	107,281	107,281	107,281	(3,154)		(3,154)
176	CSW Energy Services, Inc.	(223,874)	0	0	0	(223,874)	(223,874)	0	0		0
171	CSW Energy, Inc	13,125,436	0	0	134	13,125,570	13,125,570	13,125,570	(385,842)		(385,842)
263	CSW Services International, Inc.	0	0	0	0	0	0	0	0		0
245	Dolet Hills Lignite Co., LLC	0	0	0	0	0	0	0	0		0
324	HPL Storage, Inc.	0	0	0	0	0	0	0	0		0
170	Indiana Michigan Power - Dist	4,272,300	(49,008,000)	0	2,288,532	(42,447,168)				0	0
132	Indiana Michigan Power - Gen	553,810,327	(6,288,000)	671,000	1,275,736	549,469,063				549,469,063	0
190	Indiana Michigan Power - Nucl	(550,474,572)	(97,632,000)	0	2,116,135	(645,990,437)				0	0
280	Indiana Michigan Power - RTD	8,710,336	0	0	36,330	8,746,666				8,746,666	0
120	Indiana Michigan Power - Trans	159,984,615	(40,608,000)	0	1,416,480	120,793,095				120,793,095	0
	I&M - Consolidated						(9,428,781)	0	0	679,008,624	
110	Kentucky Power - Dist	12,003,325	(22,560,000)	0	737,965	(9,818,710)				0	0
117	Kentucky Power - Gen	58,641,193	(41,196,000)	0	212,694	17,657,887				17,657,887	(396,909)
180	Kentucky Power - Trans	50,095,690	(26,172,000)	0	137,279	24,060,969				24,060,969	(540,835)
	KPCO - Consolidated						31,900,146	31,900,146	(937,744)	41,718,856	
230	Kingsport Power - Dist	(5,344,725)	(2,676,000)	0	185,954	(7,834,771)				0	0
260	Kingsport Power - Trans	5,464,042	(1,044,000)	0	3,232	4,423,274				4,423,274	0
	KGPRT - Consolidated						(3,411,497)	0	0	4,423,274	
250	Ohio Power - Dist	186,337,177	(146,088,000)	0	19,426,568	59,675,745				59,675,745	(1,754,242)
160	Ohio Power - Trans	109,918,785	(75,026,600)	0	2,400,100	37,292,285				37,292,285	(1,096,252)
181	Ohio Power - Gen	0	0	0	0	0				0	0
270	Cook Coal Terminal	0	0	0	0	0				0	0
404	AEP Generation Resources	0	0	0	0	0				0	0
408	Ohio Phase-In Recovery Funding	0	0	0	0	0				0	0
	OPCO - Consolidated						96,968,030	96,968,030	(2,850,494)	96,968,030	
167	Public Service Co. of Ok - Dist	50,625,583	(73,404,000)	0	967,494	(21,810,923)				0	0
198	Public Service Co. of Ok - Gen	(44,132,265)	(15,468,000)	0	661,140	(58,939,125)				0	0
114	Public Service Co. of Ok - Trans	76,431,052	(59,952,000)	0	287,436	16,766,488				16,766,488	0
	PSO - Consolidated						(63,983,560)	0	0	16,766,488	

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2014

BU #	COMPANY NAME	ACTUAL Taxable Income (Loss) 11/30/14	Taxable Income (Loss) Adjustments BONUS DEPR	Taxable Income (Loss) Adjustments §199 DEDUCT	Taxable Income (Loss) Adjustments Charitable Adj	ADJUSTED ACTUAL Taxable Income (Loss) 11/30/14	Consolidated Taxable Income	Taxable Income Companies	INITIAL Allocation of Parent Company Loss	Unbundled Taxable Income Companies	REVISED Allocation of Parent Company Loss
227	Rep General Partner LLC	(1,285)	0	0	0	(1,285)	(1,285)	0	0		0
303	Snowcap Coal Company, Inc.	(316,727)	0	0	0	(316,727)	(316,727)	0	0		0
217	Southern Appalachian Coal	(16,741)	0	0	0	(16,741)	(16,741)	0	0		0
159	Southwestern Electric Pwr - Dist	45,362,272	(15,636,000)	0	447,208	30,173,480				30,173,480	0
161	Southwestern Electric Pwr - Dist - TX	33,209,246	(21,936,000)	0	181,780	11,455,026				11,455,026	0
168	Southwestern Electric Pwr - Gen	(42,047,358)	(60,264,000)	3,850,000	1,980,555	(96,480,803)				0	0
194	Southwestern Electric Pwr - Trans	115,164,347	(46,416,000)	0	373,787	69,122,134				69,122,134	0
111	Southwestern Electric Pwr - Trans - TX	697,803	(23,568,000)	0	0	(22,870,197)				0	0
245	Dolet Hills Lignite Co., LLC	4,302,676	(4,836,000)	0	0	(533,324)				0	0
	SWEPCO - Consolidated						(9,133,684)	0	0	110,750,640	
319	United Sciences Testing, Inc.	(555,198)	0	0	4	(555,194)	(555,194)	0	0		0
210	Wheeling Power - Dist	37,282,808	(4,778,400)	0	14,733	32,519,141				32,519,141	(955,940)
200	Wheeling Power - Trans	19,241,022	(2,328,000)	0	6,063	16,919,085				16,919,085	(497,357)
200	Wheeling Power - Gen	0	0	0	0	0				0	0
	WPCO - Consolidated						49,438,226	49,438,226	(1,453,297)	49,438,226	
380	AEP Ohio Transmission Co.	27,925,807	(235,620,000)	0	29,507	(207,664,686)	(207,664,686)	0	0		0
382	AEP Appalachian Transmission Co.	(183,404)	0	0	659	(182,745)	(182,745)	0	0		0
383	AEP West Vrginia Transmission Co.	(1,106,023)	(56,435,100)	0	1,242	(57,539,881)	(57,539,881)	0	0		0
384	AEP Kentucky Transmission Co.	(42,061)	0	0	382	(41,679)	(41,679)	0	0		0
385	AEP Indiana Michigan Transmission Co.	9,752,754	(29,340,000)	0	3,497	(19,583,749)	(19,583,749)	0	0		0
386	AEP Oklahoma Transmission Co.	18,145,586	(48,672,000)	0	3,393	(30,523,021)	(30,523,021)	0	0		0
388	AEP Southwestern Transmission Co.	13,616	0	0	142	13,758	13,758	13,758	(404)		(404)
396	RITELine Indiana, LLC	0	0	0	0	0	0	0	0		0
397	AEP Retail Energy Partners	(4,156,280)	0	0	0	(4,156,280)	(4,156,280)	0	0		0
403	Transource Energy, LLC	0	0	0	0	0	0	0	0		0
407	Transource Missouri, LLC	0	0	0	0	0	0	0	0		0
	Other Companies - Non Allocated	0	0	0	0	0	0	0	0		0
	Total System	2,397,767,959	(1,737,991,100)	40,774,800	89,958,128	790,509,787	790,509,787	1,258,196,435	1		1
						OK					

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2014

BU #	COMPANY NAME	INITIAL Tax Effect of Parent Company Loss	Rounding Adjustments	Special Adjustments	FINAL Tax Effect of Parent Company Loss
100	AEP Company	[redacted]			
203	AEP C&I Company, LLC	0	0	0	0
302	AEP Coal, Inc.	0	0	0	0
154	AEP Credit, Inc	(119,266)	266	0	(119,000)
315	AEP Desert Sky GP, LLC	(266)	266	0	0
341	AEP Desert Sky LP2, LLC	(47,230)	230	0	(47,000)
293	AEP Elmwood, LLC	0	0	0	0
175	AEP Energy Partners, Inc.	(834,806)	806	0	(834,000)
185	AEP Energy Services	0	0	0	0
102	AEP Energy Supply LLC	0	0	0	0
127	AEP Energy Srvcs Gas Holding	0	0	0	0
193	AEP Fiber Venture, LLC	0	0	0	0
181	AEP Generation Resources	(5,552,386)	386	0	(5,552,000)
174	AEP Holdco, Inc.	(252)	252	0	0
153	AEP Generating - Rockport	(315,336)	336	0	(315,000)
377	AEP Generating - Dresden	(7,566)	566	0	(7,000)
376	AEP Generating - Lawrenceburg	(73,920)	920	0	(73,000)
270	Cook Coal Terminal	(77,635)	635	0	(77,000)
	AEG - Consolidated				
196	AEP Investments	(19,894)	894	0	(19,000)
305	AEP Kentucky Coal, LLC	0	0	0	0
292	AEP Memco, LLC - Barges / Boats	(842,686)	686	0	(842,000)
364	AEP Non-Utility Funding, LLC	0	0	0	0
304	AEP Ohio Coal, LLC	0	0	0	0
373	AEP Partners	0	0	0	0
361	AEP Properties	(1,070)	70	0	(1,000)
143	AEP Pro Serv	(2,185)	185	0	(2,000)
172	AEP Resources	(12,865)	865	0	(12,000)
390	AEP Retail Energy Partners LLC	0	0	0	0
103	AEP Service Corp	0	0	0	0
204	AEP T&D Services, LLC	(14,473)	473	0	(14,000)
195	AEP Texas C&I Retail, LP	0	0	0	0
211	AEP Texas Central Co. - Dist	(1,984,044)	44	0	(1,984,000)
162	AEP Texas Central Co. - Securitization I	(54,773)	773	0	(54,000)
372	AEP Texas Central Co. - Securitization II	(39,251)	251	0	(39,000)
395	AEP Texas Central Co. - Securitization III	(24,909)	909	0	(24,000)
169	AEP Texas Central Co. - Trans	0	0	0	0
	TCC - Consolidated				
119	AEP Texas North Co. - Dist	(1,564)	564	0	(1,000)
166	AEP Texas North Co. - Gen	(35,096)	96	0	(35,000)
192	AEP Texas North Co. - Trans	0	0	0	0
371	Texas North Generation Co.	0	0	0	0
	TCN - Consolidated				
370	AEP Tranmission Company, LLC	0	0	0	0
369	AEP Transmission Holding Co.	(524,247)	247	0	(524,000)
393	AEP Transmission Partner LLC	(5,063)	63	0	(5,000)
365	AEP Transportation, LLC	0	0	0	0
216	AEP TX C&I Retail GP, LLC	0	0	0	0
101	AEP Utilities	0	0	0	0
353	AEP Utility Funding, LLC	0	0	0	0

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2014

BU #	COMPANY NAME	INITIAL Tax Effect of Parent Company Loss	Rounding Adjustments	Special Adjustments	FINAL Tax Effect of Parent Company Loss
306	AEP West Virginia Coal, Inc.	0	0	0	0
277	AEP Wind GP	(217)	217	0	0
345	AEP Wind Holding Company	0	0	0	0
339	AEP Wind LP 2	(56,284)	284	0	(56,000)
140	Appalachian Power - Dist	0	0	0	0
215	Appalachian Power - Gen	(36,283)	283	0	(36,000)
150	Appalachian Power - Trans	(98,686)	686	0	(98,000)
410	Appalachian Power - Rate Relief Fund	0	0	0	0
	APCO - Consolidated				
202	Blackhawk Coal	(75)	75	0	0
398	BlueStar Energy Holdings, Inc.	0	0	0	0
400	AEP Energy, Inc.	(171,171)	171	0	(171,000)
401	BSE Solutions LLC	0	0	0	0
225	Cedar Coal	(255)	255	0	0
125	Central Appalachian Coal	0	0	0	0
189	Central Coal Co	0	0	0	0
290	Conesville Coal	(1,104)	104	0	(1,000)
176	CSW Energy Services, Inc.	0	0	0	0
171	CSW Energy, Inc	(135,045)	45	0	(135,000)
263	CSW Services International, Inc.	0	0	0	0
245	Dolet Hills Lignite Co., LLC	0	0	0	0
324	HPL Storage, Inc.	0	0	0	0
170	Indiana Michigan Power - Dist	0	0	0	0
132	Indiana Michigan Power - Gen	0	0	0	0
190	Indiana Michigan Power - Nucl	0	0	0	0
280	Indiana Michigan Power - RTD	0	0	0	0
120	Indiana Michigan Power - Trans	0	0	0	0
	I&M - Consolidated				
110	Kentucky Power - Dist	0	0	0	0
117	Kentucky Power - Gen	(138,918)	918	0	(138,000)
180	Kentucky Power - Trans	(189,292)	292	0	(189,000)
	KPCO - Consolidated				
230	Kingsport Power - Dist	0	0	0	0
260	Kingsport Power - Trans	0	0	0	0
	KGPRT - Consolidated				
250	Ohio Power - Dist	(613,985)	985	0	(613,000)
160	Ohio Power - Trans	(383,688)	688	0	(383,000)
181	Ohio Power - Gen	0	0	0	0
270	Cook Coal Terminal	0	0	0	0
404	AEP Generation Resources	0	0	0	0
408	Ohio Phase-In Recovery Funding	0	0	0	0
	OPCO - Consolidated				
167	Public Service Co. of Ok - Dist	0	0	0	0
198	Public Service Co. of Ok - Gen	0	0	0	0
114	Public Service Co. of Ok - Trans	0	0	0	0
	PSO - Consolidated				

AEP SYSTEM
FORECASTED SEC ALLOCATION
ESTIMATE AS OF DECEMBER 2014

BU #	COMPANY NAME	INITIAL Tax Effect of Parent Company Loss	Rounding Adjustments	Special Adjustments	FINAL Tax Effect of Parent Company Loss
227	Rep General Partner LLC	0	0	0	0
303	Snowcap Coal Company, Inc.	0	0	0	0
217	Southern Appalachian Coal	0	0	0	0
159	Southwestern Electric Pwr - Dist	0	0	0	0
161	Southwestern Electric Pwr - Dist - TX	0	0	0	0
168	Southwestern Electric Pwr - Gen	0	0	0	0
194	Southwestern Electric Pwr - Trans	0	0	0	0
111	Southwestern Electric Pwr - Trans - TX	0	0	0	0
245	Dolet Hills Lignite Co., LLC	0	0	0	0
	SWEPCO - Consolidated				
319	United Sciences Testing, Inc.	0	0	0	0
210	Wheeling Power - Dist	(334,579)	579	0	(334,000)
200	Wheeling Power - Trans	(174,075)	75	0	(174,000)
200	Wheeling Power - Gen	0	0	0	0
	WPCO - Consolidated				
380	AEP Ohio Transmission Co.	0	0	0	0
382	AEP Appalachian Transmission Co.	0	0	0	0
383	AEP West Vrginia Transmission Co.	0	0	0	0
384	AEP Kentucky Transmission Co.	0	0	0	0
385	AEP Indiana Michigan Transmission Co.	0	0	0	0
386	AEP Oklahoma Transmission Co.	0	0	0	0
388	AEP Southwestern Transmission Co.	(141)	141	0	0
396	RITELine Indiana, LLC	0	0	0	0
397	AEP Retail Energy Partners	0	0	0	0
403	Transource Energy, LLC	0	0	0	0
407	Transource Missouri, LLC	0	0	0	0
	Other Companies - Non Allocated	0	0	0	0
	Total System	(12,924,601)	16,601	0	(12,908,000)
					OK

EXHIBIT ____ (LK-7)

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-21(c). The question asked:
Please confirm that the Company agrees that income tax expense should reflect a reduction for the PCLA. If the Company does not agree, then please provide all reasons why it does not agree and why the Company believes this Commission should treat it differently than Appalachian Power Company's proposal in West Virginia.

The Company's response stated:
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.

Please respond to the question that was asked in KIUC 1-21(c). The question did not ask if the Company would comply, but rather, it asked the Company to confirm that income tax expense should reflect a reduction for the PCLA.

RESPONSE

The Company has advocated the Stand-Alone Approach for the calculation of income tax expense in Cost of Service. This methodology only calculates the income taxes on the utility revenues and expenses that are included in the utility's revenue requirement. The expenses of other affiliates, including the Parent Company, are not included in this Stand-Alone Methodology. This is evident in the Company's approach for including a Section 199 Deduction in the Income Tax Calculations based on a stand-alone approach. As stated in the response to KIUC 1-21(c), the Company records a PCLA adjustment on its books as described in KIUC 1-21. The Company now understands that the Commission had historically required that the Company's portion of the parent company tax loss be included in the operating income tax expense for cost of service purposes. Based on the Commission's previous Orders, the Company should have included the PCLA as a reduction to income tax expense in this filing.

WITNESS: Jeffrey B Bartsch

EXHIBIT ____ (LK-8)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

FOR THE 12 MONTHS ENDED FEBRUARY 28, 2015

FOR THE 12 MONTHS ENDED JUNE 30, 2016

DATA:__X__BASE PERIOD__X__FORECASTED PERIOD
TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED
WORKPAPER REFERENCE NO(S).: WPH-1.A

SCHEDULE H-1
PAGE 1 OF 1
WITNESS: K. W. BLAKE

LINE NO.	DESCRIPTION		PERCENTAGE OF INCREMENTAL GROSS REVENUE STATE	FEDERAL
1	OPERATING REVENUE		100.000000%	100.000000%
2	LESS: UNCOLLECTIBLE ACCOUNTS EXPENSE		0.320000%	0.320000%
3	LESS: PSC FEES		0.195200%	0.195200%
4	LESS: PRODUCTION ACTIVITIES DEDUCTION-STATE		3.814200%	
5	INCOME BEFORE STATE INCOME TAX		95.670600%	99.484800%
6	STATE INCOME TAX	6.00%	5.740236%	5.740236%
7	LESS: PRODUCTION ACTIVITIES DEDUCTION-FEDERAL			5.391115%
8	INCOME BEFORE FEDERAL INCOME TAX			88.353449%
9	FEDERAL INCOME TAX	35.00%		30.923707%
10	OPERATING INCOME PERCENTAGE (LINES 5 - 6 - 9)			62.820857%
11	GROSS REVENUE CONVERSTION FACTOR (100% / LINE 10)			1.591828

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2014-00372

COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

FOR THE 12 MONTHS ENDED FEBRUARY 28, 2015

FOR THE 12 MONTHS ENDED JUNE 30, 2016

DATA: __X__BASE PERIOD__X__FORECASTED PERIOD

TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED

WORKPAPER REFERENCE NO(S).: WPH-1.A

SCHEDULE H-1

PAGE 1 OF 1

WITNESS: K. W. BLAKE

LINE NO.	DESCRIPTION		PERCENTAGE OF INCREMENTAL GROSS REVENUE STATE	FEDERAL
1	OPERATING REVENUE		100.000000%	100.000000%
2	LESS: UNCOLLECTIBLE ACCOUNTS EXPENSE		0.320000%	0.320000%
3	LESS: PSC FEES		0.195200%	0.195200%
4	LESS: PRODUCTION ACTIVITIES DEDUCTION-STATE		2.590200%	
5	INCOME BEFORE STATE INCOME TAX		96.894600%	99.484800%
6	STATE INCOME TAX	6.00%	5.813676%	5.813676%
7	LESS: PRODUCTION ACTIVITIES DEDUCTION-FEDERAL			3.658220%
8	INCOME BEFORE FEDERAL INCOME TAX			90.012904%
9	FEDERAL INCOME TAX	35.00%		31.504516%
10	OPERATING INCOME PERCENTAGE (LINES 5 - 6 - 9)			62.166608%
11	GROSS REVENUE CONVERSTION FACTOR (100% / LINE 10)			1.608581

EXHIBIT ____ (LK-9)

KIUC Adjustments to KPCO Capitalization and Cost of Capital - Base Rates
Test Year Ending September 30, 2014

I. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Per Book Balance	KPCO Proforma Adjustments	KPCO Adjusted Capitalization	KPCO Reapportioned Adjusted Capitalization	Kentucky Jurisdictional Factor	KPCO Reapportioned Kentucky Adjusted Capitalization	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	-	(31,246,697)	(31,246,697)	(31,248,144)	98.90%	(30,904,414)	-2.69%	0.25%	-0.01%	-0.01%	(77,646)
Long Term Debt	815,000,000	(200,289,951)	614,710,049	614,738,511	98.90%	607,976,387	52.98%	5.41%	2.87%	2.88%	33,055,212
Accts Receivable Financing	52,409,892	-	52,409,892	52,412,319	98.90%	51,835,783	4.52%	1.07%	0.05%	0.05%	557,403
Common Equity	700,853,745	(176,537,707)	524,316,038	524,340,315	98.90%	518,572,572	45.19%	10.62%	4.80%	7.87%	90,328,600
Sub Total	1,568,263,637	(408,074,355)	1,160,189,282	1,160,243,001		1,147,480,328	100.00%		7.71%	10.79%	123,863,569
Job Development Tax Credit	53,719		53,719								
Total Capital	1,568,317,356	(408,074,355)	1,160,243,001	1,160,243,001		1,147,480,328	100.00%		7.71%	10.79%	123,863,569

II. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustment 1 - Reject Proforma Adjustments Resulting in Negative Short Term Debt

	KPCO Reapportioned Adjusted Capitalization	KIUC Proforma Adjustment 1	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	(31,248,144)	31,248,144	-	98.90%	-	0.00%	0.25%	0.00%	0.00%	-	77,646
Long Term Debt	614,738,511	(16,864,011)	597,874,500	98.90%	591,297,881	51.53%	5.41%	2.79%	2.80%	32,148,414	(906,798)
Accts Receivable Financing	52,412,319	-	52,412,319	98.90%	51,835,783	4.52%	1.07%	0.05%	0.05%	557,403	-
Common Equity	524,340,315	(14,384,133)	509,956,182	98.90%	504,346,664	43.95%	10.62%	4.67%	7.66%	87,850,632	(2,477,968)
Total Capital	1,160,243,001	-	1,160,243,001		1,147,480,328	100.00%		7.50%	10.51%	120,556,449	(3,307,120)

III. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Capitalization Adjustment 2 - Remove Non-Utility Investment in AEP Utility Money Pool

	KIUC Adjusted Reapportioned Capitalization After Adjustment 1	KIUC Proforma Adjustment 2	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-		-	98.90%	-	0.00%	0.25%	0.00%	0.00%	-	-
Long Term Debt	597,874,500	(5,168,583)	592,705,918	98.90%	586,186,152	51.51%	5.41%	2.79%	2.80%	31,870,494	(277,921)
Accts Receivable Financing	52,412,319	-	52,412,319	98.90%	51,835,783	4.55%	1.07%	0.05%	0.05%	557,403	-
Common Equity	509,956,182	(4,408,535)	505,547,647	98.90%	499,986,623	43.94%	10.62%	4.67%	7.65%	87,091,169	(759,462)
Total Capital	1,160,243,001	(9,577,118)	1,150,665,883		1,138,008,558	100.00%		7.50%	10.50%	119,519,066	(1,037,383)

KIUC Adjustments to KPCO Capitalization and Cost of Capital - Base Rates
Test Year Ending September 30, 2014

IV. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization to:
Capitalization Adjustment 4 - Reflect Increase in ADIT Due to Bonus Depreciation Extension in 2014
(See Response to KIUC 1-29 and KIUC 2-3 for Company's Quantification of $23.6 Million Amount)

	KIUC Adjusted Reapportioned Capitalization After Adjustment 2	KIUC Proforma Adjustment 3	KIUC Adjusted Reapportioned Capitalization After Adjustment 3	Kentucky Jurisdictional Factor	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	-	-	98.90%	-	0.00%	0.25%	0.00%	0.00%	-	-
Long Term Debt	592,705,918	(12,739,749)	579,966,168	98.90%	573,586,540	51.46%	5.41%	2.78%	2.80%	31,185,462	(685,031)
Accts Receivable Financing	52,412,319	-	52,412,319	98.90%	51,835,783	4.65%	1.07%	0.05%	0.05%	557,403	-
Common Equity	505,547,647	(10,866,351)	494,681,296	98.90%	489,239,802	43.89%	10.62%	4.66%	7.65%	85,219,213	(1,871,956)
Total Capital	1,150,665,883	(23,606,100)	1,127,059,783		1,114,662,125	100.00%		7.49%	10.49%	116,962,078	(2,556,988)

V. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 8.75%.

	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	0.00%	0.25%	0.00%	0.00%	-	-
Long Term Debt	573,586,540	51.46%	5.41%	2.78%	2.80%	31,185,462	-
Accts Receivable Financing	51,835,783	4.65%	1.07%	0.05%	0.05%	557,403	-
Common Equity	489,239,802	43.89%	8.75%	3.84%	6.30%	70,213,570	(15,005,643)
Total Capital	1,114,662,125	100.00%		6.67%	9.15%	101,956,435	(15,005,643)
				Effect for Every 1% ROE			(8,024,408)

VI. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Gross Revenue Conversion Factor to Reflect Section 199 Production Activities Deduction

	KIUC Reapportioned Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	-	0.00%	0.25%	0.00%	0.00%	-	-
Long Term Debt	573,586,540	51.46%	5.41%	2.78%	2.80%	31,185,462	-
Accts Receivable Financing	51,835,783	4.65%	1.07%	0.05%	0.05%	557,403	-
Common Equity	489,239,802	43.89%	8.75%	3.84%	6.11%	68,097,581	(2,115,988)
Total Capital	1,114,662,125	100.00%		6.67%	8.96%	99,840,447	(2,115,988)
			Additional	Effect for Every 1% ROE			(1,131,545)

KPCO Gross Revenue Conversion Factor
As Filed and With KIUC Recommendations
Test Year Ending September 30, 2014

Source: Section V, Exhibit 1, Workpaper S-2 Page 2 of 3

		As Filed By KPCO		Debt Only As Filed By KPCO	With Section 199 Deduction		Income Tax Only With Section 199
Additional Revenue		100.00%		100.00%	100.00%		100.00%
Less: Uncollectible Expense		0.30%		0.30%	0.30%		
KPSC Maintenance Fee		0.20%		0.20%	0.20%		
Income Before Income Taxes		99.50%		99.50%	99.50%		100.00%
Less: State Income Taxes		-5.71%		0.00%	-5.55%		-5.55%
Income Before Federal Income Taxes before Prod Activities Deduction		93.80%		99.50%	93.96%		94.45%
a. Production Rate	9.0%						
b. Allocation to Production Income (% of Prod Plant)							
Steam Production Plant - Adjusted Test Year - Sch B-2	3,105,160,878						
Hydro Production Plant - Adjusted Test Year - Sch B-2	34,935,637						
Other Production Plant - Adjusted Test Year - Sch B-2	877,242,165						
Total production Plant In Service - Adjusted Test Year - Sch B-2	4,017,338,680						
Total Plant In Service - Adjusted Test Year - Sch B-2	6,641,216,646						
Allocation to Production Income	60.49%						
c. Allocated Production Rate (a x b)	5.4442%						
Less: Production Tax Deduction (5.4442% of Rate Before Deduction)					-5.12%		-5.12%
Taxable Income for Federal Income Tax		93.80%			88.84%		89.34%
Less: Federal Income Taxes (35%)		-32.83%			-31.10%		-33.06%
Operating Income Percentage		60.97%		99.50%	62.86%		61.39%
Gross Revenue Conversion Factor		1.6402		1.004977	1.5907		1.6288
Combined Effective Income Tax Rate							38.61%
State Income Tax Effective Rate							
State Income Tax Rate - Illinois		9.5000%			9.5000%		
Apportionment Factor		1.4511%			1.4511%		
Effective Kentucky State Income Tax Rate			0.1379%			0.1379%	
State Income Tax Rate - KY		6.0000%			6.0000%		
Less: Effect of Production Activities Deduction (100% - (6% x 60.49%))					96.371%		
Adjusted Tax Rate - KY		6.0000%			5.7822%		
Apportionment Factor		73.9030%			73.9030%		
Effective Kentucky State Income Tax Rate			4.4342%			4.2732%	
State Income Tax Rate - Michigan		6.0000%			6.0000%		
Apportionment Factor		0.1069%			0.1069%		
Effective Kentucky State Income Tax Rate			0.0064%			0.0064%	
State Income Tax Rate - WVA		6.5000%			6.5000%		
Apportionment Factor		17.7890%			17.7890%		
Effective West Virginia State Income Tax Rate			1.1563%			1.1563%	
Total Effective State Income Tax Rate			5.7348%			5.5738%	

EXHIBIT ____ (LK-10)

Kentucky Power Company

REQUEST

Refer to Adjustment 49 on Tab W49 of Section V Exhibit 2 showing the calculation of the three-year average of the removal cost Schedule M deduction that the Company proposes.

a. Please provide the comparable information for each year 2009, 2010, and 2014.

b. Please confirm that the removal cost deduction is a temporary difference and there should be a related effect on ADIT, i.e., if there is a change in a Schedule M deduction, there is an offsetting change in deferred tax expense so that there is no net change in total income tax expense. Please explain your response.

c. Please identify where in its filing the Company made an adjustment to reduce deferred tax expense to reflect the proposed reduction in the removal cost Schedule M.

RESPONSE

a. Please see KIUC_1_26_Attachment1.xls.

b. The removal cost Schedule M is treated as flow-thru for Kentucky ratemaking purposes. Please also see the Response to KPSC 2-22.

c. Not Applicable.

WITNESS: Jeffrey B Bartsch

Kentucky Power
Removal Cost - Per Tax Return

	2009	2010	2011	2012	2013	2014 *
Removal Cost Schedule M	(4,961,137)	(3,462,777)	(5,198,929)	(11,335,207)	(7,376,136)	(8,045,000)

*** PER YEAR-END CLOSING**

EXHIBIT ____ (LK-11)

Kentucky Power Company
KIUC Recommendation to Remove Company's Proposed 3 Yr Average of Removal Cost Schedule M Deductions
In Addition, Alternative Recommendation to Use Average of Years 2012 through 2014
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

Primary Recommendation	
As Filed Average Deduction Calculation Using Years 2011 Through 2013	
2011 Removal Cost Schedule M Deduction	(5.199)
2012 Removal Cost Schedule M Deduction	(11.335)
2013 Removal Cost Schedule M Deduction	(7.376)
3 Yr Average Removal Cost Schedule M Deduction	(7.970)
Test Year Removal Cost Schedule M Deduction - Per Company	(8.300)
Removal Cost Schedule M Deduction under Test Year Amount Using Average of Years 2011 through 2013 - Total Company	0.330
KY Jurisdictional Allocation Factor - GP-TOT	0.989
Removal Cost Schedule M Deduction under Test Year Amount Using Average of Years 2011 through 2013 - KY Jurisdiction	0.326
Effective Combined Income Tax Rate	38.61%
KIUC Recommendation to Remove Company's Proforma Income Tax Expense Adjustment Due to Change in Removal Cost	(0.126)
KIUC Recommendation to Remove Company's Proforma Income Tax Expense Adjustment Due to Change in Removal Cost - Grossed Up for Income Taxes	(0.205)
Alternative Recommendation	
Calculation to Show the Average of Deductions Using Years 2012 Through 2014	
2012 Removal Cost Schedule M Deduction	(11.335)
2013 Removal Cost Schedule M Deduction	(7.376)
2014 Removal Cost Schedule M Deduction	(8.045)
3 Yr Average Removal Cost Schedule M Deduction	(8.919)
Test Year Removal Cost Schedule M Deduction - Per Company	(8.300)
Removal Cost Schedule M Deduction over Test Year Amount Using Average of Years 2012 through 2014 - Total Company	(0.619)
KY Jurisdictional Allocation Factor - GP-TOT	0.989
Removal Cost Schedule M Deduction under Test Year Amount Using Average of Years 2012 through 2014 - KY Jurisdiction	(0.612)
Effective Combined Income Tax Rate	38.61%
KIUC Alternative Recommendation to Utilize 2012 through 2014 Average	(0.236)
KIUC Alternative Recommendation to Utilize 2012 through 2014 Average	(0.385)
KIUC Alternative Recommendation to Utilize 2012 through 2014 Average compared to Proforma Amount in Company Filing	(0.590)

Source: See Company Adjustment WP 49 in Section V Exhibit 2 and Response to KIUC 1-26

EXHIBIT ____ (LK-12)

Kentucky Power Company

REQUEST

Please provide a copy of the Company's written acceptance of the Commission's conditions set forth in its order in Case No. 2012-00578.

RESPONSE

Please see KIUC_1_52_Attachment1.pdf.

WITNESS: Gregory G Pauley

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	Case No. 2012-00578

Kentucky Power Company's Notice Of Filing Of Its Acceptance Of Modifications To Stipulation And Settlement Agreement Identified In Appendix B To The Commission's October 7, 2014 Order

Kentucky Power Company files herewith the October 14, 2014 written notice of Gregory G. Pauley, President and Chief Operating Officer of Kentucky Power Company, on behalf of the Company, accepting and agreeing to be bound by the modifications to the Stipulation and Settlement Agreement set forth in Appendix B to the Commission's October 7, 2013 Order in this proceeding.

Respectfully submitted,

Mark R. Overstreet
STITES & HARBISON PLLC
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(614) 716-3410
hgarcia@aep.com
(Admitted *Pro Hac Vice*)

COUNSEL FOR KENTUCKY POWER COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail, postage prepaid, upon the following parties of record, this 14th day of October, 2013.

Michael L. Kurtz
Jody Kyler Cohn
Boehm, Kurtz & Lowry
Suite 1510
36 East Seventh Street
Cincinnati, OH 45202

Joe F. Childers
Joe F. Childers & Associates
300 The Lexington Building
201 West Short Street
Lexington, KY 40507

Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook
Assistant Attorney General
Office for Rate Intervention
P.O. Box 2000
Frankfort, KY 40602-2000

Kristin Henry
Sierra Club
85 Second Street
San Francisco, CA 94105

Shannon Fisk
Earthjustice
1617 JFK Boulevard, Suite 1675
Philadelphia, PA 19103

Mark R. Overstreet

October 14, 2013

Re: Case No. 2012-00578

Dear Mr. Derouen:

Pursuant to ordering paragraph 4 of the Commission's October 7, 2013 Order in Case No. 2012-00578 I write to notify the Commission that Kentucky Power Company accepts and agrees to be bound by the modifications to the July 2, 2013 Stipulation and Settlement Agreement set forth in Appendix B to the Commission's Order.

Respectfully yours,

Greg G. Pauley

Gregory G. Pauley
President and COO
Kentucky Power Company

EXHIBIT ____ (LK-13)

Kentucky Power Company

REQUEST

Please confirm that the Company has written off the deferred Big Sandy 2 FGD investigation costs that it seeks to recover in this proceeding.

RESPONSE

The Company has recorded an offsetting regulatory provision against the Big Sandy 2 FGD investigation costs pending the outcome of the current proceeding wherein it seeks recovery of such costs.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a copy of the accounting journal entries for the write-off of the Big Sandy 2 FGD investigation costs.

RESPONSE

See the Company's response to KIUC_1_51.

WITNESS: Jason M Yoder

Kentucky Power Company

REQUEST

Please provide a copy of all analyses and accounting research that led to the decision to write-off the Big Sandy 2 investigation costs after the Commission issued its order in Case No. 2012-00578 and the Company's acceptance of the Commission's conditions set forth in that order.

RESPONSE

Please see KIUC_1_51_Attachment1.pdf for this response. Please note, the yellow highlighting in this document was for internal purposes only and does not indicate confidentiality.

WITNESS: Jason M Yoder

AEP
AMERICAN ELECTRIC POWER

Date: December 5, 2013

Subject: Accounting Implications Memo Regarding the Kentucky Public Service Commission (KPSC) Approval of Kentucky Power Company's (KPCo) Stipulation and Settlement Agreement (Stipulation) to Transfer a Fifty Percent Interest the Mitchell Generation Station (Mitchell Plant) in Case No. 2012-00578

From: Tom Mitchell/Jeff Brubaker and Jason Yoder

To: Brian Frantz, Scott Travis, Ranie Wohnhas, Dale Patterson, Chuck Oberlin, Bruce Hutchins, Brian Lysiak, Lila Munsey, Bill Allen and Janet Swanger

The purpose of this memo is to document KPCo's accounting for the Stipulation approved with certain modifications by the KPSC which allows for the transfer of a fifty percent interest in the Mitchell Plant and changes to certain surcharges effective January 1, 2014.

Background

On December 12, 2012 KPCo filed an application seeking a Certificate of Public Convenience and Necessity (CPCN) for the proposed transfer of fifty percent of the Mitchell Plant. The Application also included a request to defer for future recovery $28 million related to FGD environmental study costs for Big Sandy Units 1 and 2.

Stipulation

On July 2, 2013 KPCo filed a Stipulation entered into by KPCo, Kentucky Industrial Utility Customers, Inc. (KIUC) and Sierra Club (Attachment 1). The Stipulation, among other provisions, included the following:

- Transfer of fifty percent of Mitchell Plant to KPCo at December 31, 2013
- Withdrawal of the pending rate case in Case No. 2013-00197
- KPCo agrees to file its next base case utilizing a September 30, 2014 test year
- Effective January 1, 2014, KPCo will implement an Asset Transfer Rider (ATR) designed to collect $44 million annually, with a true-up mechanism. When new base rates are established, the ATR will be used to recover Big Sandy 1 and Big Sandy 2 retirement costs
- Effective January 1, 2014 the Environmental Surcharge Factor will be zero until new base rates are set by the Commission. When new rates are set, the Flue Gas Desulfurization (FGD) costs related to the Mitchell Plant will be recovered through the Environmental Surcharge.

- Effective January 1, 2014 the System Sales Adjustment Factor will be zero. Calendar year off-system sales margins above $15,290,363 (amount in base rates) will be retained by KPCo until new base rates are set.
- Recovery of $28 million of cost incurred related to an FGD at Big Sandy.
- Agreement that the Company would provide $100,000 per year for five years for economic development which would not be recovered from ratepayers.
- Recovery of retirement costs of Big Sandy and other site related retirement costs that will not continue in use over a 25 year period (including a Weighted Average Cost of Capital (WACC)) when new rates are set in the next base case. The costs will be recovered in the Asset Transfer Rider-2 which would include over/under-recovery.
- If the Mitchell Plant is retired early, collection of the retirement costs with a debt-only carrying cost.
- If the Commission did not accept and approve the Stipulation without modification none of the signing parties were bound by any provision of the Stipulation.

<u>Order</u>

The KPSC issued its order on October 7, 2013 (Attachment 2) approving the Stipulation with modifications provided in Appendix B of the order. The modifications are summarized as follows:

- The Commission denied deferral for future recovery in a future base case the $28,113,304 FGD costs.
- The commitments to provide economic development were increased by the Commission to provide shareholder contributions of $233,000 per year for five years (from $100,000).
- The Commission clarified that KPCo's shareholder contribution commitment to assist energy management programs would be incremental funding for the school energy manager program, which could be for new school managers or additional funds for existing school managers, and that the funding is limited to schools in Lawrence and contiguous Kentucky counties impacted.
- The Commission clarified that KPCo would need to seek Commission approval to lower annual expenditures related to Demand Side Management (DSM) below $6 million.

On October 14, 2013, KPCO accepted and agreed to be bound by the modifications to the Stipulation set forth in Appendix B of the KPSC order (Attachment 3).

<u>Accounting Implications</u>

1) <u>Rates</u>

The rate changes are effective January 1, 2014 and will be implemented through the MACSS system by Customer Billings (Dale Patterson, Manager) on January 1, 2014 to implement the ATR and change the Environmental Surcharge Factor and the System Sales Adjustment Factor to zero until new base rates are set by the Commission. After these changes effective January 1, 2014, no further action will be required to properly bill customers under the order and record the revenues on KPCo's ledger as functionalized by Revenue Accounting (Chuck Oberlin, Manager).

2) <u>Transfer of Fifty Percent of Mitchell Plant</u>
The KPSC approved the Stipulation which allows the transfer of the Mitchell Plant (fifty percent interest including associated assets and liabilities) on December 31, 2013. According to the Stipulation on page 4, the transfer will be at actual net book value as of December 31, 2013, including accumulated deferred income tax benefits as shown in RKW- Exhibit 2. The entries for the transfer should be recorded by Regulatory Accounting (Brian Frantz Manager) and Property Accounting (Janet Swanger, Manager) in December 2013 business. Note that Regulated Accounting (led by Scott Travis, Managing Director) will address the various transfer and disclosure issues including accounting for the effect of Mitchell employee liabilities.

The order did have one qualification on the NBV discussed on page 44 which states that:

> "In the event the West Virginia PSC approves APCo's request to acquire the remaining 50 percent undivided interest in the Mitchell Station at a NBV that is lower than the $536 million NBV proposed in the instant matter, Kentucky Power's authority to acquire Mitchell Station shall be limited to the NBV as found by the West Virginia PSC."

Regulatory and Finance (Ranie Wohnhas, Managing Director) along with input from legal is monitoring the impact of this ordering paragraph on the transfer of Mitchell Plant and will participate with accounting in the determination of any adjustments to Mitchell NBV to be recorded by Property Accounting (Janet Swanger, Manager).

<u>Mitchell Plant Depreciation</u>
Property Accounting (Janet Swanger, Manager) will continue to use existing OPCo depreciation rates for Mitchell Plant (Attachment 4) based on an estimated retirement date of 2031 until new rates are established in a future base case. Note that KPCo must propose that depreciation rates reflect a 2040 retirement date for the Mitchell units in its next base case.

3) <u>ATR Over/Under</u>
The Company will implement the ATR effective January 1, 2014 to initially recover a portion of KPCo's 50% interest in Mitchell Plant costs. The KPSC ordered over/under accounting and as shown on Exhibit 1-A of the order (Attachment 2) the tariff rate includes a monthly over/under-recovery adjustment.

Accounting for this rider is subject to the provisions for accounting for alternative revenue programs included in FASB ASC 980-60-25 (formerly EITF No, 92-7). ASC 980-605-25 addresses alternative revenue programs and segregates them into two categories, Type A and Type B. Type A programs adjust billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives. Type B programs provide for additional billings (incentive awards) if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service. Both types of programs enable the utility to adjust rates (usually as a surcharge).

ASC 980-605-25 addresses the accounting for revenues that are the subject of recovery mechanisms that do not qualify for deferral as a regulatory asset under ASC 980-340-25. ASC 980-605-25 concludes that once the specific events permitting billing of the additional revenues under Type A and Type B programs have been completed, the regulated utility shall recognize the additional revenues if all of the following conditions are met:

a. The program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment to future rates by the regulator would not preclude the adjustment from being considered automatic.

b. The amount of additional revenues for the period is objectively determinable and is probable of recovery.

c. The additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

The requirements in ASC 980-605-25 are met as a Type A program which adjust billings for external factors (i.e. major change in utility power source) under the rider because the collection of revenues related to the rider is established by the Order (which provides probability of recovery), as it allows for monthly adjustment of future rates and the revenues are expected to be collected within 24 months.

Discussions with Regulatory Services (Bill Allen, Managing. Director) indicate that the $44 million annually should be compared on straight line basis to the actual monthly ATR revenues because the amount was not determined on an individual monthly basis. Each month beginning with January 2014 business, Regulated Accounting (Brian Frantz, Manager) will compare the monthly revenues from the ATR (which are provided by Revenue (Chuck Oberlin, Manager) to one twelfth of the $44 million annual ATR revenues. To the extent that the revenues collected are less than the monthly amount, the following journal should be recorded:

Account	Description	Debit	Credit
1823XXXX	Mitchell ATR under-recovery	$XXXXXX	
440-445,447	Revenue		$XXXXXX

To record under-recovery of KPSC approved Mitchell Plant recovery via the ATR.

Note that if an over-recovery previously existed, then the regulatory liability should be reduced to zero before recording the regulatory asset.

If there is an over recovery of the $44 million allowed recovery of Mitchell Plant costs, then the following entry should be recorded to reduce revenue:

Account	Description	Debit	Credit
440-445,447	Revenue	$XXXXXX	

254XXXX Mitchell ATR over-recovery $XXXXXX

To record over-recovery of KPSC approved Mitchell Plant cost recovery via the ATR.

Note that if an under-recovery previously existed, then the regulatory asset should be reduced to zero before recording the regulatory liability.

4) Cost Recovery of FGD and Other Deferred Costs
   a. The KPSC ordered that the provision of the Stipulation that allowed the Company to defer $28 million of FGD costs for future recovery in the next base case be stricken (Order, page 38). They stated that the impact to the ratepayer in light of the Mitchell plant costs was not reasonable. Additionally, the costs were over a long period of time but never resulted in a formal proposal from KPCo to the Commission for a decision to be made. Finally, the Commission found the cost unreasonable because the magnitude of the costs did not result in the addition of environmental equipment at Big Sandy.
   b. The KPSC decision raises doubt about the probability of recovery of the $28 million FGD costs because they have removed paragraph 8 from the Stipulation that would have allowed KPCo to defer and recover the $28 million in a future base case.
   c. Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 855-10 (Subsequent Events) addresses accounting for events that occur after the balance sheet date but before the financial statements are issued.
   d. This decision is considered a recordable subsequent event as defined by ASC 855-10-20 where the order provided additional evidence about conditions that existed at the date of the balance sheet. Deferral and recovery was objected to by intervenor testimony filed in the hearing urging the KPSC deny KPCo's request to defer and recover the $28 million (Attachment 5) which shows there was evidence in the record opposing recovery. Also, previous to the Commission order on the Settlement, the Company had determined as documented by legal that recovery was probable. The Commission's determination raised doubt that the Company's previous judgment that the $28 million was probable.
   e. KPCo had also filed for recovery of several other previously deferred costs including IGCC, CARRS and Carbon Capture and Storage (CCS). The Commission's decision to strike the provision of the Stipulation regarding the $28 million FGD raises similar doubts about the future recovery of these previously deferred costs which had been thought to be probable of recovery.
   f. Therefore, since KPCo has concluded that the Commission order is a recordable subsequent event, a provision for these deferred costs has been recorded by Regulatory Accounting (Brian Frantz Manager) in September 30, 2013 business as follows:

Account	**Description**	**Debit**	**Credit**
4265002	Other Deductions	$4,824,047	
1830004	Resv IGCC costs		$1,331,254
1830004	Resv CARRS site work		$2,619,935
1823325	Resv CCS FEED study		$872,858

To reserve KPCO IGCC costs, CARRS site engineering and survey work & CCS FEED Study.

Account	Description	Debit	Credit
4265002	Other Deductions	$28,023,271	
1830004	Resv BS FGD Landfill		$2,294,639
1830004	Resv BS FGD		$25,728,632

To reserve KPCo Big Sandy FGD and FGD landfill costs.

g. A provision is recorded on the books because Regulatory (Ranie Wohnhas, Mng. Director) plans to request recovery of the costs in the next KPCo base case. Additionally, Regulatory Accounting (Brad Funk Manager) will track any additional activity related to these accounts to ensure the reserves do not require additional adjustments in future periods.

5) KPSC Ordered Contributions to Economic Development

With the approval of the order, the KPSC also required KPCo to provide funding for economic development in the amount of $233,000 per year for five years. In September 2013 Regulated Accounting (Brian Frantz, Manager) recorded a liability of $1,165,000 ($233,000 times 5 years) as follows:

Account	Description	Debit	Credit
4265002	Other Deductions	$1,165,000	
2420088	Contributions – ST		$233,000
2284027	Contributions - LT		$932,000

To record the KPSC ordered contributions to be made for economic development.

The obligation ordered by the KPSC is a liability for GAAP according to FASB ASC 720-25 – Other Expenses – Contributions made. This subtopic provides the guidance on accounting for contributions made. The KPSC order has established a contribution (specifically an unconditional promise to give) and therefore KPCo needs to recognize a liability and offsetting expense. Additionally, these contributions provide no identifiable benefit to KPCo through reduced cost or additional revenue. Typically, unconditional promises will be recognized at their present value of future cash flows except for those amounts to be paid in less than one year. However, KPSC will record the amount at its nominal value due to low applicable interest rates because there is an immaterial difference between the nominal amount and the present value.

Note due to the complexity and magnitude of the other issues in the Stipulation including KPCo's acceptance of the Mitchell Plant transfer no liability was recorded (prior to the order). However, it is appropriate to record the liability in the third quarter 2013 given the existence of the potential obligation included in the Stipulation.

Regulatory and Finance (Ranie Wohnhas, Managing Director), will track the monthly expenditures related to these funds and will be responsible for coding invoices prior to payment using appropriate chartfields including cost component and projects.

The payments will be charged to the respective FERC account 228 – Accumulated Misc. Operating Provision as long as a portion of the obligation remains a long-term liability either directly or after reclasses recorded by Regulatory Accounting (Brad Funk, Manager) for those expenses that cannot be charged directly to the liability due to system limitations.

Each quarter, Regulated Accounting (Brian Frantz Manager) will review the liability to determine the proper classification between current and long term. When the account balance in the respective FERC account 228 – Accumulated Misc Operating Provision reaches zero, then the payments should be made to account 242 – Misc Current & Accrued Liabilities until the total obligation is reduced to zero.

Note also that the Commission ordered that the program implemented under the Stipulation (paragraph 12) to help fund energy management at schools be shareholder funded instead of recovered through demand side management (DSM) cost recovery. The $75,000 to be funded in 2014 and $50,000 to be funded in 2015 were not accrued in September 2013 because they will provide KPCo future energy efficiency benefits. As such these are period costs to be expensed as incurred similar to other DSM activities.

6) Off-System Sales (OSS) Margins Sharing
As noted in the Rates section above, the KPCo system sales clause tariff was modified so that the rate is zero effective January 1, 2014. Therefore, sharing of OSS margins shall cease effective January 1, 2014. In January 2014 business Fuel Accounting (Brian Lysiak, Supervisor) will calculate the final true-up for December 2013 and cease the calculation of over/under on OSS margins going forward.

7) Fuel Adjustment Clause (FAC)
Effective January 1, 2014, KPCo's 50% share of Mitchell related fuel costs shall be included in the calculation of charges or credits under the KPCo FAC as coordinated by Regulatory Services (Lila Munsey, Manager) and Fuel Accounting (Brian Lysiak, Supervisor).

8) Entry on Rehearing,Withdrawal of Pending Base Case No. 2013-00197 and Appeal
On November 15, 2013 the Commission denied the Kentucky Attorney General's request for rehearing.

On November 18, 2013 KPCo withdrew its application for a base case.

On December 4, 2013 the Kentucky Attorney General filed an appeal of the Commission's decision approving the Mitchell Plant transfer with the Franklin Circuit Court in Frankfort, Kentucky. The appeal included a request for an injunction to stop the transfer. KPCo management and legal are assessing the impact if any on the Mitchell Plant transfer.

9) Earnings Offset
There is no EO related to O&M due to this subject order.

Attachments

Cc: with attachments:

Rich Mueller	Tyler Ross
Nick Roger – D&T	George Fackler D&T

Cc: without attachments:

Greg Adams	John Huneck	Eric Wittine	Betsy Sekula
Michele Bair	Pam Sicilian	Ollie Sever	Hector Garcia
Mike Baird	Jennifer McLravy	Brian Tierney	Shelli Sloan
Jeff Bartsch	Rich Munczinski	Janet Tully-Green	
Joe Buonaiuto	Danielle Dorsey	Julie Williams	
Kellie Conklin	Phil Nelson	Greg Pauley	
Lonni Dieck	Mark Pyle	Brad Funk	
Pam Flemming	Julie Sloat	Larry Foust	
Renee Hawkins	Franz Messner	Jim Keeton	

EXHIBIT ____ (LK-14)

Kentucky Power Company

REQUEST

Please confirm that the Company is not now or in the future obligated to pay the Ohio income tax expense that had been deferred on Ohio Power Company's accounting books for the Mitchell Plant before the transfer of 50% of the plant and the ADSIT to Kentucky Power Company. If this is not correct, then please provide a detailed description of this obligation and the manner in which the Company will pay Ohio income taxes.

RESPONSE

The deferred state income taxes that were transferred from Ohio Power Company to Kentucky Power Company related to the Mitchell Plant is not a direct future state income tax obligation of the Company. However, these accumulated deferred state income taxes were used to reduce the Company's future state income tax obligation that is recorded in accordance with SFAS 109. The Company is recommending that this balance be amortized over the remaining life of the Mitchell plant since the Company has not historically recorded deferred state income taxes for ratemaking purposes.

WITNESS: Jeffrey B Bartsch

EXHIBIT ____ (LK-15)

Kentucky Power Company
KIUC Recommendation to Shorten Amortization Life of OH ADIT on Mitchell Plant over Three Years Instead of Life of Unit
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($ Millions)

Mitchell Plant OH ADIT Acquired	(4.724)
KIUC Recommended Amortization Period in Years	3
KIUC Recommended Mitchell Plant OH ADIT Annual Amortization	(1.575)
Amortization Included in Company Filing Based on Life of Unit of 23.59 Years	(0.200)
KIUC Recommendation to Shorten Amortization of OH ADIT to Reflect Amortization Over 3 Years Instead of Life of Unit - Total Company	(1.374)
KY Jurisdictional Allocation Factor - PDAF	0.986
KIUC Recommendation to Shorten Amortization of OH ADIT to Reflect Amortization Over 3 Years Instead of Life of Unit - KY Jurisdiction	(1.355)

Source: See Adjustment WP 59 in Section V, Exhibit 2 Page 59
See also responses to KIUC 1-22, 1-24, and 1-25

EXHIBIT ____ (LK-16)

Kentucky Power Company
KIUC Recommendation to Reduce Depreciation to Remove Terminal Net Salvage Inflation Escalation of 2.35%
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Acct. No	Description	Depreciable Electric Plant In Service as of 9/30/2014	Company's Proposed Annual Rates	Company's Pro Forma Annualized Depreciation on EPIS as of 09/30/2014	KIUC Recommended Annual Rates	KIUC Recommemded Annualized Depreciation on EPIS as of 09/30/2014	KIUC Recommemded Depreciation Expense Adjustment
	Mitchell Plant Production Plant						
311	Structures & Improvements	51,403,012	2.74%	1,408,443	2.66%	1,367,320	(41,123)
312	Boiler Plant Equipment	833,068,997	3.13%	26,075,060	3.05%	25,408,604	(666,456)
312	Boiler Plant Equipment (SCR Catalyst)	8,190,115	12.50%	1,023,764	12.50%	1,023,764	0
314	Turbogenerator Units	53,306,968	1.84%	980,848	1.76%	938,203	(42,645)
315	Accessory Electrical Equip.	17,515,019	1.64%	287,246	1.56%	273,234	(14,012)
316	Misc. Power Plant Equip.	7,736,008	2.80%	216,608	2.72%	210,419	(6,189)
Total Production Plant - Mitchell - Total Co.		971,220,119		29,991,969		29,221,545	(770,424)
	Allocation Factor - GP-TOT						0.989
	KIUC Recommendation to Reduce Mitchell Plant Depreciation Expense - KY Jurisdiction						(761,949)

AS FILED
KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
Mitchell Plant										
311	Structures & Improvements	42,000,197	1.07	44,940,211	18,282,178	16,183,402	28,756,809	25.01	1,149,812	2.74%
312	Boiler Plant Equipment	765,644,984	1.07	819,240,133	245,324,500	238,518,432	580,721,701	24.25	23,947,287	3.13%
312	Boiler Plant Equip SCR Catalyst (2)	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.07	57,026,396	29,106,660	33,613,523	23,412,873	23.84	982,084	1.84%
315	Accessory Electrical Equip.	17,080,672	1.07	18,276,319	9,466,086	11,043,285	7,233,034	25.81	280,242	1.64%
316	Misc. Power Plant Equip.	7,693,412	1.07	8,231,951	3,289,590	3,072,520	5,159,431	23.96	215,335	2.80%
	Total	893,905,077	1.07	955,905,125	309,492,408	304,809,655	651,095,470	23.59	27,598,524	3.09%

AS ADJUSTED BY KIUC
KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
Mitchell Plant (3)										
311	Structures & Improvements	42,000,197	1.05	44,100,207	18,282,178	16,183,402	27,916,805	25.01	1,116,226	2.66%
312	Boiler Plant Equipment	765,644,984	1.05	803,927,233	245,324,500	238,518,432	565,408,801	24.25	23,315,827	3.05%
312	Boiler Plant Equip SCR Catalyst (2)	8,190,115	1.05	8,599,621	4,023,394	2,378,493	6,221,128	4.07	1,074,953	12.50%
314	Turbogenerator Units	53,295,697	1.05	55,960,482	29,106,660	33,613,523	22,346,959	23.84	937,372	1.76%
315	Accessory Electrical Equip.	17,080,672	1.05	17,934,706	9,466,086	11,043,285	6,891,421	25.81	267,006	1.56%
316	Misc. Power Plant Equip.	7,693,412	1.05	8,078,083	3,289,590	3,072,520	5,005,563	23.96	208,913	2.72%
	Total	893,905,077	1.05	938,600,332	309,492,408	304,809,655	633,790,677	23.54	26,920,297	3.01%

EXHIBIT ____ (LK-17)

Kentucky Power Company
KIUC Recommendation to Reflect Reduction in Mitchell FGD Revenue Requirement
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Rev Req (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
I. As Filed													
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	10.79%	$2,026,360	$1,257,552	$3,283,911	0.9076	$2,980,478
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	10.79%	$2,017,608	$1,257,552	$3,275,159	0.9076	$2,972,534
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	10.79%	$2,008,856	$1,257,552	$3,266,407	0.9076	$2,964,591
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	10.79%	$2,000,159	$1,278,321	$3,278,480	0.9076	$2,975,549
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	10.79%	$1,991,463	$1,186,493	$3,177,956	0.9076	$2,884,313
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	10.79%	$1,982,767	$1,310,939	$3,293,706	0.9076	$2,989,367
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	10.79%	$1,974,071	$1,373,764	$3,347,834	0.9076	$3,038,495
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	10.79%	$1,965,374	$1,307,932	$3,273,307	0.9076	$2,970,853
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	10.79%	$1,956,678	$1,178,850	$3,135,528	0.9076	$2,845,805
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	10.79%	$1,947,982	$1,367,810	$3,315,792	0.9076	$3,009,413
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	10.79%	$1,939,286	$1,081,502	$3,020,788	0.9076	$2,741,667
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	10.79%	$1,930,590	$1,232,354	$3,162,943	0.9076	$2,870,687
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	10.79%	$1,921,893	$1,257,552	$3,179,445	0.9076	$2,885,664
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	10.79%	$1,913,197	$1,257,552	$3,170,749	0.9076	$2,877,771
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	10.79%	$1,904,501	$1,257,552	$3,162,052	0.9076	$2,869,879
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	10.79%	$1,895,812	$1,278,321	$3,174,133	0.9076	$2,880,843
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	10.79%	$1,887,124	$1,186,493	$3,073,617	0.9076	$2,789,615
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	10.79%	$1,878,436	$1,310,939	$3,189,375	0.9076	$2,894,677
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	10.79%	$1,869,747	$1,373,764	$3,243,511	0.9076	$2,943,811
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	10.79%	$1,861,059	$1,307,932	$3,168,991	0.9076	$2,876,176
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	10.79%	$1,852,371	$1,178,850	$3,031,220	0.9076	$2,751,136
											Total Revenue Requirement for July 2015 through June 2016		$34,391,339

Kentucky Power Company
KIUC Recommendation to Reflect Reduction in Mitchell FGD Revenue Requirement
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Rev Req (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
II. Reject Proforma Adjustments Resulting in Negative Short Term Debt													
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	10.51%	$1,973,060	$1,257,552	$3,230,611	0.9076	$2,932,103
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	10.51%	$1,964,538	$1,257,552	$3,222,090	0.9076	$2,924,369
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	10.51%	$1,956,016	$1,257,552	$3,213,568	0.9076	$2,916,634
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	10.51%	$1,947,549	$1,278,321	$3,225,870	0.9076	$2,927,799
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	10.51%	$1,939,081	$1,186,493	$3,125,574	0.9076	$2,836,771
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	10.51%	$1,930,614	$1,310,939	$3,241,553	0.9076	$2,942,033
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	10.51%	$1,922,146	$1,373,764	$3,295,910	0.9076	$2,991,368
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	10.51%	$1,913,679	$1,307,932	$3,221,611	0.9076	$2,923,934
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	10.51%	$1,905,211	$1,178,850	$3,084,061	0.9076	$2,799,094
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	10.51%	$1,896,744	$1,367,810	$3,264,554	0.9076	$2,962,909
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	10.51%	$1,888,276	$1,081,502	$2,969,778	0.9076	$2,695,371
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	10.51%	$1,879,809	$1,232,354	$3,112,163	0.9076	$2,824,599
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	10.51%	$1,871,341	$1,257,552	$3,128,893	0.9076	$2,839,783
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	10.51%	$1,862,874	$1,257,552	$3,120,426	0.9076	$2,832,098
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	10.51%	$1,854,406	$1,257,552	$3,111,958	0.9076	$2,824,413
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	10.51%	$1,845,947	$1,278,321	$3,124,267	0.9076	$2,835,585
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	10.51%	$1,837,487	$1,186,493	$3,023,980	0.9076	$2,744,564
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	10.51%	$1,829,027	$1,310,939	$3,139,966	0.9076	$2,849,833
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	10.51%	$1,820,567	$1,373,764	$3,194,331	0.9076	$2,899,175
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	10.51%	$1,812,107	$1,307,932	$3,120,039	0.9076	$2,831,748
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	10.51%	$1,803,647	$1,178,850	$2,982,497	0.9076	$2,706,914

Total Revenue Requirement for July 2015 through June 2016	$33,846,992
Revenue Requirement Reduction	-$544,347

Kentucky Power Company
KIUC Recommendation to Reflect Reduction in Mitchell FGD Revenue Requirement
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Rev Req (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
III. Remove Non Utility Investment in AEP Utility Money Pool													
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	10.50%	$1,972,362	$1,257,552	$3,229,914	0.9076	$2,931,470
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	10.50%	$1,963,844	$1,257,552	$3,221,395	0.9076	$2,923,738
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	10.50%	$1,955,325	$1,257,552	$3,212,876	0.9076	$2,916,007
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	10.50%	$1,946,860	$1,278,321	$3,225,181	0.9076	$2,927,175
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	10.50%	$1,938,396	$1,186,493	$3,124,889	0.9076	$2,836,149
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	10.50%	$1,929,931	$1,310,939	$3,240,870	0.9076	$2,941,414
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	10.50%	$1,921,467	$1,373,764	$3,295,231	0.9076	$2,990,751
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	10.50%	$1,913,002	$1,307,932	$3,220,935	0.9076	$2,923,320
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	10.50%	$1,904,538	$1,178,850	$3,083,388	0.9076	$2,798,483
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	10.50%	$1,896,073	$1,367,810	$3,263,883	0.9076	$2,962,300
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	10.50%	$1,887,609	$1,081,502	$2,969,111	0.9076	$2,694,765
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	10.50%	$1,879,144	$1,232,354	$3,111,498	0.9076	$2,823,996
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	10.50%	$1,870,680	$1,257,552	$3,128,232	0.9076	$2,839,183
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	10.50%	$1,862,215	$1,257,552	$3,119,767	0.9076	$2,831,501
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	10.50%	$1,853,751	$1,257,552	$3,111,303	0.9076	$2,823,818
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	10.50%	$1,845,294	$1,278,321	$3,123,615	0.9076	$2,834,993
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	10.50%	$1,836,837	$1,186,493	$3,023,330	0.9076	$2,743,974
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	10.50%	$1,828,380	$1,310,939	$3,139,319	0.9076	$2,849,246
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	10.50%	$1,819,924	$1,373,764	$3,193,687	0.9076	$2,898,591
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	10.50%	$1,811,467	$1,307,932	$3,119,399	0.9076	$2,831,166
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	10.50%	$1,803,010	$1,178,850	$2,981,860	0.9076	$2,706,336

Total Revenue Requirement for July 2015 through June 2016	$33,839,869
Revenue Requirement Reduction	-$7,123

Kentucky Power Company
KIUC Recommendation to Reflect Reduction in Mitchell FGD Revenue Requirement
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Rev Req (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
IV. Reflect Increase in ADIT Due to Bonus Depreciation Extension in 2014													
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	10.49%	$1,970,593	$1,257,552	$3,228,144	0.9076	$2,929,864
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	10.49%	$1,962,082	$1,257,552	$3,219,633	0.9076	$2,922,139
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	10.49%	$1,953,571	$1,257,552	$3,211,122	0.9076	$2,914,414
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	10.49%	$1,945,114	$1,278,321	$3,223,435	0.9076	$2,925,589
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	10.49%	$1,936,657	$1,186,493	$3,123,150	0.9076	$2,834,571
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	10.49%	$1,928,200	$1,310,939	$3,239,139	0.9076	$2,939,842
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	10.49%	$1,919,743	$1,373,764	$3,293,507	0.9076	$2,989,187
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	10.49%	$1,911,286	$1,307,932	$3,219,218	0.9076	$2,921,763
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	10.49%	$1,902,829	$1,178,850	$3,081,679	0.9076	$2,796,932
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	10.49%	$1,894,372	$1,367,810	$3,262,182	0.9076	$2,960,756
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	10.49%	$1,885,915	$1,081,502	$2,967,417	0.9076	$2,693,228
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	10.49%	$1,877,458	$1,232,354	$3,109,812	0.9076	$2,822,465
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	10.49%	$1,869,002	$1,257,552	$3,126,553	0.9076	$2,837,660
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	10.49%	$1,860,545	$1,257,552	$3,118,096	0.9076	$2,829,984
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	10.49%	$1,852,088	$1,257,552	$3,109,639	0.9076	$2,822,309
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	10.49%	$1,843,638	$1,278,321	$3,121,959	0.9076	$2,833,490
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	10.49%	$1,835,189	$1,186,493	$3,021,682	0.9076	$2,742,479
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	10.49%	$1,826,740	$1,310,939	$3,137,679	0.9076	$2,847,757
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	10.49%	$1,818,291	$1,373,764	$3,192,054	0.9076	$2,897,109
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	10.49%	$1,809,841	$1,307,932	$3,117,774	0.9076	$2,829,691
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	10.49%	$1,801,392	$1,178,850	$2,980,242	0.9076	$2,704,868

Total Revenue Requirement for July 2015 through June 2016	$33,821,796
Revenue Requirement Reduction	-$18,073

Kentucky Power Company
KIUC Recommendation to Reflect Reduction in Mitchell FGD Revenue Requirement
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Rev Req (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
V. Reflect Return on Equity of 8.75%													
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	9.15%	$1,717,776	$1,257,552	$2,975,327	0.9076	$2,700,407
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	9.15%	$1,710,357	$1,257,552	$2,967,908	0.9076	$2,693,673
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	9.15%	$1,702,937	$1,257,552	$2,960,489	0.9076	$2,686,940
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	9.15%	$1,695,565	$1,278,321	$2,973,886	0.9076	$2,699,099
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	9.15%	$1,688,193	$1,186,493	$2,874,686	0.9076	$2,609,065
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	9.15%	$1,680,822	$1,310,939	$2,991,761	0.9076	$2,715,322
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	9.15%	$1,673,450	$1,373,764	$3,047,213	0.9076	$2,765,651
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	9.15%	$1,666,078	$1,307,932	$2,974,010	0.9076	$2,699,211
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	9.15%	$1,658,706	$1,178,850	$2,837,556	0.9076	$2,575,366
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	9.15%	$1,651,334	$1,367,810	$3,019,144	0.9076	$2,740,175
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	9.15%	$1,643,962	$1,081,502	$2,725,464	0.9076	$2,473,631
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	9.15%	$1,636,590	$1,232,354	$2,868,944	0.9076	$2,603,853
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	9.15%	$1,629,218	$1,257,552	$2,886,770	0.9076	$2,620,032
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	9.15%	$1,621,846	$1,257,552	$2,879,398	0.9076	$2,613,341
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	9.15%	$1,614,474	$1,257,552	$2,872,026	0.9076	$2,606,651
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	9.15%	$1,607,109	$1,278,321	$2,885,430	0.9076	$2,618,816
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	9.15%	$1,599,744	$1,186,493	$2,786,237	0.9076	$2,528,788
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	9.15%	$1,592,378	$1,310,939	$2,903,317	0.9076	$2,635,051
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	9.15%	$1,585,013	$1,373,764	$2,958,777	0.9076	$2,685,386
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	9.15%	$1,577,648	$1,307,932	$2,885,580	0.9076	$2,618,953
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	9.15%	$1,570,283	$1,178,850	$2,749,133	0.9076	$2,495,113

Total Revenue Requirement for July 2015 through June 2016	$31,239,790
Revenue Requirement Reduction	-$2,582,006

Kentucky Power Company
KIUC Recommendation to Reflect Reduction in Mitchell FGD Revenue Requirement
Case No. 2014-00396
For the Test Year Ended September 30, 2014
($)

Month (1)	Year (2)	Environmental Utility Plant at Original Cost (3)	Accumulated Depreciation (4)	Monthly Depreciation (5)	ADFIT (6)	Monthly ADFIT (7)	Rate Base (8)	WACC (9)	Monthly Return on Rate Base (10)	Monthly O & M (11)	Total FGD Monthly Environmental Rev Req (12)	Retail Allocation (13)	Proposed Revenue Increase (14)
VI. Adjust Gross Revenue Conversion Factor to Reflect Section 199 Production Activities Deduction													
Balance as of September 30, 2014		$327,193,412	$76,112,982		$24,747,361		$226,333,069						
October	2014	$327,193,412	$76,966,411	$853,429.48	$24,867,276	$119,915	$225,359,724	8.84%	$1,659,921	$1,257,552	$2,917,473	0.9076	$2,647,898
November	2014	$327,193,412	$77,819,841	$853,429.48	$24,987,191	$119,915	$224,386,380	8.84%	$1,652,752	$1,257,552	$2,910,303	0.9076	$2,641,391
December	2014	$327,193,412	$78,673,270	$853,429.48	$25,107,106	$119,915	$223,413,035	8.84%	$1,645,582	$1,257,552	$2,903,134	0.9076	$2,634,884
January	2015	$327,193,412	$79,526,700	$853,429.48	$25,220,819	$113,713	$222,445,893	8.84%	$1,638,459	$1,278,321	$2,916,780	0.9076	$2,647,269
February	2015	$327,193,412	$80,380,129	$853,429.48	$25,334,532	$113,713	$221,478,750	8.84%	$1,631,335	$1,186,493	$2,817,828	0.9076	$2,557,461
March	2015	$327,193,412	$81,233,559	$853,429.48	$25,448,245	$113,713	$220,511,608	8.84%	$1,624,211	$1,310,939	$2,935,151	0.9076	$2,663,943
April	2015	$327,193,412	$82,086,988	$853,429.48	$25,561,958	$113,713	$219,544,466	8.84%	$1,617,088	$1,373,764	$2,990,852	0.9076	$2,714,497
May	2015	$327,193,412	$82,940,418	$853,429.48	$25,675,671	$113,713	$218,577,323	8.84%	$1,609,964	$1,307,932	$2,917,896	0.9076	$2,648,283
June	2015	$327,193,412	$83,793,847	$853,429.48	$25,789,384	$113,713	$217,610,181	8.84%	$1,602,841	$1,178,850	$2,781,690	0.9076	$2,524,662
July	2015	$327,193,412	$84,647,277	$853,429.48	$25,903,097	$113,713	$216,643,038	8.84%	$1,595,717	$1,367,810	$2,963,527	0.9076	$2,689,697
August	2015	$327,193,412	$85,500,706	$853,429.48	$26,016,810	$113,713	$215,675,896	8.84%	$1,588,593	$1,081,502	$2,670,095	0.9076	$2,423,378
September	2015	$327,193,412	$86,354,136	$853,429.48	$26,130,523	$113,713	$214,708,753	8.84%	$1,581,470	$1,232,354	$2,813,823	0.9076	$2,553,826
October	2015	$327,193,412	$87,207,565	$853,429.48	$26,244,236	$113,713	$213,741,611	8.84%	$1,574,346	$1,257,552	$2,831,898	0.9076	$2,570,230
November	2015	$327,193,412	$88,060,995	$853,429.48	$26,357,949	$113,713	$212,774,468	8.84%	$1,567,222	$1,257,552	$2,824,774	0.9076	$2,563,765
December	2015	$327,193,412	$88,914,424	$853,429.48	$26,471,662	$113,713	$211,807,326	8.84%	$1,560,099	$1,257,552	$2,817,650	0.9076	$2,557,299
January	2016	$327,193,412	$89,767,854	$853,429.48	$26,584,504	$112,842	$210,841,054	8.84%	$1,552,982	$1,278,321	$2,831,302	0.9076	$2,569,690
February	2016	$327,193,412	$90,621,283	$853,429.48	$26,697,346	$112,842	$209,874,783	8.84%	$1,545,864	$1,186,493	$2,732,357	0.9076	$2,479,887
March	2016	$327,193,412	$91,474,713	$853,429.48	$26,810,188	$112,842	$208,908,511	8.84%	$1,538,747	$1,310,939	$2,849,686	0.9076	$2,586,375
April	2016	$327,193,412	$92,328,142	$853,429.48	$26,923,030	$112,842	$207,942,240	8.84%	$1,531,630	$1,373,764	$2,905,394	0.9076	$2,636,935
May	2016	$327,193,412	$93,181,572	$853,429.48	$27,035,872	$112,842	$206,975,968	8.84%	$1,524,513	$1,307,932	$2,832,445	0.9076	$2,570,727
June	2016	$327,193,412	$94,035,001	$853,429.48	$27,148,714	$112,842	$206,009,697	8.84%	$1,517,395	$1,178,850	$2,696,245	0.9076	$2,447,112

Total Revenue Requirement for July 2015 through June 2016	$30,648,923
Revenue Requirement Reduction	-$590,867

EXHIBIT ____ (LK-18)

Kentucky Power Company
BSRR Revenue Requirement
I. As Filed By Company

Grossed Up WACC	10.7873%
Annual Payment	(22,166,309.89)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(21,855,981.56)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	19,471,535	(22,166,309.89)	15,228,668.57	$148,072,759.40
2	$148,072,759.40	12,618,110	(22,166,309.89)	16,300,422.81	$154,824,982.32
3	$154,824,982.32	14,527,661	(22,166,309.89)	17,163,217.84	$164,349,551.27
4	$164,349,551.27	8,509,280	(22,166,309.89)	17,936,354.94	$168,628,876.31
5	$168,628,876.31	2,240,926	(22,166,309.89)	18,102,104.16	$166,805,596.58
6	$166,805,596.58	368,869	(22,166,309.89)	17,800,011.56	$162,808,167.24
7	$162,808,167.24	371,840	(22,166,309.89)	17,346,976.26	$158,360,673.61
8	$158,360,673.61	374,886	(22,166,309.89)	16,842,921.21	$153,412,170.93
9	$153,412,170.93	378,008	(22,166,309.89)	16,282,070.87	$147,905,939.91
10	$147,905,939.91	250,000	(22,166,309.89)	15,651,309.58	$141,640,939.59
11	$141,640,939.59	250,000	(22,166,309.89)	14,941,049.44	$134,665,679.14
12	$134,665,679.14	250,000	(22,166,309.89)	14,150,267.45	$126,899,636.70
13	$126,899,636.70	250,000	(22,166,309.89)	13,269,834.88	$118,253,161.68
14	$118,253,161.68	250,000	(22,166,309.89)	12,289,588.08	$108,626,439.87
15	$108,626,439.87	250,000	(22,166,309.89)	11,198,211.17	$97,908,341.15
16	$97,908,341.15	250,000	(22,166,309.89)	9,983,105.37	$85,975,136.62
17	$85,975,136.62	43,797,850	(22,166,309.89)	10,849,167.77	$118,455,844.50
18	$118,455,844.50	-	(22,166,309.89)	12,299,827.71	$108,589,362.32
19	$108,589,362.32	-	(22,166,309.89)	11,181,269.28	$97,604,321.70
20	$97,604,321.70	-	(22,166,309.89)	9,935,900.40	$85,373,912.21
21	$85,373,912.21	-	(22,166,309.89)	8,549,344.64	$71,756,946.95
22	$71,756,946.95	-	(22,166,309.89)	7,005,595.71	$56,596,232.77
23	$56,596,232.77	-	(22,166,309.89)	5,286,832.69	$39,716,755.56
24	$39,716,755.56	-	(22,166,309.89)	3,373,214.31	$20,923,659.97
25	$20,923,659.97	-	(22,166,309.89)	1,242,649.92	$0.00
			$554,157,747.34	314,209,916.61	

Total Revenue for Components Subject to WACC

Kentucky Power Company
BSRR Revenue Requirement
II. Reject Proforma Adjustments Resulting in Negative Short Term Debt

Grossed Up WACC	10.5062%
Annual Payment	(21,772,011.43)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(21,467,203.27)
As Filed by Company	(21,855,981.56)
Revenue Requirement Effect	(388,778.29)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	19,471,535	(21,772,011.43)	14,832,009.58	$148,070,398.87
2	$148,070,398.87	12,618,110	(21,772,011.43)	15,874,042.33	$154,790,539.77
3	$154,790,539.77	14,527,661	(21,772,011.43)	16,709,771.19	$164,255,960.53
4	$164,255,960.53	8,509,280	(21,772,011.43)	17,455,106.04	$168,448,335.14
5	$168,448,335.14	2,240,926	(21,772,011.43)	17,606,578.50	$166,523,828.21
6	$166,523,828.21	368,869	(21,772,011.43)	17,301,530.90	$162,422,216.69
7	$162,422,216.69	371,840	(21,772,011.43)	16,849,387.11	$157,871,432.36
8	$157,871,432.36	374,886	(21,772,011.43)	16,347,716.04	$152,822,022.98
9	$152,822,022.98	378,008	(21,772,011.43)	15,791,064.58	$147,219,084.13
10	$147,219,084.13	250,000	(21,772,011.43)	15,166,872.25	$140,863,944.96
11	$140,863,944.96	250,000	(21,772,011.43)	14,466,081.12	$133,808,014.65
12	$133,808,014.65	250,000	(21,772,011.43)	13,688,012.65	$125,974,015.86
13	$125,974,015.86	250,000	(21,772,011.43)	12,824,145.35	$117,276,149.78
14	$117,276,149.78	250,000	(21,772,011.43)	11,865,018.05	$107,619,156.41
15	$107,619,156.41	250,000	(21,772,011.43)	10,800,126.29	$96,897,271.27
16	$96,897,271.27	250,000	(21,772,011.43)	9,617,807.25	$84,993,067.08
17	$84,993,067.08	43,797,850	(21,772,011.43)	10,464,507.99	$117,483,413.64
18	$117,483,413.64	-	(21,772,011.43)	11,875,476.68	$107,586,878.89
19	$107,586,878.89	-	(21,772,011.43)	10,784,170.31	$96,599,037.77
20	$96,599,037.77	-	(21,772,011.43)	9,572,523.89	$84,399,550.23
21	$84,399,550.23	-	(21,772,011.43)	8,227,267.31	$70,854,806.11
22	$70,854,806.11	-	(21,772,011.43)	6,733,667.20	$55,816,461.88
23	$55,816,461.88	-	(21,772,011.43)	5,075,365.46	$39,119,815.91
24	$39,119,815.91	-	(21,772,011.43)	3,234,200.19	$20,582,004.67
25	$20,582,004.67	-	(21,772,011.43)	1,190,006.75	($0.00)
			$544,300,285.74	304,352,455.01	

Total Revenue for Components Subject to WACC

Kentucky Power Company
BSRR Revenue Requirement
III. Remove Non Utility Net Investment in AEP Utility Money Pool

Grossed Up WACC	10.5025%
Annual Payment	(21,766,818.93)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(21,462,083.46)
Rev Req After KIUC Adj #1	(21,467,203.27)
Revenue Requirement Effect	(5,119.81)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	19,471,535	(21,766,818.93)	14,826,768.64	$148,070,350.43
2	$148,070,350.43	12,618,110	(21,766,818.93)	15,868,407.51	$154,790,049.02
3	$154,790,049.02	14,527,661	(21,766,818.93)	16,703,778.49	$164,254,669.58
4	$164,254,669.58	8,509,280	(21,766,818.93)	17,448,746.85	$168,445,877.50
5	$168,445,877.50	2,240,926	(21,766,818.93)	17,600,032.46	$166,520,017.03
6	$166,520,017.03	368,869	(21,766,818.93)	17,294,948.10	$162,417,015.21
7	$162,417,015.21	371,840	(21,766,818.93)	16,842,818.64	$157,864,854.92
8	$157,864,854.92	374,886	(21,766,818.93)	16,341,181.85	$152,814,103.85
9	$152,814,103.85	378,008	(21,766,818.93)	15,784,588.82	$147,209,881.74
10	$147,209,881.74	250,000	(21,766,818.93)	15,160,486.36	$140,853,549.17
11	$140,853,549.17	250,000	(21,766,818.93)	14,459,823.42	$133,796,553.66
12	$133,796,553.66	250,000	(21,766,818.93)	13,681,925.93	$125,961,660.67
13	$125,961,660.67	250,000	(21,766,818.93)	12,818,280.26	$117,263,122.00
14	$117,263,122.00	250,000	(21,766,818.93)	11,859,434.33	$107,605,737.39
15	$107,605,737.39	250,000	(21,766,818.93)	10,794,894.15	$96,883,812.61
16	$96,883,812.61	250,000	(21,766,818.93)	9,613,008.96	$84,980,002.65
17	$84,980,002.65	43,797,850	(21,766,818.93)	10,459,453.95	$117,470,487.67
18	$117,470,487.67	-	(21,766,818.93)	11,869,900.21	$107,573,568.95
19	$107,573,568.95	-	(21,766,818.93)	10,778,956.02	$96,585,706.04
20	$96,585,706.04	-	(21,766,818.93)	9,567,756.30	$84,386,643.41
21	$84,386,643.41	-	(21,766,818.93)	8,223,045.19	$70,842,869.68
22	$70,842,869.68	-	(21,766,818.93)	6,730,105.65	$55,806,156.39
23	$55,806,156.39	-	(21,766,818.93)	5,072,598.35	$39,111,935.81
24	$39,111,935.81	-	(21,766,818.93)	3,232,382.87	$20,577,499.76
25	$20,577,499.76	-	(21,766,818.93)	1,189,319.17	($0.00)
			$544,170,473.20	304,222,642.48	

Total Revenue for Components Subject to WACC

Kentucky Power Company
BSRR Revenue Requirement
IV. Reflect Increase in ADIT Due to Bonus Depreciation Extension in 2014

Grossed Up WACC	10.4931%
Annual Payment	(21,753,645.34)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(21,449,094.31)
Rev Req After KIUC Adj #2	(21,462,083.46)
Revenue Requirement Effect	(12,989.16)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	19,471,535	(21,753,645.34)	14,813,470.09	$148,070,225.48
2	$148,070,225.48	12,618,110	(21,753,645.34)	15,854,109.40	$154,788,799.54
3	$154,788,799.54	14,527,661	(21,753,645.34)	16,688,572.25	$164,251,387.45
4	$164,251,387.45	8,509,280	(21,753,645.34)	17,432,610.78	$168,439,632.89
5	$168,439,632.89	2,240,926	(21,753,645.34)	17,583,422.47	$166,510,336.02
6	$166,510,336.02	368,869	(21,753,645.34)	17,278,245.11	$162,403,804.78
7	$162,403,804.78	371,840	(21,753,645.34)	16,826,152.33	$157,848,151.77
8	$157,848,151.77	374,886	(21,753,645.34)	16,324,602.84	$152,793,995.27
9	$152,793,995.27	378,008	(21,753,645.34)	15,768,158.42	$147,186,516.35
10	$147,186,516.35	250,000	(21,753,645.34)	15,144,284.34	$140,827,155.34
11	$140,827,155.34	250,000	(21,753,645.34)	14,443,947.07	$133,767,457.07
12	$133,767,457.07	250,000	(21,753,645.34)	13,666,483.78	$125,930,295.51
13	$125,930,295.51	250,000	(21,753,645.34)	12,803,400.79	$117,230,050.96
14	$117,230,050.96	250,000	(21,753,645.34)	11,845,269.07	$107,571,674.69
15	$107,571,674.69	250,000	(21,753,645.34)	10,781,621.20	$96,849,650.55
16	$96,849,650.55	250,000	(21,753,645.34)	9,600,836.99	$84,946,842.20
17	$84,946,842.20	43,797,850	(21,753,645.34)	10,446,633.00	$117,437,679.86
18	$117,437,679.86	-	(21,753,645.34)	11,855,753.89	$107,539,788.41
19	$107,539,788.41	-	(21,753,645.34)	10,765,728.93	$96,551,872.00
20	$96,551,872.00	-	(21,753,645.34)	9,555,662.81	$84,353,889.47
21	$84,353,889.47	-	(21,753,645.34)	8,212,335.75	$70,812,579.88
22	$70,812,579.88	-	(21,753,645.34)	6,721,072.13	$55,780,006.67
23	$55,780,006.67	-	(21,753,645.34)	5,065,580.14	$39,091,941.47
24	$39,091,941.47	-	(21,753,645.34)	3,227,773.81	$20,566,069.94
25	$20,566,069.94	-	(21,753,645.34)	1,187,575.41	$0.00
			$543,841,133.52	303,893,302.80	

Total Revenue for Components Subject to WACC

Kentucky Power Company
BSRR Revenue Requirement
V. Reflect Return on Equity of 8.75%

Grossed Up WACC	9.1468%
Annual Payment	(19,901,987.28)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(19,623,359.46)
Rev Req After KIUC Adj #3	(21,449,094.31)
Revenue Requirement Effect	(1,825,734.85)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	19,471,535	(19,901,987.28)	12,912,197.00	$148,020,610.44
2	$148,020,610.44	12,618,110	(19,901,987.28)	13,808,239.90	$154,544,973.06
3	$154,544,973.06	14,527,661	(19,901,987.28)	14,512,802.13	$163,683,448.91
4	$163,683,448.91	8,509,280	(19,901,987.28)	15,125,802.25	$167,416,543.88
5	$167,416,543.88	2,240,926	(19,901,987.28)	15,212,366.49	$164,967,849.09
6	$164,967,849.09	368,869	(19,901,987.28)	14,898,244.53	$160,332,975.35
7	$160,332,975.35	371,840	(19,901,987.28)	14,456,195.04	$155,259,023.10
8	$155,259,023.10	374,886	(19,901,987.28)	13,972,259.71	$149,704,181.53
9	$149,704,181.53	378,008	(19,901,987.28)	13,442,449.73	$143,622,651.98
10	$143,622,651.98	250,000	(19,901,987.28)	12,856,753.08	$136,827,417.77
11	$136,827,417.77	250,000	(19,901,987.28)	12,208,472.61	$129,383,903.10
12	$129,383,903.10	250,000	(19,901,987.28)	11,498,344.76	$121,230,260.58
13	$121,230,260.58	250,000	(19,901,987.28)	10,720,469.12	$112,298,742.41
14	$112,298,742.41	250,000	(19,901,987.28)	9,868,382.41	$102,515,137.55
15	$102,515,137.55	250,000	(19,901,987.28)	8,935,004.74	$91,798,155.01
16	$91,798,155.01	250,000	(19,901,987.28)	7,912,580.77	$80,058,748.49
17	$80,058,748.49	43,797,850	(19,901,987.28)	8,665,465.32	$112,620,076.54
18	$112,620,076.54	-	(19,901,987.28)	9,888,286.73	$102,606,375.98
19	$102,606,375.98	-	(19,901,987.28)	8,932,957.41	$91,637,346.11
20	$91,637,346.11	-	(19,901,987.28)	7,886,487.56	$79,621,846.39
21	$79,621,846.39	-	(19,901,987.28)	6,740,182.16	$66,460,041.27
22	$66,460,041.27	-	(19,901,987.28)	5,484,516.66	$52,042,570.65
23	$52,042,570.65	-	(19,901,987.28)	4,109,057.89	$36,249,641.26
24	$36,249,641.26	-	(19,901,987.28)	2,602,377.29	$18,950,031.27
25	$18,950,031.27	-	(19,901,987.28)	951,956.01	($0.00)
			$497,549,682.04	257,601,851.31	

Total Revenue for Components Subject to WACC

Kentucky Power Company
BSRR Revenue Requirement
VI. Adjust Gross Revenue Conversion Factor to Reflect Section 199 Production Activities Deduction

Grossed Up WACC	8.8388%
Annual Payment	(19,487,340.89)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(19,214,518.12)
Rev Req After KIUC Adj #4	(19,623,359.46)
Revenue Requirement Effect	(408,841.34)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	19,471,535	(19,487,340.89)	12,476,764.55	$147,999,824.39
2	$147,999,824.39	12,618,110	(19,487,340.89)	13,339,323.40	$154,469,916.90
3	$154,469,916.90	14,527,661	(19,487,340.89)	14,014,235.54	$163,524,472.56
4	$163,524,472.56	8,509,280	(19,487,340.89)	14,597,881.17	$167,144,292.84
5	$167,144,292.84	2,240,926	(19,487,340.89)	14,670,837.10	$164,568,715.05
6	$164,568,715.05	368,869	(19,487,340.89)	14,356,002.57	$159,806,245.73
7	$159,806,245.73	371,840	(19,487,340.89)	13,917,703.10	$154,608,447.94
8	$154,608,447.94	374,886	(19,487,340.89)	13,439,331.32	$148,935,324.38
9	$148,935,324.38	378,008	(19,487,340.89)	12,917,205.22	$142,743,196.71
10	$142,743,196.71	250,000	(19,487,340.89)	12,341,855.87	$135,847,711.69
11	$135,847,711.69	250,000	(19,487,340.89)	11,707,072.12	$128,317,442.92
12	$128,317,442.92	250,000	(19,487,340.89)	11,013,851.53	$120,093,953.56
13	$120,093,953.56	250,000	(19,487,340.89)	10,256,814.52	$111,113,427.19
14	$111,113,427.19	250,000	(19,487,340.89)	9,430,086.29	$101,306,172.59
15	$101,306,172.59	250,000	(19,487,340.89)	8,527,251.21	$90,596,082.91
16	$90,596,082.91	250,000	(19,487,340.89)	7,541,303.04	$78,900,045.06
17	$78,900,045.06	43,797,850	(19,487,340.89)	8,272,801.53	$111,483,355.70
18	$111,483,355.70	-	(19,487,340.89)	9,453,760.52	$101,449,775.34
19	$101,449,775.34	-	(19,487,340.89)	8,530,090.37	$90,492,524.82
20	$90,492,524.82	-	(19,487,340.89)	7,521,389.10	$78,526,573.03
21	$78,526,573.03	-	(19,487,340.89)	6,419,828.93	$65,459,061.07
22	$65,459,061.07	-	(19,487,340.89)	5,216,861.46	$51,188,581.64
23	$51,188,581.64	-	(19,487,340.89)	3,903,151.35	$35,604,392.10
24	$35,604,392.10	-	(19,487,340.89)	2,468,503.88	$18,585,555.09
25	$18,585,555.09	-	(19,487,340.89)	901,785.80	$0.00
			$487,183,522.22	247,235,691.49	

Total Revenue for Components Subject to WACC

Kentucky Power Company
BSRR Revenue Requirement
VII. Remove Levelized Return Of and On Future Cost Additions Until Incurred

Grossed Up WACC	8.8388%
Annual Payment	(13,470,135.07)
KY Jurisdictional Factor	0.986
BSRR Revenue Requirement	(13,281,553.18)
Rev Req After KIUC Adj #5	(19,214,518.12)
Revenue Requirement Effect	(5,932,964.94)

Year	Bg	Additions	Payments	CC	Ending
1	$135,538,865.72	-	(13,470,135.07)	11,918,108.61	$133,986,839.26
2	$133,986,839.26	-	(13,470,135.07)	11,775,232.34	$132,291,936.52
3	$132,291,936.52	-	(13,470,135.07)	11,619,203.18	$130,441,004.63
4	$130,441,004.63	-	(13,470,135.07)	11,448,810.31	$128,419,679.88
5	$128,419,679.88	-	(13,470,135.07)	11,262,731.44	$126,212,276.24
6	$126,212,276.24	-	(13,470,135.07)	11,059,522.54	$123,801,663.71
7	$123,801,663.71	-	(13,470,135.07)	10,837,606.65	$121,169,135.29
8	$121,169,135.29	-	(13,470,135.07)	10,595,261.66	$118,294,261.88
9	$118,294,261.88	-	(13,470,135.07)	10,330,606.91	$115,154,733.71
10	$115,154,733.71	-	(13,470,135.07)	10,041,588.59	$111,726,187.23
11	$111,726,187.23	-	(13,470,135.07)	9,725,963.87	$107,982,016.03
12	$107,982,016.03	-	(13,470,135.07)	9,381,283.40	$103,893,164.36
13	$103,893,164.36	-	(13,470,135.07)	9,004,872.38	$99,427,901.66
14	$99,427,901.66	-	(13,470,135.07)	8,593,809.75	$94,551,576.34
15	$94,551,576.34	-	(13,470,135.07)	8,144,905.57	$89,226,346.85
16	$89,226,346.85	-	(13,470,135.07)	7,654,676.23	$83,410,888.00
17	$83,410,888.00	-	(13,470,135.07)	7,119,317.40	$77,060,070.33
18	$77,060,070.33	-	(13,470,135.07)	6,534,674.58	$70,124,609.85
19	$70,124,609.85	-	(13,470,135.07)	5,896,210.78	$62,550,685.56
20	$62,550,685.56	-	(13,470,135.07)	5,198,971.36	$54,279,521.84
21	$54,279,521.84	-	(13,470,135.07)	4,437,545.55	$45,246,932.32
22	$45,246,932.32	-	(13,470,135.07)	3,606,024.49	$35,382,821.74
23	$35,382,821.74	-	(13,470,135.07)	2,697,955.37	$24,610,642.03
24	$24,610,642.03	-	(13,470,135.07)	1,706,291.32	$12,846,798.29
25	$12,846,798.29	-	(13,470,135.07)	623,336.79	$0.00
			$336,753,376.78	201,214,511.06	

Total Revenue for Components Subject to WACC

EXHIBIT ____ (LK-19)

Kentucky Power Company

REQUEST

Please confirm that in December 2014, 50% bonus tax depreciation was "extended" to the entire 2014 tax year. If confirmed, please provide a narrative description of the property to which the extension applies. For example, does it apply to all property additions in 2014? Does it apply to any property additions in 2015, e.g., construction dollars incurred in 2014? Please provide a copy of sources relied on for your response.

RESPONSE

In December 2014, the Federal 50% bonus tax depreciation deduction was extended for the entire 2014 year. Under Internal Revenue Code Section 168(k), the bonus allowance is only available for new property ("original use" must begin with the taxpayer) which is depreciable under MACRS and has a recovery period of 20 years or less and computer software depreciable over three years under IRC Sec 167(f). The assets must be placed in service before January 1, 2015, unless the property qualifies as "long production property." This is defined as property that (a) is subject to IRC Sec 263A uniform capitalization rules, (b) has a production period greater than one year and a cost exceeding $1 million, and (c) has a MACRS recovery period of at least 10 years. If these additional requirements are met and the asset is placed in service in 2015, then the pre-2015 expenditures will qualify for bonus depreciation in 2015.

WITNESS: Jeffrey B Bartsch

EXHIBIT ____ (LK-20)

Kentucky Power Company

REQUEST

Refer to Items 28, 29, and 30 of KIUC's First Request and Item 171 of the AG's initial Request regarding the impact of the 50 percent bonus depreciation. Based on Kentucky Power's estimate of the bonus depreciation of $23.6 million increase in deferred federal income taxes and an additional normalized MACRS Schedule M deduction of $67,446,000, provide updated schedules for the Company's accumulated deferred income taxes, capitalization, the proposed adjustment 49 listed in Section V, Exhibit 2 of the Application, and any other schedules or exhibits affected by the 50 percent bonus depreciation.

RESPONSE

Please see KPSC_3_50_Attachment1.xlsx for the updated Tax Schedules related to the adjustment to the MACRS Normalized Schedule M deduction for 50 percent bonus depreciation. See KPSC_3_50_Attachment2.xlsx for the updated Accumulated Deferred Income Taxes as of September 30, 2014. There is no change to proposed Adjustment 49 as a result of the bonus depreciation.

There is no change in capitalization as a result of bonus depreciation. Capitalization provides the funds needed to maintain the Company's operations. It thus funds the test year and future operations as long as possible before additional debt or equity is needed to operate the Company. Bonus depreciation and ADIT allows the Company to use its capitalization to maintain its operations without having to issue additional debt or equity.

Please see KPSC_3_50_Attachment3.xls for the environmental cost calculations that are affected by bonus depreciation. A formulaic error within the deprecation calculation has also been corrected in this revision.

KPSC_3_50_Attachment4.xls provides a revised exhibit AJE-3 to reflect these revisions.

WITNESS: Jeffrey B Bartsch

EXHIBIT ____ (LK-21)

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-29. The Company was asked to provide the effects of the 2014 extension of bonus depreciation and to provide revised schedules and calculations. The Company provided a quantification of $23.6 million, but did not provide any revised schedules or calculations.

a. Please provide the revised schedules, including all calculations in electronic spreadsheet format with all formulas intact.

b. Please provide the calculation of the $23.6 million cited in the response in electronic spreadsheet format with all formulas intact.

c. In its response, the Company referred to "hypothetical revisions" to the schedules.Please explain what the Company means by the use of this term.

d. Please confirm that the Company agrees that the capitalization at September 30, 2014 should be revised to reflect the additional federal ADIT resulting from the 2014 extension of bonus depreciation. If the Company does not agree, then please provide all reasons why it does not agree and why it believes that the Commission should provide a return on amounts that the Company has not invested.

e. Please provide the accounting entries related to the 2014 extension of bonus depreciation in December 2014 and the underlying calculations in electronic spreadsheet format with all formulas intact. Provide the calculation of the incremental tax depreciation and ADIT for each month based on the plant additions in each month January 2014 through September 2014.

RESPONSE

a. See the Response to KPSC 3-50.

b. See KIUC_2_3_Attachment1.xlsx.

c. The phrase was intended to indicate that the Company did not make the adjustment because the change was signed into law after the Company's filing was prepared.

d. See the Response to KPSC 3-50.

e. For the December 2014 Accounting Entry related to the 2014 extension of bonus depreciation, see part b. See KIUC_2_3_Attachment2.xlsx for the estimated incremental tax depreciation for the monthly plant additions in each month January 2014 through September 2014 as a result of the extension of bonus depreciation.

WITNESS: Jeffrey B Bartsch

KENTUCKY POWER COMPANY
CALCULATION OF ADFIT RE: BONUS DEPRECIATION
Response to KIUC 2-3

Source: AG 1-171 Attachment 1

	With Bonus Depr	Without Bonus Depr	Change	Additional Monthly Accrual
KYPCo-Distribution	42,963,524	20,410,541	(22,552,983)	(1,880,000)
KYPCo-Transmission	40,369,544	14,202,399	(26,167,145)	(2,181,000)
KYPCo-Generation	52,149,561	10,954,561	(41,195,000)	(3,433,000)
	135,482,629	45,567,501	(89,915,128)	(7,494,000)
Number of Months in Test Period				9
Additional Tax Depreciation Accrual thru September 2014				(67,446,000)
Additional MACRS Normalized Schedule M in Test Period				(67,446,000)
Additional ADFIT @ September 30, 2014 (@ 35%)				(23,606,100)

December 2014 Tax Journal Entry Re: Bonus Tax Depreciation:

	Debit	Credit
A/C 4091001 - Current FIT Expense		(31,474,800)
A/C 2361001 - Current FIT Payable	31,474,800	
A/C 4101001 - Deferred FIT Expense	31,474,800	
A/C 2821001 - Accum Deferred FIT - Property		(31,474,800)

KENTUCKY POWER COMPANY
CALCULATION OF ESTIMATED 2014 BONUS DEPRECIATION
Response to KIUC 2-3

2014 Book Additions by Month	Book Basis	Less: Intangible Property	Less: Structures & Improvements	Less: ARO	Less: Land & Land Rights	Bonus Qualifying Tax Basis	Estimated Tax Depreciation w/ Bonus Extension	Normal MACRS Tax Depreciation	Estimated Additional Tax Depreciation
January 2014	8,750,206	(461,372)	(556,090)	-	10,982	7,743,726	4,017,058	290,390	3,726,668
February 2014	4,136,709	(231,301)	(19,983)	-	(762)	3,884,663	2,015,169	145,675	1,869,494
March 2014	7,077,774	(184,840)	(123,866)	-	609	6,769,677	3,511,770	253,863	3,257,907
April 2014	3,459,352	(274,502)	(5,632)	-	(135)	3,179,083	1,649,150	119,216	1,529,934
May 2014	5,271,827	(182,543)	(1,666)	-	(886,281)	4,201,337	2,179,444	157,550	2,021,894
June 2014	109,893,755	(425,835)	(192,955)	(42,577,813)	(8,888)	66,688,264	34,594,537	2,500,810	32,093,727
July 2014	19,687,465	(280,361)	(9,321,885)	-	(11,111)	10,074,108	5,225,944	377,779	4,848,165
August 2014	11,728,907	(476,278)	(9,034)	-	(6)	11,243,589	5,832,612	421,635	5,410,977
September 2014	4,194,142	(102,878)	(79,781)	-	(330,144)	3,681,339	1,909,695	138,050	1,771,645
	174,200,137	(2,619,910)	(10,310,892)	(42,577,813)	(1,225,736)	117,465,786	60,935,379	4,404,968	56,530,411
Annualized Tax Depreciation Thru 9/30/2014 (9/12)						Note (1)	45,701,534	3,303,726	42,397,808
Estimated Incremental ADIT as of 9/30/2014 based on actual book additions									(14,839,233)

Note: The Company records Depreciation Schedule M's based on Forecasted Tax Additions pro-rata throughout the year (-ie- 1/12th per month). The Forecast is updated periodically to reflect actual additions.

Note (1): The Company reflects the tax benefits of tax depreciation consistent with the principles of Internal Revenue Code regulation 1.6655-2(f)(3)(iv)(A).

EXHIBIT ____ (LK-22)

Kentucky Power Company

REQUEST

Refer to the $54.552 million shown on the table at Yoder-16 for the Big Sandy ARO.

a. Please provide a narrative description of these costs and how they differ from the $43.798 million shown on the table for removal cost and salvage.

b. Please provide the source documents for the amount shown on the table.

RESPONSE

a. The $54.552 million shown on the table at Yoder-16 is related to asbestos removal and ash pond remediation at the Company's Big Sandy Plant. The $43.798 million is related to the cost to demolish the Big Sandy Plant which excludes the asbestos removal and ash pond remediation.

b. The source of the calculation of the Big Sandy Plant demolition cost at retirement is provided in KIUC_1_59. The source of the ARO costs is provided in KIUC_1_17_Attachment58 pages 44 and 51.

WITNESS: Jason M Yoder

Big Sandy Retirement Cost Summary

			1	2	3	4	5	6
Components Subject to WACC Return:	Estimated June 30, 2015 Balance	Future Costs	7/1/2015	7/1/2016	7/1/2017	7/1/2018	7/1/2019	7/1/2020
NBV:	$201,911,435.45	$0.00						
Original Cost	$460,030,669.85	$0.00						
Accumulated Depreciation	($263,500,120.40)	$0.00						
CWIP to transfer to OC	$1,607,100.00	$0.00						
RWIP to transfer to AD	$3,773,786.00	$0.00						
Unusable M&S	$4,342,987.20	$0.00						
Removal Costs and Salvage	$0.00	$43,797,850.00						
Unit 2 Ongoing Misc. Exp.	$0.00	$6,058,782.00	1,198,780	880,002	730,000	250,000	250,000	250,000
ARO Cash Flow	$1,473,491.00	$54,552,333.00	18,272,755	11,738,108	13,797,661	8,259,280	1,990,926	118,869
ADIT*	($72,189,047.93)	$0.00						
	$135,538,865.72	$104,408,965.00						
Total		$239,947,830.72						
Future Cost by Year			$19,471,535	$12,618,110	$14,527,661	$8,509,280	$2,240,926	$368,869

* ADIT calculated as (NBV + Unusable M&S) * 35%.

Kentucky Power Company
September 2014 ARO Depreciation Expense Annualized

Utility Account	Plant/Function	ARO Description	Cost @ Sept 2014
31700 - ARO Steam Production Plant	1-Big Sandy	ARO Big Sandy U0 Asbestos	$277,141.44
31700 - ARO Steam Production Plant	1-Big Sandy	ARO Big Sandy U1 Asbestos	$1,616,125.87
31700 - ARO Steam Production Plant	1-Big Sandy	ARO Big Sandy U2 Asbestos	$1,721,296.04
31700 - ARO Steam Production Plant	1-Big Sandy	ASH#1 Big Sandy Ash Pond	$42,577,812.63
	1-Big Sandy Total		**$46,192,375.98**
31700 - ARO Steam Production Plant	2-Mitchell	ARO Mitchell U0 Asbestos	$372,406.99
31700 - ARO Steam Production Plant	2-Mitchell	ARO Mitchell U1 Asbestos	$1,818,650.05
31700 - ARO Steam Production Plant	2-Mitchell	ARO#1 Connor Run Ash Pond	$10,465,138.90
31700 - ARO Steam Production Plant	2-Mitchell	ARO#1 Mitchell Ash Pond	$137,925.80
	2-Mitchell Total		**$12,794,121.74**
39919 - ARO General Plant	3-General Plant	ARO Pikeville Service Center	$81,054.35
	3-General Plant Total		**$81,054.35**
	Grand Total		**$59,067,552.07**

ARO depr. to include in cost of service			
31700 - ARO Steam Production Plant	1-Big Sandy	ARO Big Sandy U0 Asbestos	$277,141.44
31700 - ARO Steam Production Plant	1-Big Sandy	ARO Big Sandy U1 Asbestos	$1,616,125.87
31700 - ARO Steam Production Plant	2-Mitchell	ARO Mitchell U0 Asbestos	$372,406.99
31700 - ARO Steam Production Plant	2-Mitchell	ARO Mitchell U1 Asbestos	$1,818,650.05
31700 - ARO Steam Production Plant	2-Mitchell	ARO#1 Connor Run Ash Pond	$10,465,138.90
31700 - ARO Steam Production Plant	2-Mitchell	ARO#1 Mitchell Ash Pond	$137,925.80
39919 - ARO General Plant	3-General Plant	ARO Pikeville Service Center	$81,054.35
			$14,768,443.40
ARO Depreciation Expense per Books			

ARO depr. to include in coal related retirement costs			ARO Asset	Accretion	Total Estimated ARO Costs
31700 - ARO Steam Production Plant	1-Big Sandy	Big Sandy Bottom Ash	$2,113,060.00	$180,815.00	$2,293,875.00
31700 - ARO Steam Production Plant	1-Big Sandy	ARO Big Sandy U2 Asbestos	$1,721,296.04	$2,384,656.96	$4,105,953.00
31700 - ARO Steam Production Plant	1-Big Sandy	ASH#1 Big Sandy Ash Pond	$42,577,812.63	$7,048,183.37	$49,625,996.00
			$46,412,168.67	**$9,613,655.33**	**$56,025,824.00**

EXHIBIT ____ (LK-23)

Kentucky Power Company

REQUEST

Please confirm that the Company agrees that it must and that it will first seek Commission authorization for dismantling and site remediation plans for the Big Sandy site before it enters any contracts or incurs any costs so that the Commission can assess the economics of retirement in place versus other alternatives and approve the appropriate alternative.

RESPONSE

The Company plans to submit CPCN applications with the Commission when and where required by KRS 278.020 or otherwise for approval for dismantling and site remediation plans for the Big Sandy site.

WITNESS: Ranie K Wohnhas

EXHIBIT ____ (LK-24)

Kentucky Power Company

REQUEST

Refer to the $43.798 million shown on the table at Yoder-16 for Big Sandy removal cost and salvage.

a. Please provide a narrative description of the Company's plans for the Big Sandy plant facilities and site.

b. Please provide all cost/benefit studies of the Company's plans and alternatives for the removal of the Big Sandy facilities and remediation of the site, including a retirement in place alternative. If the Company did not perform or does not plan to consider a retirement in place alternative, then please explain why not and provide all supporting documentation relied on for this decision.

c. Please provide the source documents for the amount shown on the table.

RESPONSE

a. As described on page 18 lines 6 through 11 of Company Witness Yoder's testimony, the Big Sandy removal cost and salvage included in the table on page 16 of Company Witness Yoder's testimony is based on a conceptual demolition cost estimate. This conceptual demolition cost estimate assumed a demolition/dismantlement methodology which complies with current OSHA rules and regulations. As described on page 10 line 17 through page 11 line 4 of Company Witness LaFleur's testimony, the Big Sandy Plant will be demolished at some point after both Unit 1 and Unit 2 have been retired. Big Sandy Unit 2 will be retired by June of 2015, while Big Sandy Unit 1 is anticipated to operate through 2031, after which Big Sandy Plant could be demolished. This anticipated retirement date for Big Sandy Unit 1 is an estimate and could be extended depending on future conditions and developments.

b. Please see KIUC_1_59_Attachment1.pdf for the Big Sandy Plant Unit 1 & 2 Conceptual Demolition Cost Estimate. The Company did not consider a retirement in place option as it is the Company's intention, upon Big Sandy Plant's retirement, to ensure a safe and secure site that does not pose a nuisance to community.

c. Please see KIUC_1_59_Attachment2.xls for this response.

WITNESS: Jeffery D LaFleur

Big Sandy Plant Unit 1 & 2

CONCEPTUAL DEMOLITION COST ESTIMATE

Prepared for:
American Electric Power Company

Project No. 11488-066
March 28, 2013
Revision 0

Sargent & Lundy LLC
55 East Monroe Street
Chicago, IL 60603-5780 USA

Issue Summary Page

Revision Number	Date	Purpose	Prepared By	Reviewed By	Approved By	Pages Affected
A	03/12/13	Comments	R. Kinsinger	J. A. Evanchik D. F. Franczak		All
0	03/28/13	Use	R. Kinsinger Robert Kinsinger	J. A. Evanchik J.A. Evanchik D. F. Franczak D.F. Franczak	S.R. Bertheau	All

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EXHIBIT	DESCRIPTION
1	Conceptual Demolition Cost Estimate No. 31983B

1.0 INTRODUCTION

The Big Sandy Plant is located near Louisa, Kentucky in Lawrence County. The plant consists of two (2) generating units with a total generating capacity of 1,097 megawatts (Unit 1 = 281MW, Unit 2 = 816 MW). Units 1 & 2 were placed in operation in 1963 and 1969 respectively.

The American Electric Power Company (AEP) recently contracted Sargent & Lundy, LLC. to prepare a conceptual demolition cost estimate using 1st Quarter 2013 pricing levels. The objective of the conceptual demolition cost estimate is to determine the gross demolition costs for Big Sandy Plant Units 1 and 2 (including gross salvage credits and any other benefits). The cost estimate considers the demolition/dismantlement methodology which complies with current OSHA rules and regulations.

2.0 COST ESTIMATE SUMMARY

Conceptual Demolition Cost Estimate No. 31983B, dated March 28, 2013, was prepared and is included as Exhibit 1. The cost estimate is structured into a code of accounts as identified in Table 2-1.

Table 2-1
Cost Estimate Code of Accounts

Account Number	Description
10	Demolition Costs (including steel, equipment & piping scrap value)
18	Scrap Value Costs
91	Other Direct & Construction Indirect Costs
93	Indirect Costs
94	Contingency Costs
96	Escalation Costs

The results of the cost estimate are provided in Table 2-2 below:

Table 2-2
Cost Estimate Results Summary

Description	Total Cost
Demolition Cost	$38,725,498
Scrap Value	$(20,887,112)
Direct Cost Subtotal	$17,838,386
Indirect Cost	$ 1,783,800
Contingency Cost	$9,209,600
Total Project Cost	$28,831,786

3.0 TECHNICAL BASIS

The scope of dismantlement includes the complete Big Sandy Plant Units 1 & 2 generating facility and plant common services associated with both units. Common facilities include:

- 825 ft Chimney
- Various Buildings
- Coal Rail and Truck Unloading Facilities

The following are excluded from the scope of the conceptual demolition cost estimate.

- Bottom Ash Pond
- Asbestos Removal
- Switchyard

The scope of the demolition cost estimate is based on a review of the facility by two (2) S&L employees conducted in January 2013 for development of the demolition cost estimate.

4.0 COMMERCIAL BASIS

4.1 General Information

The Conceptual Demolition Cost Estimate prepared for the Big Sandy Plant is a conceptual estimate of the cost to dismantle Big Sandy Plant Units 1 and 2.

Costs were calculated for (1) demolition of existing plant structures and equipment and associated site restoration costs, (2) scrap value of steel and copper, (3) associated indirect costs, and (4) contingency. All units used in the cost estimate are U.S. Standard and all costs are in US Dollars (1st Quarter 2013 levels). A two (2) year demolition schedule is anticipated not including asbestos removal (to be performed prior to start of demolition work).

4.2 Quantities/Material Cost

Quantities of pieces of equipment and/or bulk material commodities used in this cost estimate were intended to be reasonable and representative of projects of this type. Material quantities were estimated from the site plot plan and other drawings and data provided by AEP and Plant Personnel.

4.3 Construction Labor Wages

Craft labor rates (Craft Hourly Rate) for the cost estimate were calculated as Non-Union Kentucky Craft Labor rates based on Personnel Administration Services (PAS) Inc. "2013 Merit Shop Wage and Benefit Survey". The craft rates were incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew hourly rates detailed in the cost estimate. A 1.05 regional labor productivity multiplier was included based on Compass International Global Construction Yearbook, 2013 Edition, for non-union work in Kentucky.

4.3.1 Labor Work Schedule and Incentives

The estimate assumed a 5x8 work week. No other labor incentives are included.

4.3.2 Construction Indirects

Allowances were included in the cost estimate as direct costs as noted for the following:

- Freight: Material and scrap freight included in the material and scrap costs.
- Additional Crane Allowance: None included. Cost of cranes and construction machinery are included in the labor wage rates.
- Mobilization and Demobilization: Included in labor wage rates.
- Scaffolding: Included in labor wage rates.
- Consumables: Included in material and labor costs.

- Per Diem Costs: Excluded from the estimate.
- Contractor's General and Administrative Costs and Profit: Included in the labor wage rates.

4.4 Scrap Value

The value of scrap was determined by a 12 month average (March 2012 through February of 2013) using Zone 4 (USA Midwest) of the "Scrap Metals Market Watch" (www.americanrecycler.com).
Since the values obtained are delivered pieces, 10% of the values obtained were deducted to pay for separation, preparation and shipping to the mills. This resulted in realized prices of:

- Mixed Steel Value @ $287/Ton
- Copper Value @ $6,091/Ton
- Stainless Steel @ $1,336/Ton

Note: 1 Ton = 2,000 Lbs
All steel is considered to be mixed steel unless otherwise noted.

4.5 Indirect Costs

Allowances were included in the cost estimate as indirect costs as noted for the following:

- Engineering, Procurement and Project Services: None included.
- Construction Management Support: None included.
- Owners Cost: Included as 10.0% of the total direct cost. Owners Costs include owner project engineering, administration and construction management, permits and fees, legal expenses, taxes, etc.

4.6 Escalation

No allowance for escalation was included in the cost estimate. All costs are determined in 1st Quarter 2013 levels.

4.7 Contingency

Allowances were included in the cost estimate as contingency as noted for the following:

- Scrap Value: Included as a 15.0% reduction in the salvage value resulting in a total net reduction in the salvage value. The contingency assumes a potential drop in salvage value thus increasing the project cost.

- Material: Included as 15.0% of the total material cost.
- Labor: Included as 15.0% of the total labor cost.
- Indirect: Included as 15.0% of the total indirect cost.

4.8 Assumptions

The following assumptions apply to the cost estimate.

- All chemicals will be removed by the Owner prior to demolition, from the facilities to be demolished.
- All coal and fuel oil will be consumed prior to demolition.
- Catalyst, if any, is assumed to be removed and returned to the OEM by others, prior to demolition.
- All electrical equipment and wiring is de-energized prior to start of dismantlement.
- No extraordinary environmental costs for demolition have been included. Removal of five (5) feet of fill inside the bermed areas around the oil tanks and metal cleaning waste tank is included.
- Asbestos and PCB's are removed from site by others prior to start of demolition.
- Bottom Ash Pond is not included. These costs will be determined by the Owner.
- Demolition of the chimney will be subcontracted. The chimney is 825 ft high and is located approximately 580 ft from the Big Sandy River to the South and 480 ft from the main switchyard to the North. Also, the main line for the Chesapeake and Ohio Railroad is approximately 825 ft North and US 29 is approximately 50 ft beyond the railroad. Therefore Careful Demolition (top down demolition process) will be used to dismantle the chimney. The chimney is demolished by breaking it up from the top and dropping the debris down the throat of the chimney and removing the debris periodically through the duct openings on the sides of the chimney (located 75 to 100 ft above grade). The remaining chimney below the duct openings is then demolished as any other structure.
- Switchyards within the plant boundaries are not part of the scope, neither are access roads to these facilities. Fences and gates needed to protect the switchyard will be left in place. The other site fences are removed.
- All items above grade and to a depth of 2 foot will be demolished. Any other items buried more than 2 foot will remain in place. All foundations are removed and buried on site with the exception of power block (turbine building, boiler building and service building), and the one (1) chimney thick mat foundation at grade. These foundations will have two (2) feet of soil spread over them and will be graded into the surrounding area.

- Underground piping, conduit and cable ducts will be abandoned in place.
- Underground piping larger than 4 feet diameter will be filled with sand or slurry and capped at the ends to prevent collapse. Non-metal pipe will be collapsed.
- All demolished materials are considered debris, except for organic combustibles and non-embedded metals which have scrap value.
- The basis for salvage estimating is for scrap value only. No resale of equipment or material is included.
- Handling, on-site and off-site disposal of hazardous materials would be performed in compliance with methods approved by Owner.
- Disturbed areas will be buried under 2 feet of topsoil mulched and seeded with grass – no other landscaping is included.
- All borrow material is assumed to be purchased from nearby (10 mile round trip) offsite sources.
- Debris not suitable for burial is to be disposed of off-site. Assumed distance to final disposal is within a 5 mile haul.

5.0 REFERENCES

Drawings utilized in the preparation of this demolition cost estimate are identified in Table 5-1.

Table 5-1

Reference Drawings

Unit	Document Number	Revision	Title
0	12-5030-2	0	Plot Plan
0	12-5030-10	0	Plot Plan
0	12-5030A-2	0	SCR Project Plot Plan
1	1-1200A-18	1	Auxiliary One Line
1	1-5031-2	1	General Cross Section
1	1-5032-2	1	Long Section Thru Turbine Room & Service Building Unit 1
1	1-5033-2	1	Long Section Thru Heater Bay & Service Building & Elev. South Side of Blr
2	2-1395	2	Fire Protection Foam House Electrical Assembly
2	2-1396	2	Fire Protection Sump F.O. Tank, & Truck Unloading Station Electrical Assemblies
2	2-3044-4-1	2	Concrete Stack Circular Steel Platforms
2	2-4101-2	2	Plumbing & Drainage, Roof & Drain System Sheet 1 of 6
2	2-4103-1	2	Plumbing & Drainage, Roof & Drain System Sheet 3 of 6
2	2-4107-2	2	Plumbing & Drainage, Floor Plan Service Building
2	2-4112-4	2	Plumbing & Drainage, Locomotive House & Tractor Shed Building
2	2-4122	2	Plumbing & Drainage, Service Building Annex Plans & Details
2	2-5001-3	2	Composite Cycle Diagram Unit 2
2	2-5050-15	2	Circulating Water Piping Sheet 1 of 3
2	2-5051-10	2	Circulating Water Piping Sheet 2 of 3
2	2-5109-1	2	Metal Cleaning Waste Treatment Facility General Arrangement & Yard Piping
2	2-5110-1	2	Metal Cleaning Waste Treatment Facility Piping Details
2	2-5135-32	2	Yard Piping Unit No 2, Sheet 1 of 3
2	2-536801-3	2	Urea Conversion Area Piping Composite
2	2-536802-0	2	Urea Preparation Area Piping Composite
2	2-536803-2	2	Urea Conversion Area Piping Composite
2	2-536804-2	2	Urea Conversion Area Piping Composite
2	2-538806-0	2	SCR Project Composite Piping Units 1 & 2 Precipitator Area
2	2-538807-1	2	SCR Project Piping Site Key Plan
2	2-538829-0	2	SCR Project Composite Piping Plans El. 116' 3"
2	Figure BS-2-3-15-1	2	Cooling Tower
2	2-MSK-459	2	Study of Revised River Water Makeup for Units 1 & 2
2	100109-9267512-02	2	SCR General Arrangement, Front Sectional View
2	100109-9267513-02	2	SCR General Arrangement, Unit 2 - Rear Sectional Views

Unit	Document Number	Revision	Title
2	100109-9267514-02	2	SCR General Arrangement, Unit 2 - Auxiliary Views
2	100109-9267520-02	2	SCR General Arrangement, SCR 2 - Plan View
2	100109-9267521-02	2	SCR General Arrangement, Unit 2 - Plan View
2	100109-9267530-02	2	SCR General Arrangement, Big Sandy 2, Isometric View
2	Training Document	2	Big Sandy Unit 2 Longitudinal Sections
2	Training Document	2	Big Sandy Unit 2 General Cross Section

0 = Common For Units 1& 2

1 = Unit 1

2 = Unit 2

EXHIBIT 1
Big Sandy Plant Units 1 & 2
Conceptual Demolition Cost Estimate No. 31983B

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Project name	Big Sandy
Estimator	RCK
Labor rate table	13NUKY
Project No.	11488-066
Station Name	Big Sandy
Unit	1, 2 and Common
Location	Kentucky
Product Factor	1
Price Level	2013
Issue Date	3/28/2013
Estimate Date	3/28/2013
Reviewed By	JAE
Approved By	MNO
Estimate No.	31983B
Estimate Class	Conceptual
Report format	Sorted by 'Area/Group phase' 'Group phase' summary
Cost index	NUKY

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Estimate Totals

Description	Amount	Totals	Hours
LABOR	29,540,432		357,988,217 hrs
MATERIAL	7,535,066		
SUBCONTRACT	1,650,000		
SCRAP RECOVERY	(20,887,112)		
	17,838,386	17,838,386	
91-1 SCAFFOLDING			
91-2 OT WORKING 5-10 HOUR DAYS			
91-3 OT Working 7-10 Hr Days			
91-2 PER DIEM			
91-5 CONSUMABLES			
91-6 FREIGHT ON EQUIPMENT			
91-7 FREIGHT ON SPECIAL EQUIP.			
91-8 FREIGHT ON MATERIAL			
91-9 FREIGHT ON SCRAP INCL			
91-10 SALES TAX			
91-11 CONTRACTOR'S G&A EXPENSE			
91-12 CONTRACTOR'S PROFIT			
		17,838,386	
93-1 EP&P SERVICES			
93-2 CM SUPPORT			
93-3 START-UP/COMMISSIONING			
93-4 START-UP/SPARE PARTS			
93-5 EXCESS LIABILITY INSUR.			
93-6 SALES TAX ON INDIRECTS			
93-7 OWNER'S COST	1,783,800		
93-8 EPC FEE			
	1,783,800	19,622,186	
94-3 CONTINGENCY ON MATERIAL	1,130,300		
94-4 CONTINGENCY ON LABOR	4,431,100		
94-5 CONTINGENCY ON SUB.	247,500		
94-6 CONTINGENCY ON SCRAP	3,133,100		
94-7 CONTINGENCY ON INDIRECTS	267,600		
	9,209,600	28,831,786	
96-3 ESCALATION ON MATERIAL			
96-4 ESCALATION ON LABOR			
96-5 ESCALATION ON SUB.			
96-6 ESCALATION ON SCRAP			
96-7 ESCALATION ON INDIRECTS			
		28,831,786	
98 INTEREST DURING CONSTR.			
		28,831,786	
Total		***28,831,786***	

ESTIMATE NO.: 31983B
PROJECT NO.: 11488-066
ISSUE DATE: 3/28/2013
PREP./REV.: RCK/JAE
APPROVED: MNO

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

AREA	GROUP	PHASE	DESCRIPTION	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR AMOUNT	TOTAL AMOUNT
Common								
	10.00.00		WHOLE PLANT DEMOLITION		7,449,896	74,076	8,819,470	17,919,366
	18.00.00		SCRAP VALUE	(2,183,209)				(2,183,209)
			Common	**(2,183,209)**	**7,449,896**	**74,076**	**8,819,470**	**15,736,157**
Unit 1								
	10.00.00		WHOLE PLANT DEMOLITION		27,770	82,596	6,043,293	6,071,063
	18.00.00		SCRAP VALUE	(5,153,373)				(5,153,373)
			Unit 1	**(5,153,373)**	**27,770**	**82,596**	**6,043,293**	**917,690**
Unit 2								
	10.00.00		WHOLE PLANT DEMOLITION		57,400	201,314	14,677,668	14,735,068
	18.00.00		SCRAP VALUE	(13,550,530)				(13,550,530)
			Unit 2	**(13,550,530)**	**57,400**	**201,314**	**14,677,668**	**1,184,539**

ESTIMATE NO.: 319838
PROJECT NO.: 11488-066
ISSUE DATE: 3/28/2013
PREP./REV.: RCK/JAE
APPROVED: MNO

AMERICAN ELECTRIC POWER
Decommissioning Study Big Sandy
Units 1, 2 and Common Facilities

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
Common										
	10.00.00		WHOLE PLANT DEMOLITION							
		10.21.00	CIVIL WORK							
			COVERED DISTURBED AREAS OF SITE W/2 FT TOPSOIL	296,500.00 CY	-	7,116,000	15,572	102.05 /MH	1,589,171	8,705,171
			SEED AND MULCH	92.00 AC	-	256,496	2,609	32.86 /MH	85,740	342,236
			PAVED SURFACES	15,400.00 SY	-	0	1,941	102.05 /MH	198,097	198,097
			DEMOLITION - 26450 TRACK FEET of 110# RAILROAD TRACK	26,450.00 TF	-	0	8,335	102.05 /MH	850,595	850,595
			DEMOLITION - PERIMETER FENCE	4,500.00 LF	-	0	189	102.05 /MH	19,295	19,295
			CIVIL WORK			7,372,496	28,647		2,742,899	10,115,395
		10.22.00	CONCRETE							
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS	2,555.00 CY	-	0	3,019	76.08 /MH	229,708	229,708
			EQUIPMENT FOUNDATION 110 LB/CY, MISC EQUIPMENT	1,300.00 CY	-		1,387	76.08 /MH	105,553	105,553
			INTAKE CLOSURE	800.00 CY	-	73,600	840	76.08 /MH	63,933	137,533
			CONCRETE			73,600	5,247		399,194	472,794
		10.24.00	ARCHITECTURAL							
			BUILDING, WAREHOUSE #4, 100 ' X 35' X 14' TALL	49,000.00 CF	-		309	74.88 /MH	23,125	23,125
			BUILDING, CHEMICAL BLDG, 3900 SF X 14' TALL	54,600.00 CF	-		344	74.88 /MH	25,768	25,768
			BUILDING, WAREHOUSE #5, 100' X50' X14' TALL	70,000.00 CF	-		441	74.88 /MH	33,035	33,035
			BUILDING, CONSTRUCTION OFFICES, 140' X 50' X 14' TALL	98,000.00 CF	-		618	74.88 /MH	46,249	46,249
			BUILDING, CONSTRUCTION LOCKERROOM / WAREHOUSE, 100' X 40' X 14' TALL	56,000.00 CF	-		353	74.88 /MH	26,428	26,428
			BUILDING, ANNEX, 85' X 48' 14' TALL	57,120.00 CF	-		360	74.88 /MH	26,957	26,957
			BUILDING, CAR DUMPER, 40' X68' X 22' TALL	59,840.00 CF	-		377	74.88 /MH	28,240	28,240
			BUILDING, SHOWER BLDG & COAL HANDLING OFFICE, 80' X 74' X 20' TALL	118,400.00 CF	-		746	74.88 /MH	55,877	55,877
			BUILDING, THAW-OUT SHED, 220' X 24' X 14' TALL	73,920.00 CF	-		466	74.88 /MH	34,885	34,885
			BUILDING, THAW-OUT SHED ELECTRICAL, 90' X 20' X 14' TALL	25,200.00 CF	-		159	74.88 /MH	11,893	11,893
			BUILDING, TRACTOR REPAIR BUILDING PART 1 88' X 25' X 14' TALL	30,800.00 CF	-		194	74.88 /MH	14,536	14,536
			BUILDING, TRACTOR REPAIR BUILDING PAR2 1 40' X 24' X 14' TALL	13,440.00 CF	-		85	74.88 /MH	6,343	6,343
			BUILDING, PICNIC SHELTER, 60' X 34' X 10' TALL	20,400.00 CF	-		129	74.88 /MH	9,627	9,627
			BUILDING, WAREHOUSE BOB AREA, 150' X 74' X 14' TALL	155,400.00 CF	-		979	74.88 /MH	73,338	73,338

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		10.24.00	ARCHITECTURAL							
			BUILDING, OLD GATEHOUSE - TRAIONING BLDG, 35' X 30' X 12' TALL	12,600.00 CF	-		79	74.88 /MH	5,946	5,946
			BUILDING, RIVER SCREEN HOUSEM 50' X 30' X 14' TALL	21,000.00 CF	-		132	74.88 /MH	9,911	9,911
			BUILDING, FOAM HOUSE, 30' X 30' X 12' TALL	10,800.00 CF	-		68	74.88 /MH	5,097	5,097
			BUILDING, WATER TREATING BLDG, 40' X 30' X 14' TALL	16,800.00 CF	-		106	74.88 /MH	7,928	7,928
			BUILDING, GATEHOUSE - NORTH ENTRANCE, 20' X 16' X 14' TALL	4,480.00 CF	-		28	74.88 /MH	2,114	2,114
			BUILDING, FIREHOUSE, 30' X 15' X 12' TALL	5,400.00 CF	-		34	74.88 /MH	2,548	2,548
			BUILDING, UNIDENTIFED BLDG WEST OF FIRE HOUSE, 60' X 24' X 12' TALL	17,280.00 CF	-		109	74.88 /MH	8,155	8,155
			BUILDING, UNIDENTIFED BLDG EAST OF FIRE HOUSE, 60' X 24' X 12' TALL	17,280.00 CF	-		109	74.88 /MH	8,155	8,155
			BUILDING, SHED SW OF UNIT 1 SERVICE BLDG, 40' X 30' X 12' TALL	14,400.00 CF	-		91	74.88 /MH	6,796	6,796
			ARCHITECTURAL				6,316		472,952	472,952
		10.25.00	CONCRETE CHIMNEY & STACK							
			825' TALL CONCRETE CHIMNEY	825.00 VLF	-			76.08 /MH		1,650,000
			CONCRETE CHIMNEY & STACK							1,650,000
		10.31.00	MECHANICAL EQUIPMENT							
			TANKS, FUEL OIL TANK, 3,400,000 GALLONS, BOTTOM ONLY (TOP HAS BEEN REMOVED)	32.40 TN	-		91	65.32 /MH	5,940	5,940
			TANKS, FUEL OIL TANK, 500,000 GALLONS	50.00 TN	-		140	65.32 /MH	9,167	9,167
			TANKS, METAL CLEANING WASTE TANK 1,000,000 GALLONS	83.00 TN	-		233	65.32 /MH	15,217	15,217
			MECHANICAL EQUIPMENT				464		30,324	30,324
		10.33.00	MATERIAL HANDLING EQUIPMENT							
			MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM	1,015.00 TN	-		2,159	65.32 /MH	141,026	141,026
			MATERIAL HANDLING EQUIPMENT				2,159		141,026	141,026
		10.35.00	PIPING							
			PIPING - CIRC WATER PIPING AND TUNNELS	1.00 LS	-		1,071	76.08 /MH	81,514	81,514
			PIPING - DEMO BOP PIPING AND HANGERS	1.00 LS	-		535	65.32 /MH	34,924	34,924
			PIPING				1,606		116,439	116,439
		10.41.00	ELECTRICAL EQUIPMENT							
			MISCELLANEOUS ELECTRICAL EQUIPMENT	75.00 TN	-		211	65.32 /MH	13,750	13,750
			MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS	50.00 TN	-		140	65.32 /MH	9,167	9,167

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
			ELECTRICAL EQUIPMENT				351		22,917	22,917
		10.42.00	RACEWAY, CABLE TRAY, & CONDUIT							
			RACEWAY, CABLE TRAY, & CONDUIT -	225.00 TN	-		479	65.32 /MH	31,262	31,262
			RACEWAY, CABLE TRAY, & CONDUIT				479		31,262	31,262
		10.86.00	WASTE							
			WASTE - OIL CONTAMINATED FILL, 3,400,000 GALLON OIL TANK COINTAINMENT	16,225.00 CY	-	0	20,179	168.94 /MH	3,409,039	3,409,039
			WASTE - METAL CLEANING TANK BERMED AREA CONTAMINATED FILL	3,889.00 CY	-	0	4,837	168.94 /MH	817,119	817,119
			WASTE - BUILDING WASTE - COMMON BLDGS	380.00 CY	-	3,800	40	65.32 /MH	2,607	6,407
			WASTE - OIL CONTAMINATED FILL, 500,000 GALLON OIL TANK COINTAINMENT	3,016.00 CY	-	0	3,751	168.94 /MH	633,693	633,693
			WASTE			3,800	28,807		4,862,457	4,866,257
			WHOLE PLANT DEMOLITION			7,449,896	74,076		8,819,470	17,919,366
	18.00.00		SCRAP VALUE							
		18.10.00	MIXED STEEL							
			MIXED STEEL REBAR RECOVERY FROM OUTBUILDINGS FOUNDATIONS & MISC FDNS	-164.00 TN	(47,068)	-		65.89 /MH		(47,068)
			MIXED STEEL REBAR RECOVERY FROM 825' CHIMNEY	-448.00 TN	(128,576)	-		65.89 /MH	0	(128,576)
			MIXED STEEL, STEEL LINER FROM 825' CHIMNEY	-278.00 TN	(79,786)	-		65.89 /MH	0	(79,786)
			MIXED STEEL, EQUIPMENT FOUNDATION110 LB/CY, MISC EQUIPMENT, REINFORCING	-72.00 TN	(20,664)	-		65.89 /MH		(20,664)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - COAL HANDLING SYSTEM, COMMON	-1,015.00 TN	(291,305)	-		65.89 /MH		(291,305)
			MIXED STEEL, 26450 TF OF RAILROAD TRACK , 110# rRAIL	-970.00 TN	(278,390)	-		65.89 /MH	0	(278,390)
			MIXED STEEL, RACEWAY, CABLE TRAY, & CONDUIT -	-225.00 TN	(64,575)	-		65.89 /MH	0	(64,575)
			MIXED STEEL, MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS	-25.00 TN	(7,175)	-		65.89 /MH		(7,175)
			MIXED STEEL, TANKS, FUEL OIL TANK, 3,400,000 GALLONS, BOTTOM ONLY (TOP HAS BEEN REMOVED)	-32.40 TN	(9,299)	-		65.89 /MH		(9,299)
			MIXED STEEL, TANKS, FUEL OIL TANK, 500,000 GALLONS	-50.00 TN	(14,350)	-		65.89 /MH		(14,350)

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.10.00	MIXED STEEL							
			MIXED STEEL, TANKS, METAL CLEANING WASTE TANK 1,000,000 GALLONS	-83.00 TN	(23,821)	-		65.89 /MH		(23,821)
			MIXED STEEL		(965,009)					(965,009)
		18.30.00	COPPER							
			COPPER SCRAP CABLE & COMMON	-150.00 TN	(913,650)	-		65.89 /MH		(913,650)
			COPPER, MISCELLANEOUS ELECTRICAL EQUIPMENT, TRANSFORMERS	-50.00 TN	(304,550)	-		65.89 /MH		(304,550)
			COPPER		(1,218,200)					(1,218,200)
			SCRAP VALUE		(2,183,209)					(2,183,209)
			Common		**(2,183,209)**	**7,449,896**	**74,076**		**8,819,470**	**15,736,157**
Unit 1										
	10.00.00		WHOLE PLANT DEMOLITION							
		10.22.00	CONCRETE							
			BUILDING PAD FOUNDATION 110 LB/CY, UNIT 1 COOLING TOWER BASIN	3,835.00 CY	-	0	4,532	76.08 /MH	344,787	344,787
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS	49.00 CY	-		58	76.08 /MH	4,405	4,405
			ELEVATED FOUNDATION 110/CY, UNIT 1 COOLING TOWER SHELL	7,112.00 CY	-	0	4,475	76.08 /MH	340,449	340,449
			ELEVATED FOUNDATION, UNIT 1 TURBINE AND BLR BLDGS	2,000.00 CY	-	0	1,258	76.08 /MH	95,739	95,739
			TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 1	1,911.00 CY	-	0	3,613	76.08 /MH	274,895	274,895
			CONCRETE				13,936		1,060,276	1,060,276
		10.23.00	STEEL							
			DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 1	537.00 TN		0	1,507	65.89 /MH	99,310	99,310
			STEEL				1,507		99,310	99,310
		10.24.00	ARCHITECTURAL							
			BUILDING, UNIT 1 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS	4,501,000.00 CF	-	0	47,279	74.88 /MH	3,540,282	3,540,282
			BUILDING, UNIT 1 THAW-OUT SHED, 60' X 22' X 16' TALL	21,120.00 CF	-		133	74.88 /MH	9,967	9,967
			ARCHITECTURAL				47,413		3,550,250	3,550,250
		10.31.00	MECHANICAL EQUIPMENT							
			MAIN BOILER AND APPURTENANCES, UNIT 1	3,218.00 TN	-	0	6,845	71.35 /MH	488,392	488,392
			FD & ID FANS, UNIT 1	214.00 TN	-	0	455	71.35 /MH	32,478	32,478
			FEEDWATER DEARATING EQUIPMENT, UNIT 1	100.00 TN	-	0	213	65.32 /MH	13,894	13,894
			TANKS, UNIT 1 CONDENSATE STORAGE TANK, 300,000 GALLONS	29.00 TN	-		81	65.32 /MH	5,317	5,317

ESTIMATE NO.: 31983B
PROJECT NO.: 11488-066
ISSUE DATE: 3/28/2013
PREP./REV.: RCK/JAE
APPROVED: MNO

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		10.31.00	MECHANICAL EQUIPMENT							
			WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 1	138.00 TN	-	0	289	65.32 /MH	18,896	18,896
			TURBINE GENERATOR, UNIT 1	750.00 TN	-	0	1,595	65.32 /MH	104,207	104,207
			CONDENSER, UNIT 1	423.00 TN	-	0	900	65.32 /MH	58,773	58,773
			CIRCULATING WATER EQUIPMENT, UNIT 1	69.00 TN	-	0	147	65.32 /MH	9,587	9,587
			COOLING TOWER, UNIT 1 REMOVE FILL	295,000.00 CF	-	0	1,859	65.32 /MH	121,446	121,446
			MECHANICAL EQUIPMENT - UNIT 1 MISC. POWER PLANT EQUIPMENT	155.00 TN	-	0	330	65.32 /MH	21,536	21,536
			MECHANICAL EQUIPMENT - DEMOLISH UNIT 1 TURBINE ROOM OVERHEAD CRANE	1.00 LS	-	0	331	65.32 /MH	21,613	21,613
			MECHANICAL EQUIPMENT - UNIT 1 DUST COLLECTORS	137.00 TN	-	0	291	65.32 /MH	19,035	19,035
			MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 1	200.00 TN	-	0	425	65.32 /MH	27,788	27,788
			MECHANICAL EQUIPMENT				13,762		942,962	942,962
		10.33.00	MATERIAL HANDLING EQUIPMENT							
			MATERIAL HANDLING EQUIPMENT - UNIT 1 ASH HANDLING EQUIPMENT	77.00 TN	-	0	164	65.32 /MH	10,699	10,699
			MATERIAL HANDLING EQUIPMENT - UNIT 1 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	837.00 TN	-	0	1,780	65.32 /MH	116,295	116,295
			MATERIAL HANDLING EQUIPMENT				1,944		126,993	126,993
		10.34.00	HVAC							
			HVAC - UNIT 1	1.00 LS	-		897	65.32 /MH	58,596	58,596
			HVAC				897		58,596	58,596
		10.35.00	PIPING							
			PIPING - UNIT 1 BOILER PLANT AND TURBINE PIPING	799.00 TN	-	0	1,784	65.32 /MH	116,552	116,552
			PIPING				1,784		116,552	116,552
		10.41.00	ELECTRICAL EQUIPMENT							
			GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER	344.00 TN	-	0	966	65.32 /MH	63,067	63,067
			STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS	34.00 TN	-	0	95	65.32 /MH	6,233	6,233
			ELECTRICAL EQUIPMENT				1,061		69,301	69,301
		10.86.00	WASTE							
			WASTE - UNIT 1 COOLING TOWER FILL	1,094.00 CY	-	10,940	115	65.32 /MH	7,506	18,446
			WASTE - UNIT 1 BLDG WASTE	1,683.00 CY	-	16,830	177	65.32 /MH	11,548	28,378
			WASTE			27,770	292		19,054	46,824
			WHOLE PLANT DEMOLITION			27,770	82,596		6,043,293	6,071,063
	18.00.00		SCRAP VALUE							
		18.10.00	MIXED STEEL							

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.10.00	MIXED STEEL							
			MIXED STEEL, UNIT 1 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS & SERVICE BLDG	-2,251.00 TN	(646,037)	-		65.89 /MH		(646,037)
			MIXED STEEL, REBAR RECOVERED, TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 1	-105.00 TN	(30,135)	-		65.89 /MH	0	(30,135)
			MIXED STEEL, UNIT 1 COOLING TOWER REINFORCING RECOVERED	-603.00 TN	(173,061)	-		65.89 /MH	0	(173,061)
			MIXED STEEL, ELEVATED FOUNDATION, UNIT 1 TURBINE AND BLR BLDGS, REINFORCING	-110.00 TN	(31,570)	-		65.89 /MH		(31,570)
			MIXED STEEL, MAIN BOILER AND APPURTENANCES, UNIT 1	-3,218.00 TN	(923,566)	-		65.89 /MH	0	(923,566)
			MIXED STEEL, FD & ID FANS, UNIT 1	-214.00 TN	(61,418)	-		65.89 /MH	0	(61,418)
			MIXED STEEL, DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 1	-537.00 TN	(154,119)	-		65.89 /MH	0	(154,119)
			MIXED STEEL, FEEDWATER DEARATING EQUIPMENT, UNIT 1	-100.00 TN	(28,700)	-		65.89 /MH	0	(28,700)
			MIXED STEEL, WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 1	-136.00 TN	(39,032)	-		65.89 /MH	0	(39,032)
			MIXED STEEL, UNIT 1 CONDENSER	-287.00 TN	(82,369)	-		65.89 /MH	0	(82,369)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 1 ASH HANDLING EQUIPMENT	-77.00 TN	(22,099)	-		65.89 /MH	0	(22,099)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 1 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	-837.00 TN	(240,219)	-		65.89 /MH	0	(240,219)
			MIXED STEEL, TURBINE GENERATOR, UNIT 1	-750.00 TN	(215,250)	-		65.89 /MH	0	(215,250)
			MIXED STEEL, CIRCULATING WATER EQUIPMENT, UNIT 1	-69.00 TN	(19,803)	-		65.89 /MH	0	(19,803)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 1 MISC. POWER PLANT EQUIPMENT	-155.00 TN	(44,485)	-		65.89 /MH	0	(44,485)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 1 DUST COLLECTORS	-137.00 TN	(39,319)	-		65.89 /MH	0	(39,319)
			MIXED STEEL, PIPING - UNIT 1 BOILER PLANT AND TURBINE PIPING	-799.00 TN	(229,313)	-		65.89 /MH		(229,313)
			MIXED STEEL, MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 1	-200.00 TN	(57,400)	-		65.89 /MH	0	(57,400)
			MIXED STEEL, GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER	-193.50 TN	(55,535)	-		65.89 /MH	0	(55,535)

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.10.00	MIXED STEEL							
			MIXED STEEL, STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS	-19.70 TN	(5,654)	-		65.89 /MH	0	(5,654)
			MIXED STEEL, TANKS, UNIT 1 CONDENSATE STORAGE TANK, 300,000 GALLONS	-20.00 TN	(8,323)	-		65.89 /MH		(8,323)
			MIXED STEEL		(3,107,406)					(3,107,406)
		18.30.00	COPPER							
			COPPER, UNIT 1 CONDENSER TUBES COPPER / NI	-135.40 TN	(824,721)	-		65.89 /MH		(824,721)
			COPPER, GENERATOR BUS TRANSFORMERS UNIT 1 MAIN POWER TRANSFORMER	-147.50 TN	(898,423)	-		65.89 /MH		(898,423)
			COPPER, STATION AUXILIARY TRANSFORMERS, UNIT 1 MAIN AUX TRANSFORMERS	-53.00 TN	(322,823)	-		65.89 /MH		(322,823)
			COPPER		(2,045,967)					(2,045,967)
			SCRAP VALUE		(5,153,373)					(5,153,373)
			Unit 1		**(5,153,373)**	**27,770**	**82,596**		**6,043,293**	**917,690**
Unit 2										
	10.00.00		WHOLE PLANT DEMOLITION							
		10.22.00	CONCRETE							
			BUILDING PAD FOUNDATION 110 LB/CY, UNIT 2 COOLING TOWER BASIN	9,583.00 CY	-		11,324	76.08 /MH	861,564	861,564
			BUILDING PAD FOUNDATION 110LB/CY, OUTBUILDINGS & MISC FDNS	363.00 CY	-		429	76.08 /MH	32,636	32,636
			ELEVATED FOUNDATION 110/CY, UNIT 2 COOLING TOWER SHELL	13,122.00 CY	-		8,256	76.08 /MH	628,146	628,146
			ELEVATED FOUNDATION , UNIT 2 TURBINE AND BLR BLDGS	2,035.00 CY	-		1,280	76.08 /MH	97,415	97,415
			TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 2	7,778.00 CY	-		14,706	76.08 /MH	1,118,856	1,118,856
			CONCRETE				35,997		2,738,616	2,738,616
		10.23.00	STEEL							
			DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 2	1,022.00 TN	-		2,868	65.89 /MH	189,004	189,004
			STEEL				2,868		189,004	189,004
		10.24.00	ARCHITECTURAL							
			BUILDING, UNIT 2 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS	8,863,000.00 CF	-	0	93,099	74.88 /MH	6,971,234	6,971,234
			BUILDING, UNIT 2, UREA SYSTEM BLDG, 80' 45' X 40' TALL	108,000.00 CF	-		681	74.88 /MH	50,969	50,969

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		10.24.00	ARCHITECTURAL							
			BUILDING, UNIT 2 UREA SYSTEM AMMONIOA ON DEMAND (AOD) BLDG, 60' X 40' X14' TALL	33,600.00 CF	-		212	74.88 /MH	15,857	15,857
			BUILDING, UNIT 2 SCR BLDG, 70' 67' X 20' TALL	93,800.00 CF	-		591	74.88 /MH	44,267	44,267
			ARCHITECTURAL				94,582		7,082,327	7,082,327
		10.31.00	MECHANICAL EQUIPMENT							
			MAIN BOILER AND APPURTENANCES, UNIT 2	12,160.00 TN	-		25,866	71.35 /MH	1,845,507	1,845,507
			FD & ID FANS, UNIT 2	6,135.00 TN	-		13,050	71.35 /MH	931,101	931,101
			FEEDWATER DEARATING EQUIPMENT, UNIT 2	215.00 TN	-		457	65.32 /MH	29,873	29,873
			TANKS, UNIT 2 CLEAN CONDENSATE TANK, 750,000 GALLONS	77.00 TN	-		216	65.32 /MH	14,117	14,117
			TANKS, UNIT 2 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS	50.00 TN	-		140	65.32 /MH	9,167	9,167
			TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK103-100	25.00 TN	-		70	65.32 /MH	4,583	4,583
			TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK104-100	25.00 TN	-		70	65.32 /MH	4,583	4,583
			WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 2	269.00 TN	-		572	65.32 /MH	37,375	37,375
			TURBINE GENERATOR, UNIT 2	2,045.00 TN	-		4,350	65.32 /MH	284,137	284,137
			CONDENSER, UNIT 2	1,165.00 TN	-		2,478	65.32 /MH	161,868	161,868
			CIRCULATING WATER EQUIPMENT, UNIT 2	484.00 TN	-		1,030	65.32 /MH	67,248	67,248
			COOLING TOWER, UNIT 2 REMOVE FILL	684,000.00 CF	-		4,185	65.32 /MH	273,356	273,356
			MECHANICAL EQUIPMENT - UNIT 2 MISC. POWER PLANT EQUIPMENT	613.00 TN	-		1,304	65.32 /MH	85,172	85,172
			MECHANICAL EQUIPMENT - DEMOLISH UNIT 2 TURBINE ROOM OVERHEAD CRANE	1.00 LS	-		331	65.32 /MH	21,613	21,613
			MECHANICAL EQUIPMENT - UNIT 2 DUST COLLECTORS	269.00 TN	-		572	65.32 /MH	37,375	37,375
			MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 2	600.00 TN	-		1,276	65.32 /MH	83,365	83,365
			MECHANICAL EQUIPMENT - SCR UNIT 2	664.00 TN	-		1,412	65.32 /MH	92,258	92,258
			MECHANICAL EQUIPMENT				57,380		3,982,698	3,982,698
		10.33.00	MATERIAL HANDLING EQUIPMENT							
			MATERIAL HANDLING EQUIPMENT - UNIT 2 ASH HANDLING EQUIPMENT	377.00 TN	-		802	65.32 /MH	52,381	52,381
			MATERIAL HANDLING EQUIPMENT - UNIT 2 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	32.00 TN	-		68	65.32 /MH	4,446	4,446

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Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
			MATERIAL HANDLING EQUIPMENT				870		56,827	56,827
		10.34.00	HVAC							
			HVAC - UNIT 2	1.00 LS	-		1,780	65.32 /MH	116,300	116,300
			HVAC				1,780		116,300	116,300
		10.35.00	PIPING							
			PIPING - UNIT 2 BOILER PLANT AND TURBINE PIPING	2,690.00 TN	-		6,007	65.32 /MH	392,396	392,396
			PIPING				6,007		392,396	392,396
		10.41.00	ELECTRICAL EQUIPMENT							
			GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMER	328.00 TN	-		921	65.32 /MH	60,134	60,134
			STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS	109.00 TN	-		306	65.32 /MH	19,984	19,984
			ELECTRICAL EQUIPMENT				1,227		80,117	80,117
		10.86.00	WASTE							
			WASTE - UNIT 2 COOLING TOWER FILL	2,460.00 CY	-	24,600	258	65.32 /MH	16,879	41,479
			WASTE - UNIT 2 BLDG WASTE	3,280.00 CY	-	32,800	345	65.32 /MH	22,505	55,305
			WASTE			57,400	603		39,384	96,784
			WHOLE PLANT DEMOLITION			57,400	201,314		14,677,668	14,735,068
	18.00.00		SCRAP VALUE							
		18.10.00	MIXED STEEL							
			MIXED STEEL, UNIT 2 POWER BLOCK, INCLUDING TURBINE BLDG, BOILER HOUSE PREHTR FAN ENCLOSURE & COAL BUNKERS & SERVICE BLDG	-4,431.50 TN	(1,271,841)	-		65.89 /MH		(1,271,841)
			MIXED STEEL, REBAR RECOVERED, TURBINE PEDESTAL FOUNDATION 140 LB/CY, UNIT 2	-467.00 TN	(134,029)	-		65.89 /MH		(134,029)
			MIXED STEEL, UNIT 2 COOLING TOWER REINFORCING RECOVERED	-1,249.00 TN	(358,463)	-		65.89 /MH		(358,463)
			MIXED STEEL, ELEVATED FOUNDATION , UNIT 2 TURBINE AND BLR BLDGS, REINFORCING	-112.00 TN	(32,144)	-		65.89 /MH		(32,144)
			MIXED STEEL, MAIN BOILER AND APPURTENANCES, UNIT 2	-12,160.00 TN	(3,489,920)	-		65.89 /MH		(3,489,920)
			MIXED STEEL, FD & ID FANS, UNIT 2	-6,135.00 TN	(1,760,745)	-		65.89 /MH		(1,760,745)
			MIXED STEEL, DUCTWORK W/BREECHINGS AND STEEL SUPPORTS, UNIT 2	-1,022.00 TN	(293,314)	-		65.89 /MH		(293,314)
			MIXED STEEL, FEEDWATER DEARATING EQUIPMENT, UNIT 2	-215.00 TN	(61,705)	-		65.89 /MH		(61,705)
			MIXED STEEL, WATER TREATMENT DEMINERALIZATION & CHEMICAL TREATMENT EQUIPMENT, UNIT 2	-269.00 TN	(77,203)	-		65.89 /MH		(77,203)
			MIXED STEEL, UNIT 2 CONDENSER	-792.00 TN	(227,304)	-		65.89 /MH		(227,304)

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Units 1, 2 and Common Facilities

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.10.00	MIXED STEEL							
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 2 ASH HANDLING EQUIPMENT	-377.00 TN	(108,199)	-		65.89 /MH		(108,199)
			MIXED STEEL, MATERIAL HANDLING EQUIPMENT - UNIT 2 FUEL EQUIPMENT, CONVEYORS INCL TRUSSES & BENTS	-35.00 TN	(10,045)	-		65.89 /MH		(10,045)
			MIXED STEEL, TURBINE GENERATOR, UNIT 2	-2,045.00 TN	(586,915)	-		65.89 /MH		(586,915)
			MIXED STEEL, CIRCULATING WATER EQUIPMENT, UNIT 2	-484.00 TN	(138,908)	-		65.89 /MH		(138,908)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 2 MISC. POWER PLANT EQUIPMENT	-613.00 TN	(175,931)	-		65.89 /MH		(175,931)
			MIXED STEEL, MECHANICAL EQUIPMENT - UNIT 2 DUST COLLECTORS	-269.00 TN	(77,203)	-		65.89 /MH		(77,203)
			MIXED STEEL, PIPING - UNIT 2 BOILER PLANT AND TURBINE PIPING	-2,690.00 TN	(772,030)	-		65.89 /MH		(772,030)
			MIXED STEEL, MECHANICAL EQUIPMENT - PRECIPITATORS UNIT 2	-600.00 TN	(172,200)	-		65.89 /MH		(172,200)
			MIXED STEEL, GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMERS	-180.50 TN	(51,804)	-		65.89 /MH		(51,804)
			MIXED STEEL, STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS	-56.00 TN	(16,072)	-		65.89 /MH		(16,072)
			MIXED STEEL, MECHANICAL EQUIPMENT - SCR UNIT 2	-664.00 TN	(190,568)	-		65.89 /MH		(190,568)
			MIXED STEEL, TANKS, UNIT 2 CLEAN CONDENSATE TANK, 750,000 GALLONS	-77.00 TN	(22,099)	-		65.89 /MH		(22,099)
			MIXED STEEL, TANKS, UNIT 2 CONTAMINATED CONDENSATE TANK, 500,000 GALLONS	-50.00 TN	(14,350)	-		65.89 /MH		(14,350)
			MIXED STEEL, TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK103-100	-25.00 TN	(7,175)	-		65.89 /MH		(7,175)
			MIXED STEEL, TANKS, UNIT 2 UREA SOLUTION STORAGE TANK, 200,000 GALLONS TK104-100	-25.00 TN	(7,175)	-		65.89 /MH		(7,175)
			MIXED STEEL		(10,057,341)					(10,057,341)
		18.30.00	COPPER							
			COPPER, UNIT 2 CONDENSER TUBES COPPER / NI	-373.00 TN	(2,271,943)	-		65.89 /MH		(2,271,943)
			COPPER, GENERATOR BUS TRANSFORMERS UNIT 2 MAIN POWER TRANSFORMER	-147.50 TN	(898,423)	-		65.89 /MH		(898,423)

Area	Group	Phase	DESCRIPTION	TAKEOFF QUANTITY	SCRAP AMOUNT	MATERIAL AMOUNT	LABOR MAN HRS	LABOR PRICE	LABOR AMOUNT	TOTAL AMOUNT
		18.30.00	COPPER							
			COPPER, STATION AUXILIARY TRANSFORMERS, UNIT 2 MAIN AUX TRANSFORMERS	-53.00 TN	(322,823)	-		65.89 /MH		(322,823)
			COPPER		(3,493,189)					(3,493,189)
			SCRAP VALUE		(13,550,530)					(13,550,530)
			Unit 2		**(13,550,530)**	**57,400**	**201,314**		**14,677,668**	**1,184,539**

KENTUCKY POWER COMPANY
CALCULATION OF TERMINAL SALVAGE AND REMOVAL AT RETIREMENT - BIG SANDY PLANT
USING SARGENT & LUNDY STUDY DATA AND LIVINGSTON SURVEY ESCALATION INDEX

Plant/Units	Terminal Salvage	Terminal Removal	Terminal Net Salvage	Average Inflation Rate (1)	Plant Retirement Year	Escalation Period	Terminal Salvage	Terminal Removal	Terminal Net Salvage
Big Sandy Plant									
S&L Estimate (2)	$20,887,112	$49,718,898	$28,831,786	2.35%	2031	18	$31,729,238	$75,527,088	($43,797,850)
Total Big Sandy Plant	$20,887,112	$49,718,898	$28,831,786				$31,729,238	$75,527,088	($43,797,850)

Notes:
(1) Source Livingston Survey dated December 2013 (survey performed by Federal Reserve Bank of Philadelphia)
(2) Sargent & Lundy estimate based on December 2012 indexed prices.

KENTUCKY POWER COMPANY
CALCULATION OF TERMINAL SALVAGE AND REMOVAL - BIG SANDY

Plant/Units	Terminal Salvage	Terminal Removal	Net Salvage	KPCo Share of Plant/Unit	Terminal Salvage - Price Level 2013	Terminal Removal - Price Level 2013	Terminal Net Salvage - Price Level 2013
Big Sandy Plant							
S&L Estimate	$20,887,112	$49,718,898	-$28,831,786	100.00%	$20,887,112	$49,718,898	-$28,831,786
Total Big Sandy Plant	$20,887,112	$49,718,898	-$28,831,786		$20,887,112	$49,718,898	-$28,831,786

Note: Asbestos and Ash Pond Closure costs are included in cost of service separately through the accounting for asset retirement obligations.

EXHIBIT ____ (LK-25)

Big Sandy 1 Operations Rider (BS1OR)
Big Sandy 1 Coal Operations
Revenue Requirement

	KY Retail	
Non Fuel Plant O&M - Demand	$ 9,150,077	a
Non Fuel Plant O&M - Energy	$ 3,351,767	b
Jan- Sept 14 PJM Charges and Credits	$ 4,239,908	c
Annualize PJM Charges and Credits	$ 5,653,211	d = c/9*12
Total BS1 Operational Expense	$ 18,155,055	e = a+b+d
gross up factor	1.004977	f
KY Retail Total	$ 18,245,413	g = e*f
Demand Total	$ 9,195,617	h = a*f
Energy Total	$ 9,049,796	i= (b+d)*f
Total	$ 18,245,413	

Kentucky Power Company
Exhibit AEV 4
Big Sandy 1 Operation Rider Rate Design

	Demand	Energy	Total
KY Retail Jurisdiction Revenue Requirement	$9,195,617	$9,049,796	$18,245,413

Class (1)	Historic Period Billing Energy (2)	Historic Period Billing Demand (3)	Test Year CP / kWh Ratio (4)	CP Demand Allocation Factor (5) = (2) x (4	Allocated Demand Related Costs (6) on (5)	Allocated Energy Related Costs (7) on (2)	$ / kW Rate (8) = (6) / (3)	$ / kWh Rate (9) = (7) / (2)	Revenue Verification (10)	Difference (11) = (10) - (6) - (
RES	2,260,149,747		0.0236060%	533,531	$4,315,835	$3,150,585	$ -	$0.00330	$7,458,494	-$7,926
SGS	142,560,729		0.0163937%	23,371	189,053	198,726	$ -	$0.00272	387,765	-$14
MGS	507,158,704	2,119,598	0.0177002%	89,768	726,151	706,965	$ 0.34	$0.00141 [2]	1,435,757	$2,641
Non Demand MGS Sec [1]	6,484,718		0.0177002%	1,148	9,286	9,040	$ -	$0.00283	18,352	$26
LGS	705,405,060	2,169,269	0.0169381%	119,482	966,513	983,315	$ 0.45	$0.00139	1,956,684	$6,856
LGS LMTOD	1,959,939		0.0169381%	332	2,686	2,732	$ -	$0.00276	5,409	-$9
IGS (QP / CIP-TOD)	2,818,677,591	5,429,712	0.0130626%	368,192	2,978,376	3,929,159	$ 0.55	$0.00139	6,904,303	-$3,232
MW	3,864,039		0.0134057%	518	4,190	5,386	$ -	$0.00248	9,583	$7
OL	37,640,598		0.0009431%	355	2,872	52,470	$ -	$0.00147	55,332	-$10
SL	8,190,082		0.0009890%	81	655	11,417	$ -	$0.00147	12,039	-$33
Total	6,492,091,207	9,718,579		1,136,778	$9,195,617	$9,049,795			$18,243,719	($1,693)

Notes:
[1] Non Demand MGS Sec includes MGS RL, MGS LMTOD and MGS TOD
[2] Revised after Revenue Verification

KPCo KY Retail PSC Jurisdiction
Class Billing Determinants
12 Months Ended Sept 2014

Class (1)	kWh Energy	kW 12 CP
RES	2,260,149,747	533,531
SGS	142,560,729	23,371
MGS	507,158,704	89,768
Non Demand MGS Sec	6,484,718	
LGS	705,405,060	119,482
LGS LMTOD	1,959,939	
QP/CIP	2,818,677,591	368,192
MW	3,864,039	518
OL	37,640,598	355
SL	8,190,082	81
Total	6,492,091,207	1,135,298