COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00179

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 2017

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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 ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo.

I also earned a Master of Arts ("MA") degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant ("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations.

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 hundreds of 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. 2014-00396, 2009-00459, and 2005-00341; Mitchell acquisition proceeding, Case No. 2012-00578; allocation of fuel costs to off-system sales proceeding, Case No. 2014-00255; ecoPower biomass purchased power agreement ("PPA") proceeding, Case No. 2013-00144; Big Sandy 2 environmental retrofit proceeding, Case No. 2011-00401; wind power PPA 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.[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. KIUC has been an active participant in all significant KPC rate and certification proceedings for more than thirty years.

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 cost of capital recommendations, including return on equity, provided by KIUC witness Mr. Richard Baudino, and 4) address the ratemaking implications of a potential federal income tax rate reduction.

Q. Please summarize your testimony.

A. The Commission should carefully scrutinize the Company's requests and consider KIUC's recommendations in this proceeding in order to limit the additional increases to just and reasonable amounts and to mitigate the effects on customers. The Company's rates charged to customers already have increased 71% over the last ten

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

years and 141% over the last fifteen years. The requests in this proceeding seek additional increases of more than 11% compared to present rates.

I recommend that the Commission increase the Company's base rates by no more than $13.385 million compared to the Company's revised proposed base increase of $60.397 million.[2] In the following table, I provide a summary of the KIUC recommendations compared to the Company's request for a base rate increase. The KIUC recommendations regarding the cost of capital will also reduce the Environmental Surcharge and Decommissioning Rider[3] revenue requirements, although I do not show the quantification of these amounts in the table.

Summary of KIUC Recommendations
Case No. 2017-00179
For the Test Year Ended February 28, 2017
($ Millions)

Base Rate Increase Requested by Company	
Requested Base Increase As Modified by Aug 7, 2017 Suppl Filing	60.397
Operating Income Issues	
Defer Rockport Unit 2 Lease Expense	(20.307)
Increase Revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	(0.400)
Reduce Variable O&M Expense Adjustments Due to Revenue Adjustments	(0.172)
Remove Incentive Compensation Expense Tied to Financial Performance	(3.153)
Reject Post Test Year Merit and Related Overtime Increases Projected in 2017	(0.981)
Reject Increases in Staffing	(0.174)
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	(1.221)
Reduce Depreciation Expense by Extending Rem Service Life of BS1 to 30 Years	(4.764)
Reduce Depreciation Expense by Removing Terminal Net Salvage for BS1	(0.372)
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell Plant	(0.570)
Include Section 199 Deduction in Gross Revenue Conversion Factor	(1.320)
Capitalization Issues	
Remove Net DSM, Other Surcharge, and Non-Utility Costs from Capitalization	(0.912)
Reduce Low Sulfur Coal Inventory to Reflect Actual	(0.117)
Cost of Capital Issues	
Increase Short Term Debt to 2% of Capital Structure and Set Debt Rate at 1.25%	(0.712)
Reduce Return on Equity from 10.31% to 8.85%	(11.838)
Total KIUC Adjustments to KPCo Request	**(47.012)**
Increase After KIUC Adjustments	**13.385**

[2] The Company filed a supplemental on August 28, 2017.

[3] The Company has proposed renaming the present Big Sandy Retirement Rider to the Decommissioning Rider ("DR"). Hereafter, I refer to this surcharge mechanism as the Decommissioning Rider or DR.

In addition to the issues shown on the preceding table, I address the effects of potential federal income tax rate reductions and recommend that the Commission direct the Company to defer any reductions in income tax expense until the savings can be reflected in rates.

The remainder of my testimony is structured to address each of the issues on the preceding table followed by the potential federal income tax rate reduction issue. The amounts that I cite throughout my testimony are Kentucky retail-jurisdictional ("jurisdictional") unless otherwise indicated as "total Company."

II. THE INCREASES IN THIS PROCEEDING WILL COMPOUND THE NEGATIVE EFFECTS OF PRIOR 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 significantly compared to the rates that were in effect ten and fifteen years ago. The Company's rates have increased an average of 71% over the last ten years and 141% over the last fifteen years. These rates include all forms of rate recovery, including base rates and all riders, such as the FAC and the ES, among others. And more rate increases are likely. The Company estimates that its transmission costs alone will increase from $74 million in the test year to $130.9 million in 2022, an increase of $56.9 million or 77%.

Q. Would the increases in rates that you cite have been greater but for the actions of KIUC?

A. Yes. KIUC has saved *all* customers, not only industrial customers, hundreds of millions of dollars through its participation in rate and certification proceedings, all at its own expense. In a recent proceeding, KIUC identified errors in Kentucky Power Company's calculation of the FAC whereby it allocated excessive fuel costs to retail customers that should have been allocated to off-system sales.[4] In that proceeding, KIUC's actions saved *all* customers tens of millions of dollars, both through FAC refunds and lower FAC recoveries going forward. In another recent proceeding, KIUC opposed the Company's proposed uneconomic purchased power contract with ecoPower and the associated rate recovery.[5] That case was ultimately resolved by the Kentucky Court of Appeals. KIUC's actions saved *all* customers approximately $700 million over the 20 year term of the proposed ecoPower PPA.

Q. Why is the history of increases in customer rates relevant in this proceeding?

A. The history of increases provides a context for the review of the Company's requests in this proceeding for several reasons. First, the magnitude of the cumulative rate increases harmed residential, business, and government customers, and contributed to the continuing loss of load experienced by the Company. The rate increases and other relief sought in this proceeding will compound the harm from the prior increases and, in turn, will cause greater rate increases in the future even as the Company's load continues to shrink. Rate increases negatively affect the viability and competitiveness of businesses in local, regional, national, and international markets, which is contrary to the Company's economic development efforts.

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[4] KPSC Case No. 2014-00225.
[5] KPSC Case No. 2013-00144.

Second, the magnitude of the cumulative rate increases should lead the Company to search for *greater efficiencies* and implement *cost reductions*, rather than allowing increases or intentionally driving costs upward year after year. The Commission has the ability to influence the Company's behavior in this respect through the ratemaking process and to ensure that rates reflect the least reasonable cost to serve the retail customer load.

Third, the Company's history of increases and the negative effects, including the loss of load, in its service territory should lead the Commission to search for opportunities to mitigate the increases sought in this proceeding. These opportunities, include, but are not limited to, minimizing the rate increases in this proceeding through various ratemaking adjustments, such as temporary deferrals of costs that can be recovered by the Company through savings after the costs no longer are incurred, and rejecting the Company's proposed modifications to the FAC and PPA surcharge mechanisms, both of which will result in future automatic and significant rate increases with no further authorization by the Commission.

III. OPERATING INCOME ISSUES

<u>Defer $20.3 Million Rockport 2 Lease Expense</u>

Q. Please describe the Rockport Unit Power Agreement ("UPA") and the related purchased power expense.

A. Kentucky Power purchases 15% of the capacity of and energy generated by the Rockport 1 and 2 units. Rockport 1 is owned 50% each by AEP affiliates Indiana

Michigan Power Company ("I&M") and AEP Generating Company ("AEG"). Rockport 2 is owned by Wilmington Trust Co. I&M and AEG each lease 50% of Rockport 2 from Wilmington Trust Co. Kentucky Power purchases 30% of AEG's ownership interest in Rockport 1 and 30% of AEG's leased interest in Rockport 2 pursuant to the Unit Power Agreement ("UPA").

The UPA expires December 7, 2022.[6] Similarly, the Rockport 2 lease terminates in December 2022. Kentucky Power has no right or obligation to purchase the capacity or energy of Rockport 1 or Rockport 2 after that date. Whether Kentucky Power will seek authority from the Commission to extend the UPA Rockport 1 is not known. However, we know that the Company will not seek such authority from the Commission for Rockport 2. On July 21, 2017, the Company and certain of its affiliates filed a motion in U.S. District Court seeking to modify a Consent Decree that was entered into with the U.S. Department of Justice. In that Motion, they stated that *"AEP does not currently plan on extending the term of the Lease, which will terminate in 2022."*[7] Thus, Kentucky Power will no longer purchase Rockport 2 after December 7, 2022.

Q. What was the Rockport 2 purchased power expense and lease expense during the test year?

A. The Company incurred $59.936 million (total Company) in Rockport 2 purchased power expense in the test year, consisting of $20.485 million (total Company) in

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[6] Company's response to AG 1-2(e). I have attached a copy of the response to AG 1-2 as my Exhibit___(LK-2).

[7] Company's response to AG 1-2(l), a copy of which is included in my Exhibit___(LK-2).

lease expense, $12.015 million in other non-fuel operation and maintenance ("O&M") expense, and $27.437 million in fuel expense.[8] The retail portion of the Rockport 2 lease expense was $20.198 million and the associated revenue requirement was $20.307 million after gross-up for PSC assessment fees and bad debt.

The Company recovers various components of the Rockport 2 purchased power expense through base rates, the fuel adjustment clause surcharge, and the environmental surcharge. In addition, the Company recovers another $6.4 million in revenues for Rockport 1 and Rockport 2 through the Capacity Charge ("CC") tariff as an incentive authorized in Case No. 2004-00420. That incentive is treated "below the line," meaning that it is not used to offset revenue requirements in a rate case. It is an "equity kicker." That $6.4 million incentive also ends on December 7, 2022.

There will be rate reductions of $38.9 million after the Rockport 2 purchase terminates in December, 2022. The Company no longer will incur any Rockport 2 purchased power or the lease expense and no longer will recover the incentive through the CC surcharge after December, 2022.

Q. Is it likely that the Company will seek to replace the Rockport 2 capacity when the purchase and lease expire in December 2022?

A. No. The Company presently has capacity well in excess of its load and PJM reserve requirements, and it projects that this excess will continue to grow through the date

[8] Company's response to KIUC 1-43, which included Attachments with copies of the monthly Rockport UPA invoices and support. The Rockport 2 lease expense shown in account 507 Rents on the monthly supporting schedule entitled "Rockport Operation & Maintenance Expenses Unit 2." I have attached a copy of the relevant pages from this response as my Exhibit___(LK-4).

when the Rockport purchase and Rockport 2 lease terminate in December 2022. The Company projects a UCAP reserve margin of 33.6%, including the Rockport 2 capacity, in the PJM 2017/2018 plan year, and projects that this will increase to 48.1% in the PJM 2021/2022 plan year as its load continues to decline. The following chart demonstrates that the Rockport 2 capacity is excess.[9]

KENTUCKY POWER COMPANY PROJECTED RESERVE MARGINS WITH AND WITHOUT ROCKPORT 2 CAPACITY

Planning Year	MW Available Capacity (UCAP)	MW Obligation to PJM (UCAP)	KPCo Reserve Margin	Planning (Installed) Reserve Margin	MW Excess Capacity	MW Rockport 2 (UCAP)	MW Excess Capacity w/o Rockport 2
2017/18	1,282	960	33.58%	16.6%	163	176	(13)
2018/19	1,317	953	38.22%	16.6%	206	176	30
2019/20	1,317	957	37.6%	16.6%	201	176	25
2020/21	1,322	955	38.5%	16.6%	209	176	33
2021/22	1,322	893	48.06%	16.6%	281	176	105

Q. Does the termination of the Rockport 2 lease in 2022 provide an opportunity to reduce the revenue requirement now in this proceeding?

A. Yes. The Company's purchased power rate recoveries should decline by $38.9 million (total Company) annually starting in December 2022, $20.3 million (KY retail) of which is the recovery for the Rockport 2 lease expense.

The 2022 termination of the Rockport purchase and Rockport 2 lease provides the Commission with the opportunity to reduce the revenue requirement now, while still providing the Company recovery of the entirety of its Rockport 2 expenses, albeit over an extended recovery period. More specifically, the

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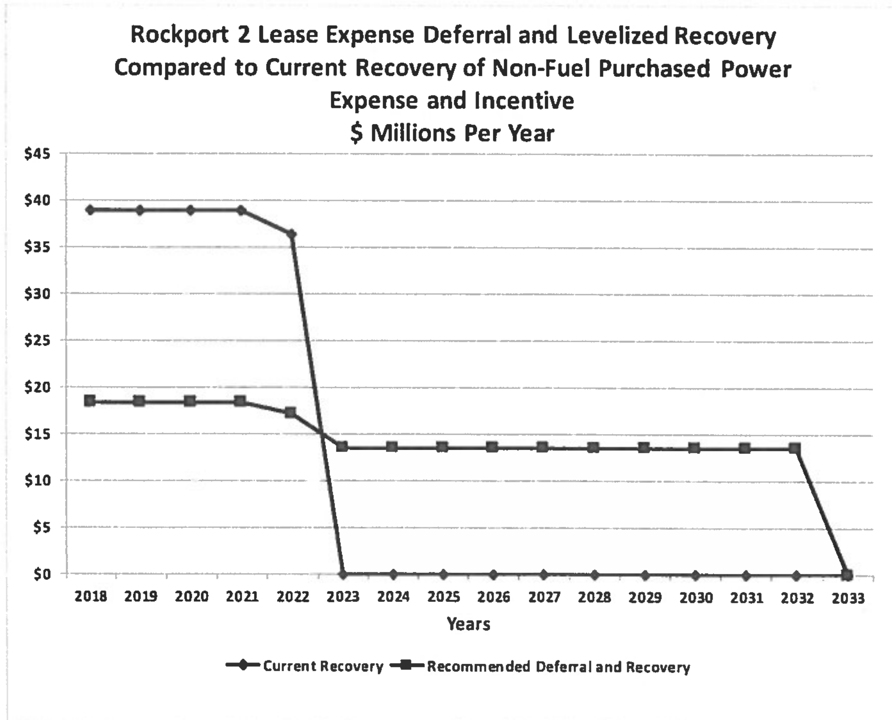
[9] Company's response to KIUC 1-5 Attachment 1. A copy of this response is attached as my Exhibit___(LK-5).

Commission could direct that the Company temporarily defer the $20.3 million Rockport 2 lease expense from the date when rates are reset in this proceeding through December 2022 when the Rockport 2 lease is terminated. This would reduce the Company's revenue requirement in this proceeding by $20.3[10] million. Beginning December 2022, the deferrals would be amortized to expense and recovered over the subsequent ten years as a partial offset to the reduction in the expense after the termination of the lease. Instead of a $39 million rate reduction in 2022, consumers would get a $20.3 million rate reduction now, and another reduction of $4.7 million in 2022. Taking part of the 2022 rate reduction today is reasonable because of the severely depressed state of the Eastern Kentucky economy. The following graph portrays the Rockport 2 non-fuel purchase power expense compared to KIUC's deferral proposal

[10] The reduction of $20.2 million in expense equates to a reduction of $20.3 million in the revenue requirement after gross-up for PSC assessment fees and bad debt.



Q. Why should the Commission authorize a temporary deferral followed by a subsequent amortization and recovery?

A. There are several reasons. First, it constructively resolves the cost recovery related to the Company's excess capacity problem in a manner that balances the Company's recovery of costs with the need to restrain growth in customer rates now because of the depressed Eastern Kentucky economy.

Second, it lowers the rate increase in this proceeding by $20.3 million and provides lower rates for the next five years. It allows recovery over the subsequent ten years as a partial offset to the rate reduction that will occur due to the elimination of the $39 million Rockport 2 non-fuel purchased power expense. It does this without harming the Company financially because it will fully recover the expenses that are deferred. No Rockport 2 costs would be disallowed. KIUC's deferral recommendation only changes the timing of cost recovery.

Third, it mitigates the increases in future proceedings by amortizing and recovering the deferrals over a longer period of time, such as ten years, and on a levelized basis, rather than front-loading the recovery under the traditional revenue requirement cost recovery curve.

Fourth, it provides the Company additional time to acquire new customers and incremental load through its economic development activities, including its Coal Plus, Appalachian Sky Initiative activities,[11] as well as the new aluminum mill recently announced by Braidy Industries, Inc.[12] To the extent that the Company successfully adds load, the deferral and subsequent amortization of the Rockport 2 lease expense will further reduce the cost of the deferrals to all customers on a billing unit basis.

Q. Has the Commission previously authorized deferrals of production costs to limit a rate increase?

A. Yes. The Commission previously directed Big Rivers Electric Corporation to defer \$26 million per year in depreciation expense related to the Coleman and Wilson power plants. The Commission found that both plants were excess capacity due to the loss of two large aluminum smelter loads and that the deferrals were necessary to avoid rate shock to the remaining customers. Without the smelter loads, the Big Rivers system is roughly half the size of Kentucky Power.

[11] Satterwhite Direct Testimony at 10-13, 15-16.
[12] Satterwhite Direct Testimony at 5.

Q. Is the temporary deferral of the Rockport 2 lease expense even more appropriate than the Wilson and Coleman depreciation deferrals?

A. Yes. With the Rockport 2 lease expense, the deferrals are temporary and there is a plan that will ensure the Company fully recovers its costs, albeit it on a delayed and extended basis.

The KIUC plan in this proceeding is different from the Big Rivers deferrals where there is no plan for or certainty of recovery. The Big Rivers deferrals continue to grow because Big Rivers still owns the plants and they still remain excess capacity. But at some point, the deferrals must stop. At that time, the deferral balance (which was $103 million in August 2017) must either be written off from the excess member equity resulting from the LG&E Unwind or recovered in member rates, or some combination of writeoff and recovery. Importantly, at that time there also may be recovery of ongoing depreciation expense for Wilson, which is still operating (Coleman is effectively retired). That means there could be a double hit on ratepayers—the recovery of all or part of the Wilson and/or Coleman deferral balances plus the recovery of all or part of the ongoing Wilson depreciation expense.

The opposite is true with respect to KIUC's recommended Rockport 2 lease expense deferral. The $20.3 million per year deferral will end in December 2022 when the lease expires. At that time, the Company will have a $39 million per year rate reduction, all else equal. So the repayment of the deferral would be funded through associated rate savings. A deferral of the Rockport 2 lease expense is essentially borrowing against future known rate savings. This is reasonable and necessary now since Kentucky Power's load is shrinking due to a depressed local economy, and recovery of the excess capacity Rockport 2 lease expense in current rates would only make matters worse.

Q. What is your recommendation?

A. I recommend that the Commission defer the Rockport 2 lease expense from the effective date when rates are reset in this proceeding through December 2022 when the Rockport 2 lease terminates. I recommend that the Commission allow recovery of the deferred expense starting in December 2022 over ten years on an annuitized (mortgage or levelized) basis through the PPA surcharge mechanism. The Company should earn a carrying charge on the deferral at its weighted average cost of capital.

Q. What is the effect of your recommendation on the revenue requirement in this proceeding and on the revenue requirement in 2022 after the UPA and lease are terminated?

A. This will result in a reduction in the base revenue requirement of $20.3 million now and another reduction in the revenue requirement of approximately $4.7 million in December 2022.

Increase Revenues to Reflect Weather Normalization of Commercial Sales

Q. Please describe the Company's proposed weather normalization of revenues.

A. The Company proposes an adjustment to increase revenues to reflect "normal" temperatures, but its adjustment applies only to the residential customer sales revenues. It did not propose or apply similar adjustments to the commercial or any other retail sales revenues. It limited the proposed weather normalization ratemaking adjustment to the residential class based only on its assertion that the residential class is the most sensitive to temperature variations.

Q. Does temperature also affect commercial sales revenues?

A. Yes. The Company states in response to KIUC discovery that the "weather sensitive classes include the Residential, Commercial, and Wholesale classes. The Industrial and Other Retail class sales are much less responsive to changes in temperature."[13]

Q. Does the Company calculate the effect of normalized temperature on commercial sales revenues in addition to residential sales revenues for other purposes?

A. Yes. In response to KIUC discovery, the Company confirmed that it calculates the effects of temperature on commercial sales revenues in addition to residential sales revenues for both internal management reporting purposes and external financial reporting purposes.[14]

Q. What was the effect of normalized temperature on commercial sales revenues in the test year?

A. For internal management and financial reporting purposes, the Company calculated that commercial sales revenues would have been $0.914 million greater at

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[13] Company's response to KIUC 1-83. I have attached a copy of this response as my Exhibit___(LK-6).

[14] Company's responses to KIUC 1-83 and 1-84. I have attached a copy of the response to KIUC 1-84 as my Exhibit___(LK-7).

normalized temperatures compared to the actual temperatures in the test year.[15]

The Company also claims that there is a related effect on variable expenses equal to 59.0% of the change in revenues. If this assumption is applied to the increase in commercial sales revenues, then there also would be an increase in variable expenses of $0.539 million.[16] However, as I subsequently discuss, KIUC recommends that the related effect on variable expenses be reduced to 56.44%. Consequently, I reflect effect on revenues less the related effect on variable expenses at 56.44% on the table in the Summary section of my testimony.

Q. What is your recommendation?

A. I recommend that the Commission include the effects of normalized temperatures on commercial sales revenues in addition to residential sales revenues. Temperatures affect the revenues in both classes, not just the residential class. The Company recognizes this fact for its internal management and external financial reporting. The Company offers no valid reason for excluding such an adjustment from the revenue requirement. This reduces the rate increase by $0.4 million.

<u>Reduce O&M Expense Adjustments Related to Revenue Adjustments</u>

Q. Please describe the Company's proposed adjustments to increase or reduce variable expenses in conjunction with its adjustments to annualize customer

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[15] Company's response to KIUC 2-16. I have attached a copy of the response, Attachment 1, and my calculation showing the total test year effect of the monthly amounts for the commercial class as my Exhibit___(LK-8).

[16] I show an adjustment of $0.914 million to increase revenues and an adjustment of $0.516 million to increase expenses on the table in the Summary section of my testimony.

revenues and weather normalize residential sales revenues.

A. The Company proposed an adjustment to reduce variable expenses by $1.932 million in conjunction with its adjustment to reduce revenues by $3.274 million for customer annualization (Adjustment 12). The Company also proposed an adjustment to increase variable expenses by $3.941 million in conjunction with its adjustment to increase residential sales revenues by $6.679 million for weather normalization (Adjustment 15). In both instances, the Company used a 59% variable expense ratio, which it applied to the change in revenues.

Q. Have you reviewed the Company's calculation of the 59% variable expense ratio?

A. Yes. It includes both variable expenses that vary directly with energy sales and revenues and fixed expenses that do not vary directly with energy sales and revenues in the test year. The Company provided a schedule in response to KIUC discovery that details the expenses it considers to be variable in the calculation of the 59% ratio.[17] These expenses include fuel expenses, which are variable, as well as expenses such as supervision, advertising, meter reading, and gas reservation fee, which are not variable as a function of sales revenues in the test year.

Q. Have you calculated a corrected variable expense ratio that excludes the fixed expenses that do not vary directly with energy sales and revenues in the test year?

[17] Company's response to KIUC 1-28.

A. Yes. The corrected variable expense ratio is 56.44%.[18]

Q. What is the effect on the revenue requirement if the corrected variable expense ratio is applied to the Company's two revenue adjustments?

A. The effect is a reduction of $0.172 million in the revenue requirement based on the difference between the corrected variable expense ratio and the Company's proposed variable expense ratio.[19]

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

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

A. The Company included $3.136 million in incentive compensation expense tied to AEP's financial performance. Of this amount, $1.727 million was incurred pursuant to the AEP Long Term Incentive Plan ("LTIP")[20] and $1.409 million was incurred pursuant to the AEP Incentive Compensation Plan ("ICP").

Q. Please describe the AEP LTIP incentive compensation expense.

A. The AEP LTIP was implemented to incentivize AEP executives and managers to enhance shareholder value. If AEP executives and managers achieve or exceed the

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[18] The calculation of the ratio is detailed in my workpapers, which are filed contemporaneously with my testimony.

[19] The calculation of the reduction in expense and the revenue requirement is detailed in my workpapers, which are filed contemporaneously with my testimony.

[20] Company's response to KIUC 1-31. The Company provided the incentive compensation expense included in the test year revenue requirement incurred directly by the Company and incurred by AEP Service Corporation and allocated to the Company. I have attached a copy of this response as my Exhibit___(LK-9).

LTIP target metrics for total shareholder returns ("TSR") and earnings per share ("EPS"), they are rewarded with additional compensation.[21]

The LTIP incentive compensation consists of performance share incentives ("PSIs") and restricted stock units ("RSUs").[22] The LTIP PSI incentive compensation is based on target metrics for AEP's EPS and TSR, both of which are measures of AEP's financial performance. The LTIP RSU incentive compensation is based on the stock price of AEP at the grant date.[23] The stock price, by definition, is a measure of AEP's financial performance.

Q. Please describe the AEP ICP incentive compensation expense.

A. The AEP ICP was implemented to reward employees for achieving or exceeding targets for AEP's EPS as well as certain operations and safety metrics, weighted 75% to AEP's EPS and 25% to the other target metrics.[24] The Company incurred $1.879 million in ICP incentive compensation expense in the test year,[25] of which $1.409 million was tied to the achievement of AEP's EPS.

Q. Should the Commission include the AEP LTIP and ICP incentive compensation expense tied to AEP's financial performance in the Company's revenue requirement?

A. No. The Commission historically has disallowed and removed incentive compensation expenses from the revenue requirement that were incurred to

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[21] Company's response to KIUC 1-30.
[22] "Units" are similar to shares of AEP common stock, but have no voting rights.
[23] *Id.*
[24] Response to KIUC 1-30, KPCO_R_KIUC_1_30_Attachment1.pdf. I have not attached a copy of this response or the attachment due to the size.
[25] Section V-Application Exhibit 2 W32.

incentivize the achievement of shareholder goals as measured by financial performance, not incurred to incentivize the achievement of customer and safety goals. That is because the achievement of AEP LTIP and ICP target metrics tied to financial performance benefits shareholders to the detriment of customers in rate proceedings such as this. The entirety of the AEP LTIP and 75% of the ICP incentive compensation expense were incurred to achieve shareholder goals and was not directly tied to the achievement of regulated utility service requirements.

In the Company's last base rate proceeding, the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals. In its discussion related to the disallowance, the Commission stated:

> Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as service quality, call-center response, or other customer-focused criteria are clearly shareholder oriented. As noted in Case No. 2013-00148, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find that Kentucky Power's argument to the contrary does nothing to change this holding as it is unpersuasive.

Likewise, in its order in Kentucky-American Water Company Case No. 2010-00036, the Commission disallowed incentive compensation expense tied to "financial goals that primarily benefited shareholders."[26]

Again, 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

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

on this matter, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. . . It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures."[27] Thus, the LTIP and ICP expense tied to EPS and total shareholder return should be borne by shareholders, not customers.

Further, incentive compensation incurred to incentivize AEP financial performance also provides the Company's executives, managers, and employees a direct incentive to seek greater and more frequent rate increases from customers in order to improve AEP's EPS and TSR. The greater the rate increases and revenues, the greater AEP's EPS and TSR and the greater the incentive compensation expense. Thus, there is an inherent conflict between achieving lower rates for customers on the one hand and achieving greater financial performance for shareholders and greater incentive compensation for executives, managers, and other employees on the other hand. Thus, all such expenses should be allocated to shareholders, not to customers.

Finally, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling. The additional revenues ensure that the expense is covered regardless of the Company's actual performance and regardless of its operational and safety performance. Thus, the expenses should be directly assigned to AEP shareholders, not customers.

In summary, the Company's requests for recovery of LTIP and ICP expense tied to EPS and total shareholder return fall clearly within the disallowance

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

precedent and should be allocated to shareholders and not recovered from customers.

<u>Reject Post Test Year Merit and Related Overtime Wage and Salary Increases</u>

Q. Please describe the Company's request to include post-test year merit and related overtime wage and salary increases in the revenue requirement.

A. The Company made two proforma adjustments to increase expense related to post-test year merit and related overtime wage and salary increases. The discussion for the increases are found in the Direct Testimony of Mr. Tyler H. Ross at pages 14-15. The adjustment for the post-test year merit increase increased expenses by $0.827 million.[28] The adjustment was made to reflect merit increases for Company and AEPSC employees projected after the end of the test year in April, May, and June of 2017. The adjustment for the related overtime increase based on the percentage merit increases increased expenses by $0.149 million.[29]

Q. Should the Commission allow the Company's proposed ratemaking adjustment for these post-test year increases in expense?

A. No. These proposed adjustments are selective single issue adjustments that increase expense and the revenue requirement. The Company has proposed no other post-test year increases to revenues or reductions to expense that could or would offset more, all, or part of the proposed increases in the revenue requirement. The Company had the option to propose a fully forecast test year, but chose to file using a historic test

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[28] Section V, Exhibit 2, Adjustment W33.
[29] Section V, Exhibit 2, Adjustment W34.

year. It should not be allowed to use a historic test year for its filing and then selectively superimpose post-test year increases in expenses that it would have included if it chose a forecast test year. This mix and match of historic and forecast test years is unfair to customers and easily manipulated to achieve an increase in the revenue requirement and requested increase.

In addition, these adjustments simply assume that the Company will not achieve any offsetting cost reductions through labor productivity improvements, staffing reductions, adoption of more efficient work processes, or otherwise downsizing the Company to match its declining load profile. The Commission can influence the Company's behavior and its costs by denying recovery of these selective post-test year increases, thus requiring the Company to reduce other costs or limit other cost increases so that its costs more closely match its revenues. In other words, the Commission should deny the Company an incentive to increase its costs post-test year rather providing it an incentive to live within its means.

<u>Reject Expense for Proposed Increases in Staffing</u>

Q. Please describe the Company's proposed increase in staffing and the related increase in expense and revenue requirement.

A. The Company made a proforma adjustment to increase expense related to five post-test year distribution employee increases.[30] The adjustment for the post-test year merit increase increased expenses by $0.173 million.[31] The adjustment was made to

[30] The discussion for the increase is found in the Direct Testimony of Mr. Ranie K. Wohnhas at 19-22.
[31] Section V, Exhibit 2, Adjustment W52.

reflect the actual or expected additions of a Safety Coordinator, two Distribution System Inspectors, and two administrative associates after the end of the test year.

Q. Are the increases in staffing and the related expense dependent on including these expenses in the revenue requirement?

A. Yes, that appears that to be the case. Normally, the Company does not seek Commission approval to increase staffing or incur expense unless it is discretionary. Instead, it staffs to perform its utility functions in a reasonable and cost-effective manner. The Company has not identified any specific post-test year change in regulations, safety, or other requirements that did not already exist in the test year. In other words, the Company has not justified a post-test year increase in staffing and the related expenses.

Q. Is this another selective post-test year adjustment that fails to consider any other opportunities for cost reductions or increases in revenues?

A. Yes. Even if the increased staffing and related expenses were justified, the Company has identified no other reductions in costs or increases in revenues that would offset the increase in expense. More specifically, it has identified no reductions in staffing and related expense that could be achieved through attrition or otherwise due to its declining load, reductions in expense due to capital investments that were made to improve productivity, or savings from other initiatives and improvements in efficiency.

<u>Reduce Amortization Expense to Properly Calibrate Storm Damage Amortization</u>

Q. Please describe the Company's request for storm damage amortization expense.

A. The Company seeks $2.429 million in annual amortization expense for storm damage deferrals. This is the amount of amortization expense that was authorized in Case No. 2014-00336. The Company had a remaining unamortized balance of $8.097 million at February 28, 2017.[32] It will continue to amortize and recover the deferrals at the same $2.429 million until its rates are reset in this proceeding, most likely on or about January 1, 2018. The remaining unamortized balance will be $6.073 million at that time. The balance will be fully amortized in June 2020 if the amortization expense is not reset in this proceeding. This reflects a 2.5 year effective amortization period.

Q. Should the amortization expense be reset in this proceeding?

A. Yes. The Commission should reset the amortization period to five years and calculate the amortization expense using the remaining unamortized balance at January 1, 2018, the date when rates will be reset in this proceeding. This is appropriate for two reasons. First, because the Commission does not know when the Company will file its next base rate case or when the rates from that case will become effective. If rates are not reset in the next case for three years, then the Company will recover $7.287 million in amortization expense even though the balance remaining is only $6.087 million at December 31, 2017.

Second, the Company will over-recover the return on the deferred storm

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[32] Company's response to KIUC 2-15, a copy of which is attached as my Exhibit___(LK-10).

expense regardless of the amortization period and regardless of whether the remaining unamortized balance is determined at February 28, 2017 or December 31, 2017. The only question is the amount of the over-recovery.

Q. How does the Company over-recover the return on the deferred storm expenses?

A. That occurs because the amount of the remaining unamortized deferral included in capitalization is fixed at the end of the historic test year under the Company's proposal. The revenue requirement includes the return on that amount from the date rates are reset in this proceeding until rates are reset in the next base rate proceeding. Meanwhile, customers continue to pay down the deferral each month, first from March 1, 2017 through December 31, 2017, the day before rates are reset in this proceeding, and then continue to pay down the deferral each month thereafter. These recoveries reduce the Company's capitalization and its financing costs each month. However, even as the Company's financing costs continue to decline, it continues to recover the return on the remaining unamortized deferral as if that balance never declined. Under the Company's proposal, the return will be based on the balance at February 28, 2017 even though customers will have paid down the balance by another $2.024 million by December 31, 2017. Under the KIUC proposal, the return will be based on the lower balance at December 31, 2017, but the Company still will over-recover until base rates again are reset in the next base rate case.

Q. Why is it appropriate to use a five year amortization period and the remaining unamortized deferral as of the date when rates are reset in this proceeding?

A. First, it correctly sets the amortization to correspond to the balance at the date when rates are reset. This is the balance that remains to be recovered, which is less than the balance at February 28, 2017. This reduces the amortization expense based on the remaining balance and minimizes the likelihood that the Company will over-recover the deferrals themselves.

Second, it sets the amortization expense based on a reasonably short recovery period and one that is consistent with the amortization period approved by the Commission in the last base rate proceeding.

Third, the longer amortization period (five years versus the Company's 2.5 years) minimizes the Company's over-recovery of the return on the remaining unamortized deferrals.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $1.215 million in amortization expense.

<u>Reduce Depreciation Rates and Expense to Reflect Converted Big Sandy 1 Remaining Service Life of 30 Years</u>

Q. Please describe the Company's proposed service life for the depreciation rates and expense on the converted Big Sandy 1 natural gas-fired generating unit.

A. The Company proposes depreciation rates and expense that reflect a 15 year service life for the converted Big Sandy 1 natural gas-fired generating unit starting from the date of the conversion in June 2016. This proposed service life assumes a probable retirement date of mid-2031.[33] This is the same retirement date the Company assumed for the pre-conversion Big Sandy 1 coal-fired generating unit.

Q. Does the Company have any specific plans to retire Big Sandy 1 in mid-2031?

A. No. The Company has no plans to retire Big Sandy 1 in mid-2031. The mid-2031 date is not supported by any planning or engineering studies, according to the Company's response to KIUC discovery.[34] The mid-2031 date is simply a carryover of the prior assumption for the plant when it was coal-fired and prior to the conversion to a gas-fired generation and the installation of new boiler and the installation and/or refurbishment of certain other balance of plant equipment. As a coal-fired plant, the mid-2031 probable retirement date was based, in large part, on the avoidance of costs necessary to comply with numerous environmental requirements applicable to coal-fired generation.

As a newly converted gas-fired plant, the Company will continue to invest in, operate, and maintain Big Sandy 1 indefinitely unless and until there are other more economic alternatives. In the conversion, the Company more than doubled its net plant investment in Big Sandy 1,[35] meaning that more than half of the net investment in the plant represents new and refurbished equipment and balance of plant. The Company and its affiliate utilities have a history of continuously extending the

[33] Direct Testimony of Jason Cash at 7.

[34] Company's response to KIUC 1-73. I have attached a copy of the response as my Exhibit___(LK-11).

[35] Company's response to KIUC 1-41(a). I have attached a copy of the response to KIUC 1-41 as my Exhibit___(LK-12).

service lives of their generating units through ongoing investment in plant and effective maintenance practices as long as it remains economic for them to do so.

Finally, as a natural gas-fired unit, Big Sandy 1 is no longer subject to the same environmental and premature shutdown and retirement risks that exist for coal-fired units. The historic focus of the U.S. Environmental Protection Agency ("EPA") has been to reduce emissions and other residuals at coal-fired generating units. This has led to the premature retirement of coal-fired generating units when it was uneconomic to make additional plant investments to comply with these requirements.

Q. What remaining service life do you recommend for the depreciation rates on Big Sandy 1?

A. I recommend a remaining service life for Big Sandy of 30 years from the Company's depreciation study date of December 31, 2016 based on a probable retirement date of December 31, 2046. Similar to the depreciation rates on all plant, the Commission can periodically review the status of Big Sandy 1 in the various Integrated Resource Plan ("IRP") proceedings to determine if it is appropriate to assume that Big Sandy 1 will be retired prior to or after December 31, 2046. If there is, then this assumption can be reflected in the Company's next depreciation study. The Company will recover all prudent and reasonable costs of Big Sandy 1 regardless of the timing of the recovery.

I propose the 30 year life based on the relative age of the plant, including the new equipment and balance of plant, the Company's intent to continue to make plant investments and maintain the plant indefinitely so long as there are no other more economic options, the ability of the Commission to extend or shorten the remaining life in future IRP and rate case proceedings, and the Company's ability to recover the cost of the plant regardless of the actual retirement date.

Q. What is the effect of your recommendation?

A. The effect is a reduction in depreciation expense of $4.738 million.[36]

__Eliminate Terminal Net Salvage in Big Sandy 1 and Mitchell Plant Depreciation Rates__

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

A. The Company included terminal net negative salvage of $11.404 million (net salvage income of $8.261 million less cost of removal of $19.665 million), or negative 7.32%, in its proposed depreciation rates for Big Sandy 1. The terminal net negative salvage estimate was based on a "conceptual dismantling estimate" in 2013 dollars developed by Sargent & Lundy in 2012 for the entire Big Sandy plant site, which includes both Big Sandy 1 and Big Sandy 2. The Company allocated the Big Sandy plant site estimate to Big Sandy 1 based on the Big Sandy 1 capacity compared to the sum of the Big Sandy 1 and Big Sandy 2 capacity. Finally, the Company escalated the S&L estimate by 2.30% annually to 2031 to calculate the amount included in the proposed Big Sandy 1 depreciation rate.[37]

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[36] The calculations are shown on my Exhibit___(LK-13)
[37] Direct Testimony of Jason Cash at 7-8.

The Company included terminal net salvage of $21.186 million (net salvage income of $19.032 less cost of removal of $40.218 million), or negative 2.37%, based on the calculation of depreciation rates for the Mitchell plant established in the last base rate proceeding using plant at December 31, 2013. The Company proposes no change in the Mitchell depreciation rates in this proceeding.

Q. Is the Company's proposed recovery of future terminal net negative salvage for Big Sandy 1 and Mitchell appropriate?

A. No. As a threshold matter, the Commission should not attempt to forecast today the scope of any future dismantling activities and site restoration necessary or reasonable when Company's generating units are retired decades in the future. The default assumption should be "retirement in place" unless and until the generating units are retired or near retirement and then changed only after the Company files and the Commission approves a dismantling and site restoration plan, including the estimated cost at that time. The Company would be required to make a filing and demonstrate that the dismantling and site restoration plan was necessary and that the estimated cost was reasonable.

If the Commission approves a dismantling and site restoration plan, then the Company would be allowed to defer the actual and prudent costs incurred pursuant to the approved plan and recover those costs prospectively either through base rates or through the Company's "Decommissioning Rider," previously approved by the Commission to recover the actual costs of dismantling and coal-related site remediation for Big Sandy 1 and Big Sandy 2. The Commission authorized recovery of these Big Sandy coal-related costs based on actual costs incurred and on a levelized (annuitized) basis over 25 years.

Q. Why is this a better approach?

A. First, this approach establishes a default "retirement in place" rather than assuming dismantlement and site restoration for ratemaking purposes.

Second, it requires the Company to demonstrate that dismantling and site restoration, the scope of such activities, and the estimated cost are necessary and reasonable after or near the actual retirement of the generating units.

Third, it ensures that costs are incurred only if dismantling and site restoration is necessary and the Commission approves the scope of the activities after or near the retirement date.

Fourth, it ensures that only actual costs are recovered from customers after they are incurred. This avoids the guesswork of estimates developed and recovery of these estimates through depreciation rates decades before the generating units are retired, let alone dismantled and the site restored.

Q. Is there another reason that the Commission should not allow the terminal net negative salvage for Big Sandy 1?

A. Yes. It would result in double recovering the same costs twice, once in the base revenue requirement and again in the Big Sandy Retirement Rider (or the proposed renamed "Decommissioning Rider"). The S&L conceptual cost estimate is based on dismantlement and site remediation for Big Sandy 1 as a coal-fired facility.[38] The Company made no effort to correct the S&L estimate to remove the coal-related costs or to obtain a new S&L study and estimate.

Q. If the Commission does not remove the terminal net negative salvage from the Big Sandy 1 depreciation rates and expense, do you have another recommendation?

A. Yes. The Commission should remove the 2.30% annual escalation on the Big Sandy 1 terminal net negative salvage rate. This escalation methodology "front-loads" recovery of an uncertain estimate of future costs in future dollars, which also is uncertain.

In addition, the Company's proposed escalation assumes that there will be no changes in the physical dismantling and site restoration approach assumed by S&L, no efficiencies from technology, equipment and disposal advances, and no improvements in productivity, any of which could offset future inflation in costs.

Further, the use of estimated 2031 dollars for 2017 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.

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[38] Company's response to KIUC 1-36.

Q. What is the effect of your recommendation to remove the cost of future dismantling and site restoration from the depreciation rates and expense on Big Sandy 1 and the Mitchell plant?

A. The effect is a reduction of $0.370 million in depreciation expense on Big Sandy 1 and $0.567 million on the Mitchell plant.[39] The reduction in depreciation expense on Big Sandy 1 is in addition to the reduction from extending the remaining service life.

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

Q. Please describe 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. 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. Most utilities 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 in this proceeding?

A. No. It assumed that there would be no §199 deduction in the calculation of income

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[39] The calculations are shown on my Exhibit___(LK-14).

tax expense for the adjusted test year before any rate increases. The Company also assumed that there would be no §199 deduction in the calculation of the gross revenue conversion factor ("GRCF") used to determine the income tax expense due to the rate increases. In part, this represents a change from the prior proceeding wherein the Company used a three-year historic average of the §199 deduction in the calculation of income tax expense for the adjusted test year before any rate increases.

Q. Is the §199 deduction dependent on taxable income in the test year?

A. Yes. If the Company has positive taxable income from all sources, then it is able to take a §199 deduction, all else equal. As a threshold matter, the ability to take a §199 deduction is determined at the entity level, not at the Kentucky retail or retail base rate level. The ability to take any deduction is dependent on the Company's total taxable income from *all* sources during the year, not only the taxable income due to Kentucky retail rates, including base rates and surcharge mechanisms, but also *all* other taxable income from other sources, including wholesale taxable income. In the test year, the Company had positive taxable income from all sources.[40]

If the Company is able to take a §199 deduction, then any increase in taxable income necessarily increases the §199 deduction, after allocation to the production function, all else equal. Consequently, any incremental taxable income due to the rate increases that are authorized in this proceeding and that is allocable to the production function qualifies for the §199 deduction.

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[40] Sch 4 tab on KPSCO_SR_KPSC_1_73_SupplementalAttachment3_SectionVSchedules_TYE2-28-2017FINAL.xlsx.

Q. What does that mean in this proceeding?

A. It means that the Company's gross revenue conversion factor ("GRCF") should reflect the §199 deduction for the purpose of grossing up the operating income deficiency.

Q. In prior proceedings, the Company has argued against a §199 deduction on the basis that the AEP consolidated tax return overrides the Company's ability to take the deduction on a standalone basis. Please address this argument.

A. The Commission should reject this argument as a matter of consistency. The Commission has consistently taken the position that income tax expense should be calculated on a utility standalone basis without consideration of parent consolidated income tax benefits even when those benefits are allocated to the utility pursuant to an intercompany tax allocation agreement. For example, in the Company's last base rate proceeding, the Commission rejected the AG's position that the parent company loss adjustment ("PCLA") tax benefit allocated from AEP to the Company be used to reduce income tax expense for ratemaking purposes. In its Order in that proceeding, the Commission stated:

> The Commission finds that the AG's proposal to include the PCLA in Kentucky Power's federal income tax expense is inappropriate. This recommendation, if adopted, would represent a significant departure from over 25 years of the Commission's established and balanced policy prohibiting affiliate cross-subsidization.63 Therefore, the "stand-alone" approach the Commission has historically used shall be used to allocate income tax liabilities for Kentucky ratemaking purposes. Accordingly, we deny the AG's proposed adjustment for ratemaking purposes.

Thus, the Commission should reject any argument by the Company that the

Commission should not include a §199 deduction based on the lack of such a deduction in prior years due to the parent company's consolidated tax return limitations.

Q. What is your recommendation?

A. I recommend that the Commission reflect the §199 deduction in the GRCF. This is appropriate because the Company is able to take a deduction even with no rate increases. Thus, any rate increases authorized in this proceeding mathematically will increase the Company's taxable income and the amount of the deduction, and thus reduce the income tax expense that should be recovered from customers in the revenue requirement.

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 deductions that are available. Yet the Company's proposal incorrectly assumes that the §199 deduction does not apply to the additional taxable income, which is not true. 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.

Q. How should the GRCF be modified to reflect the §199 deduction applicable to the increase in taxable income resulting from any rate increases authorized in this proceeding?

A. The GRCF should be modified to capture the effects of the §199 deduction based on the production portion of taxable income (qualified domestic production activities income) in the same manner that the Commission previously adopted and used in prior Kentucky Power, KU, and LG&E base rate and environmental surcharge proceedings. In those prior proceedings, the Commission used the percentage of production plant to total plant included in the base or ES rate base. The Commission then multiplied 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.

Q. What is the effect on the revenue requirement of properly including the §199 deduction in the GRCF?

A. The first effect is a reduction of $1.320 million in the Company's base revenue requirement. The second effect is a reduction of $0.227 million in the ES revenue requirement. I calculated these effects using the methodology that I previously described.[41] I quantified these reductions 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. To the extent that the Commission does not fully adopt certain of

[41] The calculations are detailed in my electronic workpapers filed coincident with my testimony.

KIUC's recommendations (for example the Commission authorizes a return on equity above 8.85%), then the reduction in the revenue requirement due to the §199 deduction will be more.

IV. CAPITALIZATION ISSUES

Correct Capitalization So that It Reflects Adjustments to Remove Non-Utility and Surcharge Investments

Q. Is the Commission's historic use of capitalization to calculate the Company's "return on" utility investment as a component of the revenue requirement generally a reasonable proxy for rate base?

A. Yes. In theory, capitalization (outstanding financing) and rate base should be equivalent. In practice, there may be differences due to financial reporting (capitalization) compared to ratemaking (rate base), timing and/or structure of financing, and other factors. In its administrative filing requirements, the Commission requires that the utility reconcile capitalization and rate base to ensure that there are no significant differences. In base rate filings, the Commission generally requires utilities to reduce total Company capitalization for rate base amounts that are reflected in surcharge mechanisms, such as the ES, non-utility investments, disallowed investments, and non-jurisdictional investments.

Q. Has the Company followed this historic approach in this proceeding?

A. Generally, yes. However, there are certain balance sheet assets and liabilities that the Company should have removed from capitalization in the same manner that these amounts would be removed or not included in rate base, but it failed to do so. Consequently, capitalization is overstated, the return on capitalization and the related income tax expense is overstated, and the revenue requirement is overstated.

Q. Why should capitalization be adjusted to remove the financing associated certain balance sheet assets and liabilities?

A. All assets and liabilities generally affect the capitalization on the Company accounting books. Assets generally must be financed unless they are simply bookkeeping entries, such as an asset retirement obligation. Thus, an increase in assets generally results in an increase in capitalization. On the other hand, liabilities generally allow the utility to avoid financing. Thus, an increase in liabilities generally results in a reduction in capitalization.

If the Commission determines that the financing costs of certain assets, such as environmental assets, are to be recovered through a surcharge, such as the ES, then the per books capitalization used for the base revenue requirement should be reduced accordingly. In this case, the Company reduced capitalization for the rate base investment in the Mitchell Plant FGD and consumable inventory, which are included in the Company's ES.[42]

Q. Are there other adjustments to capitalization that are necessary, but that the Company did not include?

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[42] Ratemaking Adjustment 04 shown in Exhibit 2 of the Company's filing.

A. Yes. There are numerous costs that should be removed or added to capitalization so that it is consistent with the appropriate ratemaking recovery of the return on these costs. Some are related to non-utility activities and some are related to surcharges and either are or should be included in the costs recovered through those surcharges. Some simply vary from positive to negative amounts over time and are not appropriate to include in base rates under the assumption that they generally will net to zero over time. These costs include the following:

Asset Account 175.0001	Curr Unreal Gains NonAffil
Asset Account 175.0002	Long-Term Unreal Gns – Non Aff
Asset Account 182.3009	DSM Incentives
Asset Account 182.3010	Energy Efficiency Recovery
Asset Account 182.3011	DSM Lost Revenues
Asset Account 182.3012	DSM Program Costs
Asset Account 182.3063	Unrecovered Fuel Costs
Asset Account 182.3519	Unrecovered Purch Power-PPA
Asset Account 182.3520	Deferred Dep – Environmental
Asset Account 182.3521	Carrying Charge – Environmental
Asset Account 182.3522	CC – Environmental Unrec Equity
Asset Account 182.3523	Deferred O&M – Environmental
Asset Account 182.3524	Deferred Consumable Exp – Envi
Asset Account 182.3525	Deferred Property Tax - Enviro

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

A. The effect is a reduction of \$9.569 million to Kentucky adjusted capitalization and a reduction of \$0.912 million in the base revenue requirement.[43]

<u>Reduce Coal Inventory to Reflect Lower of Actual or Target</u>

[43] The calculations are detailed in my electronic workpapers filed coincident with my testimony. Refer also to Section II on Exhibit___(LK-15) for the effect on the base rate revenue requirement.

Q. Please describe the Company's proposed adjustment to increase actual low sulfur coal inventory to a target inventory level.

A. The Company made a proforma adjustment to reflect capitalization for the Mitchell Plant coal stock based on its target levels of low and high sulfur coal instead of the actual test year levels. The discussion for the adjustment is found in the Direct Testimony of Mr. Wohnhas at pages 10-11 and the calculation is provided in Section V, Workpaper S-3. The Company's target level based adjustment represented a net decrease in capitalization of $6.709 million. While the Company's adjustment for high sulfur coal to target represented a decrease from test year levels, the low sulfur coal adjustment represented an increase over actual test year levels of $1.250 million.

Q. Is this an appropriate adjustment?

A. No. The Commission historically has adjusted capitalization to remove the investment costs of coal inventories that exceed the Company's target days of inventory. This adjustment ensures that the return on the coal inventory investment is not excessive. However, that ratemaking *protection* should not translate into an *entitlement* to include an investment in capitalization that does not exist when the Company's investment in coal inventory is less than the target days.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed adjustment to increase capitalization for inventory that did not exist in the test year.

Q. What is the effect of your recommendation?

A. The effect is a reduction in Kentucky adjusted capitalization of $1.232 million and a reduction in the revenue requirement of $0.117 million.[44]

V. COST OF CAPITAL ISSUES

Effect of Short-Term Debt In Capitalization

Q. Please describe the Company's proposed capital structure.

A. The company proposes capital structure of 0% short-term debt, 54.45% long-term debt, 3.87% receivables, and 41.68% common equity. The actual capital structure at the end of the test year was 0.06% short-term debt, 54.93% long-term debt, 2.96% receivables, and 42.05% common equity. The Company first eliminated short-term debt in conjunction with its ratemaking adjustment to reduce coal inventories.

Q. Is 0% short-term debt reasonable?

A. No. The Company routinely utilized short-term debt during the test year in lieu of other forms of financing as do most other utilities.[45] Short-term debt is the least cost form of financing and is readily available to the Company through the AEP Utility Money Pool. The cost of short-term debt during the test year was a mere 0.80%. This compares to the Company's proposed costs of long-term debt at 4.36%, receivables at 1.95%, and common equity at 16.94%, including the related income tax gross-up.

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[44] The calculations are detailed in my electronic workpapers filed coincident with my testimony. Refer also to Section III on Exhibit___(LK-15) for the effect on the base rate revenue requirement.

[45] Refer to Company's filing at Section V, Workpaper S-3, page 3 of 4.

Q. Should the Commission reflect short-term debt in the capital structure?

A. Yes. The Company relied on short-term debt during the test year and historically has relied on short-term debt. In my experience, most utilities rely on short-term debt in order to minimize their cost of financing, particularly during construction. The cost of short-term debt is a fraction of the cost of long-term debt and common equity. In addition, there is no other way to recognize this lower cost form of financing since the Company does not use Allowance for Funds Used During Construction ("AFUDC").[46]

Q. How much short-term debt should be reflected in the capital structure for ratemaking purposes?

A. I recommend that the Commission reflect 2.0% short-term debt and reduce the long-term debt to 52.52%[47]. The 2.0% is consistent with the Company's actual use of short-term debt during the test year, although the percentage has been much greater in other years.[48]

Q. Does your recommendation change the total debt and common equity capitalization proposed by the Company?

A. No. It only modifies the debt component to reflect short-term debt in lieu of a comparable percentage of long-term debt.

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[46] Under the FERC Uniform System of Accounts, all short-term debt is first assigned to construction work in progress as a component of the cost of capital used for calculating AFUDC. If there is no AFUDC, then all short-term debt should be reflected in the revenue requirement in order to accurately reflect the utility's cost of capital incurred to finance its rate base investment.

[47] KIUC previously reduced long-term debt rate to 54.43%.

[48] At some dates during the test year in Case No. 2009-00459, the Company's short-term debt was nearly 17% of capitalization. Kollen Direct in Case No. 2009-00459 at 39.

Q. Have you quantified the effect on the Company's revenue requirement of including short-term debt in the capitalization and applying the debt rate recommendation of 1.25% sponsored by KIUC witness Mr. Richard Baudino?

A. Yes. The effects are reductions of $0.712 million in the base revenue requirement and $0.123 million in the ES revenue requirement. These reductions are incremental to the reductions for the other cost of capital recommendations that I address.[49]

<u>**Effect of Return on Common Equity Recommended by KIUC**</u>

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 $11.838 million in the base revenue requirement and $2.037 million in the ES revenue requirement. There is an additional effect on the Decommissioning Rider revenue requirement, although I have not quantified this effect. These reductions are incremental to the reductions for the other cost of capital recommendations that I address.[50]

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

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[49] Refer to Section IV on Exhibit___(LK-15) for the effect on the base rate revenue requirement. Changes in the grossed up rate of return were applied to the ES total plant of $203.252 million to determine the effects on the ES revenue requirement. The calculations for ES are detailed in my electronic workpapers filed coincident with my testimony.

[50] Refer to Section V on Exhibit___(LK-XX) for the effect on the base rate revenue requirement. Changes in the grossed up rate of return were applied to the ES total plant of $203.252 million to determine the effects on the ES revenue requirement. The calculations for ES are detailed in my electronic workpapers filed coincident with my testimony.

A. The effects of each 1.0% return on common equity are $8.108 million on the base revenue requirement and $1.395 million on the ES revenue requirement. As I noted previously, there also is an effect on the Decommissioning Rider revenue requirement, but I have not quantified it.

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 16.94%. The pretax return recommended by KIUC, excluding any changes related to the §199 deduction in the GRCF, is 14.54%. 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.

Q. Please describe why there will be an effect on the ES revenue requirement in addition to the effect on the Mitchell FGD ES revenue requirement.

A. 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 ES. Thus, the return on equity will apply to all rate base investment in the ES in addition to the Mitchell FGD. However, the quantification will be dependent on the rate base included in the monthly ES filings after the date rates are reset in this proceeding.[51]

Q. Please explain why there will be an effect on the Decommissioning Rider revenue requirement in addition to the effects on the base and ES revenue requirements.

A. The DR includes a return on the unamortized deferred costs, but on a levelized basis over 25 years.

VI. POTENTIAL FEDERAL INCOME TAX RATE REDUCTION

Q. Do the Company's base and surcharge revenue requirements reflect income tax expense and ADIT at the present federal income tax rate of 35%?

A. Yes. The Company's income tax expense and ADIT are calculated based on a federal income tax rate of 35% for base rate and surcharge purposes.

Q. If the federal income tax rate is reduced to 20%, as recently proposed by the Trump administration, then what will be the effect on the Company's income tax expense, ADIT, and base rate and surcharge revenue requirements?

A. There will be significant reductions in the Company's income tax expense and revenue requirements, one due to the reduction in current and deferred income tax expense calculated using the lower federal income tax rate, and another due to an

[51] 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.

additional reduction in deferred income tax expense from an amortization of the "excess" ADIT resulting from the lower federal income tax rate.

The reduction in the federal income tax rate will reduce current and deferred income tax expense included in the base revenue requirement, environmental surcharge revenue requirement and all other surcharge revenue requirements that include income tax expense.

In the first instance, current and deferred income tax expense will be reduced by 43% if the federal income tax rate is reduced from 35% to 20%. For the Company, this will result in a reduction in income tax expense of $12.583 million compared to the income tax expense based on the KIUC capitalization and cost of capital recommendations in this proceeding. I haven't calculated the reductions in the ES or DR revenue requirements for purposes of this proceeding, but the effects will be significant and in addition to the effects on the base revenue requirement.

In addition, 43% of the existing ADIT at 35% will become "excess" at 20%. The ADIT represents the amount of future tax liabilities that have already been collected from ratepayers before these amounts are ultimately be paid to the federal government. The "excess" ADIT no longer will represent a future tax liability to be paid to the federal government and will need to be returned to customers. The ADIT will be amortized as negative income tax expense. This negative deferred income tax amortization expense will further reduce the Company's base and surcharge revenue requirements.

Q. Can these reductions be calculated using a formula?

A. Yes. The Company's income tax expense is based on the gross-up on the weighted return on common equity applied to the allowed capitalization for ratemaking purposes, all else equal. If the income tax rate is reduced, then the new federal income tax rate would be substituted for the 35% in the calculation of the GRCF. The difference in the GRCF at 35% and at the new rate then is multiplied times the weighted common equity in the capital structure and then multiplied times the allowed capitalization.

The reduction in the deferred income tax expense resulting from an amortization of the excess ADIT is calculated by dividing the net ADIT amounts over the average amortization period for each temporary difference.

Finally, any change in income tax expense must be multiplied by the new GRCF to determine the effect on the revenue requirement.

Q. What is your recommendation?

A. I recommend that the Commission monitor the federal tax legislation developments and act in a timely manner to reduce the Company's revenue requirements coincident with the effective date of the federal income tax rate reduction (which could be effective back to January 1, 2017) through either immediate rate reductions or deferrals followed by subsequent reductions. This will not occur automatically for the base revenue requirement. However, it should be reflected automatically in the ES and DR revenue requirements through the true-up provisions of those surcharges and the calculation of income tax expense going forward.

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
2nd day of October 2017.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVINGS ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00179

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 2017

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 September 2017

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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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 (Surrebuttal)	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.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.

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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.
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.

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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.
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.

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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.

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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.
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.

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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.
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.

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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.
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.

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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 Heallthcare 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.
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.

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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.
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.

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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.
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.

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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.
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.

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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, ELG v ASL depreciation procedures, 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.
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.

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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.
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.

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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.
04/10	2009-00548, 2009-00549	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.

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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.
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.

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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.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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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.

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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.
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.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
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.

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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.
12/14	14-1152-E-42T	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.
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 Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.

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07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 0/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

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Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, Incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Acquisition of Oncor by Next Era Energy; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
08/17	17-0296-E-PC	WV	Public Service Commission of West Virginia Charleston	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.

EXHIBIT ____ (LK-2)

DATA REQUEST

AG_1_002

Regarding the Rockport station and the Unit Power Agreement ("UPA"), confirm the following:

a. Rockport Unit 1 is owned by KPCo affiliates Indiana Michigan Power Co. ("I&M") and AEP Generating Company ("AEG");

b. Rockport Unit 2 is owned by Wilmington Trust Co., which leases an undivided 50% share of Unit 2 to I&M, and an undivided 50% share to AEG;

c. Under the terms of the UPA, KPCo is entitled to 30% of the output of AEG's share in the Rockport Units;

d. Under the terms of the New Source Review Consent Decree ("Consent Decree," as modified by four Modifications to the Consent Decree) that KPCo and other American Electric Power ("AEP") operating companies entered into with the U.S. Department of Justice, among others, and as more fully described in: (i) the McManus testimony at p. 3 and Exhibit JMM-1 attached thereto in Case No. 2017-00179; and (ii) ECP Plan Project 19, KPCo will be required to pay its proportionate share of the costs of installing Selective Catalytic Reduction ("SCR") technology at Rockport Unit 1;

e. the Rockport UPA expires in 2022;

f. Under the terms of the Consent Decree, Rockport Unit 2 will require approximately $1.4 billion in new pollution controls by 2028;

g. I&M's 2015 IRP filing calls for renewing the Rockport lease, and adding SCR technology in 2019, and FGD systems in 2025 and 2028;

h. In April, 2017 the U.S. Sixth Circuit Court of Appeals issued a ruling ("Appellate Court Ruling") holding that AEG will be responsible for the costs of installing an FGD at Rockport Unit 2 estimated to cost $1.4 billion;

i. The Appellate Court Ruling stated, inter alia, that the EPA initiated and ultimately settled ". . . enforcement litigation against various AEP affiliates for alleged Clean Air Act violations at other coal-burning power plants. But it did not do so with respect to Rockport 2. Rather, having made no allegations regarding the owners' plant, the EPA gained the ability to impose the scrubber requirement only by virtue of the consent decree agreed to by its lessees—one whereby AEP traded away Rockport 2's long-term value in exchange for a more favorable settlement of claims against their other interests."

j. Neither the Kentucky Public Service Commission nor the Kentucky Office of the Attorney General were parties to the cases in which the Consent Decree and the four modifications thereto were formulated and approved.

k. On or about July 21, 2017, KPCo and certain of its affiliates filed a motion in the U.S. District Court for the Southern District of Ohio (Eastern Division; hereinafter: "U.S. District Court Motion") seeking a fifth Modification to the Consent Decree;

l. The U.S. District Court Motion states, inter alia, at pp. ii-iii, "The Modification seeks to remedy the uncertainty that currently surrounds AEP's rights with respect to Rockport Unit 2 by removing commitments for future pollution control installations (specifically the obligations to install a selective catalytic reduction system ("SCR") by the end of 2019 and a high-efficiency flue gas desulfurization system ("FGD") by the end of 2028) at that Unit and instead committing AEP to one of two alternative courses of action with respect to the Rockport Units";

m. The U.S. District Court Motion states, inter alia, at p. 17 that ". . . given the ongoing dispute with the Lessors concerning the terms of the [Rockport Unit 2] Lease, AEP does not currently plan on extending the term of the Lease, which will terminate in 2022";

n. The U.S. District Court Motion states, inter alia, at p. 18 that ". . . AEP proposes modifying the Consent Decree as follows. . . (1) remove the requirements for additional control installations at Rockport Unit 2 (the SCR and the high-efficiency FGD); (2) memorialize AEP's commitment to seek any appropriate state regulatory approvals to replace Rockport Unit 2's capacity and energy, including but not limited to actions related to the Rockport Unit 2 Lease. . . . ";

o. In the instant case, KPCo seeks approval of its Fifth Amended Environmental Compliance Plan, which includes, inter alia, Project 19 regarding the installation of a selective catalytic converter (SCR) at Rockport Unit 1;

p. The construction of the Rockport Unit 1 SCR is required by the Consent Decree;

q. KPCo and its affiliates are not seeking to delay or negate the construction of the Rockport Unit 1 SCR in their U.S. District Court Motion;

r. The return on equity applicable to construction of the Rockport Unit 1 SCR is 12.16%.

RESPONSE

a. Confirmed.

b. Rockport Unit 2 is owned by Wilmington Trust Co., not in its individual capacity, but solely as owner trustee under twelve separate trusts. Wilmington Trust Co. leases an undivided 50% share of Unit 2 to I&M, and an undivided 50% share to AEG.

c. AEG controls 50% of the Rockport Plant, and the Company is entitled to 30% of the output from AEG's share. Thus, the Company is entitled to 15% of the total output of Rockport.

d. The UPA, not the Consent Decree, governs the Company's payment of costs related to the Rockport Unit 1 SCR. The Consent Decree requires that the Unit 1 SCR be installed and operated by December 31, 2017. Pursuant to the terms of the UPA, the costs paid by Kentucky Power for its 15% share of the output of the Rockport Plant include a portion of the cost of the Unit 1 SCR and are reflected in the purchased power bill that the Company receives from AEG. The UPA is attached as "AG_1_002_Attachment1.pdf."

e. Confirmed.

f. The Consent Decree does not address the cost of emissions control technology. The Consent Decree requires an SCR to be installed and operated on Rockport Unit 2 by December 31, 2019. It further requires that one Rockport unit "Retrofit, Retire, Re-power, or Refuel" by December 31, 2025, and that the other Rockport unit "Retrofit, Retire, Re-power, or Refuel" by December 31, 2028. These terms are defined in the Part III, "Definitions," of the Consent Decree.

g. As a threshold matter, the extension of the UPA between Kentucky Power and AEG is a question that is independent and different from I&M's resource planning decisions with respect to Rockport. As explained in Kentucky Power's 2017 Integrated Resource Plan ("IRP"), the UPA expires December 7, 2022. Kentucky Power anticipates that it will address whether to extend the UPA in its 2019 IRP, and it will seek appropriate approval from the Commission for an extension of the UPA or the acquisition of replacement energy and capacity.

I&M's 2015 IRP did not "call for" any specific actions but rather identified (at page ES-6) maintaining Rockport as one part of I&M's "preferred portfolio." I&M's 2015 IRP made clear (at page ES-13) that the "IRP process is a continuous activity" and "assumptions and plans are continually reviewed as new information becomes available and modified as appropriate." I&M's 2015 IRP further clarified that it was "not a commitment to a specific course of action, as the future is highly uncertain." Id. Rather, the I&M 2015 IRP was "simply a snapshot of the future at this time" (i.e., 2015), as the "complexities" of resource planning "necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes." Id.

In addition, I&M's 2015 IRP explained (at page ES-1) that I&M had evaluated multiple resource planning scenarios including cases which removed one or both Rockport units. The results of these analyses showed that the decision whether to retire a Rockport unit was "highly dependent on assumptions" and was "near break-even" in some scenarios. Id.

I&M's 2015 IRP is available at:

https://www.indianamichiganpower.com/info/projects/IntegratedResourcePlan/

h. The referenced "Appellate Court Ruling" has been superseded by a subsequent decision. The U.S. Court of Appeals for the Sixth Circuit ("Sixth Circuit") issued a decision on April 14, 2017. However, in response to a petition for rehearing, the Sixth Circuit granted rehearing and issued a superseding "Amended Opinion" on June 8, 2017. This Amended Opinion reversed the district court's dismissal of certain of plaintiffs' claims. Critically, however, the Amended Opinion made no liability determination and remanded the case to the district court for further proceedings. Please see the Company's response to KPSC 2-49, which provides the Amended Opinion as "KPCO_R_KPSC_2_049_Attachment1.pdf." The Amended Opinion speaks for itself.

i. The Company confirms the quoted language is contained in the June 8, 2017 Amended Opinion. The Company notes that the Sixth Circuit's decision considered all allegations in the lessors' complaint to be true, and that there had been no opportunity to develop a complete factual record in the district court. As noted in subpart (h) above, the June 8, 2017 "Amended Opinion" made no liability determination and remanded the case to the district court for further proceedings. The Amended Opinion, which is provided in the Company's response to KPSC 2-49, speaks for itself.

j. Confirmed. Neither of these entities moved to intervene in the cases.

k. Confirmed. This motion was previously provided to the Attorney General on July 25, 2017 by Kentucky Power and is attached as "AG_1_002_Attachment2.pdf."

l. The Company confirms that the quoted language is contained in the motion, but notes that the specifics of the requested relief are explained in greater detail elsewhere in the motion. The motion ("AG_1_002_Attachment2.pdf") speaks for itself.

m. The Company confirms that the quoted language is contained in the motion, but notes that the circumstances surrounding the litigation with the lessors are set forth more fully elsewhere in the motion. The motion ("AG_1_002_Attachment2.pdf") speaks for itself.

n. Although the quoted language may be found in the motion, the excerpt is only a partial list of the proposed Consent Decree modifications. A complete list can be found on pages 18-22 of the motion ("AG_1_002_Attachment2.pdf").

o. Confirmed.

p. Confirmed.

q. Confirmed. The Rockport Unit 1 SCR went into service on August 9, 2017.

r. Kentucky Power confirms that under the terms of the FERC-approved UPA, the rate it pays for its 15% share of the output of Rockport reflects a 12.16% ROE.

Witness: Matthew J. Satterwhite

EXHIBIT ____ (LK-3)

DATA REQUEST

AG_1_301

Unit Power Agreement. Does KPCo have a Unit Power Agreement with AEP Generating Company? If "yes" explain fully and:
a. Provide a copy of the Unit Power Agreement ("UPA") between KPCo and AEP Generating Company.
b. Confirm that the UPA is the same as the Unit Power Supply Agreement ("UPSA") which was approved by the Commission in its Order dated October 25, 2004 in Case No. 2001-00420. If not confirmed, explain fully why not, and provide a copy of the UPA applicable to Rockport.
c. Identify all FERC proceedings from 2004 through 2017 that have addressed the Rockport Unit Power Supply Agreement.
d. Identify all costs, by account, that the Company is requesting in the test year related to the Rockport Unit Power Supply Agreement.
e. Identify and provide all invoices to the Company in 2015, 2016 and 2017 (to date) related to charges associated with the Rockport Unit Power Supply Agreement.

RESPONSE

a. Please refer to the Company's response to AG 1-2 for the requested information.

b. The Company cannot confirm the statement. The Commission by order Dated December 13, 2004 approved the Stipulation and Settlement Agreement among Kentucky Power Company, Kentucky Industrial Utility Customers, Inc, and the Office of the Attorney General Office of Rate Intervention in Case No. 2004-00420.

Please refer to the Company's response to AG 1-2 for a copy of the Unit Power Agreement.

c. Docket ER13-286 was the only FERC proceeding addressing the Rockport Unit Power Supply Agreement in the years from 2004 through 2017.

d. Rockport purchase power is recorded in the test year in accounts 5550027 and 5550046 in the amounts of $51,785,042 and $48,218,333, respectively. There were no specific adjustment to these accounts in the test year.

e. Please refer to the Company's response to KIUC 1-43 for the requested information.

Witness: Ranie K. Wohnhas
Matthew J. Satterwhite

EXHIBIT ____ (LK-4)

DATA REQUEST

KIUC_1_043 Please provide copies of all Rockport Unit Power Agreement monthly invoices billed to the Company from AEP for the period January 2015 through the most recent month available in electronic format with all formulas intact.

RESPONSE

Please refer to KPCO_R_KIUC_1_43_Attachment1.xls through KPCO_R_KIUC_1_43_Attachment31.xls for the requested information.

Witness: Ranie K. Wohnhas

A E P GENERATING COMPANY

March, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	160,041
501	FUEL	918,850
502	STEAM EXPENSES	306,714
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	61,102
506	MISC. STEAM POWER EXPENSES	136,574
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	7,273,533
510	MAINTENANCE SUPER. AND ENGINEERING	96,591
511	MAINTENANCE OF STRUCTURES	19,700
512	MAINTENANCE OF BOILER PLANT	155,999
513	MAINTENANCE OF ELECTRIC PLANT	(1,058)
514	MAINTENANCE OF MISC. STEAM PLANT	50,250
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	321,482
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	1,410
557	OTHER POWER SUPPLY EXPENSES	7,716
	TOTAL OTHER SUPPLY EXPENSES	9,126

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	3
THIS BILLING IS FOR MONTH OF	March, 2016

A E P GENERATING COMPANY

April, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	182,923
501	FUEL	2,804,734
502	STEAM EXPENSES	319,505
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	79,968
506	MISC. STEAM POWER EXPENSES	111,036
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	9,188,419
510	MAINTENANCE SUPER. AND ENGINEERING	90,994
511	MAINTENANCE OF STRUCTURES	14,062
512	MAINTENANCE OF BOILER PLANT	165,178
513	MAINTENANCE OF ELECTRIC PLANT	135,183
514	MAINTENANCE OF MISC. STEAM PLANT	38,138
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	443,555
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	(4,437)
557	OTHER POWER SUPPLY EXPENSES	(7,880)
	TOTAL OTHER SUPPLY EXPENSES	(12,317)

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	30
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	4
THIS BILLING IS FOR MONTH OF	April, 2016

A E P GENERATING COMPANY

May, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	201,984
501	FUEL	7,228,379
502	STEAM EXPENSES	1,024,514
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	55,191
506	MISC. STEAM POWER EXPENSES	80,535
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	14,280,856
510	MAINTENANCE SUPER. AND ENGINEERING	84,457
511	MAINTENANCE OF STRUCTURES	11,847
512	MAINTENANCE OF BOILER PLANT	149,185
513	MAINTENANCE OF ELECTRIC PLANT	56,951
514	MAINTENANCE OF MISC. STEAM PLANT	51,365
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	353,805
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	978
557	OTHER POWER SUPPLY EXPENSES	3,682
	TOTAL OTHER SUPPLY EXPENSES	4,659

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	5
THIS BILLING IS FOR MONTH OF	May, 2016

A E P GENERATING COMPANY

June, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	149,478
501	FUEL	8,184,768
502	STEAM EXPENSES	878,552
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	62,304
506	MISC. STEAM POWER EXPENSES	95,284
507	RENTS	5,690,246
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	15,060,631
510	MAINTENANCE SUPER. AND ENGINEERING	87,372
511	MAINTENANCE OF STRUCTURES	25,208
512	MAINTENANCE OF BOILER PLANT	105,636
513	MAINTENANCE OF ELECTRIC PLANT	32,300
514	MAINTENANCE OF MISC. STEAM PLANT	30,656
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	281,172
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	1,647
557	OTHER POWER SUPPLY EXPENSES	7,319
	TOTAL OTHER SUPPLY EXPENSES	8,966

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	30
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	6
THIS BILLING IS FOR MONTH OF	June, 2016

A E P GENERATING COMPANY

July, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	165,825
501	FUEL	9,011,508
502	STEAM EXPENSES	940,969
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	53,624
506	MISC. STEAM POWER EXPENSES	97,375
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	15,959,554
510	MAINTENANCE SUPER. AND ENGINEERING	91,414
511	MAINTENANCE OF STRUCTURES	28,380
512	MAINTENANCE OF BOILER PLANT	229,288
513	MAINTENANCE OF ELECTRIC PLANT	42,295
514	MAINTENANCE OF MISC. STEAM PLANT	30,084
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	421,462
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	(3)
557	OTHER POWER SUPPLY EXPENSES	4,304
	TOTAL OTHER SUPPLY EXPENSES	4,301

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	7
THIS BILLING IS FOR MONTH OF	July, 2016

A E P GENERATING COMPANY

August, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	201,696
501	FUEL	9,223,440
502	STEAM EXPENSES	959,152
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	53,194
506	MISC. STEAM POWER EXPENSES	68,804
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	16,196,539
510	MAINTENANCE SUPER. AND ENGINEERING	114,176
511	MAINTENANCE OF STRUCTURES	27,575
512	MAINTENANCE OF BOILER PLANT	163,359
513	MAINTENANCE OF ELECTRIC PLANT	24,080
514	MAINTENANCE OF MISC. STEAM PLANT	36,983
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	366,171
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	1,621
557	OTHER POWER SUPPLY EXPENSES	7,691
	TOTAL OTHER SUPPLY EXPENSES	9,312

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	8
THIS BILLING IS FOR MONTH OF	August, 2016

A E P GENERATING COMPANY

September, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	168,835
501	FUEL	8,493,263
502	STEAM EXPENSES	974,540
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	52,843
506	MISC. STEAM POWER EXPENSES	164,977
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	15,544,711
510	MAINTENANCE SUPER. AND ENGINEERING	94,541
511	MAINTENANCE OF STRUCTURES	4,106
512	MAINTENANCE OF BOILER PLANT	121,595
513	MAINTENANCE OF ELECTRIC PLANT	(25,760)
514	MAINTENANCE OF MISC. STEAM PLANT	35,106
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	229,587
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	(4,134)
557	OTHER POWER SUPPLY EXPENSES	(9,870)
	TOTAL OTHER SUPPLY EXPENSES	(14,004)

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	30
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	9
THIS BILLING IS FOR MONTH OF	September, 2016

A E P GENERATING COMPANY

October, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	144,882
501	FUEL	8,911,821
502	STEAM EXPENSES	1,092,407
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	52,733
506	MISC. STEAM POWER EXPENSES	111,126
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	16,003,221
510	MAINTENANCE SUPER. AND ENGINEERING	85,008
511	MAINTENANCE OF STRUCTURES	7,860
512	MAINTENANCE OF BOILER PLANT	193,157
513	MAINTENANCE OF ELECTRIC PLANT	24,649
514	MAINTENANCE OF MISC. STEAM PLANT	16,398
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	327,072
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	686
557	OTHER POWER SUPPLY EXPENSES	5,644
	TOTAL OTHER SUPPLY EXPENSES	6,330

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	10
THIS BILLING IS FOR MONTH OF	October, 2016

C:\Users\Jessica1\Desktop\Shared Project Folders\Kentucky Power 2017-00179\Data Requests\KIUC\KPCO_R_KIUC_1_43_Attachment22_Oct_2016.xls

A E P GENERATING COMPANY

November, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	172,478
501	FUEL	7,939,935
502	STEAM EXPENSES	930,819
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	49,752
506	MISC. STEAM POWER EXPENSES	110,291
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	14,893,528
510	MAINTENANCE SUPER. AND ENGINEERING	86,713
511	MAINTENANCE OF STRUCTURES	(8,046)
512	MAINTENANCE OF BOILER PLANT	286,737
513	MAINTENANCE OF ELECTRIC PLANT	23,959
514	MAINTENANCE OF MISC. STEAM PLANT	35,309
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	424,671
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	136
557	OTHER POWER SUPPLY EXPENSES	2,141
	TOTAL OTHER SUPPLY EXPENSES	2,277

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	30
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	11
THIS BILLING IS FOR MONTH OF	November, 2016

A E P GENERATING COMPANY

December, 2016
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	176,670
501	FUEL	10,623,614
502	STEAM EXPENSES	1,124,689
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	56,749
506	MISC. STEAM POWER EXPENSES	90,848
507	RENTS	5,690,248
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	17,762,818
510	MAINTENANCE SUPER. AND ENGINEERING	99,873
511	MAINTENANCE OF STRUCTURES	15,233
512	MAINTENANCE OF BOILER PLANT	224,582
513	MAINTENANCE OF ELECTRIC PLANT	30,614
514	MAINTENANCE OF MISC. STEAM PLANT	32,011
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	402,312
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	498
557	OTHER POWER SUPPLY EXPENSES	(7,894)
	TOTAL OTHER SUPPLY EXPENSES	(7,396)

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	366
CURRENT YEAR IS	2016
CURRENT MONTH IS	12
THIS BILLING IS FOR MONTH OF	December, 2016

A E P GENERATING COMPANY

January, 2017
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	153,707
501	FUEL	5,426,053
502	STEAM EXPENSES	717,880
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	83,669
506	MISC. STEAM POWER EXPENSES	207,620
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	12,279,182
510	MAINTENANCE SUPER. AND ENGINEERING	102,466
511	MAINTENANCE OF STRUCTURES	26,802
512	MAINTENANCE OF BOILER PLANT	289,355
513	MAINTENANCE OF ELECTRIC PLANT	202,153
514	MAINTENANCE OF MISC. STEAM PLANT	41,225
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	662,001
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	3,500
557	OTHER POWER SUPPLY EXPENSES	14,199
	TOTAL OTHER SUPPLY EXPENSES	17,699

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	31
NO OF DAYS IN CURRENT YEAR >	365
CURRENT YEAR IS	2017
CURRENT MONTH IS	1
THIS BILLING IS FOR MONTH OF	January, 2017

C:\Users\Jessica1\Desktop\Shared Project Folders\Kentucky Power 2017-00179\Data Requests\KIUC\KPCO_R_KIUC_1_43_Attachment25_Jan_2017.xls

A E P GENERATING COMPANY **February, 2017**
ESTIMATE

ROCKPORT OPERATION & MAINTENANCE EXPENSES UNIT 2
50% OWNERSHIP INTEREST OF ROCKPORT PLANT

500	SUPERVISION AND ENGINEERING	130,795
501	FUEL	8,439,465
502	STEAM EXPENSES	965,978
503	STEAM FROM OTHER SOURCES	0
504	STEAM TRANSFERRED - CR	0
505	ELECTRIC EXPENSES	54,790
506	MISC. STEAM POWER EXPENSES	87,402
507	RENTS	5,690,253
508	OPERATION SUPPLIES AND EXPENSES	0
509	CARRYING CHARGES - ALLOWANCES	0
	TOTAL OPERATION EXPENSE	15,368,682
510	MAINTENANCE SUPER. AND ENGINEERING	69,469
511	MAINTENANCE OF STRUCTURES	10,455
512	MAINTENANCE OF BOILER PLANT	177,804
513	MAINTENANCE OF ELECTRIC PLANT	(56,723)
514	MAINTENANCE OF MISC. STEAM PLANT	32,774
515	MAINTENANCE NORMALIZING	0
	TOTAL MAINTENANCE EXPENSES	233,780
555	PURCHASED POWER	0
556	SYSTEM CONTROL AND LOAD DISPATCHING	(203)
557	OTHER POWER SUPPLY EXPENSES	1,685
	TOTAL OTHER SUPPLY EXPENSES	1,482

	AMOUNT MUST BE ZERO
IS FUEL IN BALANCE ON PAGE 2	0

BE SURE THIS IS CORRECT

NO OF DAYS IN CURRENT MO >	28
NO OF DAYS IN CURRENT YEAR >	365
CURRENT YEAR IS	2017
CURRENT MONTH IS	2
THIS BILLING IS FOR MONTH OF	February, 2017

EXHIBIT ____ (LK-5)

DATA REQUEST

KIUC_1_005 Please provide a load and capability analysis for the Company showing capacity resources, demand response resources, retail and wholesale load and reserve margin for the historic period 2013 through 2016 and the forecast period 2017 through 2027. Also include the Company's Fixed Resource Requirement capacity obligation for each year. The analysis can be presented on either a calendar year or PJM delivery year basis.

RESPONSE

Please refer to KPCO_R_KIUC_1_5_Attachment1.pdf for load, capability and reserve margin including a forecast of the Company's Fixed Resource Requirement obligation for each year. KPCO_R_KIUC_1_5_Attachment2.pdf provides actual and forecast retail and wholesale energy for the Company. KPCO_R_KIUC_1_5_Attachment3.pdf provides forecast retail and wholesale demands coincident with the Company's internal peak demand. The Company does not have hourly meters on all of its customers, therefore historical coincident peak demand data by class are not available.

Witness: Ranie K. Wohnhas

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (June 2017) Load Forecast
2017

				Obligation to PJM							Resources						KPCo Position (MW)		PJM Reserve Margin			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(16)	(17)	(18)	(19)	(20)	(21)				
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)			=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))		=((11)-(12) +(15)) *(1-(17)) -(10)-	=(18)-(10)-(19)				
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Net ICAP	AEP EFORd (j)	Available UCAP	BASE UCAP Removed (l)	Net Position w/o New Capacity	Net Position w/ New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	KPCo Reserve Margin Above PJM IRM	Total KPCo Reserve Margin
2013 /14	(k)	1,136	(3)	0	1,136	0	0.957	1.089	1,237	0	1,237	1,470	50	1,420	4.65%	1,354	0	117	117	1,067	15.90%	10.96%	26.86%
2014 /15	(k)	1,084	(1)	0	1,084	0	0.954	1.093	1,185	0	1,185	2,250	0	2,250	20.77%	1,783	0	598	598	1,020	16.20%	58.64%	74.84%
2015 /16	(k)	1,096	(2)	0	1,096	0	0.951	1.091	1,196	0	1,196	1,450	0	1,450	10.16%	1,303	0	107	107	1,035	15.60%	10.34%	25.94%
2016 /17	(k)	1,088	(3)	0	1,088	0	0.953	1.095	1,191	0	1,191	1,457	0	1,457	11.09%	1,295	0	104	104	1,023	16.40%	10.16%	26.56%
2017 /18	(k)	1,021	(3)	0	1,021	0	0.947	1.097	1,119	0	1,119	1,457	0	1,457	11.98%	1,282	0	163	163	960	16.60%	16.98%	33.58%
2018 /19	(k)	1,020	(7)	0	1,020	0	1.000	1.089	1,111	0	1,111	1,463	0	1,463	9.99%	1,317	0	206	206	953	16.60%	21.62%	38.22%
2019 /20	(k)	1,025	(9)	0	1,025	0	1.000	1.089	1,116	0	1,116	1,463	0	1,463	9.99%	1,317	0	201	201	957	16.60%	21.00%	37.60%
2020 /21	(k)	1,022	(10)	0	1,022	0	1.000	1.089	1,113	0	1,113	1,468	0	1,468	9.97%	1,322	0	209	209	955	16.60%	21.90%	38.50%
2021 /22		960	(11)	(3)	957	1	1.000	1.089	1,040	0	1,040	1,468	0	1,468	9.97%	1,322	1	281	281	893	16.60%	31.46%	48.06%
2022 /23		957	(12)	(7)	951	1	1.000	1.089	1,034	0	1,034	1,468	0	1,468	9.97%	1,322	1	287	287	888	16.60%	32.31%	48.91%
2023 /24		955	(12)	(9)	946	1	1.000	1.089	1,029	0	1,029	1,468	0	1,468	9.97%	1,322	1	292	292	884	16.60%	33.04%	49.64%
2024 /25		953	(13)	(10)	942	1	1.000	1.089	1,025	0	1,025	1,468	0	1,468	9.97%	1,322	1	296	296	880	16.60%	33.62%	50.22%
2025 /26		952	(12)	(11)	941	1	1.000	1.089	1,023	0	1,023	1,465	0	1,465	9.98%	1,319	1	295	295	879	16.60%	33.57%	50.17%
2026 /27		951	(12)	(12)	939	1	1.000	1.089	1,021	0	1,021	1,465	0	1,465	9.98%	1,319	1	297	297	877	16.60%	33.87%	50.47%
2027 /28		950	(11)	(12)	938	1	1.000	1.089	1,020	0	1,020	1,465	0	1,465	9.98%	1,319	1	298	298	876	16.60%	34.01%	50.61%

Notes: (a) Based on (June 2017) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and VVO
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f)

(g) GAS CONVERSION RERATES:
2015/16: Big Sandy 1: 285 MW
RETIREMENTS:
2015/16: Big Sandy 2
2030/31: Big Sandy 1

(h)

(i)
(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year

(k) Actual PJM forecast

(l) Capacity Removed as part of PJM Capacity Peformance Rule
Current CP Assumptions are:
Wind 5%, Solar 38%, ROR Hydro 25%
Demand Response 50%

EXHIBIT ____ (LK-6)

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
KIUC First Set of Data Requests
Dated August 14, 2017

DATA REQUEST

KIUC_1_083 Please confirm that the Company calculates the effects of temperature on revenues for all major customer classes, including residential, commercial, and industrial for internal management reporting purposes.

RESPONSE

The Company calculates the effects of temperature on revenues for all major weather sensitive customer classes and publishes these estimates for both internal and external purposes. For Kentucky Power, the weather sensitive classes include the Residential, Commercial, and Wholesale classes. The Industrial and Other Retail class sales are much less responsive to changes in temperatures. As a result, no weather impact is estimated or published for the non-weather sensitive classes.

Witness: Alex E. Vaughan

EXHIBIT ____ (LK-7)

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
KIUC First Set of Data Requests
Dated August 14, 2017

DATA REQUEST

KIUC_1_084 Please confirm that the Company calculates the effects of temperature on revenues for all major customer classes, including residential, commercial, and industrial for financial reporting purposes.

RESPONSE

Refer to the Company's response to KIUC 1-83

Witness: Alex E. Vaughan

EXHIBIT ____ (LK-8)

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
KIUC's Second Set of Data Requests
Dated September 8, 2017

DATA REQUEST

KIUC_2_016 Refer to the responses to KIUC 1-83, 1-84, and 1-85. Provide the Company's calculation of the weather normalized base revenues and the difference in weather normalized base revenues compared to actual unadjusted base revenues developed for internal management and external reporting purposes by customer class and in total for all classes for each month January 2015 through February 2017. Provide these calculations in live electronic spreadsheet format with all formulas intact.

RESPONSE

See KPCO_R_KIUC_2_016_Attachment1.xls for the actual unadjusted nonfuel revenues, weather normalized non-fuel revenues, and the Company's computed weather impact that was developed and reported for internal management and external reporting purposes by customer class and in total for the months requested. The actual computations are performed in the SAS software and not in a spreadsheet. The Company does not have a spreadsheet that replicates the weather normalization calculations as specifically requested.

Witness: Alex E. Vaughan

Kentucky Power Non-fuel Revenue Impact of Weather

JURIS	YEAR	MONTH	Revenue Class	Actual Non-Fuel Revenues (000s)	Weather Normalized Revenues (000s)	Weather Impact ($000s)
KPC	2015	1	Residential	$ 19,339.47	$ 17,975.21	$ 1,364.25
KPC	2015	1	Commercial	$ 9,395.14	$ 9,117.45	$ 277.69
KPC	2015	1	Industrial	$ 7,718.76	$ 7,718.76	$ -
KPC	2015	1	Other Retail	$ 118.11	$ 118.11	$ -
KPC	2015	1	Munis	$ 347.50	$ 340.23	$ 7.27
			Total	**$ 36,918.98**	**$ 35,269.76**	**$ 1,649.21**
KPC	2015	2	Residential	$ 20,588.39	$ 15,656.59	$ 4,931.80
KPC	2015	2	Commercial	$ 9,933.27	$ 8,891.01	$ 1,042.26
KPC	2015	2	Industrial	$ 7,476.26	$ 7,476.26	$ -
KPC	2015	2	Other Retail	$ 118.93	$ 118.93	$ -
KPC	2015	2	Munis	$ 375.58	$ 340.68	$ 34.90
			Total	**$ 38,492.43**	**$ 32,483.47**	**$ 6,008.96**
KPC	2015	3	Residential	$ 16,109.97	$ 15,879.27	$ 230.70
KPC	2015	3	Commercial	$ 7,987.20	$ 7,956.67	$ 30.53
KPC	2015	3	Industrial	$ 7,040.88	$ 7,040.88	$ -
KPC	2015	3	Other Retail	$ 115.64	$ 115.64	$ -
KPC	2015	3	Munis	$ 291.40	$ 290.05	$ 1.35
			Total	**$ 31,545.09**	**$ 31,282.51**	**$ 262.58**
KPC	2015	4	Residential	$ 10,775.92	$ 11,301.03	$ (525.10)
KPC	2015	4	Commercial	$ 7,523.75	$ 7,651.13	$ (127.38)
KPC	2015	4	Industrial	$ 7,927.38	$ 7,927.38	$ -
KPC	2015	4	Other Retail	$ 131.07	$ 131.07	$ -
KPC	2015	4	Munis	$ 206.33	$ 210.05	$ (3.72)
			Total	**$ 26,564.45**	**$ 27,220.66**	**$ (656.20)**
KPC	2015	5	Residential	$ 11,886.35	$ 11,271.84	$ 614.51
KPC	2015	5	Commercial	$ 9,346.36	$ 9,092.81	$ 253.55
KPC	2015	5	Industrial	$ 8,069.44	$ 8,069.44	$ -
KPC	2015	5	Other Retail	$ 129.68	$ 129.68	$ -
KPC	2015	5	Munis	$ 220.65	$ 215.22	$ 5.43
			Total	**$ 29,652.48**	**$ 28,778.99**	**$ 873.49**
KPC	2015	6	Residential	$ 11,376.47	$ 11,054.10	$ 322.37
KPC	2015	6	Commercial	$ 8,145.24	$ 8,032.49	$ 112.76
KPC	2015	6	Industrial	$ 7,035.06	$ 7,035.06	$ -
KPC	2015	6	Other Retail	$ 101.73	$ 101.73	$ -
KPC	2015	6	Munis	$ 2,082.88	$ 2,051.55	$ 31.33
			Total	**$ 28,741.38**	**$ 28,274.93**	**$ 466.46**
KPC	2015	7	Residential	$ 12,327.68	$ 12,937.86	$ (610.18)
KPC	2015	7	Commercial	$ 8,129.64	$ 8,359.70	$ (230.06)
KPC	2015	7	Industrial	$ 7,149.49	$ 7,149.49	$ -
KPC	2015	7	Other Retail	$ 129.99	$ 129.99	$ -
KPC	2015	7	Munis	$ 363.52	$ 372.44	$ (8.92)
			Total	**$ 28,100.32**	**$ 28,949.48**	**$ (849.16)**

KPC	2015	8	Residential	$ 13,788.37	$	14,839.83	$	(1,051.46)
KPC	2015	8	Commercial	$ 9,189.58	$	9,590.38	$	(400.80)
KPC	2015	8	Industrial	$ 6,919.71	$	6,919.71	$	-
KPC	2015	8	Other Retail	$ 122.77	$	122.77	$	-
KPC	2015	8	Munis	$ 343.95	$	356.55	$	(12.60)
			Total	**$ 30,364.38**	**$**	**31,829.24**	**$**	**(1,464.86)**
KPC	2015	9	Residential	$ 12,476.61	$	12,306.89	$	169.71
KPC	2015	9	Commercial	$ 9,104.53	$	9,038.69	$	65.83
KPC	2015	9	Industrial	$ 8,343.41	$	8,343.41	$	-
KPC	2015	9	Other Retail	$ 137.56	$	137.56	$	-
KPC	2015	9	Munis	$ 337.79	$	335.59	$	2.20
			Total	**$ 30,399.90**	**$**	**30,162.14**	**$**	**237.74**
KPC	2015	10	Residential	$ 11,058.04	$	11,500.15	$	(442.11)
KPC	2015	10	Commercial	$ 9,655.91	$	9,782.09	$	(126.18)
KPC	2015	10	Industrial	$ 8,504.42	$	8,504.42	$	-
KPC	2015	10	Other Retail	$ 138.35	$	138.35	$	-
KPC	2015	10	Munis	$ 275.40	$	279.25	$	(3.85)
			Total	**$ 29,632.12**	**$**	**30,204.26**	**$**	**(572.14)**
KPC	2015	11	Residential	$ 13,290.53	$	15,018.21	$	(1,727.68)
KPC	2015	11	Commercial	$ 9,089.19	$	9,396.91	$	(307.73)
KPC	2015	11	Industrial	$ 8,244.02	$	8,244.02	$	-
KPC	2015	11	Other Retail	$ 131.89	$	131.89	$	-
KPC	2015	11	Munis	$ 328.79	$	342.68	$	(13.89)
			Total	**$ 31,084.42**	**$**	**33,133.71**	**$**	**(2,049.30)**
KPC	2015	12	Residential	$ 16,943.98	$	22,384.28	$	(5,440.30)
KPC	2015	12	Commercial	$ 8,852.27	$	9,876.88	$	(1,024.60)
KPC	2015	12	Industrial	$ 8,142.62	$	8,142.62	$	-
KPC	2015	12	Other Retail	$ 136.95	$	136.95	$	-
KPC	2015	12	Munis	$ 331.21	$	366.30	$	(35.09)
			Total	**$ 34,407.03**	**$**	**40,907.03**	**$**	**(6,499.99)**
KPC	2016	1	Residential	$ 26,340.62	$	24,210.29	$	2,130.34
KPC	2016	1	Commercial	$ 12,525.35	$	12,110.83	$	414.52
KPC	2016	1	Industrial	$ 8,272.27	$	8,272.27	$	-
KPC	2016	1	Other Retail	$ 143.63	$	143.63	$	-
KPC	2016	1	Munis	$ 420.03	$	408.46	$	11.57
			Total	**$ 47,701.90**	**$**	**45,145.48**	**$**	**2,556.43**
KPC	2016	2	Residential	$ 19,911.66	$	20,582.44	$	(670.78)
KPC	2016	2	Commercial	$ 8,766.00	$	8,913.31	$	(147.31)
KPC	2016	2	Industrial	$ 7,134.75	$	7,134.75	$	-
KPC	2016	2	Other Retail	$ 128.58	$	128.58	$	-
KPC	2016	2	Munis	$ 377.49	$	382.08	$	(4.59)
			Total	**$ 36,318.48**	**$**	**37,141.16**	**$**	**(822.68)**
KPC	2016	3	Residential	$ 13,458.09	$	16,171.55	$	(2,713.46)
KPC	2016	3	Commercial	$ 8,367.97	$	8,953.01	$	(585.04)
KPC	2016	3	Industrial	$ 7,497.32	$	7,497.32	$	-
KPC	2016	3	Other Retail	$ 131.19	$	131.19	$	-
KPC	2016	3	Munis	$ 306.62	$	324.48	$	(17.85)

Total	**$ 29,761.19**	**$ 33,077.55**	**$ (3,316.35)**

KPC	2016	4 Residential	$	12,536.09	$	12,078.92	$	457.17
KPC	2016	4 Commercial	$	9,305.11	$	9,185.67	$	119.43
KPC	2016	4 Industrial	$	7,924.52	$	7,924.52	$	-
KPC	2016	4 Other Retail	$	140.87	$	140.87	$	-
KPC	2016	4 Munis	$	277.85	$	274.60	$	3.25
		Total	**$**	**30,184.44**	**$**	**29,604.58**	**$**	**579.85**
KPC	2016	5 Residential	$	12,269.33	$	12,166.25	$	103.08
KPC	2016	5 Commercial	$	10,047.31	$	10,035.27	$	12.05
KPC	2016	5 Industrial	$	7,914.72	$	7,914.72	$	-
KPC	2016	5 Other Retail	$	143.81	$	143.81	$	-
KPC	2016	5 Munis	$	(515.88)	$	(514.46)	$	(1.42)
		Total	**$**	**29,859.29**	**$**	**29,745.59**	**$**	**113.71**
KPC	2016	6 Residential	$	14,722.76	$	14,019.41	$	703.36
KPC	2016	6 Commercial	$	10,680.40	$	10,443.01	$	237.39
KPC	2016	6 Industrial	$	8,311.86	$	8,311.86	$	-
KPC	2016	6 Other Retail	$	160.45	$	160.45	$	-
KPC	2016	6 Munis	$	283.91	$	279.86	$	4.05
		Total	**$**	**34,159.38**	**$**	**33,214.59**	**$**	**944.80**
KPC	2016	7 Residential	$	17,872.24	$	17,315.15	$	557.09
KPC	2016	7 Commercial	$	10,695.09	$	10,519.28	$	175.81
KPC	2016	7 Industrial	$	7,630.24	$	7,630.24	$	-
KPC	2016	7 Other Retail	$	148.34	$	148.34	$	-
KPC	2016	7 Munis	$	310.50	$	307.37	$	3.13
		Total	**$**	**36,656.41**	**$**	**35,920.38**	**$**	**736.03**
KPC	2016	8 Residential	$	18,058.03	$	16,309.71	$	1,748.32
KPC	2016	8 Commercial	$	10,797.46	$	10,234.47	$	562.98
KPC	2016	8 Industrial	$	7,500.90	$	7,500.90	$	-
KPC	2016	8 Other Retail	$	137.44	$	137.44	$	-
KPC	2016	8 Munis	$	309.60	$	299.66	$	9.95
		Total	**$**	**36,803.43**	**$**	**34,482.18**	**$**	**2,321.25**
KPC	2016	9 Residential	$	11,968.76	$	10,105.71	$	1,863.05
KPC	2016	9 Commercial	$	8,168.05	$	7,562.39	$	605.66
KPC	2016	9 Industrial	$	6,504.00	$	6,504.00	$	-
KPC	2016	9 Other Retail	$	128.93	$	128.93	$	-
KPC	2016	9 Munis	$	286.45	$	272.22	$	14.23
		Total	**$**	**27,056.19**	**$**	**24,573.25**	**$**	**2,482.94**
KPC	2016	10 Residential	$	11,939.50	$	12,833.25	$	(893.75)
KPC	2016	10 Commercial	$	9,356.73	$	9,441.84	$	(85.11)
KPC	2016	10 Industrial	$	7,157.98	$	7,157.98	$	-
KPC	2016	10 Other Retail	$	131.61	$	131.61	$	-
KPC	2016	10 Munis	$	213.05	$	216.89	$	(3.84)
		Total	**$**	**28,798.87**	**$**	**29,781.57**	**$**	**(982.70)**
KPC	2016	11 Residential	$	14,549.19	$	16,209.51	$	(1,660.32)
KPC	2016	11 Commercial	$	10,991.97	$	11,304.98	$	(313.01)
KPC	2016	11 Industrial	$	8,872.69	$	8,872.69	$	-
KPC	2016	11 Other Retail	$	145.69	$	145.69	$	-
KPC	2016	11 Munis	$	266.56	$	274.63	$	(8.07)

		Total	**$ 34,826.10**	**$ 36,807.50**	**$ (1,981.40)**
KPC	2016	12 Residential	$ 20,736.54	$ 21,105.83	$ (369.29)
KPC	2016	12 Commercial	$ 9,744.06	$ 9,821.99	$ (77.92)
KPC	2016	12 Industrial	$ 7,610.54	$ 7,610.54	$ -
KPC	2016	12 Other Retail	$ 138.62	$ 138.62	$ -
KPC	2016	12 Munis	$ 337.28	$ 339.19	$ (1.91)
		Total	**$ 38,567.04**	**$ 39,016.17**	**$ (449.12)**
KPC	2017	1 Residential	$ 19,233.57	$ 22,741.61	$ (3,508.05)
KPC	2017	1 Commercial	$ 9,148.12	$ 9,893.07	$ (744.95)
KPC	2017	1 Industrial	$ 7,156.03	$ 7,156.03	$ -
KPC	2017	1 Other Retail	$ 133.62	$ 133.62	$ -
KPC	2017	1 Munis	$ 324.06	$ 346.34	$ (22.28)
		Total	**$ 35,995.40**	**$ 40,270.67**	**$ (4,275.28)**
KPC	2017	2 Residential	$ 14,536.40	$ 18,445.07	$ (3,908.67)
KPC	2017	2 Commercial	$ 8,479.08	$ 9,300.52	$ (821.44)
KPC	2017	2 Industrial	$ 7,276.16	$ 7,276.16	$ -
KPC	2017	2 Other Retail	$ 136.46	$ 136.46	$ -
KPC	2017	2 Munis	$ 293.59	$ 322.28	$ (28.69)
		Total	**$ 30,721.69**	**$ 35,480.49**	**$ (4,758.80)**

Kentucky Power Non-fuel Revenue Impact of Weather

JURIS	YEAR	MONTH	Revenue Class	Actual Non-Fuel Revenues (000s)	Weather Normalized Revenues (000s)	Weather Impact ($000s)	Weather Impact Commercial($000s)
KPC	2015	1	Residential	$ 19,339.47	$ 17,975.21	$ 1,364.25	
KPC	2015	1	Commercial	$ 9,395.14	$ 9,117.45	$ 277.69	
KPC	2015	1	Industrial	$ 7,718.76	$ 7,718.76	$ -	
KPC	2015	1	Other Retail	$ 118.11	$ 118.11	$ -	
KPC	2015	1	Munis	$ 347.50	$ 340.23	$ 7.27	
			Total	**$ 36,918.98**	**$ 35,269.76**	**$ 1,649.21**	
KPC	2015	2	Residential	$ 20,588.39	$ 15,656.59	$ 4,931.80	
KPC	2015	2	Commercial	$ 9,933.27	$ 8,891.01	$ 1,042.26	
KPC	2015	2	Industrial	$ 7,476.26	$ 7,476.26	$ -	
KPC	2015	2	Other Retail	$ 118.93	$ 118.93	$ -	
KPC	2015	2	Munis	$ 375.58	$ 340.68	$ 34.90	
			Total	**$ 38,492.43**	**$ 32,483.47**	**$ 6,008.96**	
KPC	2015	3	Residential	$ 16,109.97	$ 15,879.27	$ 230.70	
KPC	2015	3	Commercial	$ 7,987.20	$ 7,956.67	$ 30.53	
KPC	2015	3	Industrial	$ 7,040.88	$ 7,040.88	$ -	
KPC	2015	3	Other Retail	$ 115.64	$ 115.64	$ -	
KPC	2015	3	Munis	$ 291.40	$ 290.05	$ 1.35	
			Total	**$ 31,545.09**	**$ 31,282.51**	**$ 262.58**	
KPC	2015	4	Residential	$ 10,775.92	$ 11,301.03	$ (525.10)	
KPC	2015	4	Commercial	$ 7,523.75	$ 7,651.13	$ (127.38)	
KPC	2015	4	Industrial	$ 7,927.38	$ 7,927.38	$ -	
KPC	2015	4	Other Retail	$ 131.07	$ 131.07	$ -	
KPC	2015	4	Munis	$ 206.33	$ 210.05	$ (3.72)	
			Total	**$ 26,564.45**	**$ 27,220.66**	**$ (656.20)**	
KPC	2015	5	Residential	$ 11,886.35	$ 11,271.84	$ 614.51	
KPC	2015	5	Commercial	$ 9,346.36	$ 9,092.81	$ 253.55	
KPC	2015	5	Industrial	$ 8,069.44	$ 8,069.44	$ -	
KPC	2015	5	Other Retail	$ 129.68	$ 129.68	$ -	
KPC	2015	5	Munis	$ 220.65	$ 215.22	$ 5.43	
			Total	**$ 29,652.48**	**$ 28,778.99**	**$ 873.49**	
KPC	2015	6	Residential	$ 11,376.47	$ 11,054.10	$ 322.37	
KPC	2015	6	Commercial	$ 8,145.24	$ 8,032.49	$ 112.76	
KPC	2015	6	Industrial	$ 7,035.06	$ 7,035.06	$ -	
KPC	2015	6	Other Retail	$ 101.73	$ 101.73	$ -	
KPC	2015	6	Munis	$ 2,082.88	$ 2,051.55	$ 31.33	
			Total	**$ 28,741.38**	**$ 28,274.93**	**$ 466.46**	
KPC	2015	7	Residential	$ 12,327.68	$ 12,937.86	$ (610.18)	
KPC	2015	7	Commercial	$ 8,129.64	$ 8,359.70	$ (230.06)	
KPC	2015	7	Industrial	$ 7,149.49	$ 7,149.49	$ -	
KPC	2015	7	Other Retail	$ 129.99	$ 129.99	$ -	
KPC	2015	7	Munis	$ 363.52	$ 372.44	$ (8.92)	
			Total	**$ 28,100.32**	**$ 28,949.48**	**$ (849.16)**	
KPC	2015	8	Residential	$ 13,788.37	$ 14,839.83	$ (1,051.46)	
KPC	2015	8	Commercial	$ 9,189.58	$ 9,590.38	$ (400.80)	
KPC	2015	8	Industrial	$ 6,919.71	$ 6,919.71	$ -	
KPC	2015	8	Other Retail	$ 122.77	$ 122.77	$ -	
KPC	2015	8	Munis	$ 343.95	$ 356.55	$ (12.60)	
			Total	**$ 30,364.38**	**$ 31,829.24**	**$ (1,464.86)**	
KPC	2015	9	Residential	$ 12,476.61	$ 12,306.89	$ 169.71	
KPC	2015	9	Commercial	$ 9,104.53	$ 9,038.69	$ 65.83	
KPC	2015	9	Industrial	$ 8,343.41	$ 8,343.41	$ -	
KPC	2015	9	Other Retail	$ 137.56	$ 137.56	$ -	
KPC	2015	9	Munis	$ 337.79	$ 335.59	$ 2.20	

Kentucky Power Non-fuel Revenue Impact of Weather

JURIS	YEAR	MONTH	Revenue Class	Actual Non-Fuel Revenues (000s)	Weather Normalized Revenues (000s)	Weather Impact ($000s)	Weather Impact Commercial($000s)
			Total	**$ 30,399.90**	**$ 30,162.14**	**$ 237.74**	
KPC	2015	10	Residential	$ 11,058.04	$ 11,500.15	$ (442.11)	
KPC	2015	10	Commercial	$ 9,655.91	$ 9,782.09	$ (126.18)	
KPC	2015	10	Industrial	$ 8,504.42	$ 8,504.42	$ -	
KPC	2015	10	Other Retail	$ 138.35	$ 138.35	$ -	
KPC	2015	10	Munis	$ 275.40	$ 279.25	$ (3.85)	
			Total	**$ 29,632.12**	**$ 30,204.26**	**$ (572.14)**	
KPC	2015	11	Residential	$ 13,290.53	$ 15,018.21	$ (1,727.68)	
KPC	2015	11	Commercial	$ 9,089.19	$ 9,396.91	$ (307.73)	
KPC	2015	11	Industrial	$ 8,244.02	$ 8,244.02	$ -	
KPC	2015	11	Other Retail	$ 131.89	$ 131.89	$ -	
KPC	2015	11	Munis	$ 328.79	$ 342.68	$ (13.89)	
			Total	**$ 31,084.42**	**$ 33,133.71**	**$ (2,049.30)**	
KPC	2015	12	Residential	$ 16,943.98	$ 22,384.28	$ (5,440.30)	
KPC	2015	12	Commercial	$ 8,852.27	$ 9,876.88	$ (1,024.60)	
KPC	2015	12	Industrial	$ 8,142.62	$ 8,142.62	$ -	
KPC	2015	12	Other Retail	$ 136.95	$ 136.95	$ -	
KPC	2015	12	Munis	$ 331.21	$ 366.30	$ (35.09)	
			Total	**$ 34,407.03**	**$ 40,907.03**	**$ (6,499.99)**	
KPC	2016	1	Residential	$ 26,340.62	$ 24,210.29	$ 2,130.34	
KPC	2016	1	Commercial	$ 12,525.35	$ 12,110.83	$ 414.52	
KPC	2016	1	Industrial	$ 8,272.27	$ 8,272.27	$ -	
KPC	2016	1	Other Retail	$ 143.63	$ 143.63	$ -	
KPC	2016	1	Munis	$ 420.03	$ 408.46	$ 11.57	
			Total	**$ 47,701.90**	**$ 45,145.48**	**$ 2,556.43**	
KPC	2016	2	Residential	$ 19,911.66	$ 20,582.44	$ (670.78)	
KPC	2016	2	Commercial	$ 8,766.00	$ 8,913.31	$ (147.31)	
KPC	2016	2	Industrial	$ 7,134.75	$ 7,134.75	$ -	
KPC	2016	2	Other Retail	$ 128.58	$ 128.58	$ -	
KPC	2016	2	Munis	$ 377.49	$ 382.08	$ (4.59)	
			Total	**$ 36,318.48**	**$ 37,141.16**	**$ (822.68)**	
KPC	2016	3	Residential	$ 13,458.09	$ 16,171.55	$ (2,713.46)	
KPC	2016	3	Commercial	$ 8,367.97	$ 8,953.01	$ (585.04)	$ (585.04)
KPC	2016	3	Industrial	$ 7,497.32	$ 7,497.32	$ -	
KPC	2016	3	Other Retail	$ 131.19	$ 131.19	$ -	
KPC	2016	3	Munis	$ 306.62	$ 324.48	$ (17.85)	
			Total	**$ 29,761.19**	**$ 33,077.55**	**$ (3,316.35)**	
KPC	2016	4	Residential	$ 12,536.09	$ 12,078.92	$ 457.17	
KPC	2016	4	Commercial	$ 9,305.11	$ 9,185.67	$ 119.43	$ 119.43
KPC	2016	4	Industrial	$ 7,924.52	$ 7,924.52	$ -	
KPC	2016	4	Other Retail	$ 140.87	$ 140.87	$ -	
KPC	2016	4	Munis	$ 277.85	$ 274.60	$ 3.25	
			Total	**$ 30,184.44**	**$ 29,604.58**	**$ 579.85**	
KPC	2016	5	Residential	$ 12,269.33	$ 12,166.25	$ 103.08	
KPC	2016	5	Commercial	$ 10,047.31	$ 10,035.27	$ 12.05	$ 12.05
KPC	2016	5	Industrial	$ 7,914.72	$ 7,914.72	$ -	
KPC	2016	5	Other Retail	$ 143.81	$ 143.81	$ -	
KPC	2016	5	Munis	$ (515.88)	$ (514.46)	$ (1.42)	
			Total	**$ 29,859.29**	**$ 29,745.59**	**$ 113.71**	
KPC	2016	6	Residential	$ 14,722.76	$ 14,019.41	$ 703.36	
KPC	2016	6	Commercial	$ 10,680.40	$ 10,443.01	$ 237.39	$ 237.39
KPC	2016	6	Industrial	$ 8,311.86	$ 8,311.86	$ -	
KPC	2016	6	Other Retail	$ 160.45	$ 160.45	$ -	

Kentucky Power Non-fuel Revenue Impact of Weather

JURIS	YEAR	MONTH	Revenue Class	Actual Non-Fuel Revenues (000s)	Weather Normalized Revenues (000s)	Weather Impact ($000s)	Weather Impact Commercial($000s)
KPC	2016	6	Munis	$ 283.91	$ 279.86	$ 4.05	
			Total	**$ 34,159.38**	**$ 33,214.59**	**$ 944.80**	
KPC	2016	7	Residential	$ 17,872.24	$ 17,315.15	$ 557.09	
KPC	2016	7	Commercial	$ 10,695.09	$ 10,519.28	$ 175.81	$ 175.81
KPC	2016	7	Industrial	$ 7,630.24	$ 7,630.24	$ -	
KPC	2016	7	Other Retail	$ 148.34	$ 148.34	$ -	
KPC	2016	7	Munis	$ 310.50	$ 307.37	$ 3.13	
			Total	**$ 36,656.41**	**$ 35,920.38**	**$ 736.03**	
KPC	2016	8	Residential	$ 18,058.03	$ 16,309.71	$ 1,748.32	
KPC	2016	8	Commercial	$ 10,797.46	$ 10,234.47	$ 562.98	$ 562.98
KPC	2016	8	Industrial	$ 7,500.90	$ 7,500.90	$ -	
KPC	2016	8	Other Retail	$ 137.44	$ 137.44	$ -	
KPC	2016	8	Munis	$ 309.60	$ 299.66	$ 9.95	
			Total	**$ 36,803.43**	**$ 34,482.18**	**$ 2,321.25**	
KPC	2016	9	Residential	$ 11,968.76	$ 10,105.71	$ 1,863.05	
KPC	2016	9	Commercial	$ 8,168.05	$ 7,562.39	$ 605.66	$ 605.66
KPC	2016	9	Industrial	$ 6,504.00	$ 6,504.00	$ -	
KPC	2016	9	Other Retail	$ 128.93	$ 128.93	$ -	
KPC	2016	9	Munis	$ 286.45	$ 272.22	$ 14.23	
			Total	**$ 27,056.19**	**$ 24,573.25**	**$ 2,482.94**	
KPC	2016	10	Residential	$ 11,939.50	$ 12,833.25	$ (893.75)	
KPC	2016	10	Commercial	$ 9,356.73	$ 9,441.84	$ (85.11)	$ (85.11)
KPC	2016	10	Industrial	$ 7,157.98	$ 7,157.98	$ -	
KPC	2016	10	Other Retail	$ 131.61	$ 131.61	$ -	
KPC	2016	10	Munis	$ 213.05	$ 216.89	$ (3.84)	
			Total	**$ 28,798.87**	**$ 29,781.57**	**$ (982.70)**	
KPC	2016	11	Residential	$ 14,549.19	$ 16,209.51	$ (1,660.32)	
KPC	2016	11	Commercial	$ 10,991.97	$ 11,304.98	$ (313.01)	$ (313.01)
KPC	2016	11	Industrial	$ 8,872.69	$ 8,872.69	$ -	
KPC	2016	11	Other Retail	$ 145.69	$ 145.69	$ -	
KPC	2016	11	Munis	$ 266.56	$ 274.63	$ (8.07)	
			Total	**$ 34,826.10**	**$ 36,807.50**	**$ (1,981.40)**	
KPC	2016	12	Residential	$ 20,736.54	$ 21,105.83	$ (369.29)	
KPC	2016	12	Commercial	$ 9,744.06	$ 9,821.99	$ (77.92)	$ (77.92)
KPC	2016	12	Industrial	$ 7,610.54	$ 7,610.54	$ -	
KPC	2016	12	Other Retail	$ 138.62	$ 138.62	$ -	
KPC	2016	12	Munis	$ 337.28	$ 339.19	$ (1.91)	
			Total	**$ 38,567.04**	**$ 39,016.17**	**$ (449.12)**	
KPC	2017	1	Residential	$ 19,233.57	$ 22,741.61	$ (3,508.05)	
KPC	2017	1	Commercial	$ 9,148.12	$ 9,893.07	$ (744.95)	$ (744.95)
KPC	2017	1	Industrial	$ 7,156.03	$ 7,156.03	$ -	
KPC	2017	1	Other Retail	$ 133.62	$ 133.62	$ -	
KPC	2017	1	Munis	$ 324.06	$ 346.34	$ (22.28)	
			Total	**$ 35,995.40**	**$ 40,270.67**	**$ (4,275.28)**	
KPC	2017	2	Residential	$ 14,536.40	$ 18,445.07	$ (3,908.67)	
KPC	2017	2	Commercial	$ 8,479.08	$ 9,300.52	$ (821.44)	$ (821.44)
KPC	2017	2	Industrial	$ 7,276.16	$ 7,276.16	$ -	
KPC	2017	2	Other Retail	$ 136.46	$ 136.46	$ -	
KPC	2017	2	Munis	$ 293.59	$ 322.28	$ (28.69)	
			Total	**$ 30,721.69**	**$ 35,480.49**	**$ (4,758.80)**	
							$ (914.15)

EXHIBIT ____ (LK-9)

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
KIUC First Set of Data Requests
Dated August 14, 2017

DATA REQUEST

KIUC_1_031 Please provide the amount of incentive compensation expense pursuant to the Long Term Incentive Plan (LTIP) 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

The information cannot be provided as requested. The LTIP is comprised of two components: Restricted Stock Units (RSUs) and Performance Share Incentives (PSIs). RSUs do not have a target metric as payout of RSUs is based on the grant date stock price of American Electric Power Company, Inc. PSIs have two target metrics: Earnings per Share (EPS) and Total Shareholder Return (TSR). Separate entries were not recorded to the ledger in the test year related to these two PSI target metrics. In addition, the expense related to the PSI is calculated based on the performance of the components over a three-year period and not the test year as requested.

The Company is providing the total PSI and total RSU expense included in the test year revenue requirement for the twelve months ended February 28, 2017. Please see KIUC_1_31_Attachment1.xls and KIUC_1_31_Attachment2.xls for total LTIP and total RSU expense included in the test year revenue requirement for the twelve months ended February 28, 2017 related to Kentucky Power employees and AEPSC employees that were billed to Kentucky Power, respectively.

Witness: Tyler H. Ross

Kentucky Power Company
AEPSC Billings to Kentucky Power Company in Cost of Service
For Long Term Incentive (PSI & RSU)
For the Test Year Ended February 2017

	PSI - Performance Share Incentive			RSU - Restricted Stock Units			LTIP Total		
FERC Account	Amount Billed by AEPSC to KPCO	Less: Mitchell Amount Billed by KPCO to Co-Owner	Adjusted Amount Billed KPCO	Amount Billed by AEPSC to KPCO	Less: Mitchell Amount Billed by KPCO to Co-Owner	Adjusted Amount Billed KPCO	Amount Billed by AEPSC to KPCO	Less: Mitchell Amount Billed by KPCO to Co-Owner	Adjusted Amount Billed KPCO
5000	137,115	46,100	91,015	17,315	11,884	5,432	154,430	57,984	96,447
5010	4,053	390	3,663	1,391	141	1,250	5,444	531	4,913
5020	2,177	815	1,362	157	46	110	2,333	861	1,472
5050	7	0	7	13	0	13	21	0	21
5060	3,587	1,462	2,126	1,003	393	610	4,590	1,855	2,735
5100	12,615	4,834	7,782	3,220	1,212	2,008	15,836	6,046	9,790
5110	13,352	5,507	7,845	2,866	1,047	1,819	16,218	6,554	9,663
5120	19,212	6,116	13,096	4,552	1,700	2,851	23,764	7,316	15,948
5130	27,265	9,448	17,817	7,275	2,225	5,051	34,540	11,673	22,867
5140	11,091	5,175	5,917	2,031	958	1,072	13,122	6,133	6,989
5280	43	18	25	7	3	4	50	21	29
5300	2	0	2	0	0	0	2	0	2
5310	188	80	108	58	25	34	246	105	141
5350	2	1	1	0	0	0	2	1	1
5560	15,299	6,502	8,797	3,949	1,679	2,271	19,249	8,181	11,068
5570	45,759	18,647	27,112	11,124	4,650	6,474	56,883	23,297	33,585
5600	20,118	113	20,005	10,216	35	10,181	30,334	149	30,186
5611	92	0	92	65	0	65	157	0	157
5612	13,575	8	13,567	6,508	2	6,506	20,082	9	20,073
5615	1,681	67	1,615	954	24	930	2,635	90	2,545
5620	2,239	0	2,239	1,205	0	1,205	3,444	0	3,444
5630	689	0	689	392	0	392	1,082	0	1,082
5660	12,759	220	12,539	5,466	69	5,397	18,225	290	17,936
5680	401	(2)	403	194	1	193	596	(1)	596
5690	77	0	77	2	0	2	78	0	78
5691	21	0	21	12	0	12	32	0	32
5692	993	3	990	507	1	505	1,500	4	1,495
5693	9	0	9	5	0	5	14	0	14
5700	6,721	1	6,720	3,307	0	3,307	10,028	1	10,027
5710	10,730	0	10,730	4,588	0	4,588	15,318	0	15,318
5720	1	0	1	0	0	0	1	0	1
5730	6,498	0	6,498	2,825	0	2,825	9,323	0	9,323
5800	11,215	412	10,803	3,349	72	3,277	14,564	484	14,080
5810	52	0	52	24	0	24	75	0	75
5820	1,863	0	1,863	1,154	0	1,154	3,017	0	3,017
5830	(3)	0	(3)	0	0	0	(3)	0	(3)
5840	167	0	167	49	0	49	216	0	216
5860	2,427	1	2,426	659	0	659	3,086	1	3,085
5880	12,230	62	12,167	3,067	13	3,054	15,297	76	15,221
5890	4	0	4	0	0	0	4	0	4
5900	101	0	101	36	0	36	137	0	137
5910	92	0	92	29	0	29	121	0	121
5920	4,430	0	4,430	2,044	0	2,044	6,474	0	6,474
5930	643	0	643	166	0	166	808	0	808
5970	84	0	84	16	0	16	99	0	99
5980	20	0	20	38	0	38	59	0	59
9010	960	(0)	960	284	0	284	1,243	(0)	1,243
9020	1,507	5	1,502	437	1	437	1,945	6	1,939
9030	84,281	31	84,250	23,616	6	23,609	107,897	38	107,859
9050	298	0	298	89	0	89	387	0	387
9070	1,166	0	1,166	335	0	335	1,501	0	1,501
9080	436	0	436	126	0	126	562	0	562
9100	(1)	(0)	(1)	2	0	1	1	0	1
9200	983,571	210,611	772,960	244,530	54,724	189,806	1,228,101	265,335	962,766
9230	7,067	1,744	5,323	1,706	416	1,290	8,774	2,161	6,613
9250	79	20	59	42	10	32	121	30	91
9260	942	236	705	264	65	199	1,205	302	904
9280	29,035	3,125	25,909	10,963	1,222	9,741	39,998	4,347	35,650
9301	240	0	240	71	0	71	311	0	311
9302	3,799	570	3,229	1,048	157	891	4,847	727	4,120
9350	4,712	217	4,495	1,081	54	1,027	5,793	271	5,522
Grand Total	1,519,784	322,538	1,197,247	386,431	82,836	303,595	1,906,216	405,374	1,500,841

Kentucky Power Company
Adjusted LTIP in Cost of Service by Account
For the Test Year Ended 2/28/17

Account	O&M Labor Equalivent FERC pg 354	Percent	RSU Incentive at going Level Total Company	RSU Incentive at going Level Jurisdictional	PSI Incentive at going Level Total Company	PSI Incentive at going Level Jurisdictional
			$ 49,864	$ 49,465	$ 195,097	$ 193,536
Generation:						
5000	549,015.61	2.0325%	$ 1,013.48	$ 1,005.37	$ 3,965.31	$ 3,933.58
5010	56,383.78	0.2087%	104.08	103.25	407.24	403.98
5010	339,539.40	1.2570%	626.79	621.77	2,452.35	2,432.73
5020	617,569.78	2.2863%	1,140.03	1,130.90	4,460.44	4,424.75
5020	467.77	0.0017%	0.86	0.86	3.38	3.35
5020	433.40	0.0016%	0.80	0.79	3.13	3.11
5020	814.20	0.0030%	1.50	1.49	5.88	5.83
5020	103,683.06	0.3838%	191.40	189.87	748.86	742.87
5050	755.80	0.0028%	1.40	1.38	5.46	5.42
5060	4,321,953.62	16.0001%	7,978.27	7,914.43	31,215.63	30,965.87
5100	2,095,165.60	7.7564%	3,867.65	3,836.70	15,132.49	15,011.41
5110	247,433.20	0.9160%	456.76	453.10	1,787.10	1,772.81
5120	4,723,003.83	17.4848%	8,718.60	8,648.84	34,112.24	33,839.30
5130	1,288,338.76	4.7695%	2,378.26	2,359.23	9,305.12	9,230.67
5140	689,790.61	2.5536%	1,273.34	1,263.16	4,982.06	4,942.20
Transmission:						
5600	3.48	0.0000%	0.01	0.01	0.03	0.02
5710	54,811.53	0.2029%	101.18	100.37	395.88	392.71
Distribution:						
5800	173,469.56	0.6422%	320.22	317.66	1,252.90	1,242.87
5830	217,242.21	0.8042%	401.03	397.82	1,569.05	1,556.49
5840	25,155.58	0.0931%	46.44	46.07	181.69	180.23
5850	2,536.38	0.0094%	4.68	4.64	18.32	18.17
5860	590,500.47	2.1861%	1,090.06	1,081.33	4,264.93	4,230.81
5870	132,374.66	0.4901%	244.36	242.41	956.09	948.44
5880	2,137,110.97	7.9117%	3,945.08	3,913.51	15,435.44	15,311.94
5900	325.88	0.0012%	0.60	0.60	2.35	2.33
5930	4,200,542.79	15.5506%	7,754.14	7,692.10	30,338.73	30,095.98
5930	623,215.33	2.3072%	1,150.45	1,141.24	4,501.22	4,465.20
5940	9,332.45	0.0345%	17.23	17.09	67.40	66.86
5950	34,377.81	0.1273%	63.46	62.95	248.30	246.31
5960	18,183.04	0.0673%	33.57	33.30	131.33	130.28
5970	59,409.09	0.2199%	109.67	108.79	429.09	425.65
5980	23,186.00	0.0858%	42.80	42.46	167.46	166.12
9010	147,237.49	0.5451%	271.80	269.62	1,063.43	1,054.92
9020	2,075.81	0.0077%	3.83	3.80	14.99	14.87
9020	205,770.64	0.7618%	379.85	376.81	1,486.19	1,474.30
9020	1,090.97	0.0040%	2.01	2.00	7.88	7.82
9030	33,826.65	0.1252%	62.44	61.94	244.32	242.36
9030	152,610.67	0.5650%	281.72	279.46	1,102.24	1,093.42
9030	654,882.21	2.4244%	1,208.90	1,199.23	4,729.93	4,692.09
9030	108,818.46	0.4029%	200.88	199.27	785.95	779.66
9050	811.83	0.0030%	1.50	1.49	5.86	5.82
9070	70,143.66	0.2597%	129.48	128.45	506.62	502.56
9080	217,140.50	0.8039%	400.84	397.63	1,568.31	1,555.76
9080	330,137.46	1.2222%	609.43	604.55	2,384.44	2,365.36
9100	3,687.69	0.0137%	6.81	6.75	26.63	26.42
Admin. and General:						
9200	1,492,673.94	5.5259%	2,755.46	2,733.41	10,780.95	10,694.69
9210	-975.04	-0.0036%	(1.80)	(1.79)	(7.04)	(6.99)
9220	-533,702.00	-1.9758%	(985.21)	(977.32)	(3,854.70)	(3,823.86)
9250	5,788.20	0.0214%	10.68	10.60	41.81	41.47
9260	11,475.50	0.0425%	21.18	21.01	82.88	82.22
9280	85,649.94	0.3171%	158.11	156.84	618.61	613.66
9301	1,227.71	0.0045%	2.27	2.25	8.87	8.80
9302	3,561.67	0.0132%	6.57	6.52	25.72	25.52
9302	19,307.72	0.0715%	35.64	35.36	139.45	138.34
9350	654,509.13	2.4230%	1,208.21	1,198.55	4,727.24	4,689.42
9350	8,240.91	0.0305%	15.21	15.09	59.52	59.04
Total	27,012,117.37	100%	49,864.00	49,465.00	195,097.00	193,536.00

EXHIBIT ____ (LK-10)

DATA REQUEST

KIUC_2_015 Provide a schedule that shows the amortization expense related to each deferred asset included in the base revenue requirement. For each expense, provide a citation to the relevant Commission Order authorizing recovery of the deferred asset, if any.

RESPONSE

Please refer to KPCO_R_KIUC_2_15_Attachment1.xls for the requested information.

Witness: Tyler H. Ross

EXHIBIT ____ (LK-11)

Kentucky Power Company
KPSC Case No. 2017-00179 General Rate Adjustment
KIUC First Set of Data Requests
Dated August 14, 2017

DATA REQUEST

KIUC_1_073 Please provide all studies or analysis to support the expected retirement date of Big Sandy 1 at 2031.

RESPONSE

No such studies exist. Retirement dates are established by AEP Engineering based on many factors, including the original design, the current condition of the unit - including maintenance and replacements, and its operational conditions - including number of startups and hours of operation. Also considered in determining retirement dates is the potential cost to replace the generation with another source.

Witness: Debra L. Osborne

EXHIBIT ____ (LK-12)

DATA REQUEST

KIUC_1_041 Refer to the Big Sandy plant balances on Section V Exhibit 2 page 46.
a. Separate the plant balances into pre-conversion plant and conversion plant.
b. Describe all overhaul/rebuild work performed on the pre-conversion Big Sandy 1 equipment/plant to enable continued use or re-use after the conversion.
c. Describe all new equipment/plant installed at Big Sandy 1 due to the conversion.

RESPONSE

a. Please refer to KPCO_R_KIUC_1_41a_Attachment1.xls for the separated plant balances.

b. Modifications to pre-conversion Big Sandy plant and equipment included the following:

1. Boiler modification to allow for natural gas combustion;
2. Boiler Pressure Part replacements to accommodate expected increase in operating temperatures;
3. Electronic monitoring system upgrades and modifications to accommodate new and modified equipment;
4. Electrical upgrades including new power distribution equipment to serve new electrical loads;
5. Instrumentation upgrades as required by new equipment installations;
6. Fire Protection System upgrades including Hazard Area Classifications, upgraded building ventilation, and modifications to fire water supply system;
7. Relocation of the Plant Hydrogen Supply tanks;
8. Relocation of Unit 2 station batteries to serve Unit 1 loads;
9. Modifications to burner platforms to provide safe access to new gas burners and associated equipment;
10. Emissions Monitoring System (CEMS) upgrades and modifications as required by air permit.

c. New equipment installed at Big Sandy 1 for the gas conversion included the following:

1. Main Gas & Igniter supply header station with flow metering equipment and pressure reducing, shutoff, and vent valves;
2. Duplex blower system to supply combustion/cooling air to burners and igniters;
3. Burner and igniter gas racks, burners, igniters, and flame scanners;

4. Natural Gas Pipeline terminating at a new gas metering station on the plant site;
5. Fuel Gas conditioning equipment, including pressure reducing station, water bath heater, scrubber vessel, and check-metering station;
6. Gas piping from Check-Metering station to Main Gas & Igniter station;
7. Electric Auxiliary boiler to feed existing steam space heaters and combustion air heating coils;
8. Dedicated Unit 1 demineralized water treatment system, including pre-treatment, reverse osmosis, and deionization equipment;
9. New hydrogen piping to Unit 1 turbine/generator area.

Witness: Debra L. Osborne
Jason A. Cash

EXHIBIT ____ (LK-13)

Kentucky Power Company
KIUC Recommendation to Reduce Depreciation to Extend Estimated Service Life of Big Sandy 1 from 15 to 30 Years
Case No. 2017-00179
For the Test Year Ended February 28, 2017
($)

Acct. No	Description	Depreciable Electric Plant In Service as of 2/28/2017	Company's Proposed Annual Rates	Company's Pro Forma Annualized Depreciation on EPIS 2/28/2017	KIUC Recommended Annual Rates Adj #1	KIUC Recommemded Annualized Depreciation on EPIS 2/28/2017	KIUC Recommemded Depreciation Expense Adjustment
	Big Sandy Unit 1						
311	Structures & Improvements	12,184,471	4.83%	588,694	2.30%	280,425	(308,269)
312	Boiler Plant Equipment	75,395,244	7.15%	5,391,340	3.32%	2,502,789	(2,888,551)
314	Turbogenerator Units	61,396,870	4.52%	2,777,454	2.14%	1,311,155	(1,466,299)
315	Accessory Electrical Equip.	3,909,915	3.03%	118,393	1.44%	56,250	(62,143)
316	Misc. Power Plant Equip.	3,587,666	4.52%	162,251	2.15%	77,087	(85,164)
Total Production Plant - BS1 - Total Co.		156,474,166		9,038,132		4,227,706	(4,810,426)
	Allocation Factor Per Company Filing						0.985
	KIUC Reducton in Depreciation Expense to Extend Service Life of BS1 30 Years - KY Jurisdiction						(4,738,269)

Source: Section V Exhibit 2 - Page 46 of 60

AS FILED
KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF BIG SANDY UNIT 1 DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
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	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
BIG SANDY UNIT 1										
311	Structures & Improvements	11,756,127	1.09	12,814,178	7,526,502	4,805,397	8,008,781	14.10	567,999	4.83%
312	Boiler Plant Equipment	75,388,722	1.09	82,173,707	22,552,265	9,774,280	72,399,427	13.43	5,390,873	7.15%
314	Turbogenerator Units	61,392,346	1.09	66,917,657	36,338,075	28,424,981	38,492,676	13.86	2,777,249	4.52%
315	Accessory Electrical Equip.	3,877,136	1.09	4,226,078	2,964,549	2,578,951	1,647,127	14.03	117,400	3.03%
316	Misc. Power Plant Equip.	3,321,344	1.09	3,620,265	2,153,127	1,512,867	2,107,398	14.03	150,207	4.52%
	Total	155,735,675	1.09	169,751,885	71,534,518	47,096,476	122,655,409	13.62	9,003,728	5.78%

AS ADJUSTED BY KIUC TO EXTEND SERVICE LIFE OF BS1 FROM 15 to 30 YEARS
KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF BIG SANDY UNIT 1 DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
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	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
BIG SANDY UNIT 1										
311	Structures & Improvements	11,756,127	1.09	12,814,178	7,526,502	4,805,397	8,008,781	29.60	270,567	2.30%
312	Boiler Plant Equipment	75,388,722	1.09	82,173,707	22,552,265	9,774,280	72,399,427	28.93	2,502,573	3.32%
314	Turbogenerator Units	61,392,346	1.09	66,917,657	36,338,075	28,424,981	38,492,676	29.36	1,311,058	2.14%
315	Accessory Electrical Equip.	3,877,136	1.09	4,226,078	2,964,549	2,578,951	1,647,127	29.53	55,778	1.44%
316	Misc. Power Plant Equip.	3,321,344	1.09	3,620,265	2,153,127	1,512,867	2,107,398	29.53	71,365	2.15%
	Total	155,735,675	1.09	169,751,885	71,534,518	47,096,476	122,655,409	29.13	4,211,341	2.70%

EXHIBIT ____ (LK-14)

Kentucky Power Company
KIUC Recommendation to Reduce Depreciation to Remove Terminal Net Salvage for Big Sandy 1
Case No. 2017-00179
For the Test Year Ended February 28, 2017
($)

Acct. No	Description	Depreciable Electric Plant In Service as of 2/28/2017	KIUC Recommended Annual Rates After Adj #1	Company's Pro Forma Annualized Depreciation on EPIS 2/28/2017	KIUC Recommended Annual Rates Adj #2	KIUC Recommemded Annualized Depreciation on EPIS 2/28/2017	KIUC Recommemded Depreciation Expense Adjustment
	Big Sandy Unit 1						
311	Structures & Improvements	12,184,471	2.30%	280,425	2.07%	251,611	(28,814)
312	Boiler Plant Equipment	75,395,244	3.32%	2,502,789	3.08%	2,320,360	(182,429)
314	Turbogenerator Units	61,396,870	2.14%	1,311,155	1.90%	1,164,773	(146,382)
315	Accessory Electrical Equip.	3,909,915	1.44%	56,250	1.20%	46,981	(9,269)
316	Misc. Power Plant Equip.	3,587,666	2.15%	77,087	1.91%	68,583	(8,504)
Total Production Plant - BS1 - Total Co.		156,474,166		4,227,706		3,852,308	(375,398)
	Allocation Factor Per Company Filing						0.985
	KIUC Reducton in Depreciation Expense to Remove Terminal Net Salvage for BS1 - KY Jurisdiction						(369,767)

AS ADJUSTED BY KIUC TO REMOVE TERMINAL NET SALVAGE
KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF BIG SANDY UNIT 1 DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016
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)
BIG SANDY UNIT 1										
311	Structures & Improvements	11,756,127	1.02	11,991,250	7,526,502	4,805,397	7,185,853	29.60	242,765	2.07%
312	Boiler Plant Equipment	75,388,722	1.02	76,896,496	22,552,265	9,774,280	67,122,216	28.93	2,320,160	3.08%
314	Turbogenerator Units	61,392,346	1.02	62,620,193	36,338,075	28,424,981	34,195,212	29.36	1,164,687	1.90%
315	Accessory Electrical Equip.	3,877,136	1.02	3,954,679	2,964,549	2,578,951	1,375,728	29.53	46,587	1.20%
316	Misc. Power Plant Equip.	3,321,344	1.02	3,387,771	2,153,127	1,512,867	1,874,904	29.53	63,492	1.91%
	Total	155,735,675	1.02	158,850,389	71,534,518	47,096,476	111,753,913	29.13	3,837,691	2.46%

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AT DECEMBER 31, 2016
CALCULATION OF NET SALVAGE RATIO - BIG SANDY UNIT 1

As Filed

Plant/Units	Terminal Salvage	Interim Salvage Amount	Total Salvage Amount	Terminal Removal	Interim Removal Amount	Total Removal Amount	Original Cost at Dec. 2016	Salvage as a % of Original Cost	Removal as a % of Original Cost	Net Salvage Percent	Net Salvage Ratio
Big Sandy Unit 1	$8,261,424	$1,045,110	$9,306,534	$19,665,185	$4,099,354	$23,764,539	$155,735,675	5.98%	15.26%	-9.28%	1.09
Total Big Sandy Unit 1	$8,261,424	$1,045,110	$9,306,534	$19,665,185	$4,099,354	$23,764,539	$155,735,675				

As Adjusted by KIUC

Plant/Units	Terminal Salvage	Interim Salvage Amount	Total Salvage Amount	Terminal Removal	Interim Removal Amount	Total Removal Amount	Original Cost at Dec. 2016	Salvage as a % of Original Cost	Removal as a % of Original Cost	Net Salvage Percent	Net Salvage Ratio
Big Sandy Unit 1	$0	$1,045,110	$1,045,110	$0	$4,099,354	$4,099,354	$155,735,675	0.67%	2.63%	-1.96%	1.02
Total Big Sandy Unit 1	$0	$1,045,110	$1,045,110	$0	$4,099,354	$4,099,354	$155,735,675				

Kentucky Power Company
KIUC Recommendation to Reduce Depreciation to Remove Terminal Net Salvage for Mitchell Plant
Case No. 2017-00179
For the Test Year Ended February 28, 2017
($)

Acct. No	Description	Depreciable Electric Plant In Service as of 2/28/2017	Company's Proposed Annual Rates	Company's Pro Forma Annualized Depreciation on EPIS 2/28/2017	KIUC Recommended Annual Rates	KIUC Recommemded Annualized Depreciation on EPIS 2/28/2017	KIUC Recommemded Depreciation Expense Adjustment
	Mitchell Plant						
311	Structures & Improvements	$39,689,654	2.66%	1,055,745	2.58%	1,023,080	(32,665)
312	Boiler Plant Equipment	$543,318,597	3.05%	16,571,217	2.96%	16,097,328	(473,889)
312	Boiler Plant Equip - SCR Catalyst	$8,255,456	12.50%	1,031,932	12.50%	1,031,932	-
314	Turbogenerator Units	$53,960,834	1.76%	949,711	1.67%	903,802	(45,909)
315	Accessory Electrical Equip.	$23,765,408	1.56%	370,740	1.49%	353,086	(17,654)
316	Misc. Power Plant Equip.	$6,552,009	2.72%	178,215	2.63%	172,450	(5,765)
Total Production Plant - BS1 - Total Co.		675,541,958		20,157,560		19,581,678	(575,882)
	Allocation Factor Per Company Filing						0.985
	KIUC Reducton in Depreciation Expense to Extend Service Life of BS1 from 15 to 40 Years - KY Jurisdiction						(567,244)

Source: Section V Exhibit 2 - Page 43 of 60

AS ADJUSTED BY KIUC - MATCHES ORDER 2014-00396 DETERMINED RATES
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	1.00	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	1.05	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	938,190,826	309,492,408	304,809,655	633,381,171	23.57	26,869,109	3.01%

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	1.03	43,260,203	18,282,178	16,183,402	27,076,801	25.01	1,082,639	2.58%
312	Boiler Plant Equipment	765,644,984	1.03	788,614,334	245,324,500	238,518,432	550,095,902	24.25	22,684,367	2.96%
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	1.03	54,894,568	29,106,660	33,613,523	21,281,045	23.84	892,661	1.67%
315	Accessory Electrical Equip.	17,080,672	1.03	17,593,092	9,466,086	11,043,285	6,549,807	25.81	253,770	1.49%
316	Misc. Power Plant Equip.	7,693,412	1.03	7,924,214	3,289,590	3,072,520	4,851,694	23.96	202,491	2.63%
	Total	893,905,077	1.03	920,476,526	309,492,408	304,809,655	615,666,871	23.55	26,139,693	2.92%

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AT DECEMBER 31, 2013
CALCULATION OF NET SALVAGE RATIO - MITCHELL PLANT

Plant/Units	Terminal Salvage	Interim Salvage Amount	Total Salvage Amount	Terminal Removal	Interim Removal Amount	Total Removal Amount	Original Cost at Dec. 2013	Salvage as a % of Original Cost	Removal as a % of Original Cost	Net Salvage Percent	Net Salvage Ratio
AS FILED - In 2014-00396											
Mitchell Plant (a)	$35,633,102	$9,414,094	$45,047,196	$75,298,756	$35,556,306	$110,855,062	$893,905,077	5.04%	12.40%	-7.36%	**1.07**
Total Mitchell Plant	**$35,633,102**	**$9,414,094**	**$45,047,196**	**$75,298,756**	**$35,556,306**	**$110,855,062**	**$893,905,077**				
(a) Kentucky's share at 50%.											
TO REMOVE TERMINAL NET SALVAGE ESCALATION OF 2.35% - Order in 2014-00396 Based on KIUC Recommendation in that Case.											
Mitchell Plant (a)	$19,031,883	$9,414,094	$28,445,977	$40,217,580	$35,556,306	$75,773,886	$893,905,077	3.18%	8.48%	-5.30%	**1.05**
Total Mitchell Plant	**$19,031,883**	**$9,414,094**	**$28,445,977**	**$40,217,580**	**$35,556,306**	**$75,773,886**	**$893,905,077**				
(a) Kentucky's share at 50%.											
TO REMOVE ALL TERMINAL NET SALVAGE - KIUC Recommendation in 2017-00179											
Mitchell Plant (a)	$0	$9,414,094	$9,414,094	$0	$35,556,306	$35,556,306	$893,905,077	1.05%	3.98%	-2.93%	**1.03**
Total Mitchell Plant	**$0**	**$9,414,094**	**$9,414,094**	**$0**	**$35,556,306**	**$35,556,306**	**$893,905,077**				
(a) Kentucky's share at 50%.											

EXHIBIT ____ (LK-15)

KIUC Adjustments to KPCO Capitalization and Cost of Capital - Base Rates
Case No. 2017-00179
Test Year Ending February 28, 2017

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	1,022,872	(1,022,872)	-	-	98.50%	-	0.00%	0.80%	0.00%	0.00%	-
Long Term Debt	870,000,000	(211,151,766)	658,848,234	658,848,915	98.49%	648,913,758	54.45%	4.36%	2.37%	2.38%	28,396,984
Accts Receivable Financing	46,807,067	-	46,807,067	46,807,115	98.50%	46,105,009	3.87%	1.95%	0.08%	0.08%	958,548
Common Equity	666,016,164	(161,644,243)	504,371,921	504,372,442	98.49%	496,766,726	41.68%	10.31%	4.30%	7.07%	84,211,304
Sub Total	1,583,846,103	(373,818,881)	1,210,027,222	1,210,028,472		1,191,785,493	100.00%		6.75%	9.53%	113,566,837
Job Development Tax Credit	1,250		1,250			-					
Total Capital	1,583,847,353	(373,818,881)	1,210,028,472	1,210,028,472		1,191,785,493	100.00%		6.75%	9.53%	113,566,837

II. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization to:
Capitalization Adjustment 1 - Remove Certain Balances Consistent With Appropriate Ratemaking Recovery for Non-Utility and Surcharge Investments

	KPCO Reapportioned Kentucky Adjusted Capitalization	KIUC Proforma Adjustment 1	Kentucky Jurisdictional Factor	KIUC Kentucky Proforma Adjustment 1	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%	0.80%	0.00%	0.00%	-	-
Long Term Debt	648,913,758	(5,496,719)	98.60%	(5,419,765)	643,493,993	54.43%	4.36%	2.37%	2.38%	28,168,986	(227,998)
Accts Receivable Financing	46,105,009	-		-	46,105,009	3.90%	1.95%	0.08%	0.08%	950,852	(7,696)
Common Equity	496,766,726	(4,207,935)	98.60%	(4,149,024)	492,617,702	41.67%	10.31%	4.30%	7.07%	83,535,176	(676,129)
Total Capital	1,191,785,493	(9,704,654)		(9,568,788)	1,182,216,704	100.00%		6.75%	9.53%	112,655,014	(911,823)

III. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization to:
Capitalization Adjustment 2 - Reduce Low Sulfur Coal Inventory to Reflect Actual

	KPCO Reapportioned Kentucky Adjusted Capitalization	KIUC Proforma Adjustment 1	Kentucky Jurisdictional Factor	KIUC Kentucky Proforma Adjustment 1	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%	0.80%	0.00%	0.00%	-	-
Long Term Debt	643,493,993	(707,825)	98.60%	(697,916)	642,796,078	54.43%	4.36%	2.37%	2.38%	28,139,627	(29,360)
Accts Receivable Financing	46,105,009	-		-	46,105,009	3.90%	1.95%	0.08%	0.08%	949,861	(991)
Common Equity	492,617,702	(541,866)	98.60%	(534,280)	492,083,423	41.67%	10.31%	4.30%	7.07%	83,448,109	(87,067)
Total Capital	1,182,216,704	(1,249,691)		(1,232,195)	1,180,984,509	100.00%		6.75%	9.53%	112,537,596	(117,418)

KIUC Adjustments to KPCO Capitalization and Cost of Capital - Base Rates
Case No. 2017-00179
Test Year Ending February 28, 2017

IV. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Capitalization for:
Cost of Capital Adjustment 1 - Reflect 2% Short Term Debt in Capital Structure at 1.25% Cost of Debt

	KPCO Reapportioned Kentucky Adjusted Capitalization	KIUC Proforma Adjustment 1	Kentucky Jurisdictional Factor	KIUC Kentucky Proforma Adjustment 1	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	-	23,979,380	98.50%	23,619,689	23,619,689	2.00%	1.25%	0.02%	0.02%	237,465	237,465
Long Term Debt	642,796,078	(23,979,380)	98.50%	(23,619,689)	619,176,388	52.43%	4.36%	2.29%	2.30%	27,189,766	(949,861)
Accts Receivable Financing	46,105,009	-	98.50%	-	46,105,009	3.90%	1.95%	0.08%	0.08%	949,861	-
Common Equity	492,083,423	-	98.50%	-	492,083,423	41.67%	10.31%	4.30%	7.07%	83,448,109	-
Total Capital	1,180,984,509	-		-	1,180,984,509	100.00%		6.69%	9.47%	111,825,201	(712,396)

V. KPCO Capitalization, Cost of Capital, and Gross Revenue Conversion Factor Adjusting Return on Common Equity to 8.85%.

	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	23,619,689	2.00%	1.25%	0.02%	0.02%	237,465	-
Long Term Debt	619,176,388	52.43%	4.36%	2.29%	2.30%	27,189,766	-
Accts Receivable Financing	46,105,009	3.90%	1.95%	0.08%	0.08%	949,861	-
Common Equity	492,083,423	41.67%	8.85%	3.69%	6.06%	71,610,121	(11,837,988)
Total Capital	1,180,984,509	100.00%		6.08%	8.47%	99,987,213	(11,837,988)
				Effect for Every 1% ROE			(8,108,211)

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	23,619,689	2.00%	1.25%	0.02%	0.02%	237,465	-
Long Term Debt	619,176,388	52.43%	4.36%	2.29%	2.30%	27,189,766	-
Accts Receivable Financing	46,105,009	3.90%	1.95%	0.08%	0.08%	949,861	-
Common Equity	492,083,423	41.67%	8.85%	3.69%	5.95%	70,290,334	(1,319,788)
Total Capital	1,180,984,509	100.00%		6.08%	8.35%	98,667,426	(1,319,788)
				Effect for Every 1% ROE			(903,964)