COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In The Matter Of:

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

PUBLIC VERSION

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

APRIL 1, 2013

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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 in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practicing license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA").

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 federal and state regulatory commissions and courts on hundreds of occasions.

I have testified before the Kentucky Public Service Commission on dozens of occasions, including the most recent Kentucky Power Company ("Kentucky Power" or "Company") base rate proceedings, Case Nos. 2009-00459 and 2005-00341; the Company's recent purchased wind power proceeding, Case No. 2009-00545; various Company Environmental Cost Recovery ("ECR") proceedings; and other proceedings involving the Company, Louisville Gas and Electric Company, Kentucky Utilities Company, Big Rivers Electric Corporation, and East Kentucky Power Cooperative, Inc. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address: 1) certain aspects of the Company's request for a Certificate of Public Convenience and Necessity ("CPCN") to acquire an undivided 50% ownership interest in each of the two Mitchell coal-fired generating units (referred to by the Company as the "transfer and assumption transaction", 2) compliance with the state affiliate transaction statute, 3) rate impacts of the acquisition, including the related impacts of the contemporaneous termination of the existing AEP Pool Agreement and sharing of off-system sales ("OSS") margins, and 4) the Company's request for authorization to defer for ratemaking purposes the costs associated with two Big Sandy environmental retrofit investigations, the first for which it incurred costs in the years 2004-2006 and the second for which it incurred costs during the years 2010-2012.

Q. Please summarize your testimony.

A. KIUC recommends that the Commission authorize the Company to acquire 20% of the Mitchell generating units contemporaneous with the planned shutdown and retirement of Big Sandy 2 on June 1, 2015. The acquisition price must be at the lower of cost or market. This acquisition would be combined with a Big Sandy 1 conversion from coal-fired to natural gas-fired and market purchases to satisfy on a short term basis any remaining native load. The environmental and other risks associated with having a system that is 100% base load coal-fired generation are too great to intentionally and prematurely acquire excess capacity. The Company has not met its burden to demonstrate that its proposal "meets a need for such facilities" or that there is no "wasteful duplication," two standards that are set forth in the CPCN statute.

KIUC witness Mr. Philip Hayet addresses the economic planning and modeling analyses that he performed of the Company's proposal and alternative resource portfolios to develop KIUC's recommendation. Mr. Hayet demonstrates that the KIUC recommendation has a cumulative net present value cost that is lower than the Company's proposal.

I provide further support for the KIUC recommendation with the following conclusions and recommendations:

- The Commission should set the acquisition price at the lower of cost or market in accordance with the statutory requirements for pricing affiliate transactions. The Company has not demonstrated that net book value is less than or equal to the market value of other capacity options. It failed to perform a market test by issuing a Request for Proposal ("RFP") to replace the Big Sandy 2 capacity and failed to actively consider other resources that are or may be for sale.

- The Company's plan does not promote fuel diversity and misses the opportunity to reduce the Company's reliance on coal-fired capacity through greater resource diversification. The KIUC proposal to acquire 20% of the Mitchell units, combined with a Big Sandy 1 conversion to natural gas, promotes fuel diversity. The KIUC proposal also increases jobs and local property taxes in Kentucky, as well as reducing the property taxes and B&O taxes paid to the state of West Virginia.

- The Company's plan unnecessarily exposes customers to increasingly stringent environmental requirements imposed by the U.S. EPA and the resulting costs and/or premature retirement and replacement of coal-fired capacity. The KIUC recommendation to acquire 20% of the Mitchell units lessens this risk exposure.

- The Company's proposal to acquire 50% of the Mitchell capacity, and to acquire it before Big Sandy 2 is retired, unnecessarily exposes customers to merchant generator risk, with vast quantities of energy sold into an extremely depressed PJM market. The Company's proposal will result in a reserve margin of more than 100% in July 2014 and more than 140% in other non-peak months before Big Sandy 2 is retired. The KIUC recommendation to acquire 20% of the Mitchell units and to delay the acquisition until June 1, 2015 lessens this risk exposure.

- The Company's decision to acquire 50% of the Mitchell units was not independent and thus, should be subjected to even greater scrutiny. AEP made the decision to reposition the Mitchell units by transferring them from an unregulated affiliate to the Company where they will become regulated for ratemaking purposes. As a result, AEP will shift the market price, operating expenses, capital expenditures, environmental, and merchant risks from its shareholders onto the Company's customers.

- The AEP decision to offer the Mitchell units to the Company on January 1, 2014 instead of when the capacity is needed on June 1, 2015 is not least cost to Kentucky customers and is timed to enable AEP to obtain a windfall in earnings from Kentucky customers. That is because AEP already recovers and will continue to recover the fixed costs of Mitchell from Ohio customers through May 31, 2015.

- The Company's planning assumptions used to support the Mitchell acquisition in this CPCN proceeding date to early 2011 and are different and more favorable for the Mitchell acquisition than the assumptions used for accounting purposes to test for impairment analysis in February 2013. The assumptions used to test for impairment should be afforded greater weight because they are reviewed by the Company's independent outside auditors and because the Company's officers must attest to the accuracy of the Company's financial statements for SEC and FERC reporting purposes.

- The Company's planning assumptions used to support the Mitchell acquisition in this proceeding date to early 2011 and understate the fixed O&M expense compared to the Company's present estimate of O&M expense for ratemaking purposes.

- The Company's Strategist modeling assumes that all OSS margins are flowed through to customers. KIUC accepts and agrees with this assumption; however, this assumption is inconsistent with the present configuration of the System Sales Clause ("SSC") component of the Company's Fuel Adjustment Clause ("FAC") mechanism, which allows the Company to retain 40% of the OSS margins above the amount included in base rates. If the Company is authorized to acquire the Mitchell units, whether 20% or 50%, then the Commission should revisit the SSC sharing. Acquiring 50% Mitchell 17 months before Big Sandy 2 retires will create vast quantities of energy for sale into the PJM market. If customers will be responsible for all of the Mitchell fixed costs through base rates and the ECR, then the entirety of the related OSS margins should be flowed through to customers, not only 60% of those margins.

In addition, the Company's proposal will result in unnecessary base rate and environmental cost recovery ("ECR") surcharge rate increases on or about January 1, 2014 to reflect the Mitchell acquisition. The Company has indicated that it plans to file a base rate increase in June of this year to recover the Mitchell costs and that it plans to recover certain environmental costs related to Mitchell through the ECR. Instead of these rate increases, there could and should be base rate reductions on or about January 1, 2014 if the Mitchell acquisition is delayed until Big Sandy is retired on June 1, 2015. Base rates should be reduced to reflect the elimination of $22 million in annual capacity equalization payments due to the termination of the AEP Pool Agreement on January 1, 2014, among other reasons. KIUC currently is evaluating whether to file an overearnings complaint case in June of this year.

Further, the Company understated the amount of the Mitchell rate increases by failing to reflect known PJM RPM capacity prices starting in 2014 and forward PJM energy prices compared to the 2011 and 2012 test years that it used for these rate impact analyses, and making normalization adjustments to improve the actual 2012 operating performance of the units and to improve the off-system sales margins in a manner that is inconsistent with the Commission's historic ratemaking practices and unlikely to be incorporated by the Company in an actual rate case filing.

Finally, the Commission should reject the Company's request to retroactively defer $29.287 million of environmental study costs for ratemaking purposes that should have been expensed when incurred. Although the Company is not seeking rate recovery in this proceeding, if the Commission authorizes the deferral for ratemaking purposes, then it virtually will ensure future recovery in the Company's next base rate case proceeding.

The remainder of my testimony is structured to address each of the preceding issues sequentially.

II. CONSIDERATIONS THAT AFFECT THE DECISION TO ACQUIRE THE MITCHELL UNITS

A. The Acquisition of Mitchell Before Big Sandy 2 Is Retired Is Not Necessary and Results in Wasteful Duplication

Q. The Company asserts in its Application that the proposed acquisition of the Mitchell units meets the requirements set forth in KRS 278.020 that such facilities be needed and that they avoid "wasteful duplication." Do you agree that the Mitchell units are needed and that they avoid wasteful duplication prior to the date when Big Sandy 2 is retired?

A. No. The Company does not need additional capacity until Big Sandy 2 is retired. The acquisition of additional capacity prior to that date is wasteful duplication and is not in the public interest.

Q. What is the Company's reserve margin using the PJM summer peak for 2014 without Mitchell, with the 20% Mitchell recommended by KIUC, and with the 50% proposed by the Company?

A. The Company's reserve margin for the 2014 PJM summer peak without Mitchell is 35%, with the 20% Mitchell is 50%, and with the 50% Mitchell is 108%. In other words, the Mitchell units are not needed and represent wasteful duplication at least until Big Sandy 2 is retired. I relied on the Company's peak load and capacity projections provided in response to KIUC 2-26 to make these calculations. In that response, the Company uses a retail peak demand of 1,082 mW and shows capacity of 2,250, including the 50% Mitchell. Excluding the entirety of Mitchell reduces the capacity to 1,460 mW and including the 20% Mitchell results in capacity of 1,618 mW.

B. The Company Failed to Demonstrate that the Net Book Value of the Mitchell Units is Less than Or Equal to the Market Value

Q. Does the Company have an obligation to demonstrate that the proposed transfer price for the Mitchell units at net book value is less than or equal to market value?

A. Yes. KRS 278.2207 *Transactions between a utility and affiliate – Pricing requirements – request for deviation* states that in transactions with an affiliate, the pricing shall be the lesser of cost or market. In other words, if the market value is less than net book value, then the utility is limited to market value..

Q. Did the Company demonstrate that the proposed transfer price for the Mitchell units at net book value was less than or equal to market value?

A. No. The Company has made no attempt to obtain an actual market value for the Mitchell units. The best way to obtain the actual market value is through an RFP either to sell (the Mitchell units) or acquire (replacement for Big Sandy 2). Another approach is to develop a proxy for market value by reviewing sales or purchases of similar units. The Company failed to employ either of these approaches. It relied solely on its economic planning analyses. However, those analyses do not address whether the net book value of the Mitchell units is more or less than the market value.

Q. Did the Company attempt to sell the Mitchell capacity to an unaffiliated third party to determine the actual market value?

A. No. In response to KIUC 1-52, the Company acknowledged that AEP had made no attempt to sell the Mitchell generating units to non-affiliated entities within the last three years. I have replicated a copy of that response as my Exhibit___(LK-2).

Q. Did or does the Company plan to issue an RFP for capacity to replace Big Sandy 2?

A. No.

Q. What reasons does the Company give for why it didn't issue an RFP?

A. Company witness Mr. Scott Weaver asserts that it wasn't necessary because the "market" cost of new generation would be equivalent to the Company's cost estimates. Mr. Weaver further assets that "for the largely baseload energy also being replaced-would likely be offered/priced at the cost of a new-build combined cycle in response to such an RFP." [Weaver Direct at 37]. Company witness Dr. Karl

McDermott asserts that it wasn't necessary to conduct a full RFP process "since the analysis conducted by the Company includes evaluations that approximate price bids that would result from an RFP process." [McDermott Direct at 3-4].

However, neither Mr. Weaver nor Dr. McDermott offered any empirical evidence whatsoever that the Company's cost estimates for new gas-fired capacity indeed would approximate price bids that would result from an RFP process for the Mitchell units or comparable coal-fired units. Such self-serving, circular, and conclusory reasoning fails to consider the age of the Mitchell units, the fuel source of the Mitchell units, or the operating characteristics of the Mitchell units, and fails to consider the cost structure, financing costs, operating costs, and required return for all other capacity that might bid into the RFP. Even worse, according to Mr. Hayet, AEP overstated the cost of combined cycle capacity by approximately 30% compared to the EIA estimate.

When asked to provide all support for this proposition in KIUC 1-68, Dr. McDermott argued that it was a matter of "economic reasoning" that sellers generally be would be unwilling to sell at or below their opportunity cost, which he defined as "either the cost to build and operate a new plant or the price that can be obtained in the market place (whichever is larger)." I have attached a copy of this response as my Exhibit___(LK-3).

When asked to explain how he could "be certain that the Company's 'evaluations' approximate price bids that would result from an RFP process" in

KIUC 1-72(b), Dr. McDermott responded that the question misstated his testimony, but provided no further explanation. I have attached a cop of this response as my Exhibit___(LK-4).

When asked if he agreed that an actual RFP process would be the "best" test of whether the Company's "evaluations" approximate price bids that would result from an RFP process in KIUC 1-72(c), Dr. McDermott surprisingly answered "no."

When asked to identify the pool of specific entities and/or resources that might bid into an RFP if one were held in KIUC 1-73(a), the Company objected to the question and simply identified the generic range of resources that might be bid into an RFP, which ranged from existing generating units to new build units to "market sourced solutions." I have attached a copy of this response as my Exhibit___(LK-5).

In short, the Company has no empirical support whatsoever for the premise that the bid prices would approximate the cost of new-build gas-fired generation as quantified by the Company and has offered no evidence that it has searched for, identified, or assessed any alternatives that may be lower cost than the Mitchell acquisition at net book value. Similarly, the Company has no empirical support whatsoever that the market value of Mitchell is equivalent to that of new-build gas-fired generation or that it is greater than or equal to the net book value of the units.

Q. Do you agree with the Company's propositions that its estimates of new-build gas-fired generation are a proxy for or the best estimates of market value or that an actual RFP would not be a superior test and potentially result in lower actual market values?

A. No. These propositions are not supported with empirical evidence and are inherently unreasonable. The only means to determine the actual market value of assets are to solicit bids for the sale of the assets, issue an RFP to acquire similar assets or assets with similar or superior capabilities, or review purchases and sales of other similar assets. In the planning world or the academic world, it may be tempting to assume that assumptions are equivalent to reality. However, they seldom are. As Yogi Bera once famously said, "in theory, there is no difference between theory and practice; in practice, there is." If, in fact, assumptions are reality, then it never would be necessary for a utility to conduct an RFP, actual market prices always would be the same or greater than the utility's self-build costs, and the entire concept of markets should be rejected in favor of centralized planning.

As a factual matter, other utilities have acquired capacity at substantial discounts to the cost of new generation, including other AEP affiliates. Yet, AEP failed to solicit bids to sell Mitchell to unaffiliated third parties or to acquire other assets on behalf of the Company in lieu of Mitchell from unaffiliated third parties. An April 1, 2013 article in the Wall Street Journal cited a sale in March of this year of three coal-fired power plants totaling 4,100 mW of capacity by Dominion

Resources to Energy Capital Partners at "just over $100" per kW of capacity. The article compared this sales price to Department of Energy estimates to build new coal-fired capacity "at about $3,000 per kilowatt." The article also cited another sale in March of this year of 4,100 mW of capacity by Ameren to Dynegy for the assumption by Dynegy of $825 million in nonrecourse debt. The article concluded that "'Dynegy is getting paid $200 million to take' the coal plants." By comparison, the Company's estimated acquisition cost of Mitchell is $648 per kW, according to Table 3 in Mr. Weaver's Direct Testimony.

Q. Are there other generating facilities on the market or available for purchase, perhaps below the cost of new capacity assumed by the Company?

A. Yes. Despite the Company's objections and failure to produce any evidence that it monitors or evaluates the market for generation assets in response to the KIUC discovery that I previously discussed, the Company provided evidence in response to KIUC 2-29(e) that in fact AEP does so. That evidence demonstrates that there have been recent transactions for coal and gas-fired capacity and evidence that the prices paid for gas-fired capacity average less than half of what the Company assumed in its planning studies for new-build. I have replicated the Company's response to KIUC 2-29 as my Exhibit___(LK-6).

Q. **Although it claims that an RFP is not necessary to test the market for capacity to replace Big Sandy 2 when it retires, has the Company recently issued an RFP for 250 mW to market test its proposal to convert Big Sandy1 to natural gas?**

A. Yes. On March 28, 2013, AEP issued the following press release describing its RFP and the reasons for issuing the RFP (to identify the least reasonable cost solution to replace Big Sandy 1 coal-fired generation when it is retired on June 1, 2015:

> Kentucky Power Company has issued a Request for Proposals (RFP) to purchase up to 250 megawatts of long-term capacity and energy in connection with its evaluation of the least reasonable cost solution to replace the impending loss of generation at Kentucky Power's Big Sandy Plant Unit 1. Unit 1, a 278-megawatt coal-fired generating station, is scheduled for retirement in 2015.
>
> The RFP seeks proposals from eligible bidders capable of being online by June 1, 2015, for a "bundled product" that includes capacity (megawatts), energy (megawatt hours) and ancillary services, if available. The RFP is seeking proposals from suppliers who are willing to sell power through a Power Purchase Agreement (PPA), Tolling Agreement (TA) and Asset Purchase Agreement (APA) or other proposals defined by the RFP.
>
> In addition, the RFP also seeks demand-side management and cost-effective energy efficiency proposals. The RFP, as well as terms and conditions and information about submitting proposals, is available at (www.kentuckypower.com/go/rfp).
>
> The RFP is one option Kentucky Power is considering to replace the generating capacity of Unit 1. Another option under consideration is to convert Big Sandy Unit 1 to natural gas generation.
>
> "This RFP will help us determine the best path forward to replace generation at our Big Sandy Plant Unit 1, which will be lost as a result of pending environmental regulations and agreements," said Greg Pauley, president and chief operating officer of Kentucky Power. "These proposals will not bind

> Kentucky Power or AEP to any particular path at this point, but will help us evaluate our options for replacing generation to meet our customers' needs."

Q. Do other Kentucky utilities also issue RFPs to solicit the market for the least cost capacity solution and/or to market test their self-build options?

A. Yes. LG&E/KU recently issued an RFP for 700 mW and EKPC recently conducted an RFP to assess whether certain the cost of proposed environmental upgrades were economic compared to the market value of other options.

C. The Company's Proposal Does Not Promote Fuel Diversity

Q. Does the Company's proposal promote fuel diversity?

A. No. The Company's proposal doubles down on coal generation located in West Virginia (Mitchell) and Indiana (Rockport) and misses a unique opportunity to diversify its base load resources to include additional gas-fired generation and purchases. This increases the Company's environmental risk exposure and its merchant generator risk.

D. Company's Proposal Increases Environmental Risk Exposure

Q. Does the Company's proposal increase its environmental risk exposure?

A. Yes. The increase in coal-fired capacity necessarily increases the Company's environmental risk exposure. The risk exposure consists of increased capital expenditures and increased operating expenses to comply with future environmental regulations applicable primarily to coal-fired generating units. Company witness Mr. John McManus lists and describes the known environmental exposures, only some of which can be and have been quantified in the Company's analyses. [McManus Direct at 6-8, 11]. However, there are other known, but unquantifiable (at this time) and still other unknown and unquantifiable environmental risk exposures.

Under the Company's proposal, it will substantially increase its coal-fired capacity for 17 months beginning on January 1, 2014 and miss the opportunity to reduce its coal-fired capacity and environmental risk exposure after Big Sandy 2 is retired. Under the Company's proposal, beginning January 1, 2014 it will own or have under contract all coal-fired capacity. This capacity will consist of 790 mW of Mitchell, 800 mW of Big Sandy 2, 268 mW of Big Sandy 1, and 390 mw of Rockport.

The Company's customers will bear this increased coal-fired environmental risk exposure, just as they now must bear the costs to replace the Big Sandy 1 and Big Sandy 2 coal-fired capacity. These units are being retired (or, in the case of Big Sandy 1, potentially converted to natural gas) prematurely, the stark reality and ultimate result of the environmental risk exposure of coal-fired capacity.

The KIUC recommendation, in addition to the lower costs compared to the Company's proposal, will reduce this increased environmental risk exposure compared to the Company's proposal.

<u>E. Company's Proposal Increases Merchant Generator Risk Exposure</u>

Q. Does the Company's proposal increase the Company's merchant generator risk exposure?

A. Yes. The Company already is energy long and is a net seller under the Pool Agreement. That means the Company already produces more energy than is necessary to meet its own load, even without the acquisition of the Mitchell units. It will continue to be energy long and a net seller after the termination of the Pool Agreement on January 1, 2014 and until Big Sandy 2 is retired in June 2015, even without the acquisition of the Mitchell units.

If the Company acquires any Mitchell capacity prior to June 2015, then it necessarily will become even more energy long. The Company does not need the energy and will have to sell the Mitchell energy into the market. The Company will be a price taker on the market energy sales and will only sell if its generation clears the market. One of the reasons that the Big Sandy 2 and Mitchell units operated at lower capacity factors in 2012 compared to prior years was that less of the energy available for sale actually cleared the market in 2012, according to the Company's response to AG 2-12. This will be an ongoing problem unless and until market prices rise. In addition, the Company's analysis shows that the projected market revenues will not be sufficient to cover the total costs of the acquisition. If they were, there would be no need for the 8% rate increase (on total revenues) quantified by Mr. Wohnhas on his RKW-Exhibit 4 using a 2011 test year or the nearly 20% increase (on total revenues) quantified by Mr. Wohnhas in response to AG 2-12 using a 2012 test year.

Q. Should the Commission willingly assume this merchant generator risk?

A. No. The Commission should direct the Company to delay the acquisition to June 1, 2015 and reduce the acquisition to 20% of each of the Mitchell units. It is far better for the Company to purchase only what it needs rather than to buy the generation and take on excessive market demand and price risk. Limiting the acquisition to only 20% of the Mitchell units not only reduces the merchant generator risk, it is an important component of a least cost plan.

F. Company's Decision-Making Is Subject to AEP and Appalachian Power Company

Q. Did AEP Service Corporation or did the Company itself perform all of the planning analyses relied on by the Company to seek the acquisition of 50% of the Mitchell units in this proceeding?

A. All of the planning analyses were performed by and supported by AEP Service Corporation employees or by a consultant retained to support AEP Service Corporation's analyses.

Q. Mr. Greg Pauley, the Company's President, asserts that he made the decision to acquire 50% of the Mitchell units. [Pauley Direct at 4]. What analyses did he do and what documents did he review in making that decision?

A. Mr. Pauley performed no analyses and reviewed no analyses conducted by AEP Service Corporation to make the decision to acquire 50% of the Mitchell units. The only documents he reviewed were a list of options under review by AEP Service Corporation sent to him via email from Mr. Weaver, according to the Company's response to KIUC 1-102 and confirmed in the Company's response to KIUC 2-51. I have attached a copy of these responses as my Exhibit___(LK-7) and Exhibit___(LK-8), respectively.

Q. Does Mr. Pauley report directly to the Mr. Nick Akins, the President and CEO of AEP?

A. No. Mr. Pauley reports directly to Mr. Charles Patton, the President and Chief Operating Officer of Appalachian Power Company, according to the Company's response to Staff 1-18. Thus, the Company's interests and those of its customers are subservient to the economic and political interests of Appalachian Power Company, which operates in Virginia and West Virginia, and its customers.

That is significant because Kentucky customers' interests may be different than West Virginia customers' interests. The Mitchell units are located in West Virginia, not in Kentucky. The acquisition of the Mitchell units will require Kentucky ratepayers to pay West Virginia taxes, such as the B&O tax. Under a 50% Mitchell scenario, this tax starts at approximately $4 million annually, increases to $6.3 million annually in 2017, and totals approximately $182 million over the assumed remaining lives of the units. The acquisition of Mitchell will result in no Kentucky property taxes and no new jobs created in Kentucky to replace those lost when Big Sandy 2 is retired. The KIUC least cost plan, which includes the conversion of Big Sandy 1 to burn natural gas, will result in local jobs and property tax revenues.

Q. What is the status of the Mitchell units in Ohio?

A. The Mitchell units presently are owned by Ohio Power Company, but will be transferred, along with the other generating units still owned by Ohio Power Company, to an unregulated affiliate, AEP Generation Resources, pursuant to a corporate separation plan recently approved by the Public Utilities Commission of Ohio ("PUCO") in PUCO Case No. 11-346.

Despite the transfer of the Mitchell units to the unregulated affiliate, Ohio Power Company will continue to receive a form of cost-based recovery for the Mitchell units through May 31, 2015, the duration of Ohio Power Company's present rate plan, according to the PUCO decision in Case No. 10-2929. Ohio Power Company was authorized by the PUCO in Case No. 10-2929 to defer the excess of its cost-based revenue requirement for the Mitchell units over the projected market revenues for the period from August 2012 through May 2015, and also was authorized in Case No. 11-346 to recover the deferrals through a surcharge.

Q. Why are the PUCO's decisions relevant to the Company's acquisition of Mitchell prior to June 1, 2015?

A. First, it provides additional evidence that AEP is the decision-maker as to the owner of the Mitchell units, not Kentucky Power Company. AEP determined the resources that would be offered to the Company and the timing of the offering.

Second, it explains why AEP structured its offer to sell the Mitchell capacity to the Company some 17 months before it is needed. In this manner, AEP can obtain a windfall in its earnings by recovering the same Mitchell fixed costs from the Ohio Power Company customers and then again from the Kentucky Power Company customers for the 17 month period.

The Commission should call AEP on this aggressive strategy and delay the acquisition of the Mitchell units until the capacity is needed. It is evident that neither the Company itself nor AEP have an independent interest in protecting Kentucky customers from incurring the Mitchell costs before the capacity is needed; to the contrary, AEP and the Company do have an interest in maximizing the value of the Mitchell capacity for AEP's shareholders. Thus, the Commission must intervene and protect Kentucky customers from this overreach.

G. Company's Planning Assumptions in Strategist Are More Favorable to Mitchell Acquisition than Assumptions Used for Recent Impairment Analysis

Q. How do the assumptions used by AEP in Strategist for the Mitchell units compare to the assumptions used by AEP recently to test for impairment for accounting and financial reporting purposes?

A. AEP used different assumptions for each purpose, with the assumptions used in Strategist favoring the acquisition of Mitchell through greater OSS margins, lower fuel and variable operating expenses, lower capital expenditures, and greater market capacity revenues.

Q. Please describe the impairment test performed by AEP for its Ohio generating units, including the two Mitchell units, during 2012.

A. AEP performed an impairment test as of November 30, 2012 for accounting and external financial reporting purposes for each of its Ohio generating units because of two triggering events. The first triggering event was the anticipated termination of the Pool Agreement effective December 31, 2013. The second triggering event was a combination of decisions by the Public Utilities Commission of Ohio in Case Nos. 10-2929 and 11-346 approving plans for separation of Ohio Power Company's generating units to an unregulated affiliate, including the Mitchell units, transition from an FRR entity to an RPM entity within PJM by May 31, 2015, and the deferral and recovery of costs in excess of projected market revenues.

The impairment testing resulted in a an impairment charge related to certain Ohio generating assets of $287 million, including amounts related to materials and supplies inventory write-off of $12.7 million. The write-off of the asset costs was included in the income statement under the caption "Asset Impairment and Other Related Charges." An impairment charge was not made for the two Mitchell units.

The Company provided a detailed description of the impairment testing that it performed in late 2012 in its response to KIUC 2-55, a copy of which I have attached as my Confidential Exhibit___(LK-9).

Q. What is an impairment test under Generally Accepted Accounting Principles ("GAAP") and why should it be made?

A. An impairment test must be performed for long-lived assets whenever the recoverability of the carrying amount, generally the net book value, is negatively affected due to certain events or changes in circumstances, such as the two triggering events noted above. This is necessary to ensure that the value of the assets is properly reflected and not overstated in the accounting books and records and in the financial statements relied on by investors and other parties.

The results of the impairment test are extremely important to investors and other parties. If the estimated future cash flows of the asset are diminished as a result of the triggering event, the impairment test may require a writeoff for accounting and financial statement purposes to reflect the diminished value of the asset. The test first compares the carrying value of the long-lived asset to its fair value, which is represented by the sum of the undiscounted cash flows expected resulting from the use and eventual disposition of the asset. If the carrying value exceeds the fair value, then the carrying value is impaired and it must be written down to reflect the net present value of the diminished value. The impairment test is set forth in Accounting Standards Codification ("ASC") promulgated by the Financial Accounting Standards Board ("FASB") in ASC 360-10-35-17, which reads:

An impairment loss shall be recognized only if the carrying amount of a

> **long-lived asset (asset group) is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset (asset group) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset (asset group). That assessment shall be based on the carrying amount of the asset (asset group) at the date it is tested for recoverability, whether in use or under development. An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset (asset group) exceeds its fair value.**

Q. When must an impairment test be performed pursuant to GAAP?

A. The ASC 360-10-35-21 describes the conditions under which impairment testing is required as follows:

> **A long-lived asset shall be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. The following are examples of such events or changes in circumstances:**
>
> **a. A significant decrease in the market price of a long-lived asset (asset group)**
>
> **b. A significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition**
>
> **c. A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset (asset group), including an adverse action or assessment by a regulator**
>
> **d. An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset (asset group)**
>
> **e. A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group)**

f. **A current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term more likely than not refers to the likelihood that it is more than 50 percent.**

AEP determined that several of the preceding criteria applied and that it was required to perform impairment tests for each of the Ohio Power Company generating plants, including the Mitchell units.

Q. How did AEP quantify the recoverable undiscounted cash flows to determine the fair value in the November 2012 impairment test?

A. This is described in detail in the Company's response to KIUC 2-55. AEP personnel from the Generation Business Planning and Analysis department utilized a model called the Spread Option Model for this purpose. This model depicts market transactions as part of its valuation, so it included adjustments related to the termination of the Pool Agreement and the transfer of the Ohio generating assets to an affiliate. As a result of the impairment testing, Ohio Power Company was required to writedown the cost of twelve generating units.

Q. Are AEP management and its independent outside auditors, presently Deloitte and Touche LLP, required to attest to the accuracy of AEP's financial statements when they are filed with the Securities and Exchange Commission ("SEC")?

A. Yes. The financial statements filed with the SEC are the ultimate responsibility of the Company's management. For that reason and due to the requirements of the Sarbanes Oxley Act, both the CEO and CFO are required to certify the annual 10-K filing that incorporates the Company's financial statements, notes to the financial statements, and management's discussion of the notes to the financial statements. In addition to the attestations by the CEO and CFO of AEP, the outside auditors must provide an attestation opinion that the financial statements present fairly, in all material respects, the financial position of the applicable company in conformity with accounting principles generally accepted in the United States of America.

Q. Are similar attestations required as part of Form 1 reporting to the Federal Energy Regulatory Commission ("FERC")?

A. Yes. The Form 1, which contains financial statements and supporting schedules for each electric utility, requires that a corporate officer sign and attest to the filing. The certification statement contained in the body of the Form 1 reads:

> **I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other information contained in this report, conform in all material respects to the Uniform System of Accounts.**

In addition, the instructions for the Form 1 require a separate certification by the Company's independent outside auditor to be filed with the FERC attesting to the:

> **conformity, in all material respects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases.**

Reference Schedules	**Pages**
Comparative Balance Sheet	**110-113**
Statement of Income	**114-117**
Statement of Retained Earnings	**118-119**
Statement of Cash Flows	**120-121**
Notes to Financial Statements	**122-123**

Deloitte and Touche LLC also has signed these certifications to the FERC in recent years for the the Company's Form 1 filings.

Q. Because of the attestations required by the SEC and FERC for these publically available financial statements, would you expect the level of scrutiny for the planning assumptions to be at a higher level than that of other quantifications used for management planning purposes and regulatory filings, such as the Company's request in this proceeding?

A. Yes. The assumptions and analyses are subject to a more rigorous review process for SEC and FERC reporting purposes than for planning analyses and regulatory filings, such as CPCN proceedings. The assumptions and analyses are subject to more intense and higher level management review and approval within AEP and require outside auditor review. Thus, the assumptions used as part of the impairment analyses would be expected to be more reliable and objective than those used for planning purposes and regulatory filings, such as CPCN proceedings.

Q. What do you conclude about the planning assumptions used to support the Mitchell acquisition in this CPCN proceeding compared to those used for accounting purposes?

A. The Company's planning assumptions used to support the Mitchell acquisition in this CPCN proceeding were more favorable than the assumptions used for accounting purposes to test for impairment. The assumptions used to test for impairment should be afforded the greater weight because they are reviewed by the Company's independent outside auditors and because the Company's officers must attest to the accuracy of the Company's financial statements for SEC and FERC reporting purposes.

H. Company's Fixed O&M Assumptions in Strategist Are Understated Compared to Company's Rate Impact Analysis

Q. Please compare the fixed O&M expense assumptions used in Strategist to the O&M expense projections included in the Company's rate impact analysis.

A. The Mitchell fixed O&M expenses used in Strategist for the AEP planning studies are significantly lower than the fixed O&M expense included in the Company's rate impact analyses. The AEP studies assume that the Mitchell fixed O&M expense will be [redacted] million in 2014 and [redacted] million in 2015 (at 100% before reduction to acquisition percentage). I obtained the projected O&M expense from Mr. Hayet, who obtained it from the workpapers used for the inputs to Strategist. The Company's rate impact analyses reflect the actual 2011 Mitchell fixed O&M expense of $67.741 million (at 100% before reduction to acquisition percentage) and the actual 2012 expense of $68.108 million (at 100%). I obtained the actual 2011 and 2012 O&M expense from the electronic workpaper entitled "Mitchell Expense Detail" provided by the Company in response to AG 2-12. I have attached a copy of this workpaper as my Exhibit___(LK-10).

The most significant difference between the O&M expense included by the Company for the rate impact analyses compared to the O&M expense used in the Strategist studies is that the planning studies do not include the administrative and general ("A&G") expenses, except for employee benefits expenses, which were loaded onto labor expenses.

Q. Does the failure by AEP to include the Mitchell A&G in the fixed O&M expense for those units bias the planning studies in favor of Mitchell, all else equal?

A. Yes.

Q. Is there any serious question that the Company will incur these expenses or that they will be included in the Company's revenue requirement and recovered from customers?

A. No. These A&G expenses actually will be incurred by the Company through affiliate charges from Appalachian Power Company, the operator of the Mitchell units, and actually will be included in the Company's revenue requirement and charged to customers.

I. Company Assumed that OSS Margins Are Allocated 100% to Customers in Strategist and Commission Should Ensure that the System Sales Clause is Modified to Reflect this Assumption for Ratemaking Purposes

Q. How did the Company model the off-system sales margins in Strategist?

A. The Company reflected 100% of the OSS margins as a credit or reduction to the cumulative net present value used to compare the planning options.

Q. Do you agree with applying 100% of the OSS margins as a credit or reduction to the fuel and fixed costs of the planning options, including the Mitchell acquisition?

A. Yes. Fundamentally, if customers pay for 100% of the fuel and fixed costs of the planning options, then customers should retain the entirety of the related benefits from those options.

Q. Did the Company also apply 100% of the OSS margins as a credit to customers in the quantification of the effect on customers provided by Mr. Wohnhas on RKW-Exhibit 4 attached to his Direct Testimony?

A. No. For the rate impact analysis reflected in this exhibit and subsequently updated for 2012 in response to AG 2-12, Mr. Wohnhas assumed that the Company would retain 40% of the OSS margins related to the termination of the Pool Agreement and the acquisition of Mitchell on January 1, 2014. The 40% sharing is consistent with the sharing provisions reflected in the present version of the System Sales Clause component of the Fuel Adjustment Clause, but assumes that the Commission will not modify the present version of the SSC in conjunction with its approval of the Mitchell acquisition or in a subsequent rate case.

Q. What effect did this assumption have on the Company's retained OSS margins and on customer revenue requirements compared to the present Pool Agreement and without the Mitchell units?

A. Under the Company's rate impact analyses, the termination of the Pool Agreement and acquisition of 50% of the Mitchell units will result in an increase of $87.110 million (total Company) in OSS margins compared to 2011 actual as reflected on RKW-Exhibit 4 and $16.413 million (total Company) compared to 2012 (as adjusted by the Company). Of these additional margins, the Company assumes that it will retain $35.234 million of the increase compared to 2011 or $7.688 million compared to 2012. These are amounts that would increase the Company's actual earnings.

The effects compared to 2011 and reflected on RKW-Exhibit 4 were provided as workpapers by the Company in response to Staff 1-12. I have attached a copy of that response as my Exhibit____(LK-11). The effects compared to 2012 were provided in response to AG 2-12. I have attached a copy of that response and the attached spreadsheet summarizing the rate impact as my Exhibit___(LK-12).

Q. If the Company is allowed to retain 40% of the OSS margins from Mitchell, would it have a self-interest in acquiring more Mitchell earlier than if it acquired less and at a later date coincident with the retirement of Big Sandy 2?

A. Yes. The retained OSS margins would represent a windfall to the Company and AEP. Meanwhile, the Company's customers would be obligated to pay for the entirety of the Mitchell costs as well as the Big Sandy 2 costs, including any remaining undepreciated plant costs.

Q. Should the Company be allowed to retain 40% of the OSS margins from Mitchell?

A. No. I recommend that if the Commission authorizes the acquisition of Mitchell capacity prior to the retirement of Big Sandy 2, that it condition its approval on flowing through to customers the entirety of the OSS margins rather than only 60%.

If the Commission authorizes the acquisition of Mitchell capacity in this proceeding, but does not condition it on flowing through to customers the entirety of the OSS margins, then the treatment of OSS margins will be an issue in the base rate case the Company plans to file in June of this year, or in any overearnings complaint case that may be filed by KIUC.

III. RATE IMPACTS OF POOL TERMINATION AND ACQUISITION OF THE MITCHELL UNITS

Q. Has the Company quantified the rate impact of the 50% Mitchell acquisition?

A. Yes. The Company estimated that the rate impact of the 50% Mitchell acquisition will be a net rate increase of $45.127 million, or 8.0% on total revenues, using 2011 as the test year. This estimate is summarized on RKW-Exhibit 4 attached to Mr. Wohnhas' Direct Testimony.

Q. Has the Company provided a more recent quantification of the rate impact of the 50% Mitchell acquisition using a 2012 test year?

A. Yes. The Company estimated that the rate impact of the 50% Mitchell acquisition will be a net rate increase of $49.5 million, or 9.9% on total revenues, using 2012 as the test year. However, the actual rate impact is almost $100 million and nearly 20%.. In order to reduce the actual rate impact, the Company "normalized" and substantially increased the test year actual generation from Big Sandy 2 and the

Mitchell units, thus increasing the OSS margins by $10 million compared to actual. The Company also "normalized" the PJM market energy prices and substantially increased the test year actual OSS margins by $36 million. Without these "normalization" adjustments, the rate impact of acquiring 50% of the Mitchell units will be an increase of nearly 20% on total revenues. The Company provided and described this estimate and its adjustments in response to AG 2-12.

Q. Are the Company's estimates actual rate impacts?

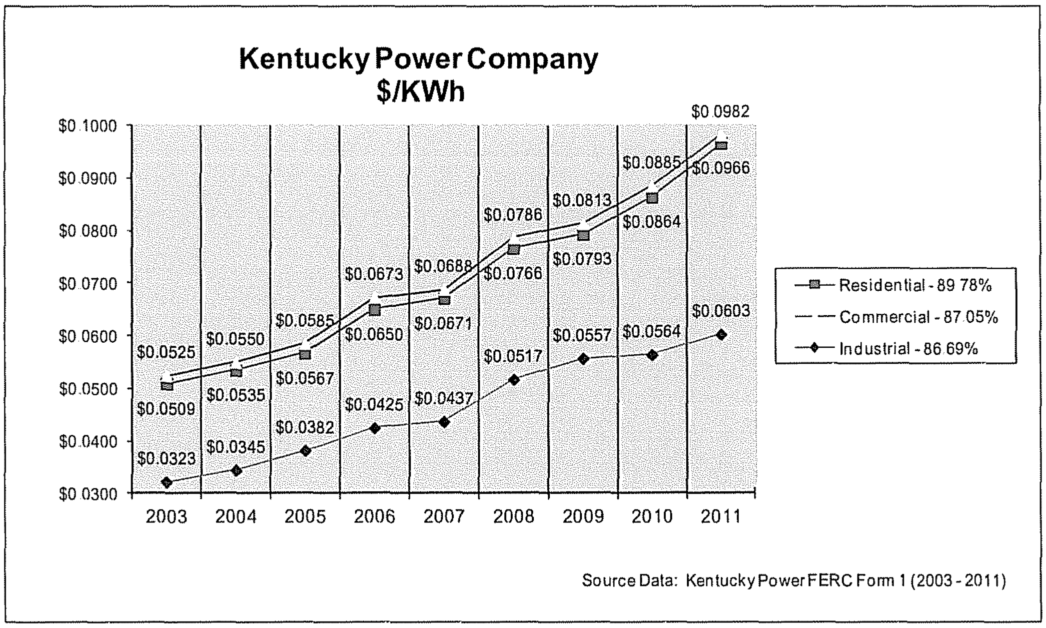
A. No. These are estimated impacts. The Company has made no commitments that it actually will propose reductions in its revenue requirement when it files its Mitchell base rate case in June of this year to "normalize" OSS margins to reflect prior year market prices or whether it will "normalize" OSS margins to reflect improved operation of Big Sandy 2 and the Mitchell units. In my experience, it is highly unlikely that the Company will voluntarily penalize its revenue requirement by amounts of that magnitude.

Q. Is a rate increase on January 1, 2014 necessary?

A. No. The rate increase on January 1, 2014 quantified by the Company, regardless of the amount, is due solely to the unnecessarily premature acquisition of the Mitchell units prior to the Big Sandy 2 retirement. If the acquisition of replacement capacity for Big Sandy 2 is delayed until it actually is needed, there should be a rate reduction on January 1, 2014, not an increase. At a minimum, a rate reduction will be necessary to reflect the $22 million reduction in the Company's capacity equalization payments due to the termination of the Pool Agreement on that date. KIUC is actively considering whether to file a complaint in June 2013 to reduce rates with an effective date of January 1, 2014.

Q. Should the Commission be concerned about unnecessary rate increases and the effects on the Company's customers and the state's economy?

A. Yes. Rates to customers have nearly doubled since 2003 as shown on the following chart. The Commission should take every opportunity to ensure that there are no unnecessary increases and to timely reduce rates if the Company's costs decline.



Q. Have you investigated why the Company's OSS margins in the two analyses of the rate impacts, the first for 2011 and the second for 2012, were significantly different?

A. Yes. In its analyses, the Company simply applied the 2011 or 2012 PJM RPM capacity prices and energy prices that were available in those test years. It made no attempt to reflect the PJM RPM or forward energy prices for 2014 or 2015 that will apply when it acquires the Mitchell capacity. In other words, it assumed a PJM world that exists only in the past, not the one that will exist during the 17 months that it will own both the Big Sandy 2 capacity and the Mitchell capacity, and not the one that will exist after Big Sandy 2 is retired.

Q. Do the Company's two rate impact analyses provide a correct quantification of the rate impact of acquiring Mitchell?

A. No. The Company assumed that it could sell the excess capacity due to the acquisition of Mitchell at the PJM RPM capacity prices set for the historical years 2011 and 2012. This is completely inconsistent with reality and overstates the capacity revenues that can be realized starting January 1, 2014.

The RPM capacity prices for 2014 and 2015 are substantially lower than in 2011, although they are somewhat greater than in 2012. The PJM RPM capacity prices are set through the Base Residual Auction ("BRA") on an annual basis for the

PJM planning/delivery year (June of one year through May of the following year) for three years into the future. As a point of comparison, the actual RPM capacity prices as determined in the BRA are as follows: $174.29/mW/day for the 2010/2011 planning/delivery year, $110.00/mW/day for the 2011/2012 planning/delivery year, $16.46/mW/day for the 2012/2013 planning/delivery year, $27.73/mW/day for the 2013/2014 planning/delivery year, and $125.99/mW/day for the 2014/2015 planning/delivery year.

Another reason that the Company's quantifications are inconsistent with reality is that the Company cannot now offer or sell the Mitchell capacity into PJM at RPM capacity prices. The BRAs for the 2013/2014, 2014/2015, and 2015/2016 planning/delivery years are fixed and the Company cannot now offer the Mitchell capacity into those auctions. Instead, and at best, assuming that AEP does not otherwise run afoul of limitations on capacity sales applicable to an FRR entity, the Company would have to offer and sell the capacity in the PJM incremental auctions. The results of PJM's 2013/2014 RPM Third Incremental Auction were posted on March 8, 2013 and the clearing price in the AEP zone was $4.05/mW/day. Further, the Company may not be able to sell the capacity at all, even in the incremental auctions, given that the Mitchell capacity already is committed to meet AEP's load obligations on a system-wide basis as an FRR entity.

Q. What is the significance of the market capacity and energy revenues and the

resulting OSS margins in the Company's rate impact analyses?

A. First, the analyses graphically and quantitatively illustrate the merchant generator risk that will be imposed on customers. The analyses demonstrate the magnitude of the Company's OSS margins on the economics of the acquisition of Mitchell and the volatility of the market revenues from year to year as well as the declining value of the market revenues, at least over the several years, compared to 2011.

Second, by overstating the market capacity and energy revenues, the analyses understate the near-term rate impact of acquiring the Mitchell capacity on January 1, 2014 instead of when it is needed in June 2015.

In short, the analyses strongly emphasize the need to acquire less of the Mitchell units and then only when it is needed. The rate impact of the Company's two analyses is bad enough, but is even worse when realistic assumptions are used for market capacity and energy revenues, two of the primary drivers of the OSS margins that affect the rate impact of the acquisition.

IV. DEFERRAL OF BIG SANDY 2 FGD INVESTIGATION COSTS

Q. Please describe the Company's request in this proceeding to establish a regulatory asset to defer costs related to investigations that it performed to assess environmental control options for Big Sandy Unit 2.

A. The Company seeks to establish a regulatory asset of $29.287 million related to two separate and distinct investigations of scrubber retrofit alternatives for Big Sandy Unit 2 in order to meet environmental requirements. Instead of expensing the costs of the investigations on its accounting books when the costs were incurred in 2004-2006 and in 2010-2012, the Company unilaterally deferred the costs. The Company now seeks ratemaking recognition of the accounting deferrals and, if its request is granted in this proceeding, it subsequently will seek recovery of the deferrals in its next base rate case proceeding. [Wohnhas Direct at 10].

Q. Briefly describe the two investigations of retrofit alternatives and the costs incurred for each.

A. Yes. The Company's investigations are described by Mr. Wohnhas in his Direct Testimony, although he describes them as if there had been a single investigation. The first investigation was commenced in 2004 and addressed the installation of a wet Flue Gas Desulfurization ("WFGD") system at Big Sandy 2 to control SO2 emissions. This investigation was discontinued for various reasons in 2006. The Company incurred $15.512 million to investigate the WFGD, according to its response to Staff 1-18 in Case No. 2011-00401, which I have replicated as my Exhibit___(LK-13). Of the amounts incurred during this first investigation, the Company spent $0.630 million to acquire the land necessary for the landfill and another $2.930 million in costs that the Company has characterized as related to the landfill, as shown on RKW-Exhibit 5 attached to Mr. Wohnhas' Direct Testimon in this proceeding.

The second investigation commenced in 2010, after the Company initially decided in mid-2009 to retire Big Sandy 2 and then reversed course, instead deciding to proceed with environmental retrofits and to seek a CPCN and ECR recovery in Case No. 2011-00401. In that proceeding, the Company also sought ratemaking recognition of its unilateral deferrals for accounting purposes related to the first investigation. KIUC opposed the ratemaking recognition of the deferrals in that proceeding, except for the costs of purchasing the land for the landfill. The Company withdrew its Application in that proceeding before the case was adjudicated.

In the second investigation, the Company incurred costs to assess the installation of a newer dry FGD technology at Big Sandy 2 to control SO2 emissions. The Company incurred $12.164 million to investigate the dry FGD alternative as shown on RKW-Exhibit 5 attached to Mr. Wohnhas's Direct Testimony.

Q. Should the Commission approve the establishment of a regulatory asset related to the 2004-2006 and the 2010-2012 investigation costs?

A. No. This request is equivalent to a request for impermissible retroactive ratemaking. The Company never sought nor obtained authority to defer these costs for ratemaking purposes before it unilaterally deferred them for accounting purposes in those prior years. In fact, this is the first time that the Company has sought the

Commission's approval for the deferral of the costs for ratemaking purposes other than its request in Case No. 2011-00401 for recovery of the costs of the first investigation, which was withdrawn. None of these costs were incurred as an expense during a test year actually used for ratemaking purposes, in which case it may have been appropriate to remove the expense as nonrecurring, defer it, and then amortize it to expense over a longer period of years. In addition, the Company may have overearned in prior years, in which case the Commission should be even more reluctant to allow such retroactive deferrals, particularly in the absence of an earnings investigation to restate the Company's earnings on a ratemaking basis so that it can determine the level of those overearnings. Further, the Commission should consider the number of years that have passed since 2004 and determine if it is appropriate some 10 years later to authorize deferrals for ratemaking purposes for costs that should have been expensed when incurred.

If the Commission allows retroactive deferrals for costs that should have been expensed in prior years absent an order authorizing such deferrals for ratemaking purposes or absent review and deferral of the expenses in an actual test year for ratemaking purposes, the Commission effectively will open the floodgates for these types of deferral requests by all of the utilities subject to its jurisdiction. This could result in asymmetric retroactive ratemaking whereby the utility is allowed to retroactively defer costs from prior years and then recover the costs from future customers while customers are prohibited from reaching back and seeking retroactive deferrals for overearnings in prior years followed by rate reductions or lower rate increases.

Q. Has the Commission recently denied recovery of unauthorized deferrals on the basis that they constitute impermissible retroactive ratemaking?

A. Yes. The Commission did so in its Order in Case No. 2010-00523 dated July 14, 2011 and in its Order in Case No. 2011-00036 dated November 17, 2011.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request for the establishment of a regulatory asset for future recovery of these costs, except for the cost of land, which probably should have been booked either to a plant account or to plant held for future use rather than to a regulatory asset. The Company never sought prior authorization to defer these costs and should not be allowed now to retroactively recover them from the 2004-2006 and 2010-2012 time periods. Even though the Company is not seeking rate recovery in this proceeding, the authorization of a deferral for ratemaking purposes virtually will ensure that it is recoverable in a future rate proceeding. The only remaining issue in a future rate proceeding will be the time period over which it will be recovered.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

APRIL 1, 2013

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
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
  Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
  Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
  Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

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

Utilities

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

**Expert Testimony Appearances
of
Lane Kollen
as of March 2013**

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

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

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

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

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

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

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

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

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
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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Date	Case	Jurisdict.	Party	Utility	Subject
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.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.

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

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

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

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

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Date	Case	Jurisdict.	Party	Utility	Subject
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs 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.

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

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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 in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in accounts 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in accounts 165 and 236; ADIT; nuclear service lives and effect 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 Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, and Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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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 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564, 2007-565, 2008-251 2008-252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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

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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	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	LA	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal	LA	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.	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. and the Entergy Operating Companies	Depreciation expense and effects on System Agreement tariffs.

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04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement Issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	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, the 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.

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11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	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. and the Entergy Operating Companies	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, including resolution of S02 allowance expense, variable O&M expense, and tiered sharing of off-system sales margins.
04/11 05/11	38306 Direct Supplemental 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 and 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	ER-11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
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.

**Expert Testimony Appearances
of
Lane Kollen
as of March 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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	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.

Expert Testimony Appearances
of
Lane Kollen
as of March 2013

Date	Case	Jurisdict.	Party	Utility	Subject
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.
10/12	120015-EI Direct 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	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.

EXHIBIT ____ (LK-2)

Kentucky Power Company

REQUEST

Please provide a description of all actual attempts and all attempts that were considered by AEP to sell the Mitchell generating units or the entire plant to one or more non-affiliated entities at any time during the last 3 years. Please describe the current status of each such attempt.

RESPONSE

There has been no attempt to sell the Mitchell generating units or the entire plant to non-affiliated entities during the last three years.

WITNESS: Ranie K Wohnhas

EXHIBIT ____ (LK-3)

Kentucky Power Company

REQUEST

Refer to page 11 starting at line 4 of Dr. McDermott's Direct Testimony. Other than discussions with the Company, what analyses did Mr. McDermott perform to conclude that the projections of market prices that Mr. Weaver used were reasonable, and that they represented the lower bound of bid prices that bidders in an RFP might submit if in fact KPCo were to conduct an RFP? Please supply all documentation, workpapers, analyses etc performed by Dr. McDermott to reach this conclusion. Please supply these analyses electronically, with all formulas intact and no pasted in values.

RESPONSE

Dr. McDermott's opinion is based on economic reasoning suggesting that sellers will generally be unwilling to sell at below their opportunity cost (or, at a minimum, Dr. McDermott does not believe one can <u>assume</u> that sellers would be willing to sell below their opportunity cost). The opportunity cost is either the cost to build and operate a new plant or the price that can be obtained in the market place (whichever is larger). There is good reason to believe that long-term contracts carry additional risk premiums above the financial costs of building or producing. The literature and practical experience with this is widespread and well-known. Dr. McDermott can provide citations to this literature and practice if asked.

WITNESS: Karl McDermott

EXHIBIT ____ (LK-4)

Kentucky Power Company

REQUEST

Refer to page 3 line 19 through page 4 line 2 of Dr. McDermott's Direct Testimony wherein he states: "It is unnecessary for Kentucky Power to conduct a full RFP process since the analysis conducted by the Company includes evaluations that approximate price bids that would result from an RFP process."

a. Please provide all quantitative or other independent analyses performed by or relied on by Dr. McDermott in support of the conclusion that the Company's "evaluations" approximate price bids that would result from an RFP process." If none, then please so state.

b. Please explain how Dr. McDermott can be certain that the Company's "evaluations" approximate price bids that would result from an RFP process."

c. Does Dr. McDermott agree that the best test of whether the Company's "evaluations" approximate price bids that would result from an RFP process would be to conduct an RFP process? Please explain your response.

d. Please provide all reasons why Dr. McDermott would oppose an actual RFP to determine the prices that would result from an RFP process. Please provide support for all assertions or claims, including, but not limited to, studies, information provided by AEP, and industry data.

e. Did Dr. McDermott or KPCo conduct any type of market survey to identify potential resources that might bid into a KPCo RFP if KPCo were to conduct one? If not, why not, if so, please supply all documentation, workpapers, analyses etc performed. If so, please supply these analyses electronically, with all formulas intact and no pasted in values.

RESPONSE

a. Dr. McDermott did not undertake or rely upon such analyses. See also KIUC 1-68.

b. The question misstates Dr. McDermott's testimony. See also KIUC 1-68; McDermott Direct, Page 11, lines 4-16.

c. No. Such processes are costly and take time, and if one believes that no additional information will be gained from such a process than running an RFP is not the best way to make this determination. Even, however, if the RFP process were costless to run, if it is expected to not produce any additional useful information then it still may not be the best way to verify the Company's evaluations. The best way in those circumstances would be to critically review the Company's data and analysis to be sure that it was including the appropriate costs in its estimates.

d. The reasons are set forth in Dr. McDermott's direct testimony. See McDermott Direct, page 11, line 4 – page 12, line 4.

e. Dr. McDermott did not undertake an independent analysis, but he did review this with AEP personnel to understand if AEP had taken these issues into account in their analysis. See the Company's response to KIUC 1-73.

WITNESS: Karl A McDermott

EXHIBIT ____ (LK-5)

Kentucky Power Company

REQUEST

Assuming that no market surveys were conducted, what formal or informal analyses were performed by Dr. McDermott and/or any other relevant AEP or KPCo employees regarding conducting an RFP:

a. The name of specific entities and resources that might bid into an RFP if one was held, whether just for 250 MW or up to 800 MW. If no specific resources were considered explain what generic kinds of resources known to exist in PJM were considered?

b. What profit margin would be necessary for the bidders to recover in order for them to be willing to submit a bid?

c. What capital structure would they likely have?

d. What length of time would they be willing to supply their resources for?

e. In general what assumptions did they consider that a bidder would have to make in order to be willing to submit a bid?

f. If no consideration formal or informal was made, please provide an answer to the questions above, based on Mr. McDermott's or AEP's experience.

RESPONSE

Company witness Weaver, at page 37 of his prefiled direct testimony, describes the Company's analysis and underlying economic basis supporting the expected results of an RFP. Specifically, Company witness Weaver states "Option # 2 (Retire and Replace Big Sandy 2 with a New Build CC option) provides a market proxy." Company witness Weaver further states "it is very reasonable to assume that a *long-term* (minimum, 10-20 year term) competitive purchase power agreement ("PPA") solicitation—for not only up to as much as 1,100 MW of replacement capacity, but for the largely baseload <u>energy</u> also being replaced—would likely be offered/priced at the cost of a new-build combined cycle in response to such an RFP."

a.) The Company objects to this request as seeking unknown or speculative information. Without waiving this objection the Company believes that each RFP is unique and expected results would be specific to the nature of the requested proposal. Entities or resources that might bid into such an RFP could potentially include, but not be limited to the following: 1) existing generating units within or external to PJM; 2) yet to be built generating units within or external to PJM; or 3) market sourced solutions with or without supporting physical assets. As Company witness Weaver describes, at page 37 of his prefiled direct testimony, a long-term PPA "would likely be offered/priced at the cost of a new-build combined cycle."

b.) The Company objects to this request as seeking unknown or speculative information. Without waiving this objection, Company witness Weaver describes, at page 37 of his prefiled direct testimony, that a long-term PPA "would likely be offered/priced at the cost of a new-build combined cycle." The profit margin embedded in a specific bid is unnecessary to reach this conclusion.

c.) The Company objects to this request as seeking unknown or speculative information. Without waiving this objection, Company witness Weaver describes, at page 37 of his prefiled direct testimony, that a long-term PPA "would likely be offered/priced at the cost of a new-build combined cycle." The capital structure embedded in a specific bid is unnecessary to reach this conclusion.

d) The Company would expect the bidders to conform to the terms of the RFP.

e.) The Company objects to this request as seeking unknown or speculative information. Without waiving this objection, Company witness Weaver describes, at page 37 of his prefiled direct testimony, that a long-term PPA "would likely be offered/priced at the cost of a new-build combined cycle." The general assumptions embedded in a specific bid is unnecessary to reach this conclusion.

(f) Dr. McDermott's experienced is summarized in his testimony. (McDermott. Dir., p. 11 lines 8-9, lines 12-15, and lines 17-22 and page 12 lines 1-4) At these cites Dr. McDermott suggests that (1) it is almost certain that contracts of a longer duration carry a risk premium; (2) gas-fired plants are likely to the fuel of choice for any new build: and (3) Louisville Gas and Electric recently solicited bids that were not cost-effective.

Dr. McDermott made these conclusions based on (1) documents and conclusions from the Commission (for the LG&E conclusion) and (2) his experience from 1998-2004 working on several generation related projects that included bidding, auctions for short-term and long-term contracts, and certificates of public convenience for independent power producers, as well as his experience observing the outcomes of various bid-based procurement methods since 2005 (e.g., Illinois, New Jersey, and Maryland in particular). That experience included areas of MISO, PJM, and the Southwest Power Pool. While this general experience did include several of the issues raised in these questions and this general experience informed Dr. McDermott's opinion, he has not formulated any specific answers to the questions asked here.

N/A on behalf of the Company.

WITNESS: Karl A.McDermott/Scott C. Weaver/Ranie K. Wohnhas

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EXHIBIT ____ (LK-6)

EXHIBIT ____ (LK-7)

Kentucky Power Company

REQUEST

Refer to page 4 lines 4-10 of Mr. Pauley's Direct Testimony. Please identify and provide a copy of all documents reviewed, relied upon, and/or prepared by Mr. Pauley to make the decision and/or communicate the decision to acquire 50% of the Mitchell units.

RESPONSE

See KIUC 1-102 Attachment 1.

WITNESS: Gregory G Pauley

Scott C Weaver /OR4/AEPIN
06/18/2012 09:34 AM

To Gregory G Pauley/OR3/AEPIN@AEPIN, Ranie K Wohnhas/OR3/AEPIN@AEPIN
cc
bcc
Subject Fw: KPCo_resource option 're-analysis'

Please take a look at this modified strawman for the KPCo re-analysis... Does this seem reasonable to you, or are you looking for something else?

KPCo_CPCN-Resource Need 'Re-analysis' (June 2012)_Modeling Overview.ppt

Scott C. Weaver
AEP Audinet: 200-1373
Outside: (614) 716-1373

----- Forwarded by Scott C Weaver/OR4/AEPIN on 06/18/2012 09 31 AM -----

Scott C Weaver /OR4/AEPIN
06/14/2012 01:31 PM

To Gregory G Pauley/OR3/AEPIN, Ranie K Wohnhas/OR3/AEPIN
cc
Subject KPCo resource option 're-analysis'

Gentlemen.

This is a KPCo resource option "re-analysis" straw-man I put together... I'd like to confer with you on this prior to meeting next Tues.... Now I realize that this meeting could certainly result in recommendations of yet other options --or combinations of options-- to be explored, but wanted to throw something out up-front to work off of.

For instance, I'm not sure that we'd want (or need) to continue to assess the Big Sandy "CC" replacement options (#2 and #3) that we assessed in the BS filing, but thought I'd continue to reflect for purpose of this 're-analysis' exercise. The only add'l option, not ID'd here, that I think is a non-starter would be ---as Rich alluded to--- the notion that we would seek any capacity transfers/sales from the Ohio-G *over-and-above* the "Mitchell (and Amos 3 for APCo) take" represented here.

If you have questions here, or you believe I've missed something, please give me a call.

[attachment "KPCo_Resource Requirement Study (June 2012)_Overview.ppt" deleted by Scott C Weaver/OR4/AEPIN]

Scott C. Weaver
AEP Audinet: 200-1373
Outside: (614) 716-1373

KPCo Capacity Resource Need "Re-analysis"

Resource Options

Option	Unit Dispositions: Big Sandy 2	Unit Dispositions: Big Sandy 1	Approx. Resulting KPCo Capacity Need (MW)	BS2 Replacement	BS1 Replacement	Overall KPCo Portfolio Replacement Strategy...
From the recent (Big Sandy) CPCN Filing (Docket No. 2011-00401)...						
#1	**Retrofit** (DFGD; 6/2016)	**Retire** (2015)	**300+**	*n/a*	**Market** (to 2025) *OR* Mitchell @20% [312-MW] (2014)	o (PJM) Capacity & Energy Market Purchases (or bi-lateral Capacity & Energy PPA) to 2025; then new-build CC capacity
#2	**Retire** (2015)	**Retire** (2015)	**1,100**	**CC (Brownfield)** (1/2016)	**Market** (to 2025) *OR* Mitchell @20% [312-MW] (2014)	o Brownfield CC (@BS), Mitsubishi 501-A 2x2x1 @ 904 MW w/ Duct-Firing o (PJM) Market Purchases (200-300 MW) (or bi-lateral PPA) to 2025; then new-build CC capacity added
#3	**Retire** (2015)	**(CC) Repower** (2015)	**300+**	**CC (BS1 Repower)** (1/2016)	**Market** (to 2025) *OR* Mitchell @20% [312-MW] (2014)	o BS1 Repower as CC, Mitsubishi 501-A 2x2x1 @ 780 MW w/ Duct-Firing o (PJM) Market Purchases (300-400 MW) (or bi-lateral PPA) to 2025; then new-build CC capacity added
~~**#4(A)**~~	~~**Retire** (2015)~~	~~**Retire** (2015)~~	~~**1,100**~~	~~**Market** (to 2020)~~	~~**Market** (to 2025)~~	~~o 5-Year (PJM) Market Purchases to 2020~~ ~~o Generic CC by 1/2020, ~900 MW w/ Duct-Firing; with additional CC capacity added in 2025~~
Other views NOT considered in that filing...						
#4	**Retire** (2015)	**Convert to Gas** (1/2016)	**800+**	**Mitchell @50%** [780-MW] (1/2014)	*n/a*	o (PJM) Capacity & Energy Market Purchases (or a bi-lateral Capacity & Energy PPA)
#5	**Retire** (2015)	**Retire** (2015)	**1,100**	**Mitchell @50%** [780-MW] (1/2014)	Market (to 2020)	o 5-Year (PJM) Market Purchases (or a bi-lateral PPA); then new-build CC capacity in 2020
#6	*same as #5 except...*				Market (to 2025)	o 10-Year (PJM) Market Purchases (or a bi-lateral PPA); then new-build CC capacity in 2025
#7	*same as #5 except...*				Market (to 2025)	o In lieu of "full" ~300 MW Capacity & Energy PPA, supplement w/ "non-traditional" resources (EE/DR, VVO, Renewables)

Others?... Re-assessment of Riverside?... Other existing facilities?

[illegible] Modeling Parameter/Data Requirements

Modeling "G" annual revenue requirements thru 2040... discounted to current$ @ KPCo WACC

Commodity Prices, Load, CSAPR:

- Continue to use latest AEP-FA suite of L/T fundamental pricing ("Fleet Transition-CSAPR")... with suite of: "HIGHER Band", "LOWER Band", "Early (2017) Carbon" and "No Carbon" pricing scenarios.
- Continue to use latest (Fall '11) AEP-EF load & peak demand forecast for KPCo.
- Continue to model to achieve company CSAPR SO_2 unit alloc (+ Assurance Prov) limits (KPCo = 7.7k per yr., eff: 2014)

'Option-specific' parameters...

Option #1 (BS2 Retrofit):

1)In-service date remain @ 6/2016?... Later? (unit would be idled in interim)

2)Update to DFGD installed cost ($839M excl AFUDC w/ 20% contingency adder) due to compressed schedule?

3)Confirm NID removal efficiency (98.5%)... removal cost (~$300/ton SO2)

4)Confirm 'on-going' BS2 capex & FOM *(in-progress... to be forwarded by Generation)*

5)Confirm 15-year Retrofit recovery period; 25-year operating life (thru '40)

6)Confirm ultimate (BS1) CC-replacement constrained/delayed until 2025

Modeling Parameter/Data Requirements (con't)

Option #2 (Brownfield CC):

1)In-service date remain @ 1/2016?... Later?

2)Update to CC installed cost (per S&L/Kiewet April/May '11 estimates... w/ 10% contingency adder)?

3)Confirm 30-year CC recovery period & operating life

Option #3 (BS1 CC Repower):

1)In-service date remain @ 1/2016?... Later?

2)Updated CC-Repower cost (per S&L July/Aug '11 estimates... w/ 20% contingency adder)?

3)Confirm 20-year CC-Repower recovery period, w/ 25-year operating life (thru '40)

Option #4 (BS1 Gas Conv; 50% Mitchell; 5 / 10 Yrs. Market for balance of need):

1)Est. capital cost of BS1 gas conversion, derate (if any), min load, heat rate (@ min & max load)

2)Mitchell "transfer value" @ 1/2014 *(in progress... to be forwarded by Reg Accounting & Tax... will include budgeted increm. Capex thru 12/2013)*

- Such value to be net of ADFIT (i.e., rate base)?... If so, will be necessary to modify levelized carrying cost rate in model

2)Confirm 'on-going' ML capex & FOM *(in-progress... to be forwarded by Generation)*

Option #7 (50% Mitchell, 5 Yrs. Market and/or 'Alternative' Resources for balance of need):

1)___ % increase to current DSM (DR/EE) (current CLR reflects 64 MW by '20); reflect 33 MW (151 circuits @ ~$37M by '17) of increment VVO (volt/var) projects; reflect ___ (nameplate) wind resources... *i.e., similar to the "Clean Energy Standard" (proxy) portfolio reflected in the most recent APCo (Virginia) IRP*

- **<u>ALL Options</u>**: "Bilateral" (intermediated-term) capacity & energy PPA (2016-2020... or, 2016-2025):
  - AEP Generation Resources Cost-based? (slice of system?... unit-specific?)

    OR
  - Market-based? (*valuation-basis:* 'fundamentals'-based?... some other (equivalent transaction) proxy?)

EXHIBIT ____ (LK-8)

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-102. Please confirm that there were no other documents relied on by Mr. Pauley to make the decision and/or communicate the decision to acquire 50% of the Mitchell units. Please supplement this response if there are additional documents, such as emails or correspondence between Mr. Pauley and Mr. Patton. If none, then please so state.

RESPONSE

There were no other documents.

WITNESS: Gregory G Pauley

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EXHIBIT ____ (LK-9)

EXHIBIT ____ (LK-10)

2011-2012 Non-Fuel O&M (including Consumables) and Depreciation - Mitchell Plant

Note: Amounts represent 100% of Mitchell Plant

FERC Acct.	Acct name	2011	2012
403	Depreciation Expense	65,173,950	65,988,203
408	Taxes Other Than Income Taxes	9,659,829	10,688,644
500	Operation Supervision and Engineering	3,384,082	3,021,079
502	Steam Expenses	15,499,446	14,539,259
505	Electric Expenses	4,336	980
506	Misc Steam Power Expenses	9,354,505	10,244,228
507	Rents	1,925	-
509	Allowances	545,821	360,665
510	Maintenance Supervision and Engineering	3,861,748	7,116,780
511	Maintenance of Structures	1,518,174	1,281,042
512	Maintenance of Boiler Plant	18,737,717	19,183,301
513	Maintenance of Electric Plant	5,742,427	4,587,317
514	Maintenance of Misc Steam Plant	1,233,660	1,058,086
556	System Control and Load Dispatching	499,084	391,463
557	Other Expenses	1,793,309	1,645,469
561	Load Dispatching	1,034,788	264,687
575	Administrative Service Fees	816,035	1,292,365
904	Uncollectible Accounts	4,073	438
920	Administrative and General Salaries	3,256,010	3,990,769
921	Office Supplies and Expenses	322,381	609,198
923	Outside Services Employed	3,051,744	3,403,489
924	Property Insurance	882,372	1,036,555
925	Inquiries and Damages	1,393,667	1,108,869
926	Employee Pensions and Benefits	4,197,228	5,356,248
928	Regulatory Commission Expenses	101,464	173,969
930	Misc General Expenses	270,106	214,893
931	Rents	1,612	1,659
935	Maintenance of General Plant	189,253	105,049
		152,530,742	157,664,706
	Less Depreciation	(65,173,950)	(65,988,203)
	Less: Taxes Other Than Income taxes	(9,659,829)	(10,688,644)
	Less: Consumables and Allowances	(9,956,450)	(12,880,150)
	Non Fuel O&M	67,740,514	68,107,708
	50% of Non Fuel O&M	33,870,257	34,053,854

Reconciliation to 2012 analysis

14,539,259	
(2,019,779)	less 5020000 - not consumables or allowances
5	less 5020025 - not consumables or allowances
12,519,485	
360,665	plus 509
12,880,150	Consumables and Allowances - 2012 Analysis

EXHIBIT ____ (LK-11)

Kentucky Power Company

REQUEST

Refer to paragraph 39 of the Application, which states, "[I]n addition, using these and other 2011 values to reflect the effects of the Mitchell transfer and the termination of the current Pool Agreement on KPCo, the Company's cost of service would have increased approximately eight percent". Provide in electronic format, with formulas intact and unprotected, the analysis supporting the approximate 8 percent increase, along with the assumption(s) used in the analysis.

RESPONSE

See KPSC Staff 1-12 Attachments 1 and 2 on the enclosed disk for the requested analysis and supporting workpapers.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
Approximate Cost of Service Impacts - Increase/(Decrease)
TOTAL COMPANY - Based on Calendar 2011 [Notes 1 and 2]
All dollars in Thousands

Line		Current	Asset Transfers and Pool Elimination	Change
1	**Revenues** Increase/(Decrease) Cost of Service			
2	OSS Revenues [Note 3]	($53,333)	($232,271)	($178,938)
3	Pool Energy Sales	($30,830)	$0	$30,830
4	Pool Capacity Revenues	$0	$0	$0
5	**Total Revenue**	**($84,164)**	**($232,271)**	**($148,107)**
6				
7	**Expenses** Increase/(Decrease) Cost of Service			
8	Net (Gain)/Expense on SO2 Emission Allowances [Note 4]	$12,364	$11,687	($676)
9	Purchased Power for Internal Load			
10	Pool/Market Capacity	$54,523	$0	($54,523)
11	Pool Energy Purchase	$15,290	$0	($15,290)
12	Market Purchased Power for IL	$4,938	$3,284	($1,655)
13	PJM Bill (LSE-portion)	$19,147	$30,024	$10,877
14	**Subtotal Expense**	**$106,262**	**$44,996**	**($61,266)**
15				
16	**Mitchell Plant Revenue Requirement [Note 5]**			
17	Depreciation	$0	$32,587	$32,587
18	Fuel & O&M Expense	$0	$159,740	$159,740
19	Taxes Other Than Income	$0	$4,828	$4,828
20	Return Requirement (Pre Tax)*	$0	57,345	$57,345
21	**Subtotal Mitchell Revenue Requirement**	**$0**	**$254,500**	**$254,500**
22	**Approximate Impact** Increase/(Decrease)			**$45,127**
23	**KPCo Sales Revenue**			**$565,286**
24	**Percent Change**			**7.98%**

Notes:

1 **Current case represents 2011 actual results, including the current Pool Agreement, unadjusted for asset transfers. Excludes amounts which do not differ between cases.**

2 **Asset Transfers and Pool Elimination case includes the impact of transferring 50% of Mitchell 1&2 to KPCo, termination of the Pool Agreement, implementation of the Power Coordination Agreement (PCA), and Big Sandy still operating.**

3 **OSS revenues include PJM capacity sales, and are net of the PJM bill and OSS margin sharing.**

4 **Includes the impact of eliminating the Interim Allowance Agreement (IAA).**

5 **Depreciation, Fuel, O&M, and Taxes represent Ohio Power's actual 2011 costs. Return Requirement uses KPCo rate of return on 12/31/11 net rate base.**

KENTUCKY POWER COMPANY
INPUTS

KENTUCKY POWER COMPANY

2011 Current Pool

			Source Workpaper
	Revenues Increase/(Decrease)		
	OSS Revenues	$53,965,215	Cal 11 Pool Energy Summary - excluding trading
	Pool Energy Sales	$30,830,359	Cal 11 Pool Energy Summary, Primary Energy tab
	Gain on Sale of Allowances	$0	IAA Impact Cal 2011.xls
	Net (Gain)/Expense on SO2 Emission Allowances	$12,363,531	IAA Impact Cal 2011.xls Tons Eqvlnt Sum w-IAA tab
	Purchased Power for Internal Load		
	Purchased Power - Pool Capacity	$54,522,751	Cal 11 Pool Energy Summary.xls Cap Equalization tab
	Pool Energy Purchase	$15,290,188	Cal 11 Pool Energy Summary, Primary Energy tab
	Market Purchased Power	$4,938,307	Cal 11 Pool Energy Summary
	PJM Bill (Purchased Power) LSE Portion	$19,147,227	Cal 11 Pool Energy Summary PJM Bill Detail tab

PCA with Asset Transfers

	Revenues Increase/(Decrease)		
	OSS Revenues	$261,108,396	Cal 11 Stand Alone Summary.xlsx
	PJM Capacity Revenues	$35,872,428	Cal 11 Stand Alone Summary.xlsx PJM Capacity tab
	PJM Bill - OSS Portion	($28,843,422)	Cal 11 Stand Alone Summary.xlsx PJM Bill Detail tab
	Total OSS Revenues	$268,137,402	Cal 11 Stand Alone Summary.xlsx
	Net (Gain)/Expense on SO2 Emission Allowances	$0	IAA Impact Cal 2011.xls
	Expenses Increase/(Decrease)		
	Allowance Expense [Note 2]	$11,687,435	IAA Impact Cal 2011.xls Tons Eqvlnt Sum wo-IAA tab
	PJM Capacity	$0	
	Market Energy Purchase	$3,283,797	Cal 11 Stand Alone Summary - Energy Model tab
	PJM Bill (Purchased Power) LSE Portion	$30,024,346	Cal 11 Stand Alone Summary - PJM Bill tab
Mitchell Transfer			
	Depreciation Expense	$ 32,586,975	This Workbook - "KPCo ML Transfer" Tab
	Fuel (net of Defd Fuel), Allowances, Chemicals	$ 125,869,243	This Workbook - "KPCo ML Transfer" Tab
	Non-Fuel, Non-Purch Power O&M	$ 33,870,257	This Workbook - "KPCo ML Transfer" Tab
	Taxes Other Than Income Taxes	$ 4,828,415	This Workbook - "KPCo ML Transfer" Tab
Retail	Total Capitalization	$ 513,598,962	This Workbook - "Retail Transfer" Tab
Retail	Return on Capitalization	$ 56,547,246	This Workbook - "Retail Transfer" Tab

KENTUCKY POWER COMPANY
INPUTS

FERC	Total Capitalization	7,246,440.14	This Workbook - "Retail Transfer" Tab
FERC	Return on Capitalization	797,833.06	This Workbook - "Retail Transfer" Tab
OSS Treatment			
	Current Pool		
	OSS Margins	$23,915,000	Cal 11 Pool Energy Summary
	Remove Financial Margins	$7,249,000	Cal 11 Pool Energy Summary - OSS Margins Tab
			These numbers come from Cal 2011 OSS Margin Backup.xl
	PCA with Asset Transfers - Pre 6-1-15		
	OSS Margins	$96,747,075	Cal 11 Stand Alone Summary, Energy Model Summary tab
	PJM Capacity Revenues	$35,872,428	Cal 11 Stand Alone Summary.xlsx PJM Capacity tab
	PJM Cost Allocated to OSS	($28,843,422)	Cal 11 Stand Alone Summary.xlsx PJM Bill Detail tab

Retail and FERC Sales Revenue	FERC Account(s)	2011 Amount
Total Retail Revenues	440, 442,444,445	559,169,090
FERC	4470027,4470033 and 4470150	6,117,376
		565,286,467

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
KPCO JURISDICTIONAL ALLOCATION

Jurisdictional Factors from Case No. 2009-00459

	Kentucky Power		
	Kentucky Retail	FERC	Total
Demand-Production	0.986	0.014	1.000
Energy	0.987	0.013	1.000

		Kentucky Power		
Account	Description	Kentucky Retail	FERC	Total
101-106, 114	Utility Plant	862,154,973.93	12,241,551.35	874,396,525.28
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(247,671,539.82)	(3,516,634.44)	(251,188,174.26)
107	Construction Work in Progress	16,142,591.75	229,205.16	16,371,796.91
121	Nonutility Property	-	-	-
124	Other Investments	1,284,482.83	18,238.09	1,302,720.92
151	Fuel Stock	15,706,863.66	206,878.65	15,913,742.31
152	Fuel Stock Undistributed	366,099.52	4,821.98	370,921.50
154	Plant Materials and Operating Supplies	10,199,767.64	144,824.29	10,344,591.93
158.1, 158.2	Allowances	4,214,862.10	55,514.90	4,270,377.00
186	Miscellaneous Deferred Debits (Property Taxes)	3,731,024.00	52,976.00	3,784,000.00
190	Accumulated Deferred Income Tax (PPE-ARO)	1,717,948.23	24,392.77	1,742,341.00
190	Accumulated Deferred Income Tax (PPE)	(472,082.50)	(6,703.00)	(478,785.50)
190	Accumulated Deferred Income Tax (228 & 242)	706,323.57	10,028.94	716,352.50
	Cash Working Capital			
230	Asset Retirement Obligations	(4,908,422.93)	(69,693.63)	(4,978,116.56)
228.2	Accumulated Provision for Injuries and Damages	-	-	-
236	Taxes Accrued (Property Taxes)	(3,731,024.00)	(52,976.00)	(3,784,000.00)
242	Miscellaneous Current and Accrued Liabilities (W/C)	-	-	-
242	Miscellaneous Current and Accrued Liabilities (NSR)	(586,573.37)	(8,328.63)	(594,902.00)
253	Other Deferred Credits (NSR)	-	-	-
282	Accum. Deferred Income Taxes-Other Property	(145,556,943.55)	(2,066,731.45)	(147,623,675.00)
283	Accum. Deferred Income Taxes-Other	(1,473,707.15)	(20,924.85)	(1,494,632.00)
	Total	511,824,643.89	7,246,440.14	519,071,084.03
501, 502, 509	Fuel (net of Defd Fuel), Allowances, Chemicals	124,232,942.84	1,636,300.16	125,869,243.00
403	Depreciation Expense	32,130,757.35	456,217.65	32,586,975.00
5xx, 9xx	Non-Fuel, Non-Purch Power O&M	33,396,073.59	474,183.60	33,870,257.19
408.1	Taxes Other Than Income Taxes	4,760,816.70	67,597.80	4,828,414.50

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
RATE BASE ADJUSTMENTS
Calendar 2011

			Rate Base Adjustments			Capitalization Adjustments	
Account	Description	Balance per Accounting	ARO Adjustment	Eliminate Items Not In Case No. 2009-00459	Cash Working Capital Adjustment	Fuel Stock Adjustment	Total Capitalization
101-106, 114	Utility Plant	862,154,973.93	(1,367,958.74)				860,787,015.19
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(247,671,539.82)	228,082.02				(247,443,457.80)
107	Construction Work in Progress	16,142,591.75					16,142,591.75
121	Nonutility Property	-					-
124	Other Investments	1,284,482.83		(1,284,482.83)			(0.00)
151	Fuel Stock	15,706,863.66				(5,470,827.91)	10,236,035.75
152	Fuel Stock Undistributed	366,099.52				-	366,099.52
154	Plant Materials and Operating Supplies	10,199,767.64					10,199,767.64
158.1, 158.2	Allowances	4,214,862.10					4,214,862.10
186	Miscellaneous Deferred Debits (Property Taxes)	3,731,024.00		(3,731,024.00)			-
190	Accumulated Deferred Income Tax (PPE-ARO)	1,717,948.23					1,717,948.23
190	Accumulated Deferred Income Tax (PPE)	(472,082.50)					(472,082.50)
190	Accumulated Deferred Income Tax (228 & 242)	706,323.57					706,323.57
Various	Cash Working Capital	-			4,174,509.11		4,174,509.11
230	Asset Retirement Obligations	(4,908,422.93)	4,908,422.93				0.00
228.2	Accumulated Provision for Injuries and Damages	-					-
236	Taxes Accrued (Property Taxes)	(3,731,024.00)		3,731,024.00			-
242	Miscellaneous Current and Accrued Liabilities (W/C)	-		-			-
242	Miscellaneous Current and Accrued Liabilities (NSR)	(586,573.37)		586,573.37			(0.00)
253	Other Deferred Credits (NSR)	-		-			-
282	Accum. Deferred Income Taxes-Other Property	(145,556,943.55)					(145,556,943.55)
283	Accum. Deferred Income Taxes-Other	(1,473,707.15)					(1,473,707.15)
	Total	511,824,643.89	3,768,546.21	(697,909.46)	4,174,509.11	(5,470,827.91)	513,598,961.84

Adjusted rate base - KY Retail	
Total Capitalization	513,598,961.84
Pre-Tax Return on Capitalization (see workpaper)	11.01%
Return on Capitalization - KY Retail	56,547,245.70
Total Rate Base - FERC	7,246,440.14
Assumed Pre-Tax Return on Capitalization	11.01%
Return on Capitalization - FERC	797,833.06
Total Company Return	**57,345,078.76**

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
KENTUCKY POWER CO RETURN ON CAPITAL CALCULATION
Calendar 2011

Class of Capital	Amount (000's) ($)	% of Total (%)	Cost Rate (%)	Weighted Cost Rate (%)	Pre Tax Weighted Cost Rate of Return (%)
Long-Term Debt	$543,263,512	54.62%	6.48%	3.54%	3.54%
Preferred Stock	$0	0.00%	0.00%	0.00%	0.00%
Short Term Debt	(21,506,621)	-2.16%	2.29%	-0.05%	-0.05%
Accounts Receivable**	$46,147,086	4.64%	2.99%	0.14%	0.14%
Common Equity	$426,786,833	42.91%	10.50%	4.51%	7.38%
Total Capital	$994,690,810	100.01%		8.14%	**11.01%**

* From Rate Case No. 2009-00459 dated June, 2010.
** Per Commission Order - March 31, 2003, Case No. 2002-00169.

1/ Tax Rate =	38.90%	
Tax Rate:		
Fed	0.35	
State-KY	0.06	
Local	0	Not in effect at this time
Combined	**0.389**	

KENTUCKY POWER COMPANY
OSS MARGIN SHARING

	KPCo		
	Kentucky Retail	FERC	Total
Demand-Production	0.986	0.014	1.000
Energy	0.987	0.013	1.000

	Kentucky Retail	Wholesale	Total
Current Pool			
OSS Margins	$23,580,190	$334,810	$23,915,000
Remove Financial Margins	$7,147,514	$101,486	$7,249,000
OSS Revenues excl. financial	$16,432,676	$233,324	$16,666,000
Base Credit	$15,290,363	$0	$15,290,363
Remainder Available for Sharing	$1,142,313	$233,324	$1,375,637
KPCo Retained percent	40.0%	75.0%	
KPCo Retained Amount	**$456,925**	**$174,993**	**$631,918**
Shared Amount	**$15,975,751**	**$58,331**	**$16,034,082**
PCA with Asset Transfers			
OSS Margins	$95,489,363	$1,257,712	$96,747,075
PJM Capacity Revenues	$35,406,087	$466,342	$35,872,428
PJM Cost Allocated to OSS	($28,468,458)	($374,964)	($28,843,422)
Net OSS Margins	$102,426,992	$1,349,089	$103,776,081
Base Credit	$15,290,363	$0	$15,290,363
Remainder Available for Sharing	$87,136,629	$1,349,089	$88,485,718
KPCo Retained	40.0%	75.0%	
KPCo Retained Amount	**$34,854,652**	**$1,011,817**	**$35,866,469**
Shared Amount	**$67,572,341**	**$337,272**	**$67,909,613**

EXHIBIT ____ (LK-12)

Kentucky Power Company

REQUEST

Reference the applicant's response to AG 1-37. Please update the information.

RESPONSE

As requested in AG 1-37, the Company used 2012 data to update its 2011 analysis. Because 2012 market conditions and operations were not representative, the results of the update were historically normalized. Employing normalized 2012 data, and all else being equal, the asset transfer and termination of the pool would have produced a 9.9% increase in the Company's cost of service when compared to the costs included in the Company's rates. Further, had the Company's 2011 revenues remained constant for 2012, this would have yielded an 8.8% increase in cost of service which is even more consistent with Mr. Wohnhas' testimony using 2011 data.

There are three subparts to the analysis: change in base rates, change in fuel costs, and change in System Sales Clause revenues. Because the Company's existing base rates are the result of a "black box" settlement, the base rate subpart is premised upon the Company's cost of service as presented in Case No. 2009-00459, which the Company adjusted using best efforts to accurately reflect the settlement. The fuel and System Sales Clause values are 2012 actual cost and credit values.

Without historical normalization, and using 2012 data, costs included in base rates would have increased by $90.2 million and fuel costs would have increased $21.2 million. Increased off-system sales revenues would have reduced the cost of service by $15.5 million for a total increased cost of service of $95.9 million.

Two principal factors rendered 2012 not representative of the prior four years. First, the 2012 capacity factor for Big Sandy was significantly depressed when compared to its average capacity factor in the prior four years. Mitchell's capacity factor was depressed to a much lesser degree. This reduction in turn was driven by lower demand and significantly higher rates of scheduled outages at both stations. Second, the AEP PJM market prices for electricity were also materially lower.

The Company performed two adjustments to reflect the average historic performance of Big Sandy and Mitchell in the stand alone comparison cases.

First, the output of Big Sandy and Mitchell were modified to reflect the average hourly output of the four-year period 2008 through 2011. 2012 was excluded because the availability of both stations (Big Sandy in particular) was reduced during 2012. This adjustment to a historic average resulted in Big Sandy's capacity factor increasing from its 2012 value of 28% to the four year average of 67%. By comparison, Big Sandy's 2011 capacity factor was 68%. Mitchell's capacity factor was also increased from 55% in 2012 to its four year average of 72%. The 2011 value was 67%. In connection with the normalization, it was assumed that the incremental generation was sold in the PJM market as additional OSS. This adjustment resulted in a cost of service reduction of approximately 2% or $10 Million.

Second, the Company adjusted the hourly prices to the 2008 through 2011 four-year average AEP PJM prices. This period was used to be consistent with the period selected for the capacity factor impact. It should be noted that all but the first 8 to 9 months or so of this 48 month period followed the economic recession and the lower prices resulted from lower region wide demand. This change, based on prices prevailing in the period following the economic boom years, would have reduced the cost of service, post-OSS sharing, by another 7% or $36 million.

With this normalization of 2012 data, the Company's cost of service would have increased $49.5 million, or 9.9%, assuming the Mitchell asset transfer and the elimination of the pool.

The requested analysis and supporting documents are in AG 2-12 Attachments 1 and 2 presented in electronic format with all formulas preserved on the enclosed CD.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY

Calendar 2012

Approximate Impacts - Increase/(Decrease) vs Current Fuel Costs and Base Rates [Notes 1 and 2]

Line		2012 Actual Fuel As Defined In Kentucky	Estimated 2012 Fuel - Asset Transfers and Pool Termination - Actual 2012 Generation	Change
1	Fuel Increase/(Decrease) Cost of Service - Total Company			
2	Total Coal Generation	$86,468,500	$86,468,500	$0
3	Rockport Fuel - 151 basis	$58,571,332	$58,571,332	$0
4	AEP Pool Primary Energy Purchases	$54,377,550	$0	($54,377,550)
5	Market Power Purchases	$9,725,877	$29,915,226	$20,189,349
6	Mitchell Actual Fuel - 151 basis	$0	$105,509,422	$105,509,422
7	Less: OSS Allocation of Sources - Note 3	($38,841,826)	($89,988,058)	($51,146,232)
8	**Total Company Net Energy Requirement (NER)**	**$170,301,433**	**$190,476,423**	**$20,174,990**
9	PJM LSE Transmission Losses			$0
10	PJM Transm loss charges - LSE 4470207	$9,917,417	$10,812,318	$894,901
11	PJM Transm loss credits-LSE 4470208	($2,824,087)	($2,427,751)	$396,336
12	Total Company Fuel Cost	$177,394,764	$198,860,990	$21,466,226
13	Ky Retail Energy Allocator	98.7%	98.7%	98.7%
14	KY Jurisdictional Cost	$175,088,632	$196,275,797	$21,187,165
15	KY Jurisdictional Sales (MWh)	6,660,656	6,660,656	6,660,656
16	**Fuel Cost per MWh**	**$26.63**	**$29.86**	**$3.22**
17				

System Sales Clause (SSC) Increase/(Decrease) Cost of Service - Note 4

	Kentucky Retail Jurisdiction	2012 Actual SSC	2012 SSC - Asset Transfers with Pool Elimination	Change
1	Actual OSS Margins	($13,951,276)	($39,803,722)	($25,852,446)
2	Base Rate Credit	$15,290,363	$15,290,363	$0
3	Difference - Shortfall (Excess) vs Base Credit	$1,339,087	($24,513,359)	($25,852,446)
4	Customer Sharing	60.0%	60.0%	60.0%
5	Customer Share - SSC	$803,452	($14,708,016)	($15,511,468)
6	KY Jurisdictional Sales (MWh)	6,660,656	6,660,656	6,660,656
7	**System Sales Clause Credit per MWh**	**$0.12**	**($2.21)**	**($2.33)**
8				
9	**Total Impact - Fuel and System Sales Clause Credit**	**$26.75**	**$27.65**	**$0.89**

Notes:

1 2012 Actual column Fuel amounts represent actual values from 2012 monthly NER's and Kentucky jurisdictional fuel deferral calculations

2 Asset Transfers and Pool Elimination includes the impact of transferring 50% of Mitchell 1&2 to KPCo

3 Assumes cost assigned to OSS includes fuel and non-fuel variable costs.

4 OSS Sharing assumes continuation of current base rate credit and sharing levels

KENTUCKY POWER COMPANY

Calendar 2012

Approximate Impacts - Asset Transfer/Pool Termination Increase/(Decrease) vs Current Base Rates [Notes 1 and 2] - KY Retail Jurisdiction

Kentucky Jurisdictional Amounts	Cost Reflected in Current Base Rates (PUE 2009-00459)	Estimated Base Rate Amounts - Asset Transfers and Pool Elimination	Estimated Change
Base Rates Increase/(Decrease) Cost of Service			
Net (Gain)/Expense on SO2 Emission Allowances	($322,601)	$0	$322,601
PJM Base Rate Admin Fees (561,565,575)	$4,404,062	$2,719,904	($1,684,157)
PJM Base Rate Ancillary Services and Other	$3,032,748	$2,775,982	($256,765)
Rockport Non Fuel Energy Costs	$39,970,517	$39,970,517	$0
Pool Energy Non-Fuel	$928,521	$0	($928,521)
Pool Capacity	$57,993,495	$0	($57,993,495)
LSE FTR's	($7,521,703)	($2,409,224)	$5,112,480
Implicit Congestion	$7,073,373	$7,602,255	$528,882
System Sales Clause Base Rate Credit	($15,290,363)	($15,290,363)	$0
Emission Allowance Expense	$1,345,609	$8,627,815	$7,282,206
Mitchell Non-Fuel Costs			
Depreciation	$0	$32,532,184	$32,532,184
Fuel Handling	$0	$3,042,109	$3,042,109
Consumables and Allowances	$0	$6,349,914	$6,349,914
Non-Fuel O&M Expense	$0	$33,577,100	$33,577,100
Taxes Other Than Income	$0	$5,269,502	$5,269,502
Return Requirement (Pre-Tax)	$0	$57,071,128	$57,071,128
Subtotal Mitchell Revenue Requirement	**$0**	**$137,841,936**	**$137,841,936**
Total Base Rate Impacts	**$91,613,657**	**$181,838,824**	**$90,225,167**
Total Estimated 2012 Change			
Fuel Cost Impact			$21,187,165
System Sales Clause Credit Impact			($15,511,468)
Base Rate Impact			$90,225,167
Total Impact			**$95,900,864**
Total Ky Retail Jurisdiction Revenues			$501,036,750
Percentage Change			19.1%

INCREMENTAL IMPACT OF BIG SANDY AND MITCHELL AT HISTORIC AVERAGE GENERATION [Note 5]

Assume all incremental generation creates additional OSS	Pool MLR Share	Stand Alone	Change
Incremental SSC Credit	($650,091)	($10,708,486)	($10,058,395)
Impact with historic Big Sandy and Mitchell Generation			**$85,842,469**
Percentage Change - With Historic Average Generation			**17.1%**

INCREMENTAL IMPACT OF HISTORIC AVERAGE GENERATION AND HISTORIC PRICES [Note 6]

Impact of 2008-2011 Market Price	Pool MLR Share	Stand Alone	Change
Incremental SSC Credit	($2,348,375)	($38,683,130)	($36,334,755)
Impact After Reprice OSS to 2008-2011 Average Market Price			**$49,507,714**
Percentage Change - Historic Average Generation with 2008-2011 Average Market Price			**9.9%**

Notes:

1 2012 Actual column Fuel amounts represent actual values from 2012 monthly NER's and Kentucky jurisdictional fuel deferral calculations

2 2012 Actual column Base Rate amounts represent amounts included in base rates in final compliance cost of service from case ???

3 Normalized generation margin assumes that the Mitchell and Big Sandy generated at their 2008-2011 hourly average generation

4 OSS Sharing Assumes continuation of current sharing levels

5 Historic generation uses average output of 2008 through 2011 inclusive.

6 Historic prices based upon average 2008 through 2011 historic prices inclusive.

KENTUCKY POWER COMPANY

PCA with Asset Transfers

Expenses Increase/(Decrease)		
Allowance Expense [Note 2]	$8,741,454	IAA Impact Cal 2012.xls Tons Eqvlnt Sum wo-IAA tab
Market Energy Purchase	$29,915,226	2012 KPCo Stand Alone Energy Transaction Model.xlsx
PJM Bill (Purchased Power) LSE Portion	$18,355,270	This file - "PJM Bill" Tab
Mitchell Transfer		
Depreciation Expense	$32,994,102	This file - "KPCo ML Transfer" Tab
Fuel (net of Defd Fuel), Allowances, Chemicals	$107,028,621	This file - "KPCo ML Transfer" Tab
Consumables and Allowances	$6,440,075	This file - "KPCo ML Transfer" Tab
Non-Fuel, Non-Purch Power O&M	$34,053,854	This file - "KPCo ML Transfer" Tab
Taxes Other Than Income Taxes	$5,344,322	This file - "KPCo ML Transfer" Tab
OSS Treatment		
PCA with Asset Transfers		
OSS Margins	$34,218,485	2012 KPCo Stand Alone Energy Transaction Model.xlsx
Trading/Financial Margins	$4,236,840	2012 AEP East System OSS Margins.xls
PJM Capacity Revenues	$10,822,890	2012 PJM Capacity Allocation.xlsx
PJM Cost Allocated to OSS	($8,950,229)	This file - PJM Bill tab
Retail Sales Revenue		
FERC Account(s)	2012 Amount	
440, 442,444,445	$501,036,750	Source KPCo Retail Revenues Calendar 2012.xls

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
KPCO JURISDICTIONAL ALLOCATION
Calendar 2012

Jurisdictional Factors from Case No. 2009-00459

	Kentucky Power		
	Kentucky Retail	FERC	Total
Demand-Production	0.986	0.014	1.000
Energy	0.987	0.013	1.000

Account	Description	Kentucky Power Kentucky Retail	FERC	Total	
101-106, 114	Utility Plant	866,733,541	12,306,561	879,040,102	
107	Construction Work in Progress	43,031,545	610,996	43,642,540	
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(275,352,538)	(3,909,671)	(279,262,209)	
121	Nonutility Property	-	-	-	
124	Other Investments	1,578,942	22,419	1,601,361	
151	Fuel Stock	28,453,928	374,773	28,828,701	
152	Fuel Stock Expenses Undistributed	731,617	9,636	741,253	
154	Plant Materials and Operating Supplies	10,193,549	144,736	10,338,285	
158.1, 158.2	Allowances	3,684,691	48,532	3,733,223	
186	Miscellaneous Deferred Debits (Property Taxes)	4,274,310	60,690	4,335,000	
190	Accumulated Deferred Income Tax (ARO)	1,773,803	25,186	1,798,989	
190	Accumulated Deferred Income Tax (PPE)	932,235	13,237	945,472	
190	Accumulated Deferred Income Tax (228 & 242)	2,245,369	31,882	2,277,251	
228.2	Accumulated Provision for Injuries and Damages	-	-	-	
230	Asset Retirement Obligations	(5,068,008)	(71,960)	(5,139,968)	
236	Taxes Accrued (Property Taxes)	(4,274,310)	(60,690)	(4,335,000)	
242	Miscellaneous Current and Accrued Liabilities (W/C)	-	-	-	
242	Miscellaneous Current and Accrued Liabilities (NSR)	(464,164)	(6,591)	(470,755)	
253	Miscellaneous Non-Current Liabilities (NSR)	(420,122)	(5,965)	(426,086)	
282	Accum. Deferred Income Taxes-Other Property (PPE)	(142,315,677)	(2,020,709)	(144,336,386)	
283	Accum. Deferred Income Taxes-Other Property (PPE)	(4,012,336)	(56,970)	(4,069,307)	
283	Accum. Deferred Income Taxes-Other (Allowances)	(1,288,335)	(18,293)	(1,306,628)	
	Total	530,438,039	7,497,799	537,935,838	
				50% of Mitchell 1 & 2	**100 % of Mitchell 1 & 2**
403	Depreciation Expense	32,532,184	461,917	32,994,102	65,988,203
501	Fuel (net of Defd Fuel)	105,530,220	1,498,401	107,028,621	214,057,242
502, 509	Consumables and Allowances	6,349,914	90,161	6,440,075	12,880,150
5xx, 9xx	Non-Fuel, Non-Purch Power O&M	33,577,100	476,754	34,053,854	68,107,708
408.1	Taxes Other Than Income Taxes	5,269,502	74,821	5,344;322	10,688,644

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
RATE BASE RATEMAKING ADJUSTMENTS
Calendar 2012

			Rate Base Adjustments				
Account	Description	KPCo Retail Balance per Accounting	ARO Adjustment	Eliminate Items Not In Case No. 2009-00459	Cash Working Capital Adjustment	Fuel Stock Adjustment	Total Capitalization
101-106, 114	Utility Plant	866,733,541	(1,367,959)				865,365,582
107	Construction Work In Progress	43,031,545					43,031,545
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(275,352,538)	278,105				(275,074,433)
121	Nonutility Property	-					-
124	Other Investments	1,578,942		(1,578,942)			-
151	Fuel Stock	28,453,928				(17,910,443)	10,543,485
152	Fuel Stock Undistributed	731,617					731,617
154	Plant Materials and Operating Supplies	10,193,549					10,193,549
158.1, 158.2	Allowances	3,684,691					3,684,691
186	Miscellaneous Deferred Debits (Property Taxes)	4,274,310		(4,274,310)			-
190	Accumulated Deferred Income Tax (PPE-ARO)	1,773,803	(1,773,803)				-
190	Accumulated Deferred Income Tax (PPE)	932,235					932,235
190	Accumulated Deferred Income Tax (228 & 242)	2,245,369					2,245,369
Various	Cash Working Capital	-			4,256,732		4,256,732
228.2	Accumulated Provision for Injuries and Damages	-					-
230	Asset Retirement Obligations	(5,068,008)	5,068,008				-
236	Taxes Accrued (Property Taxes)	(4,274,310)		4,274,310			-
242	Miscellaneous Current and Accrued Liabilities (W/C)	-					-
242	Miscellaneous Current and Accrued Liabilities (NSR)	(464,164)		464,164			-
253	Miscellaneous Non-Current Liabilities (NSR)	(420,122)		420,122			-
282	Accum. Deferred Income Taxes-Other Property (PPE)	(142,315,677)					(142,315,677)
283	Accum. Deferred Income Taxes-Other Property (PPE)	(4,012,336)					(4,012,336)
283	Accum. Deferred Income Taxes-Other (Allowances)	(1,288,335)					(1,288,335)
	Total	530,438,039	2,204,352	(694,656)	4,256,732	(17,910,443)	518,294,023

Adjusted rate base - KY Retail	
Total Capitalization	518,294,023
Pre-Tax Return on Capitalization (see workpaper)	11.01%
Return on Capitalization - KY Retail	57,071,128

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
KENTUCKY POWER CO RETURN ON CAPITAL CALCULATION
From Rate Case No. 2009-00459 dated June, 2010

Class of Capital	Amount (000's) ($)	% of Total (%)	Cost Rate (%)	Weighted Cost Rate (%)	Pre Tax Weighted Cost Rate of Return (%)
Long-Term Debt	$543,263,512	54.62%	6.48%	3.54%	3.54%
Preferred Stock	$0	0.00%	0.00%	0.00%	0.00%
Short Term Debt	(21,506,621)	-2.16%	2.29%	-0.05%	-0.05%
Accounts Receivable**	$46,147,086	4.64%	2.99%	0.14%	0.14%
Common Equity	$426,786,833	42.91%	10.50%	4.51%	7.38%
Total Capital	$994,690,810	100.01%		8.14%	**11.01%**

** Per Commission Order - March 31, 2003, Case No. 2002-00169.

1/ Tax Rate = 38.90%

Tax Rate:		
Fed	35.00%	
State-KY	6.00%	
Local	0.00%	Not in effect at this time
Combined	**38.90%**	

KENTUCKY POWER COMPANY
OSS MARGIN SHARING - CALENDAR 2012

	KPCo		
	Kentucky Retail	FERC	Total
Demand-Production	$0.986	$0.014	$1.000
Energy	$0.987	$0.013	$1.000

	Kentucky Retail	Wholesale	Total
Pool Termination with Asset Transfers - Actual 2012 Generation			
Physical OSS Margins	$33,773,645	$444,840	$34,218,485
2012 Actual Financial OSS Margins	$4,181,761	$55,079	$4,236,840
PJM Capacity Revenues	$10,682,192	$140,698	$10,822,890
PJM Cost Allocated to OSS	($8,833,876)	($116,353)	($8,950,229)
Net OSS Margins	$39,803,722	$524,264	$40,327,986
Base Credit	$15,290,363	$0	$15,290,363
Remainder Available for Sharing	$24,513,359	$524,264	$25,037,623
KPCo Retained	40.00%	75.00%	
KPCo Retained Amount	**$9,805,344**	**$393,198**	**$10,198,542**
Shared Amount - Actual 2012 Generation	**$29,998,379**	**$131,066**	**$30,129,445**

Kentucky Power Company 2012 Off-System Sales Revenues			
Month	Net Revenue Level	Base Level	Difference
Jan-12	1,341,487	528,886	812,601
Feb-12	873,897	335,167	538,730
Mar-12	879,707	1,530,489	(650,782)
Apr-12	737,801	1,371,521	(633,720)
May-12	1,050,028	1,307,472	(257,444)
Jun-12	1,291,406	767,124	524,282
Jul-12	2,483,188	616,234	1,866,954
Aug-12	1,287,658	2,136,652	(848,994)
Sep-12	1,210,409	1,850,577	(640,168)
Oct-12	1,158,991	1,739,665	(580,674)
Nov-12	573,454	1,538,455	(965,001)
Dec-12	1,063,250	1,568,121	(504,871)
Total	**13,951,276**	**15,290,363**	**(1,339,087)**

Customer Share	14,486,911
AEP Share	(535,635)
	13,951,276

EXHIBIT ____ (LK-13)

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-1. The Preliminary Scrubber Analysis 2004-2006 amount is $15,212,425.

a. Confirm whether this amount pertains to preliminary scrubber analysis for the years 2004 to 2006.

b. Provide a breakdown of the $15,212,425 identifying the types of costs that have been incurred.

c. Explain whether this amount is for costs incurred for preliminary scrubber analysis only at the Big Sandy plant or if it includes any costs allocated to Kentucky Power by AEP of an AEP system-wide study of preliminary scrubber analysis.

d. If the answer to part a. of this Item is yes, explain whether any of this cost is applicable to the scrubber technology now proposed for Big Sandy Unit 2

RESPONSE

a. These costs were incurred during the 2004 to 2006 time frame for preliminary analysis using a wet scrubber technology.

b. The $15,212,425 is provided in two components:

	FGD Landfill	WFGD
Overheads	$ 111,254	$ 848,077
Internal Labor	$ 0	$ 81,918
Outside Services	$ 673,653	$ 5,279,572
Service Corp. Chrgs.	$ 225,202	$ 1,306,534
Material	$ 0	$ 5,966,590
Land Purchase	$ 630,018	$ 0
Other	$ 8,614	$ 80,993
Total	$1,648,741	$13,563,684

c. These costs were incurred specific to the Big Sandy Unit 2 generating unit.

d. The WFGD costs do not pertain to the specific scrubber technology being proposed in this filing, however, the costs are applicable for recovery as costs incurred in our total evaluation of the proper alternative and methodology to comply the various EPA regulations and the Consent Decree. The FGD Landfill costs can and will be used with the proposed DFGD technology.

WITNESS: Ranie K. Wohnhas