COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

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PUBLIC SERVICE COMMISSION

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

MARCH 2012

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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 practice 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 ("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 the Company's request for a Certificate of Public Convenience and Necessity ("CPCN") for the Big Sandy 2 ("BS2") dry flue gas desulfurization ("DFGD") and related retrofit projects (together, the "retrofit projects") and the recovery of the related costs through the Company's Environmental Cost Recovery ("ECR") surcharge rider.

Q. Please summarize your testimony.

A. I recommend that the Commission reject the Company's request for a CPCN for the Big Sandy 2 DFGD retrofit projects and the recovery of an estimated $940 million (total Company) in capital costs and an estimated $119 million (total Company) in depreciation and other operating expenses through the ECR. AEP's proposal would result in a 35.2% rate increase in 2016.

The Company has not demonstrated that the BS2 retrofit projects are reasonable and cost-effective, the standard set forth in KRS 278.183. To the contrary, the Company's own studies demonstrate that retiring BS2 at the end of 2015 and then purchasing energy and capacity from PJM for ten years will save customers between $474 million to $785 million (total Company) compared to the Company's proposal. The purchase option would result in a 2016 rate increase of between 9.9% to 11.9%, compared to 35.2% under the Company's plan.

Even if the Commission is not prepared to make the decision today to retire BS2, the purchase option will provide the Commission additional time to study that option and other options that were not fully evaluated by the Company. Among these other options are the permanent acquisition of environmentally controlled coal-fired capacity from AEP-Ohio and/or the acquisition and conversion of natural gas-fired generation located adjacent to the Big Sandy plant site.

I recommend that the Commission initiate a separate proceeding and establish a working group to consider all of these complex and interrelated issues on a comprehensive basis to ensure that the Company has an adequate resource portfolio that will meet the needs of its Kentucky customers at the lowest reasonable cost. The Commission cannot properly assess the future of Big Sandy 1 and Big Sandy 2 without addressing the broader scope of all of the Company's resource requirements.

If, however, the Commission approves the BS2 retrofit projects , then I recommend that the Commission direct the Company to minimize the effect on ratepayers through several specific recommendations. First, the Commission should require the Company to maximize the use of extremely low cost short term debt during the construction period regardless of whether it allows CWIP in rate base during the construction period or adopts the AFUDC approach proposed by the Company. The use of short-term debt during the construction period will reduce the cost of the project by tens of millions of dollars compared to the Company's estimate, which assumed that it would not use short-term debt. I also recommend that the total Company short term debt be allocated between base rates and the ECR on the basis of CWIP amounts rather than rate base amounts to correlate more directly with the actual use of the short-term debt for costs of construction.

Second, if the Commission determines that it will allow CWIP in rate base in lieu of the Company's AFUDC approach, then the Commission should further mitigate the rate increases that still will occur in mid-2016 by using a specific form of the CWIP in rate base approach known as "mirror-CWIP." The Company would be allowed to include CWIP in rate base during the construction period, thus phasing in the rate increases necessary to recover the return on investment. The amounts collected during the construction period then would be returned to customers over a subsequent in-service phase-in period to mitigate and levelize the increase that otherwise will occur in mid-2016. The use of the mirror-CWIP approach will provide the Company full recovery of its reasonable costs, but will minimize the effect of the project on customers.

Third, the Commission should remove the costs of plant that will be retired and the related depreciation and operation and maintenance (O&M) expenses that no longer will be incurred, all in accordance with Commission precedent. The Company plans to retire and remove the existing precipitator which no longer will be necessary with the addition of the DFGD, and to substantially modify the boilers and related plant. The Commission should also direct the Company not to include any demolition or removal costs related to existing plant in the actual cost of the BS2 retrofits.

Fourth, the Commission should adopt a 30 year recovery period for the project in lieu of the Company's proposed 15 year recovery period. This recommendation is based on the useful life of the new equipment. If, in the future, the 30 years proves too long, then the Commission can increase depreciation when that becomes evident and still ensure full recovery. There is no reason to penalize customers upfront by requiring them to pay the entirety of the huge cost of this project over only the first half of the equipment's useful life.

Fifth, the Commission should reject the Company's request for environmental study costs that it incurred and deferred without Commission authorization during the 2004-2006 time period.

Further, I recommend that the Commission adopt the 9.2% return on equity recommended by KIUC witness Mr. Hill. This lower rate of return will be applicable to all of the costs in the Company's ECR and initially will result in a rate reduction of approximately $0.7 million. In addition, a lower return on equity will reduce the rate increases during the construction period if the Commission adopts a CWIP in rate base approach as well as the rate increases during the in-service period. A lower return on equity also will reduce the cost of the project and the rate increases once the project is completed and placed in-service if the Commission adopts the AFUDC approach proposed by the Company.

Finally, the Commission should adopt the cost allocation proposal recommended by KIUC witness Mr. Stephen Baron.

II. THE COMPANY'S PROPOSAL WILL RESULT IN A $200.675 MILLION RATE INCREASE IN 2016, OR 35.2%.

Q. The Company has "corrected" its quantification of the projected ECR rate increase in 2016 resulting from the BS2 retrofit projects and the 2004-2006 preliminary studies regulatory asset. Is the Company's quantification of the ECR rate increase correct?

A. No. The Company's quantification of the ECR rate increase is understated. The Company improperly reduced the BS2 retrofit gross plant for one year of accumulated depreciation and ADIT. In other words, instead of quantifying the rate increase for the June 2016 operating month, the Company inexplicably quantified it for the June 2017 operating month. In reality, the Company does not plan to reduce its rate base in the filing for June 2016 by the $63.733 million accumulated depreciation or for the $23.506 million ADIT amounts that it projects will accumulate by June 2017. Any assumption that it will do so is not correct and should be rejected. Correcting this error increases the rate base in June 2016 by $87.238 million and the total Company revenue requirement by $9.326 million to $212.118 million ($206.556 million for BS2 retrofit projects plus $5.562 million for SO2 consumption allowances, net of NOX gains) as corrected in response to Staff 1-20. I have attached a copy of the Company's response to Staff 1-20 as my Exhibit___(LK-2).

Q. Is the rate effect of the BS2 retrofit projects limited to the ECR?

A. No. There are additional rate effects because the ECR does not provide the Company recovery of the entirety of its costs. The non-jurisdictional costs that are not recovered through the ECR ultimately will be recovered through base rates, except for a small portion the Company will retain through the System Sales Clause in its Fuel Adjustment Clause ("FAC") and another small portion that will be recovered from wholesale all-requirements customers.

Q. Have you quantified the total rate increase for the BS2 retrofits?

A. Yes. The rate increase is $200.675 million on retail customers. The computations of the total retail effect are detailed on my Exhibit___(LK-3).

Q. What is the percentage rate increase from the BS2 retrofit projects when both the ECR and base rate effects are combined?

A. The total percentage increase to retail customers is 35.23%. This is 5.84% more than the 29.39% increase computed by the Company and shown on the revised Exhibit LPM-13 provided in response to Staff 1-20. The Company failed to include the effect of base rate increases.

Q. Will the Company incur and likely seek recovery from its customers of other environmental compliance costs within the next 5 to 7 years?

A. Yes. If the Rockport units are retrofitted with the environmental compliance equipment in the current AEP plan, then the Company will incur its share of those costs as well. I estimate that this will increase the Company's revenue requirement by another 10% to 15%. Although the Company refused to provide the estimated cost of these retrofits in response to KIUC 1-18, it has provided other information related to the cost of those retrofits in both confidential and public forums.

Q. Why is this discussion regarding the BS2 rate increases and other environmentally related rate increases important to the Commission's decision in this proceeding?

A. It is important because the effects of these ECR and base rate increases are staggering and may exceed 50% or more over the next 5 to 7 years. The Commission should make every effort to mitigate the effects of these increases.

III. RETIRING BS2 AT THE END OF 2015 AND THEN PURCHASING ENERGY AND CAPACITY THROUGH THE PJM MARKETS FOR TEN YEARS WILL SAVE CUSTOMERS BETWEEN $474 MILLION AND $785 MILLION (TOTAL COMPANY) BASED ON AEP'S OWN FORECASTS, AND WILL RESULT IN A 2016 RATE INCREASE OF BETWEEN 9.9% TO 11.9% COMPARED TO 35.2% UNDER THE COMPANY'S PLAN

Q. The Company claims that continued operation of BS2 and the installation of the BS2 retrofit projects provides the least cost option. Please respond.

A. The Commission should reject this conclusion. The Company's own studies show that retiring BS2 at the end of 2015 and then purchasing energy and capacity from PJM for the ten years after will save consumers between $474 million to $785 million (total Company). In addition, Company's studies show that the purchase option is less expensive on a 30 year cumulative net present value basis.

Q. Please describe the Company's two purchased power alternative scenarios.

A. In addition to the BS retrofit analysis, identified by the Company as Option 1, the Company also performed two purchased power scenarios, Option 4A and Option 4B, which are described by Company witness Mr. Scott Weaver. Under Option 4A, the

Company would retire BS2 at the end of 2015, replace the capacity and energy with purchases from PJM for five years through 2020, and then construct new natural gas-fired combined cycle capacity. Under Option 4B, the Company would retire BS2 at the end of 2015, replace the capacity and energy with purchases from PJM for ten years through 2025, and then construct new natural gas-fired combined cycle capacity.

The Company analyzed these options using *Stategist*, a proprietary planning model, and summarized the results of the model simulations in Exhibit SCW-4. It presented Option 1, the BS2 retrofit option, as its base case and compared these other options to Option 1.

Compared to Option 1, Option 4B was *less expensive* on a 30 year cumulative net present value basis by $10 million to $47 million under the Fleet Transition-CSAPR pricing, and by $82 million to $118 million under the Fleet Transition-Lower Band pricing. The range of results for each Option and each pricing band was due to whether the recovery under Option 1 occurred over a 15 year or 20 year period.

Q. Is the BS2 retrofit option the least cost among those studied by the Company on a cumulative net present value basis?

A. No. The Company's studies demonstrate that Option 4B is the least cost option on a cumulative net present value basis over 30 years, not the BS2 retrofits. The results of the Company's studies demonstrate that the retirement of BS2 at the end of 2015, followed by market purchases for ten years, and then construction and operation of a natural gas-fired combined cycle at the end of the ten year period is the least cost option.

Q. In addition to the 30 year life cycle analyses performed by the Company, should the Commission also consider the annual effects on customers in the near and medium term?

A. Yes. The Commission should consider the annual effect on customers over the ten year period 2016-2025 following the shutdown at the end of 2015 or retrofit at the beginning of 2016. This is an important consideration because of the magnitude of the BS2 retrofit cost, the lack of fuel diversity, the effect on customer rates, the lack of flexibility if the BS2 retrofit is approved, and the fact that the savings, if any, from the BS2 retrofit will only occur well into the next decade.

In its Option 4B purchased power scenario, the Company projected the costs of purchasing capacity and energy through PJM for the ten year period 2016-2025 in conjunction with the retirement of BS2 at the end of 2015.

Although the Company viewed its options from a perspective of 30 years cumulative net present value, it also is important to assess the annual cost to customers over the ten years following either the retrofit or the retirement of BS2.

To make that comparison and to determine the effect on customers, I extracted the annual revenue requirements for Option 1 (BS2 retrofit) and Option 4B (10 year purchased power) for the years 2016 through 2025 from the Company's studies that were provided in response to Staff 1-48. I then computed the annual and cumulative savings that the Company projects if BS2 is shutdown at the end of 2015 and the capacity and energy is replaced with purchases from PJM. The following tables show the annual savings in millions of dollars under all of the commodity pricing and carbon tax scenarios analyzed by the Company.

	Fleet Transition-CSAPR Commodity Pricing			
	Big Sandy 2 Retrofit	Levelized Market Replacement to 2025	Savings from Market Purchases	Cumulative Savings from Purchases
2016	621,065	509,433	111,632	**111,632**
2017	563,763	500,781	62,982	**174,614**
2018	569,255	489,883	79,372	**253,986**
2019	580,129	512,944	67,185	**321,171**
2020	580,242	523,156	57,086	**378,257**
2021	598,242	548,927	49,315	**427,572**
2022	713,673	648,370	65,303	**492,875**
2023	743,111	677,380	65,731	**558,606**
2024	753,290	699,595	53,695	**612,301**
2025	781,919	805,776	(23,857)	**588,444**

	Fleet Transition-HIGHER Band Commodity Pricing			
	Big Sandy 2 Retrofit	Levelized Market Replacement to 2025	Savings from Market Purchases	Cumulative Savings from Purchases
2016	662,840	558,568	104,272	**104,272**
2017	595,404	534,221	61,183	**165,455**
2018	600,002	526,177	73,825	**239,280**
2019	615,207	556,159	59,048	**298,328**
2020	622,237	579,600	42,637	**340,965**
2021	642,973	611,838	31,135	**372,100**
2022	760,525	716,640	43,885	**415,985**
2023	794,561	755,534	39,027	**455,012**
2024	805,167	778,445	26,722	**481,734**
2025	825,889	876,514	(50,625)	**431,109**

	Fleet Transition-LOWER Band Commodity Pricing			
	Big Sandy 2 Retrofit	Levelized Market Replacement to 2025	Savings from Market Purchases	Cumulative Savings from Purchases
2016	598,972	483,847	115,125	**115,125**
2017	540,402	474,681	65,721	**180,846**
2018	544,216	457,942	86,274	**267,120**
2019	554,555	473,462	81,093	**348,213**
2020	561,504	487,909	73,595	**421,808**
2021	580,820	514,390	66,430	**488,238**
2022	694,789	618,116	76,673	**564,911**
2023	723,254	647,735	75,519	**640,430**
2024	732,141	661,984	70,157	**710,587**
2025	762,650	781,932	(19,282)	**691,305**

	Fleet Transition-No Carbon Commodity Pricing			
	Big Sandy 2 Retrofit	**Levelized Market Replacement to 2025**	**Savings from Market Purchases**	**Cumulative Savings from Purchases**
2016	621,830	511,027	110,803	**110,803**
2017	563,517	504,798	58,719	**169,522**
2018	568,967	494,535	74,432	**243,954**
2019	580,709	517,153	63,556	**307,510**
2020	580,658	526,833	53,825	**361,335**
2021	600,456	552,498	47,958	**409,293**
2022	614,815	571,168	43,647	**452,940**
2023	646,574	604,166	42,408	**495,348**
2024	653,408	620,108	33,300	**528,648**
2025	679,969	722,763	(42,794)	**485,854**

	Fleet Transition-Early Carbon Commodity Pricing			
	Big Sandy 2 Retrofit	**Levelized Market Replacement to 2025**	**Savings from Market Purchases**	**Cumulative Savings from Purchases**
2016	619,471	502,780	116,691	**116,691**
2017	659,589	572,040	87,549	**204,240**
2018	669,621	565,577	104,044	**308,284**
2019	679,964	588,903	91,061	**399,345**
2020	691,457	608,697	82,760	**482,105**
2021	710,457	633,956	76,501	**558,606**
2022	728,041	657,593	70,448	**629,054**
2023	756,398	684,792	71,606	**700,660**
2024	766,435	701,713	64,722	**765,382**
2025	799,825	823,023	(23,198)	**742,184**

Q. Do the savings shown on the preceding tables reflect the actual savings to customers from purchases in those years?

A. No. The annual savings actually will be much greater than shown on the preceding tables because the Company's analyses use a levelized carrying cost methodology for the 30 years cumulative net present value analyses rather than the actual declining annual revenue requirements that will be reflected in the Company's rates charged to customers. That means that the revenue requirements for Option 1 actually will be much greater in the first ten years than are shown on the preceding tables. As such, the savings from purchases will be much greater than shown on the preceding tables.

Q. What does it mean that the Company's quantifications reflect the use of a levelized carrying cost methodology?

A. Instead of the reflecting the actual annual return on rate base and depreciation expense, the Company's quantifications reflect the use of a levelized carrying charge for the return on rate base. The levelized carrying charge approach annuitizes the revenue requirement over the life of the BS2 retrofit in a manner similar to a home mortgage or a lease. Such an approach is appropriate for the analyses of options on a 30 year cumulative net present value basis, but does not accurately reflect the annual revenue requirements each year. The levelized approach understates the actual annual revenue requirements in the early years and overstates them in the latter years.

The Company described the use of the levelized carrying charge for the return on rate base in response to KIUC 2-2, although it could not provide the algorithm due to its claim that this was proprietary to *Strategist*. I have attached a copy of the Company's response to KIUC 2-2 (without Attachment A) as my Exhibit___(LK-4).

Q. Have you been able to estimate how much greater the cost will be from BS2 retrofit in the first ten years in the preceding tables?

A. Yes. I estimate that the cost under the BS2 retrofit in the first year will be $36 million greater than shown in the preceding tables, $107 million greater over the first five years, and $43 million greater over the first ten years.

Q. What do you conclude from the annual revenue requirements shown in the preceding tables?

A. I conclude that the Commission should reject the BS2 retrofit CPCN, because it is not reasonable or cost-effective. The Company's studies demonstrate that the retirement of BS2 in 2015 will save customers between $474 million to $785 million (total Company) over the ten year period 2016-2025. The purchase option will result in a 2016 rate increase of between 9.9% and 11.9%, compared to 35.2% under the Company's plan.

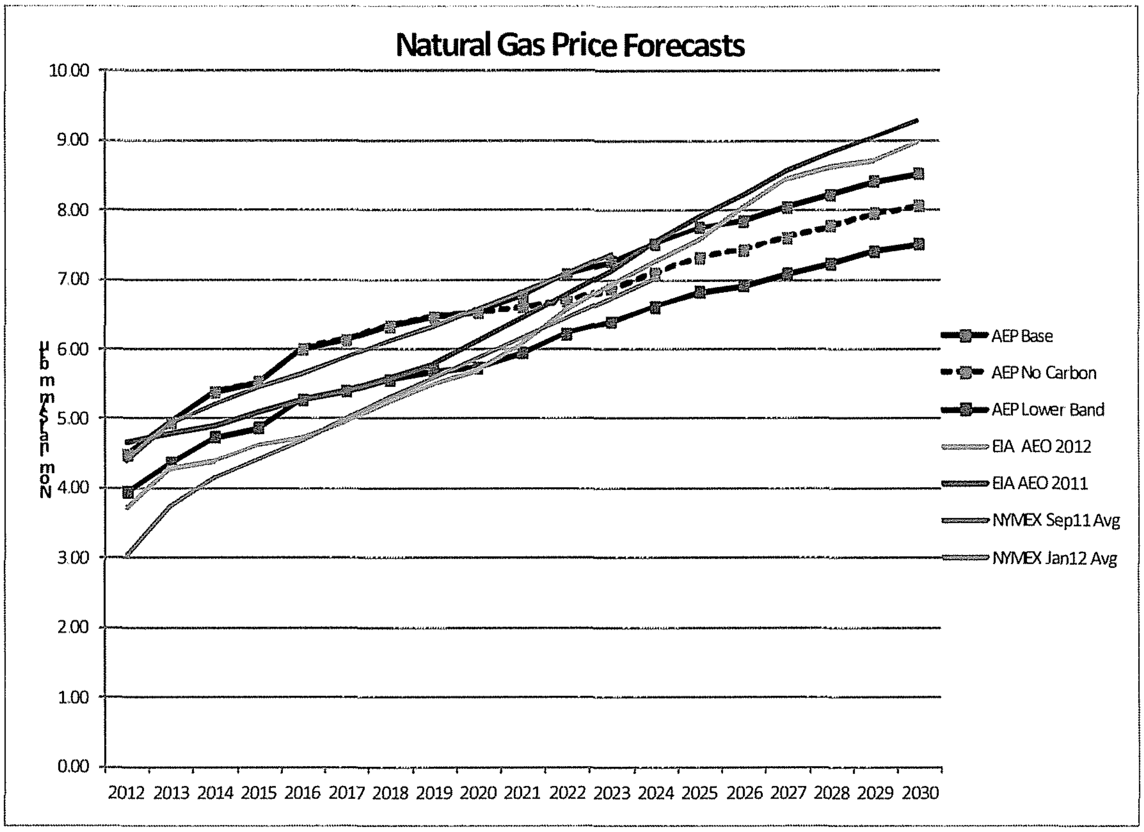
The Company can restart the retrofit process at a later date if and when the Commission subsequently finds that the retrofit is economic. Such an approach will mitigate the harm to customers from environmental compliance requirements, while preserving future flexibility to determine the least cost resource options.

Q. The Company argues against Option 4B despite the lower cost on a 30 year cumulative net present value basis and despite the tremendous savings in the earlier years that its studies indicate. Why should the Commission proceed with the delay option that you recommend?

A. There are several reasons. First, it preserves the Commission's flexibility to comprehensively study the Company's resource portfolio and work cooperatively with the Company and intervenors to ensure that these resources are adequate to meet customer requirements at the least cost. Second, it substantially mitigates the cost to customers of the Company's environmental compliance. Third, it avoids the risk associated with the huge upfront investment for the BS2 retrofit projects. Fourth, it preserves the opportunity for fuel diversity and diversity among baseload, intermediate and peaking capacity if the Company must supply its own generation reserves under a new AEP Power Cost Sharing Agreement. Fifth, it preserves the flexibility to pursue lower cost options, including the acquisition of Mitchell coal-fired capacity and local natural gas-fired capacity.

Q. Are there concerns with the Company's gas price assumptions?

A. Yes. The AEP projections are on the high side compared to other publicly available forecasts, which would favor the BS2 retrofit option compared to natural-gas fired or purchased power replacement options. The following chart compares the AEP natural gas projections under its three pricing scenarios to other publicly available forecast information from the Energy Information Administration and from NYMEX.



The NYMEX forwards are below the Company's base case natural gas price forecast. The EIA forecasts are below the Company's base case natural gas price forecast until 2026. If these other forecasts are correct, then the savings from purchasing rather than moving ahead with the BS2 retrofit will be even greater than the Company's studies indicate.

Q. If the Commission either affirmatively or through default, by rejecting the Company's proposed CPCN for the BS2 retrofits, adopts the market purchase option for one or more years, would the Company have the option of seeking a purchased power rider in addition to base rate recovery?

A. Yes. The Commission could determine the best approach to provide recovery of the purchased power capacity and energy costs prior to the shutdown of BS2.

<u>The Company's Review Failed to Consider Recent Events or All Available Options</u>

Q. Please describe the status of the AEP resource planning process and how the decision to install the BS2 retrofit projects is impacted by this process.

A. AEP is faced with significant uncertainty in its resource planning process due to rapidly changing commodity prices; changes in the competitive markets and market prices for capacity and energy; changes in the legal and regulatory status of the generating assets owned by the AEP operating utilities; its voluntary termination of the Interconnection Agreement, the potential replacement of that agreement with a new Power Cost Sharing Agreement, and the resulting system-wide reallocation of its generation resources; the Consent Decree with the U.S. Department of Justice that requires the Company to install compliance equipment at Big Sandy 1 and 2 or shut down and retire the units by the end of 2015; the indefinite stay on CSAPR by the D.C. Circuit Court; and the relentless onslaught of new and stricter environmental requirements, especially on coal.

Q. **In the midst of this uncertainty, has AEP settled on a final resource plan for the Company?**

A. No. AEP continues to change the Company's resource plan. As recently as one year prior to filing its Application in this proceeding, [redacted] according to its response to AG 1-22. [redacted] also according to its response to AG1-22. [redacted] also according to its response to AG1-22. The Company has performed no subsequent analysis of the Riverside assets, according to its response to KIUC 1-36.

As recently as two months prior to filing its Application in this proceeding, AEP planned to retire BS2 because it had determined that there were lower cost resource options. AEP then changed its plans to retire BS2 after it performed a "more robust and detailed analysis," according to Company witness Mr. Wohnhas. [Wohnhas Direct at 8]. The diametrically opposed results between the "preliminary analysis" and the present analysis provided in this proceeding are due to differences in the assumptions relied on between the two analyses, thus further illustrating the uncertainty in the Company's proposal for the BS2 retrofits compared to other options. I have attached a copy of AEP's press release issued on June 9, 2011 announcing that it planned to retire Big Sandy 2 as my Exhibit___(LK-5). I have attached a copy of the relevant pages from July 5, 2011 and September 8, 2011 presentations by AEP executives to Barclays that confirm its plans to retire Big Sandy 2 as my Exhibit___(LK-6) and Exhibit___(LK-7). Finally, I have attached a copy of the relevant pages from a November 8, 2011 presentation by AEP's President and CEO that shows AEP reversed course and now plans to retrofit BS2 with a DFGD as my Exhibit___(LK-8).

As recently as one month ago, and after it filed its Application in this proceeding, AEP proposed that AEP-Ohio sell and that Kentucky Power purchase 312 MW of the Mitchell 1 and 2 generating units located in West Virginia at net book value. These units already are environmentally controlled for SO2 and NOx. The net book value of the entire Mitchell power plant is $650 per kW, substantially less than the Company's estimated incremental cost of $1,175 per kW only for the BS2 retrofit projects. This option was not evaluated until January 2012, after the Company's filing in this case, according to its response to Sierra Club 1-52, and is a component of the recently filed AEP Section 205 filing at the FERC. I have attached a copy of the narrative portion of the response as my Exhibit___(LK-9). I obtained the cost per kW of the Mitchell capacity from a presentation made by AEP to KPSC Staff and others on January 19, 2012 entitled "AEP Interconnection Agreement (Pool) Termination and Replacement", a copy of which I have attached as my Exhibit___(LK-10). I obtained the cost per kW of the BS2 retrofit projects from the Company's response to Staff 1-17, a copy of which I have attached as my Exhibit___(LK-11).

As recently as two weeks ago, the Public Utility Commission of Ohio reversed itself on the legal separation of the AEP-Ohio generating assets, thus creating further uncertainty over AEP's proposed Power Cost Sharing Agreement and the sale by AEP-Ohio of generating assets to other AEP operating utilities, including the Mitchell capacity to Kentucky Power.

<u>The Commission Should Convene A Separate Proceeding To Develop A Least Cost Option</u>

Q. Should the Commission attempt to fully investigate the Company's resource options in this proceeding?

A. No. The Commission is faced with ensuring that the Company has adequate generation and purchased power resources to meet customer demand at the lowest reasonable cost. The future of the Company's entire generation and purchased power resource portfolio is at issue either now or in the near future. These issues require a comprehensive review of all resource options that realistically cannot be performed within the procedural confines of an ECR proceeding. In such a separate proceeding, it would be appropriate to form a working group comprised of representatives of the Company and all intervenors in this proceeding to develop a consensus resource portfolio that will be least cost to customers.

Q. Has the Company fully considered all available options or a sufficient range of assumptions, such as the acquisition of 312 MW of Mitchell or the Riverside Generating Plant?

A. No. The Company failed to fully consider all available options or a sufficient range of assumptions. None of the AEP planning scenarios included the Company's acquisition of 312 MW of Mitchell coal-fired capacity as recently proposed by AEP to the Company and reflected in AEP's Section 205 filing at the FERC. The failure to study any scenarios where Kentucky Power would acquire 312 MW of Mitchell renders the Company's analysis unreliable and flawed. If Kentucky Power acquires 312 MW of Mitchell and retrofits the 800 MW BS2, then along with its 390 MW share of Rockport Units One and Two, Kentucky Power's resource portfolio would be 100% base load coal. It would have no fuel diversity. It would have no intermediate or peaking capacity. It would have only a limited ability to hedge its position with purchased power. The failure to model to economics of the BS2 retrofit under the assumption that the Mitchell transfer would occur is a fundamental flaw which renders the analysis unreliable. Of all of the sensitivities that should have been modeled, the acquisition of Mitchell is one of the most important. The fact that the FERC cases are on hold while the Ohio situation is resolved does not change this conclusion.

None of the planning scenarios considered the acquisition of the natural gas-fired capacity owned by Riverside Generating Company, LLC, despite the fact that [redacted]. None of the AEP planning scenarios included a temporary delay in the BS2 retrofits and purchases during the shutdown period followed by a subsequent reassessment of the BS2 retrofits. Further, none of the AEP planning scenarios reflected a continuation of present lower natural gas prices. In fact, the Company claimed that it had not performed any such studies and refused to do so in response to KIUC 1-31 and KIUC 1-32. I have attached these responses as my Exhibit___(LK-12).

Q. If the Company does acquire the lower-cost Mitchell capacity and the proposed Power Cost Sharing Agreement is approved by the FERC, are there other implications for the continued operation of BS2 and the installation of the BS2 retrofits?

A. Yes. The Company's proposals to acquire more coal-fired capacity and retrofit the BS2 coal-fired capacity double down on the amount of coal-fired generation in its resource portfolio. This strategy leads to further fuel concentration rather than diversification, increases the risk exposure to future environmental requirements and results in greater risk to customers. It also results in greater profitability to AEP.

If these proposals are approved, the Company's equity earnings base will increase dramatically as it increases its investments in these power plants and earns an equity return on its investments through both the ECR and base rates. Lest there be any doubt on this point, AEP has repeatedly identified the investment in environmental projects as one of its future earnings growth opportunities in presentations to securities analysts and rating agencies. In contrast to the earnings growth resulting from additional environmental investment, purchasing power through bilateral contracts or through PJM offers no earnings growth opportunities. I have attached excerpts of two of these AEP presentations as my Exhibit___(LK-13) and Exhibit___(LK-14).

The Company's proposal also will ensure that the Company remains energy long with significant amount of energy available to sell during off-peak hours. Under the AEP Power Cost Sharing Agreement proposal filed at the FERC which was subsequently withdrawn subject to resubmission, those sales would be made to other AEP operating utilities that are parties to that agreement at less than the market price, thus benefiting those other AEP operating utilities and potentially causing Kentucky Power's customers to subsidize the other utilities.

Q. If the Commission approves the Company's proposed BS2 retrofit projects, does it lock the Company's customers into the Company's proposed resource portfolio of all base load and all coal-fired capacity and commit customers to the related costs of the BS2 retrofit projects?

A. Yes. If the Commission approves the Company's CPCN for the BS2 retrofit projects, then the die is cast and there is no flexibility if the decision turns out poorly. The approval of the CPCN will require a huge and upfront investment of $940 million dollars that customers may have to pay for even if the plant cannot operate for any reason in future years. In fact, this risk is the very reason cited by the Company for requesting a 15 year recovery period rather than a 20 or 30 year recovery period.

Q. If the Commission rejects the Company's proposed CPCN for the BS2 retrofit projects, how will the Company obtain the capacity and energy resources necessary to serve its customers?

A. The Company either will have to construct new capacity, acquire new or existing capacity, purchase capacity and energy, or pursue some combination of these options. If it purchases capacity and energy, the Company could enter into either bilateral agreements or purchase its requirements through PJM or some combination of these options. As discussed earlier, a purchase power option will result in a 2016 rate increase of between 9.9% to 11.9%, compared to 35.2% under the Company's plan.

IV. IF THE COMPANYS PLAN IS APPROVED, THEN MODIFICATIONS TO THE PROPOSAL ARE NECESSARY

Use of Short-Term Debt Is Essential to Mitigate the Cost of the BS2 Retrofit Projects

Q. Please describe the Company's proposed financing for the BS2 retrofit projects.

A. The Company's proposal reflects only long-term debt and common equity to finance the BS2 retrofit projects, although there is some short-term debt reflected in its ECR ROR for its accounts receivable financing program. The Company's proposal does not include the use of short-term debt for construction; the receivables financing is a form of permanent financing.

Q. Is it reasonable not to use any short-term debt to finance the construction costs of projects such as the BS2 retrofit projects during the construction period?

A. No. The costs of such projects typically are financed by utilities, at least in part, through short-term debt during construction and, at times, beyond the construction period. The use of short term debt reduces the cost of the project, particularly when short-term interest rates are substantially less than the utility's overall rate of return, which they are at present rates. Commercial paper interest rates are presently 0.12% to 0.16% for maturities of 30 days to 90 days, according to the *Wall Street Journal* on February 28, 2012. This minimal cost compares to the Company's proposed overall rate of return of 8.03%, which is equivalent to 10.69% when the equity component of the return is grossed-up for income taxes.

The use of lower cost short-term debt financing not only reduces the rate of return applied to rate base investment if the CWIP in rate base approach is adopted, it also reduces the AFUDC included in CWIP that is subsequently recovered if the AFUDC approach is adopted.

Q. Does the Company presently have access to short-term debt in addition to its accounts receivables financing?

A. Yes. The Company presently has access to $250 million of short-term debt through the AEP Utility Money Pool, an intercompany borrowing program that is funded by AEP through the issuance of commercial paper and excess funds from other AEP operating utilities. In addition, the Company could increase this amount to accommodate the huge cost of the BS2 retrofit projects. In my experience, utilities can and do increase their access to short-term debt to fund large construction projects. They do this in order to minimize their financing costs both during the construction period and after the assets are completed until cost-effective long-term financing is implemented. For example, Louisville Gas & Electric Company and Kentucky Utilities Company both significantly increased their access to short-term debt in anticipation of the construction funding requirements for the installation of FGDs and other environmental equipment at multiple generating units, the projects for which they sought CPCN approval in Case Nos. 2011-00161 and 2011-00162, their most recent ECR CPCN proceedings.

Q. Why should the Company maximize the use of short-term debt during construction?

A. Short-term debt reduces the financing costs that are incurred and that must be recovered from customers during the construction period if the CWIP in rate base approach is authorized or if the AFUDC approach is authorized.

Q. Why wouldn't the Company maximize the use of short-term debt?

A. The primary reason the Company would not maximize the use of short-term debt is that such costs do not contribute to earnings, but rather are a flow-through recovery cost. As I noted previously in conjunction with the Company's proposal for Option 1 rather than the lower cost Option 4B, AEP has adopted and implemented a strategy of earnings growth through investment in environmental compliance plant. The only way that strategy can work is if AEP invests equity into the Company to finance environmental compliance plant and obtains recovery of a return on that common equity. The use of short-term debt does not achieve the AEP earnings objective.

Q. Have you quantified the savings to customers if the Company finances the entirety of capital expenditures with short-term debt during the construction period?

A. Yes. The savings to customers will be $115 million using a commercial paper rate of 0.25% compared to the cost of $117 million using the rate of return proposed by the Company if the CWIP in rate base approach is adopted and all of the construction costs are financed with short term debt during the construction period. Alternatively, the savings to customers will be $53 million if only half of the construction costs are financed with short-term debt during the construction period. The computations are detailed on my Exhibit___(LK-15).

<u>Short-Term Debt Should Be Allocated to ECR on CWIP and Not on Rate Base</u>

Q. Does the present computation of the rate of return (ROR) properly allocate short term debt to the ECR revenue requirement?

A. No. The present computation understates the short-term debt used to finance ECR projects during construction and thus, overstates the ROR and the recovery through the ECR compared to the actual costs of financing these projects. The present computation assumes that the same ROR is applicable for base rates and for the ECR. That means that the present computation assumes that short-term debt is proportionally used to finance all the Company's rate base capitalization and ECR rate base investment.

However, that assumption generally is not correct. Most commonly, short-term debt is used temporarily to finance the cost of projects during construction, not to finance the plant in service amounts. This is borne out by the fact that the Company has not borrowed any short term debt since July 2010, according to its response to KIUC 1-6.

Q. Is the allocation of short-term debt on the basis of CWIP consistent with the FERC calculation of the AFUDC rate?

A. Yes. This is an important point, particularly if the Commission adopts a CWIP in rate base approach rather than an AFUDC approach. The AFUDC approach allocates short-term debt on the basis of CWIP, not rate base investment. The Company is subject to the FERC calculation of the AFUDC rate unless the Commission overrides the FERC rate for retail ratemaking purposes. The FERC calculation of the AFUDC rate assumes that short-term debt outstanding is used to finance CWIP and not to finance any other rate base investments unless the short-term debt outstanding exceeds the CWIP amounts.

If the Commission adopts the AFUDC approach, as proposed by the Company, then the short-term debt will be allocated only to the CWIP through the AFUDC rate, and this allocation will be primarily to the BS2 retrofit projects. Alternatively, if the Commission adopts the CWIP in rate base approach and it does not adopt my recommendation to modify the allocation of the short-term debt based on ECR CWIP and all other CWIP, then the short-term debt allocated to the ECR and the BS2 retrofit projects will be diluted compared to the AFUDC approach. That will occur because the existing allocation between the ECR and base rates is based on capitalization/rate base investment, not CWIP, as I previously discussed.

Q. Should the ROR in the ECR be modified to refine the allocation of short-term debt based on CWIP amounts rather than capitalization/rate base amounts?

A. Yes. The ROR used in the ECR should reflect the proper allocation of short-term debt between the financing costs on CWIP recovered through base rates and on the CWIP recovered through the ECR with the same diligence that other costs are separated between base rates and the ECR.

Q. How should the ROR calculation be refined to properly allocate short-term debt to the ECR revenue requirement?

A. The computation of the ECR ROR should be refined so that the Company's overall rate of return is adjusted to reflect the specific ECR allocation of short-term debt based on ECR CWIP divided by total Company CWIP. This requires that the capitalization that was used to compute the ROR be adjusted from total Company amounts to ECR-specific amounts for each type of capitalization, and then determine the weighted cost of capital using the ECR-specific capitalization.

There are multiple steps in this process. The first step is to remove the actual short-term debt, if any, from the total Company capitalization amounts and compute the long-term debt and common equity ratios without any short-term debt. The second step is to compute the amount of short-term debt that should be allocated to the ECR based on the percentage of ECR CWIP compared to total Company CWIP. The third step is to subtract the short-term debt allocated to the ECR from the ECR rate base investment and then multiply the remaining rate base investment times the long-term debt and common equity ratios computed in the first step. The fourth step is to compute the ECR ROR using the capitalization amounts computed in the third step and the authorized cost of each capitalization component, including any ECR-specific return on equity. This process is necessary to properly reflect the reality that short term financing is primarily used for construction, not plant in service.

<u>**Use of Mirror CWIP Will Mitigate the Effect on Customers**</u>

Q. Did the Company propose a CWIP in rate base approach for current recovery of the financing costs of the BS2 retrofit costs during construction?

A. No. The Company proposed an AFUDC approach. Under the AFUDC approach the Company's financing costs are capitalized and added to the CWIP amounts, which ultimately are transferred to plant-in-service at the in-service date of the assets.

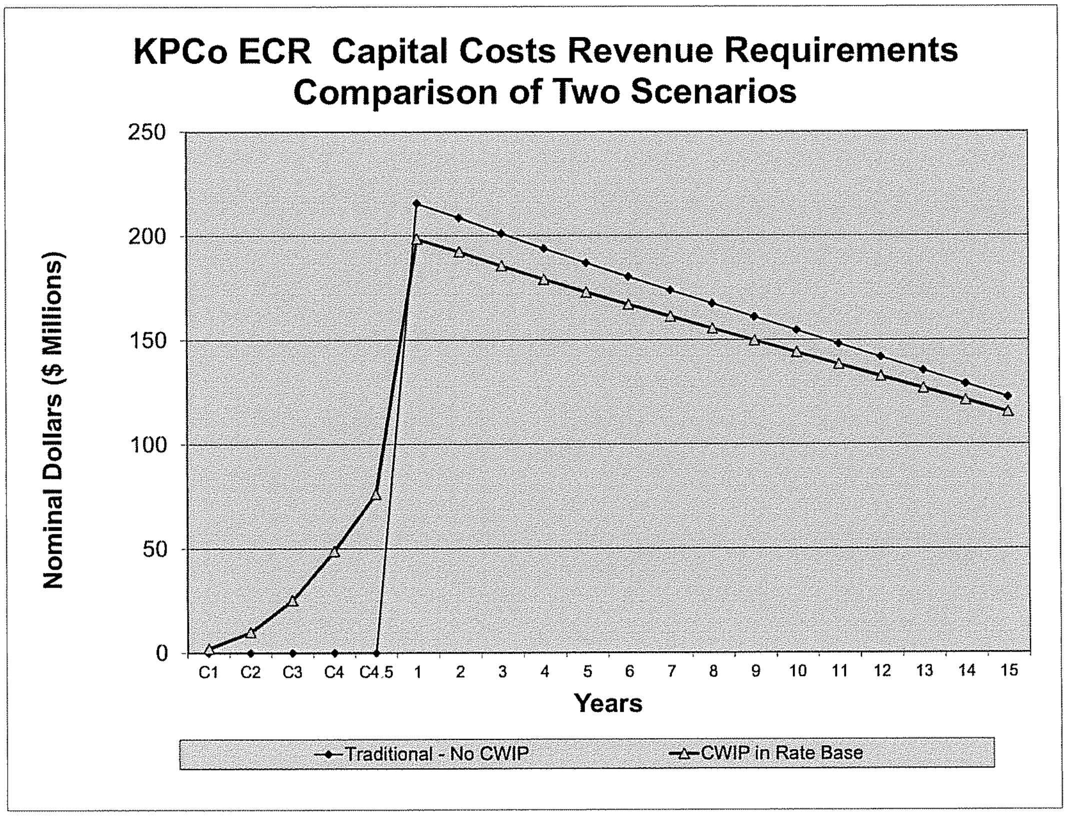
Q. How do the CWIP in rate base and AFUDC approaches differ in their effects on customers?

A. Aside from the harm to customers from CWIP in rate base compared to AFUDC due to the problem with the existing allocation of short-term debt in the ROR component in the ECR, the primary differences between the two approaches are the timing and magnitude of the rate increases. The CWIP in rate base approach results in a series of rate increases during the construction period to recover the financing costs of the project as it is constructed. Once the assets are placed in-service, there is another increase to recover any additional increment of the continuing financing costs plus the depreciation expense and other operating expenses. In contrast, the AFUDC approach results in no rate increases until the project is completed and in-service.

The CWIP in rate base approach has the effect of mitigating the one-time rate shock associated with the AFUDC approach due to the series of rate increases that precede the in-service date. The CWIP in rate base approach also results in a lower increase once the assets are placed in-service due to the lower financing costs on the lower completed cost of the asset (there is no AFUDC included in the completed cost of the assets) and due to the lower depreciation expense.

Under both approaches, once the project is completed, the revenue requirement peaks and thereafter declines as the assets are depreciated for book and tax purposes as the accumulated depreciation and accumulated deferred income tax amounts buildup.

The following graph portrays the rate path under the Company's proposed AFUDC approach compared to the CWIP in rate base approach. The two important points are that the CWIP in rate base approach results in a series of earlier rate increases than the AFUDC approach, but mitigates the peak rate increase once the assets are placed in-service.



Q. Is the Company economically indifferent whether the Commission uses the CWIP in rate base approach or the AFUDC approach?

A. No, unless the Commission corrects the misallocation of the short-term debt in the ROR, customers will pay more on a net present value basis from the CWIP in rate base approach compared to the AFUDC approach. If, however, the Commission corrects the misallocation of short-term debt in the ROR, then the two approaches generally result in the same economic result.

Q. Does the Commission typically employ the CWIP in rate base approach for the ECR?

A. Yes.

Q. If the Commission adopts the CWIP in rate base approach, is there a form of the CWIP in rate base approach that can further mitigate the peak rate increase in 2016 once the assets are placed in service?

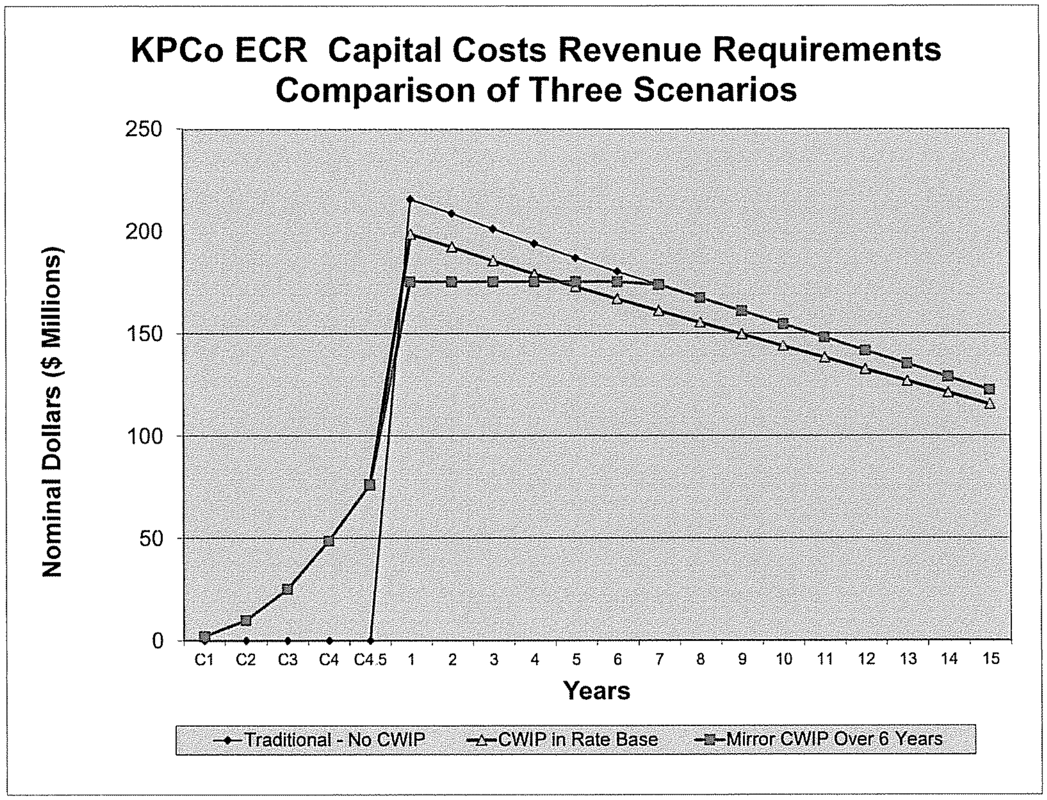
A. Yes. There is a form of the CWIP in rate base approach known as "mirror CWIP" that can further mitigate the peak rate increase by using the amounts recovered from customers during the construction period and the known reductions in the revenue requirement during a comparable post-in-service period.

Under the mirror CWIP approach, the Commission would allow CWIP in rate base during the construction period. However, the Company still would capitalize AFUDC and add it to the CWIP, but would concurrently create a regulatory liability, commonly referred to as contra-AFUDC, for the exact same amount. The AFUDC and contra-AFUDC would net to zero and the CWIP would be the same as if no AFUDC had been accrued.

The Commission then could use this contra-AFUDC regulatory liability to reduce and levelize the revenue requirements of the assets once they are placed in-service by amortizing the regulatory liability in amounts that will achieve this objective. The amortization commonly is structured so that it occurs over approximately the same number of years as the recoveries from ratepayers during construction, hence the term "mirror" CWIP.

Q. Have you prepared an illustration of the mirror CWIP proposal on revenue requirements?

A. Yes. The following graph portrays the trajectories of the traditional revenue requirements with no CWIP in rate base, the revenue requirements with CWIP in rate base during the construction period, and then the revenue requirements using the mirror CWIP approach. The mirror CWIP approach reduces and levelizes the peak revenue requirement during the early years that the assets are in-service until the regulatory liability is completely amortized and the revenue requirements return to the trajectory for the traditional revenue requirements.



Q. Do you recommend that the Commission adopt the mirror CWIP approach?

A. Yes. If the Commission approves the Company's request for a CPCN for the BS2 retrofit projects and adopts the CWIP in rate base approach, then it should take all reasonable steps to mitigate the effect of these projects on customers. The mirror CWIP approach offers the Commission a powerful regulatory tool to mitigate the peak effect on customers with no harm to the Company.

<u>Recovery of BS2 Retrofit Projects Should Be Reduced for Existing Plant Retirements</u>

Q. Does the Company plan to retire any existing assets in conjunction with the BS2 retrofit projects?

A. Yes. The Company plans to retire the existing BS2 electrostatic precipitator and to substantially modify its existing boiler and related plant, which also may result in retirements. In conjunction with the modification of the boilers, the Company plans balanced draft modifications, addition of a furnace arch addition, replacement of the existing low NOX burners, addition of furnace slag control devices, addition of superheater slag blowers, addition of a furnace imaging system, addition of furnace overlay, modification of the air heater, modification of the cola yard, according to the Company's response to Staff 1-46. I have attached a copy of the response to Staff 1-46 as my Exhibit___(LK-16).

The Company claims that there will be no retirements in conjunction with the boiler modifications, according to its response to KIUC 2-28. However, this is unlikely to be the case given the scope of the planned work. For example, the *replacement* of the low NOX burners likely will require the *retirement* and *removal* of the existing low NOX burners. I have attached a copy of the response to KIUC 2-28 as my Exhibit___(LK-17).

Q. Has the Company proposed any reductions to the ECR recovery to reflect the retirements of existing plant and the related reductions in operating expenses?

A. No. The Company's failure to do so is contrary to the Commission's precedent to reflect the reductions in rate base and operating expenses in the ECR revenue requirement. There should be reductions in the gross plant, accumulated depreciation, and ADIT rate base amounts. There also should be reductions to depreciation expense and O&M expenses, to the extent there was any specific O&M expense incurred to operate the retired plant and that no longer will be incurred after the BS2 retrofit projects are completed.

Q. What is your recommendation with respect to the retirements of existing plant and the related reductions in operating expenses?

A. I recommend that the Commission direct the Company to quantify these amounts, both the rate base and operating expense amounts, and then to reduce the ECR revenue requirement to reflect the effects of these retirements in accordance with the Commission's precedent.

Q. In addition to the retirements of plant, will the Company also incur demolition costs to dismantle, remove and dispose of these assets?

A. Yes. The Company will incur such costs for the ESP, but claims that it has not quantified those costs in response to KIUC 2-15. It also claims that, although it hasn't quantified these costs, it anticipates that the scrap value of the assets will approximate the cost of decommissioning, according to its response to KIUC 2-15. It isn't clear how the Company reached that conclusion without any quantifications. I have attached a copy of the Company's response to KIUC 2-15 as my Exhibit___(LK-18).

The Company claims that it will not retire any plant in conjunction with the boiler modifications, as I previously discussed. Thus, it has not assumed any demolition or removal costs for the boiler modifications in its cost estimate for the BS2 retrofits.

However, it is unusual, in my experience, for a utility to remove and replace equipment, as it proposes for the boiler modifications, not to retire plant and not to incur demolition or removal costs in excess of the scrap value of materials. This raises two concerns. The first concern is that the Company has in fact included the demolition and removal costs associated with the retirement of the ESP and boiler modifications in the cost estimate for the BS2 retrofit projects, but has not identified it as such. The second concern is that the Company has not included the demolition and removal costs in the cost estimate and that these costs nevertheless will be incurred and included in the actual installed costs of the new equipment.

Q. Should these costs be included in the BS2 retrofit project cost?

A. No. These costs are not a cost of the new BS2 retrofit projects, but rather are a cost of removing the retired plant assets. The cost of removal on the existing BS2 plant costs, net of salvage, is presently recovered and reflected in base rates. These costs are incurred to retire and remove plant in addition to the retirement of the plant in service amounts. The Company recovers for such costs through the net salvage component of depreciation expense and the cumulative amounts accrued for this purpose are reflected in the accumulated depreciation reserve for these assets. Consequently, in order to avoid double recovery of the demolition costs, net of salvage, these costs should not be recovered through the ECR revenue requirement.

Q. What is your recommendation on this issue?

A. I recommend that the Commission direct the Company to separate the cost of demolition and removal of existing plant from the costs of installing the new BS2 retrofit projects when it actually does its accounting for the costs that it incurs. The actual cost of demolition and removal of existing plant should be charged to the existing plant depreciation reserve in accordance with accounting requirements, not to the CWIP for the BS2 retrofit projects. The Commission should ensure that the Company correctly accounts for these demolition and removal costs so that they are not recovered through the ECR revenue requirement.

<u>BS2 Retrofit Projects Should Be Recovered Over 30 Years, Not 15 Years</u>

Q. Please describe the Company's proposal to recover the costs of the BS2 retrofits over 15 years.

A. The Company proposes a recovery period of 15 years. The 15 years is not based on a study or analysis, but rather on the Company's "concern of recovery," according to its response to Staff 1-88. I have attached a copy of this response as my Exhibit___(LK-19).

Q. How does the Company's request compare to the expected remaining life of BS2 if the retrofit projects are approved?

A. The Company claims that the expected service life could continue "until at least 2040," according to its response to Staff 1-12. The Company further cites AEP's experience in operating units that presently are 54-60 years old, ten of which are being retrofit with FGD technology after 57 years of service, according to its response to KIUC 2-4. I have attached a copy of the Company's response to Staff 1-12 as my Exhibit___(LK-20) and a copy the narrative portion of its response to KIUC 2-4 as my Exhibit___(LK-21).

Q. Should the depreciation rate be based on the expected service life of the assets that are being depreciated?

A. Yes. This is a fundamental concept underlying depreciation. The FERC USOA defines depreciation expense as the systematic and rational allocation of the asset's costs over its estimated service life. In addition, it is a fundamental concept in ratemaking that the costs of assets should be allocated to the customers that use those assets, i.e., the matching principle.

Q. Does the use of a longer recovery period, or a lower depreciation rate, reduce costs to customers?

A. Yes, according to the Company. The Company quantified a lower cumulative net present value for the BS2 retrofit, Option 1, if the recovery period is over 20 years rather than 15 years. Consequently, it follows that the Company would quantify an even lower cumulative net present value for the BS2 retrofit if the recovery period was 30 years rather than 20 years.

Q. What is your recommendation for the depreciation rate that should be used?

A. I recommend a depreciation rate of 3.33% to reflect a 30 year service life. In this manner, the costs of the BS2 retrofit projects will be allocated to the customers who use the assets, thus matching revenues, costs, and service. In addition, the longer recovery period will benefit customers on a cumulative net present value basis, according to the Company.

<u>Recovery of 2004-2006 Preliminary Investigation Costs Should Be Denied</u>.

Q. Please describe the Company's proposal to recover preliminary investigation costs that were incurred in 2004-2006.

A. In the years 2004-2006, the Company recorded and deferred preliminary investigation costs of $15.212 million. These costs were incurred by the Company for its evaluation of wet scrubber technologies and options and consisted of overheads, internal labor, outside services, service company charges, material, land, and other costs, according to the Company's response to Staff 1-18. The Company also included land purchase costs of $0.630 million in the total amount deferred. I have attached a copy of this response as my Exhibit___(LK-22).

Q. Did the Company seek Commission authorization to defer these costs or recover them prior to this proceeding?

A. No. The Company made no filings with the Commission and has not previously sought to recover the deferred costs, according to its response to KIUC 1-21, a copy of which I have attached as my Exhibit___(LK-23).

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 Case No. 2010-00523, Order of July 14, 2011 and

Case No. 2011-00036, Order of November 17, 2011.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request for 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 authorization to defer these costs and should not be allowed now to retroactively recover them from the 2004-2006 time period.

V. A REDUCTION IN THE RETURN ON EQUITY FROM 10.5% TO 9.2% WILL RESULT IN AN INITIAL RATE REDUCTION AND MITIGATE FUTURE INCREASES

Q. What is the effect of the Company's requested return on common equity in this proceeding?

A. The Company's requested return on equity is 10.50%, which is equivalent to a return of 16.55% when the related income tax expense gross-up is included. The effect of each 1.0% return on equity is $0.522 million on the existing ECR rate base and $5.228 million on the jurisdictional portion of the Company's proposed cost of $955 million for the BS2 retrofit projects and the 2004-2006 study costs.

Q. What is the effect of KIUC witness Mr. Steve Hill's recommended return on equity compared to the Company's requested return on the ECR revenue requirement?

A. The effect of Mr. Hill's recommendation of a 9.2% return on equity is an immediate rate reduction of $0.678 million when applied to the existing jurisdictional ECR rate base. I obtained the existing jurisdictional ECR rate base from the Company's November 2011 ECR filing provided in response to KIUC 1-41.

The effect of Mr. Hill's recommendation is a reduction of $6.786. million, or 1.19% in the initial rate increase for the operating month of June 2016 when the BS2 retrofit projects are projected to be in-service. The computations of these amounts are detailed on my Exhibit___(LK-24).

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

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

Lane Kollen

Sworn to and subscribed before me on this 2nd day of March 2012.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2016
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 2012

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

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

RESUME OF LANE KOLLEN, VICE PRESIDENT

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.

RESUME OF LANE KOLLEN, VICE PRESIDENT

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

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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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
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

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.

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Date	Case	Jurisdict.	Party	Utility	Subject
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 require-ments.
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	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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	Merger. Corp.
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	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	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend

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Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		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	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 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.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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

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Date	Case	Jurisdict.	Party	Utility	Subject
					mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co. and 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 Public Service Comm. 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, and 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	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/99	Rebuttal 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	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/00	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.
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	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	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. 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.
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.

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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. and 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 Public Service Comm. 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 Public Service Comm. 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 Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.

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07/01	U-21453, U-20925, U-22092 Subdocket B Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & 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 (Supplemental 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		Louisiana Public	SWEPCO	Business separation plan, T&D Term Sheet,

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Date	Case	Jurisdict.	Party	Utility	Subject
	and U-22092 (Subdocket C)		Service Commission Staff		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 Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.

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11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Unit power purchase 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,	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues,

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Date	Case	Jurisdict.	Party	Utility	Subject
	PUC Docket 29206				ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest
08/04	SOAH Docket 473-04-4556 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	Docket No. 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	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	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 05/06	31994 31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change. Retrospective ADFIT, prospective

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Date	Case	Jurisdict.	Party	Utility	Subject
					ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
3/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPioint 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.
4/06	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	33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and

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Date	Case	Jurisdict.	Party	Utility	Subject
					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.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuctionalization 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 account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.

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03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 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, 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, 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, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, incl costs recovered in existing rates, TIER
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, incl 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	WI	Wisconsin Industrial Energy	Wisconsin Power and	Nelson Dewey 3 or Colombia 3 fixed

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	Direct		Group, Inc.	Light Company	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 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

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					expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453,U-20925 U-22092 (Subdocket J)		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		Louisiana Public Service Commission	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	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		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	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 v. 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 v. 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 v. actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.

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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.
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	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 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

Expert Testimony Appearances
of
Lane Kollen
As of February 2012

Date	Case	Jurisdict.	Party	Utility	Subject
					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.
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

Expert Testimony Appearances
of
Lane Kollen
As of February 2012

Date	Case	Jurisdict.	Party	Utility	Subject
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 risksharing mechanism
07/11	ER11-2161 Direct & 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	ER11-2161 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	WE Energies, Inc.	Suspended amortization expenses; revenue

Expert Testimony Appearances
of
Lane Kollen
As of February 2012

Date	Case	Jurisdict.	Party	Utility	Subject
			Group		requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	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	39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rales.

EXHIBIT ____ (LK-2)

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-2. The heading of column 4 is "Capital Costs of Associated Utility Revenues." In Kentucky Power's environmental surcharge filings, the environmental surcharge factor on ES Form 1.00 is determined by dividing the Net KY Retail Expense amount on line 8 by the KY Retail Revenue, from ES Form 3.30, line 9.

a. Associated Utilities Revenues is shown on line 3 of the top portion of ES FORM 3.30, but is not considered in the calculation of the environmental surcharge factor on ES Form 1.00. Explain why the exhibit includes a calculation to recover environmental costs applicable to Associated Utilities Revenues.

b. Based on the current approved methodology for environmental costs recovery in Kentucky Power's environmental surcharge report, explain whether environmental costs associated with Associated Utilities Revenues are recovered through base rates.

c. If the answer to part b. of this Item is yes, explain whether the monthly environmental surcharge base rates shown on the proposed tariff, on page 1 of Exhibit LPM-15, should be revised to include environmental costs applicable to both KY Retail Revenues and Associated Utility Revenues.

RESPONSE

a. The Capital Costs of Associated Utility Revenues in column 4 of Exhibit LPM-2, shows an estimate of the environmental costs for wholesale customers that per the March 31, 2003 Order in Case No. 2002-169 should not have been included in this filing. The revised affected exhibits are attached.

b. Yes, environmental costs associated with Associated Utilities Revenues are recovered through base rates.

c. No, the base rates as shown on the proposed tariff are correct and do not need to be adjusted. The Kentucky Retail Jurisdiction Allocation Factor is applied after removing the Base Period Revenue Requirement (BRR) from the total Current Period Revenue Requirement (CRR) and therefore it is only accounting for Kentucky Retail Revenues.

WITNESS: Lila P Munsey

Kentucky Power Company
Pollution Control Environmental Facilities
Annual Revenue Requirement
Associated with Big Sandy Plant

Line No. (1)	Description (2)		Capital Costs of KY Retail Revenues (3)
	Return on Rate Base		
1	Utility Plant Installed Net (Exhibit LPM-1, L5)	$	955,512,492
2	Less: Accumulated Depreciation	$	63,732,683
3	Less: Accumulated Deferred Income Taxes	$	23,505,607
4	Net Utility Plant (L1- L2 - L3)	$	868,274,202
5	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)		10.69%
6	Annual Return on Rate Base (L4 X L5)	$	92,818,512
	Operating Expenses		
7	Annual Depreciation (L2)	$	63,732,683
8	Annual Property Tax Expense (Exhibit LPM-4, L5)	$	1,337,670
9	Annual Non-Fuel O&M Expense (Exhibit LPM-1, L8)	$	48,667,000
10	Total Operating Expenses (L7 + L8 + L9)	$	113,737,353
11	Total Revenue Requirement Associated with BS Env. Facilities (L6 + L10)	$	206,555,865
12	Annual Revenue Allocation Factor (Exhibit LPM-5, L15, C3 or C6)		78.91%
13	Subtotal (L11 X L12)	$	162,993,233
14	KY Jurisdiction Revenue Allocation Factor (Exhibit LPM-5, L14, C3)		
15	Total KY Retail Revenue Requirement (L13 X L14)	$	162,993,233
16	KY Jurisdiction 12-month Revenue (Exhibit LPM-5, L13, C3)	$	569,593,245
17	Percent Change (L15 / L16)		28.62%

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs Associated with
Allowance Inventory

Line No.	Description	Formula	KY Retail Rev Requirement
(1)	(2)	(3)	(4)
1	Estimated Monthly CSAPR SO2 Allowance Inventory	KIUC 1-20	$ 425,976
2	Estimated Monthly CSAPR NOx Allowance Inventory	KIUC 1-20	$ 2,053
3	Estimated Monthly CSAPR SO2 Consumption Expense	L11 / 12	$ 517,667
4	Estimated Monthly CSAPR NOx Consumption Expense	L12 / 12	$ (54,167)
5	Net Monthly Expenses (Consumption less Gains)	L3 + L4	$ 463,500
6	Cash Working Capital Allowance (in accordance with ES FORM 3.13)	L5 / 8	$ 57,938
7	Total Rate Base	L1 + L2 + L6	$ 485,967
8	Annual Weighted Average Cost of Capital	Exhibit LPM-3, L5, C8	10.69%
9	Return of Rate Base	L7 X L8	$ 51,950
10	Estimated Monthly CSAPR SO2 Consumption Expense	Wohnhas testimony	$ 6,212,000
11	Estimated Monthly CSAPR NOx Consumption Expense	Wohnhas testimony	$ (650,000)
12	Total Operating Expenses	L10 + L11	$ 5,562,000
13	Total Revenue Requirement	L9 + L12	$ 5,613,950
14	Annual Revenue Allocation Factor	Exhibit LPM-5, L15, C3	78.91%
15	Subtotal	L13 X L14	$ 4,429,968
16	KY Jurisdiction Revenue Allocation Factor	Exhibit LPM-5, L14, C3	98.91%
17	Total KY Retail Revenue Requirement	L15 X L16	$ 4,381,681
18	KY Jurisdiction 12-month Revenue	Exhibit LPM-5, L13, C3	$ 569,593,245
19	Percent Change	L17 / L18	0.77%

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs
Effect on Residential Customers

Line No.	Description	Formula	Annual Amount	Percent Increase
(1)	(2)	(3)	(5)	(6)
1	Annual Effect of New Environmental Pool Capacity Charges	Exhibit LPM-9, L14	$306,612	
2	KPCo's Share of Rockport	Exhibit LPM-12, L14	$480,780	
3	Total Environmental Cost	L1 + L2	$787,392	
4	KPCo's Average Retail Allocation for 12 months ended August 2011	Exhibit LPM-5, L.15, C3	78.91%	
5	Net Annual Impact on the Kentucky Retail Customers	L3 X L4	$621,331	0.10%
6	KY Retail Allowances	Exhibit LPM-13, L17, C4	$4,381,681	0.77%
7	KY Retail Revenue Requirement for Big Sandy Environmental Additions	Exhibit LPM-2, L15, C3	$162,993,233	28.62%
8	Total Environmental Projects in this Filing	L5 + L6 + L7	$167,996,245	29.49%
9	Billed Revenues for 12 months ended August 2011	Exhibit LPM-5, L13, C3	$569,593,245	
10	Percent Increase	L8 / L9	29.49%	
		Usage in kWh:	**1,000**	
11	Monthly Effect on a Residential Customers		$ 28.88	
12	Annualize		12	
13	**Annual Effect on a Residential Customers**	L11 X L12	$ 346.56	

EXHIBIT ____ (LK-3)

Kentucky Power Company
Kentucky Jurisdiction Total Retail Effect from Big Sandy 2 Retrofit Costs
($ millions)

Total Company First Year Revenue Requirement - Revised in Staff 1-20		206.556
Add: Total Company Revenue Requirement Related to SO2 and NOX Consumption		5.562
Total Company First Year Revenue Requirement - Corrected		212.118
Revenue Requirement Associated with Off System Sales at 10.88%	23.078	
Percentage Retained by KPC through System Sales Clause in its FAC	40%	
(Company Share 40% - Customer Share 60%)		
Maximum Amount Retained by KPC through System Sales Clause in its FAC		(9.231)
Total Company Total Revenue Requirement Less Amount Retained by KPCO		202.886
KY Jurisdictional Revenue Allocation Factor		98.91%
KY Jursidiction Total Retail Revenue Requirement Effect of Big Sandy 2 Retrofit		200.675
KY Jurisdiction Revenues from Exhibit LPM-13		569.593
Retail Increase for BS2 Retrofit Projects		35.23%

Sources: Revised Revenue Requirement Schedules in Response to Staff 1-20
Response to KIUC 2-18
Exhibit LPM-5 - 12 Month Avg OSS = 10.88%
KPC Tariff Sheet 19-1 and 19-2 and 2011 KPC FAC Filings

EXHIBIT ____ (LK-4)

Kentucky Power Company

REQUEST

Refer to the Company's response to Staff 1-48.

a. Please provide a copy of all assumptions used in each of the scenarios summarized in this response.

b. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Contract Revenue" represent and provide a description of how the amounts in this column were derived. Provide a copy of all assumptions and source documents relied on.

c. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Market Revenue (Cost)" represent and provide a description of how the amounts in this column were derived. Provide a copy of all assumptions and computations, including, but not limited to, the mW and mWh purchased and sold and the pricing for the capacity and energy. In addition, provide a copy of all source documents relied on for pricing the purchases and sales.

d. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Carrying Charges" represent and provide a description of how the amounts in this column were derived, including any levelization methodology that was used to derive the same amounts for multiple years. Provide a copy of all assumptions, computations, and source documents relied on, including the cash flows by project, the rate of return or "carrying charge" rate applied and the derivation of those rates, depreciation rates, tax rates, and all other assumptions incorporated in the amounts in this column whether by direct input or computation.

e. Refer to the column entitled "Carrying Charges" on Attachment 1 page 3 of 12. Please explain why the amounts went up from 155,093 in the years 2020-2024 to 257,945 in the years 2025-2030, and then down to 146,766 in the years 2031-2040. Provide the computations of each of these amounts, including all assumptions and electronic workpapers with formulas intact.

f. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Incremental O&M" represent and provide a description of how the amounts in this column were derived, including any specific increases included in 2040. Provide a copy of all assumptions and source documents relied on.

g. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Market Value of Allowances Consumed" represent and provide a description of how the amounts in this column were derived. Provide a copy of all assumptions and source documents relied on.

h. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Value of ICAP" represent and provide a description of how the amounts in this column were derived. Provide a copy of all assumptions and source documents relied on.

i. Refer to Attachment 1 page 3 of 12. Please provide the derivation of the discount rate used to compute the CPW of the revenue requirements. Provide a copy of all assumptions, computations, and source documents relied on.

j. Refer to Attachment 1 page 3 of 12. Please explain what the amounts in the column entitled "Capital Expenditures" represent and provide a description of how the amounts in this column were derived. In addition, please explain why the amounts in this column are the same as the amounts in the column entitled "Carrying Charges." Provide a copy of all assumptions and source documents relied on.

k. Refer to Attachment 1 page 11 of 12. Please explain what the amounts in the column entitled "Market Revenue (Cost)" represent and provide a description of how the amounts in this column were derived. Provide a copy of all assumptions and computations, including, but not limited to, the mW and mWh purchased and sold and the pricing for the capacity and energy. In addition, provide a copy of all source documents relied on for pricing the purchases and sales.

RESPONSE

a. A copy of the assumptions used in each of the scenarios summarized in this response may be found in the following files on the accompanying CD:

   File BS2 and NEW RESOURCE ALTERNATIVES (CONFIDENTIAL or REDACTED).PDF provides the assumptions made for the four Big Sandy alternatives and any capacity addition alternatives utilized in the Strategist analysis.

File FT-CSAPR BASE GAF (CONFIDENTIAL or REDACTED).PDF provides all of the Company's generation, transaction and market assumptions for the FT-CSAPR ('BASE') commodity price forecast.
File FT-CSAPR EARLY CARBON GAF (CONFIDENTIAL or REDACTED).PDF provides all of the Company's generation, transaction, and market assumptions for the FT-CSAPR EARLY CARBON commodity price forecast.
File FT-CSAPR HIGHER BAND GAF (CONFIDENTIAL or REDACTED).PDF provides all of the Company's generation, transaction, and market assumptions for the FT-CSAPR HIGHER BAND commodity price forecast.
File FT-CSAPR LOWER BAND GAF (CONFIDENTIAL or REDACTED).PDF provides all of the Company's generation, transaction, and market assumptions for the FT-CSAPR LOWER BAND commodity price forecast.
File FT-CSAPR NO CARBON GAF (CONFIDENTIAL or REDACTED).PDF provides all of the Company's generation, transaction, and market assumptions for the FT-CSAPR NO CARBON commodity price forecast.
File LOAD FORECAST.PDF provides all of the Company's load forecast assumptions used in the Strategist analysis.

b. The amounts reflected in the column entitled "Contract Revenue" on Attachment 1 page 3 of 12 of the response to Staff 1-48 represent the Company's net revenue from off-system contract transactions. The Contract Revenue is derived by taking the Company's contract sales revenue less contract purchase cost less emergency energy purchase cost. The amounts in the "Contract Revenue" column were derived from outputs in the Strategist model. See response to KIUC 2.2 (a) for all assumptions and source documents.

c. The amounts reflected in the column entitled "Market Revenue (Cost)" represent the Company's net revenue or cost from transacting with the PJM hourly energy market. The PJM hourly energy market price forecasts are developed by AEP's Fundamental Analysis group. On Attachment 1 page 3 of 12 of the response to Staff 1-48 "Market Revenue (Cost)" is derived by taking the Company's market energy sales revenue less Company's market energy purchase costs. The computations for arriving at the "Market" energy sales revenue and energy purchase costs are proprietary and confidential Strategist model algorithms. See Attachment 1 page 4 of 12 of the response to Staff 1-48 columns "Market Purchases" and "Market Sales" for amount of energy purchased and sold in the PJM hourly energy market. See response to KIUC 2.2 (a) for all assumptions and source documents. The pricing source for "Market" energy sales can be found on Attachment C of this response.

d. The amounts reflected in the column entitled "Carrying Charges" represent Strategist model's calculation of the Company's annual levelized carrying charge attributed to the addition of emission retrofits and new generating capacity. The capital cost from Witness Weaver's testimony Table 2, along with a construction escalation, levelized fixed charge rate, and book life were input in the model. Strategist then uses a levelized capital cost amortization method to develop a stream of annual levelized carrying costs for each option. The carrying costs for these options were then summed up to arrive at the "Carrying Charges" column on Attachment 1 page 3 of 12 of the response to Staff 1-48. See response to KIUC 2.2 (a) for all assumptions and source documents.

e. The "Carrying Charges" on Attachment 1 page 3 of 12 of the response to Staff 1-48 increase from 155,093 to 257,945 due to the addition of a combined-cycle in 2025. The values then decrease to 146,766 after the 15 year recovery of the Big Sandy 2 DFGD capital costs is completed. The computations for arriving at the "Carrying Charges" are proprietary and confidential Strategist model algorithms.

f. The amounts reflected in the column entitled "Incremental O&M" represent a delta of the sum of fixed and variable o&m between two individual cases, the DFGD Option 1 on Attachment 1 page 3 of 12 of the response to Staff 1-48 and another case with only those additions already present in 2011. A component of the fixed o&m is ongoing capital costs which are recovered through an annual carrying charge. The increased amount in 2040 represents the "terminal" value (i.e. CPW), from the recovery of any carrying charges that would continue past 2040 for all ongoing capital costs. See the accompanying CD to the response to KIUC 2.2 (a) for all assumptions and source documents.

g. The amounts in the column entitled "Market Value of Allowances Consumed" on Attachment 1 page 3 of 12 of the response to Staff 1-48 represent Strategist model's calculated output of Company's total emission cost. The amounts in this column were derived by Strategist. See response to KIUC 2.2 (a) for all assumptions and source documents.

h. The amounts in the column entitled "Value of ICAP" on Attachment 1 page 3 of 12 of the response to Staff 1-48 represent the Company's revenue or cost from transacting with the PJM capacity market. The Company must maintain enough installed capacity to meet the PJM minimum reserve margin requirement. If the Company's reserve margin drops below the required PJM minimum reserve margin target, this column represents the cost of purchasing capacity from the PJM capacity market to meet that target. In addition, this column represents the revenue from selling the Company's excess capacity above the minimum reserve margin into the PJM capacity market. The price of the PJM market capacity is based on the AEP Fundamental Analysis group's forecast of AEP GEN HUB nominal capacity prices. The amounts in this column were derived by multiplying Attachment 1 page 3 of 12 columns "Surplus MW" by "ICAP Value $/MW-wk" by the number of weeks in an year. The pricing source for "Value of ICAP" can be found on Attachment A of this response.

i. The derivation of the discount rate used to compute the CPW of revenue requirements on Attachment 1 page 3 of 12 of the response to Staff 1-48 is AEP's weighted average cost of capital of 8.64% can be found in Attachment B of this response.

j. The amounts in the column entitled "Capital Expenditures" represent Company's "Carrying Charges". See response to KIUC 2.2d for a description of "Carrying Charges." "Capital Expenditures" are an internal reporting break out of the "Carrying Charges." The amounts in column "Capital Expenditures" are duplicate and not a component reflected in the CPW on Attachment 1 page 3 of 12 of the response to Staff 1-48.

k. See response to KIUC 2.2. c.

WITNESS: Scott C Weaver

EXHIBIT ____ (LK-5)

Print

AEP Shares Plan For Compliance With Proposed EPA Regulations

Company advocates for more time and flexibility to reduce the negative impact of the proposed EPA rules on customers, jobs and the economy

COLUMBUS, Ohio, June 9, 2011 – American Electric Power (NYSE: AEP) today announced the company's plan for complying with a series of regulations proposed by the U.S. Environmental Protection Agency (EPA) that would impact coal-fueled power plants. Based on the regulations as proposed, AEP's compliance plan would retire nearly 6,000 megawatts (MW) of coal-fueled power generation; upgrade or install new advanced emissions reduction equipment on another 10,100 MW; refuel 1,070 MW of coal generation as 932 MW of natural gas capacity; and build 1,220 MW of natural gas-fueled generation. The cost of AEP's compliance plan could range from $6 billion to $8 billion in capital investment through the end of the decade. High demand for labor and materials due to a constrained compliance time frame could drive actual costs higher than these estimates. The plan, including retirements, could change significantly depending on the final form of the EPA regulations and regulatory approvals from state commissions.

The retirements and retrofits in the plan are in addition to more than $7.2 billion that AEP has invested since 1990 to reduce emissions from its coal-fueled generation fleet. Annual emissions of nitrogen oxides from AEP plants are 80 percent lower today than in 1990. Sulfur dioxide emissions from AEP plants are 73 percent lower than in 1990. The company currently owns nearly 25,000 MW of coal-fueled generation, approximately 65 percent of its total generating capacity. Coal would fuel approximately 57 percent of AEP's total generating capacity by the end of the decade.

"We support regulations that achieve long-term environmental benefits while protecting customers, the economy and the reliability of the electric grid, but the cumulative impacts of the EPA's current regulatory path have been vastly underestimated, particularly in Midwest states dependent on coal to fuel their economies. We have worked for months to develop a compliance plan that will mitigate the impact of these rules for our customers and preserve jobs, but because of the unrealistic compliance timelines in the EPA proposals, we will have to prematurely shut down nearly 25 percent of our current coal-fueled generating capacity, cut hundreds of good power plant jobs, and invest billions of dollars in capital to retire, retrofit and replace coal-fueled power plants. The sudden increase in electricity rates and impacts on state economies will be significant at a time when people and states are still struggling," said Michael G. Morris, AEP chairman and chief executive officer.

Although some jobs would be created from the installation of emissions reduction equipment, AEP expects a net loss of approximately 600 power plant jobs with annual wages totaling approximately $40 million as a result of compliance with the proposed EPA rules.

"We are deeply concerned about the impact of the proposed regulations on our customers and local economies. Communities that have depended on these plants to provide good jobs and support local services will face significant reductions in payroll and property taxes in a very short period of time. The economic impact will extend far beyond direct employment at power plants as thousands of ancillary jobs are supported by every coal-fueled generating unit. Businesses that have benefited from reasonably priced coal-fueled power will face the impact of electricity price increases ranging from 10 percent to more than 35 percent just for compliance with these environmental rules at a time when they are still trying to recover from the economic downturn," Morris said.

"Although discounted by some, the potential impacts on the reliability of the transmission system, particularly in the Midwest, are significant. The proposed timelines for compliance aren't adequate for construction of significant retrofits or replacement generation, so many coal-fueled plants would be prematurely retired or idled in just a few years. AEP's compliance plan alone would abruptly cut generation capacity in the Midwest by more than 5,400 MW. Depending on the year, another 1,500 MW to 5,200 MW of AEP generation would be idled or curtailed for extended periods as pollution control equipment is installed," Morris said.

AEP has shared its compliance plan with PJM Interconnection, Southwest Power Pool and North American Electric Reliability Corp. for use in their evaluation of the impacts of EPA's proposed rules.

"We will continue to work through the EPA process with the hope that the agency will recognize the cumulative impact of the proposed rules and develop a more reasonable compliance schedule. We also will continue talking with lawmakers in Washington about a legislative approach that would achieve the same long-term environmental goals with less negative impact on jobs and the U.S. economy," Morris said. "With more time and flexibility, we will get to the same level of emission reductions, but it will cost our customers less and will prevent premature job losses, extend the construction job benefits, and ensure the ongoing reliability of the electric system."

AEP's current plan for compliance with the rules as proposed includes permanently retiring the following coal-fueled power plants:

- Glen Lyn Plant, Glen Lyn, Va. – 335 MW (retired by Dec. 31, 2014);
- Kammer Plant, Moundsville, W.Va. – 630 MW (retired by Dec. 31, 2014);
- Kanawha River Plant, Glasgow, W.Va. – 400 MW (retired by Dec. 31, 2014);
- Phillip Sporn Plant, New Haven, W.Va. – 1,050 MW (450 MW expected to retire in 2011, 600 MW retired by Dec. 31, 2014); and
- Picway Plant, Lockbourne, Ohio – 100 MW (retired by Dec. 31, 2014).

AEP would retire generating units at the following locations but continue operating some generation at the sites:

- Big Sandy Plant, Louisa, Ky. – Units 1 and 2 (1,078 MW) retired by Dec. 31, 2014;
  Big Sandy Unit 1 would be rebuilt as a 640-MW natural gas plant by Dec. 31, 2015;
- Clinch River Plant, Cleveland, Va. – Unit 3 (235 MW) retired by Dec. 31, 2014; Units 1 and 2 (470 MW total) would be refueled with natural gas with a capacity of 422 MW by Dec. 31, 2014;
- Conesville Plant, Conesville, Ohio – Unit 3 (165 MW) retired by Dec. 31, 2012; Units 5 and 6 (800 MW total) would continue operating with retrofits;
- Muskingum River Plant, Beverly, Ohio – Units 1-4 (840 MW) retired by Dec. 31, 2014; Muskingum River Unit 5 (600 MW) may be refueled with natural gas with a capacity of 510 MW by Dec. 31, 2014, depending on regulatory treatment in Ohio;
- Tanners Creek Plant, Lawrenceburg, Ind. – Units 1, 2 and 3 (495 MW) retired by Dec. 31, 2014; Unit 4 (500 MW) would continue to operate with retrofits; and
- Welsh Plant, Pittsburg, Texas – Unit 2 (528 MW) retired by Dec. 31, 2014; Units 1 and 3 (1,056 MW) would continue to operate with retrofits.

The two coal-fueled generating units at Northeastern Plant (935 MW) in Oolagah, Okla., would be idled for a year or more while emission reduction equipment is installed. Both units would be idled beginning Jan. 1, 2016. One unit would return to service by Dec. 31, 2016. The other unit would return to service by Dec. 31, 2017.

AEP will complete construction of the Dresden Plant (580 MW natural gas) in Dresden, Ohio, in 2012.

In addition to the retrofits above, AEP would install or upgrade emissions reduction equipment at seven other coal -fueled power plants in Arkansas, Indiana, Louisiana, Ohio and Texas.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

This report made by American Electric Power and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, AEP's service territory and changes in market demand and demographic patterns; inflationary or deflationary interest rate trends; volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing AEP's ability to finance new capital projects and refinance existing debt at attractive rates; the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material; electric load and customer growth; weather conditions, including storms, and AEP's ability to recover significant storm restoration costs through applicable rate mechanisms; available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters; availability of necessary generating capacity and the performance of AEP's generating plants; AEP's ability to recover Indiana Michigan Power's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process; AEP's ability to recover regulatory assets and stranded costs in connection with deregulation; AEP's ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; AEP's ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates; new legislation, litigation and government regulation, including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of flyash and similar combustion products that could impact the continued operation and cost recovery of AEP's plants; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance); resolution of litigation (including AEP's dispute with Bank of America); AEP's ability to constrain operation and maintenance costs; AEP's ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities; changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities; changes in utility regulation, including the implementation of electric security plans and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP; accounting pronouncements periodically issued by accounting standard-setting bodies; the impact of volatility in the capital markets on the value of the investments held by AEP's pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements; prices and demand for power that AEP generates and sells at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation; and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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Melissa McHenry
Sr. Manager, Media Relations
614/716-1120

ANALYSTS CONTACT:
Bette Jo Rozsa
Managing Director, Investor Relations
614/716-2840

More news releases ...

EXHIBIT ____ (LK-6)

AEP AMERICAN® ELECTRIC POWER

Barclays Office Visit
Columbus, Ohio
July 5, 2011

Brian Tierney, EVP & CFO

Joe Hamrock, AEP Ohio President & COO

Rich Munczinski, SVP Regulatory Services

Julie Sloat, VP Regulatory Case Management

Retrofits/New Generation

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CATR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
Conesville 5	400	SCR, DSI		
Conesville 6	400	SCR, DSI		
Muskingum River 5	510	Refuel with Natural Gas		
Gavin 1	1320	FGD upgrade		
Gavin 2	1320	FGD upgrade		
Zimmer 1	330	FGD upgrade		
Total Expected Cost			2,100	2,800 *
Clinch River 1	211	Refuel with Natural Gas		
Clinch River 2	211	Refuel with Natural Gas		
Dresden	580	New Natural Gas		
Total Expected Cost			580	765 **
Rockport 1	1320	FGD, SCR		
Rockport 2	1320	FGD, SCR		
Tanners Creek 4	500	DSI, ACI		
Total Expected Cost			1,240	1,670 ***
Big Sandy 1	640	New Natural Gas		
Total Expected Cost			400	525

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 1	470	FGD, ACI, Baghouse		
	Northeastern 2	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total Expected Cost			700	940
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total Expected Cost			900	1,200
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total Expected Cost			80	100

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Total MW	**2,485**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,856**	

- ❑ Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- ❑ Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- ❑ Annual lost wages of approximately $40 million
- ❑ Tax payments could decline by more than $30 million

EXHIBIT ____ (LK-7)

AEP AMERICAN® ELECTRIC POWER

Barclays Capital CEO Energy-Power Conference Handout

New York, NY
September 8, 2011

Retrofits/New Generation

AEP®

- The tables below represent our estimated \$6 - \$8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 (\$MM)	High Cost Estimate 2012-2020 (\$MM)
AEP Ohio	Conesville 5	400	SCR, DSI		
	Conesville 6	400	SCR, DSI		
	Muskingum River 5	510	Refuel with Natural Gas		
	Gavin 1	1320	FGD upgrade		
	Gavin 2	1320	FGD upgrade		
	Zimmer 1	330	FGD upgrade		
	Total MW	**4,280**	**Total Expected Cost**	**2,100**	**2,800** *
APCO	Clinch River 1	211	Refuel with Natural Gas		
	Clinch River 2	211	Refuel with Natural Gas		
	Dresden	580	New Natural Gas		
	Total MW	**1,002**	**Total Expected Cost**	**580**	**765** **
I&M	Rockport 1	1320	FGD, SCR		
	Rockport 2	1320	FGD, SCR		
	Tanners Creek 4	500	DSI, ACI		
	Total MW	**3,140**	**Total Expected Cost**	**1,240**	**1,670** ***
KPCO	Big Sandy 1	640	New Natural Gas		
	Total MW	**640**	**Total Expected Cost**		**525**

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be \$366 million for the Dresden plant once completed; \$343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 (\$MM)	High Cost Estimate 2012-2020 (\$MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	**700**	**940**
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	**900**	**1,200**
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	**80**	**100**

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

- ❑ Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- ❑ Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- ❑ Annual lost wages of approximately $40 million
- ❑ Tax payments could decline by more than $30 million

23

EXHIBIT ____ (LK-8)

AEP AMERICAN® ELECTRIC POWER

46th EEI Financial Conference Presentation

Orlando, FL
November 8, 2011

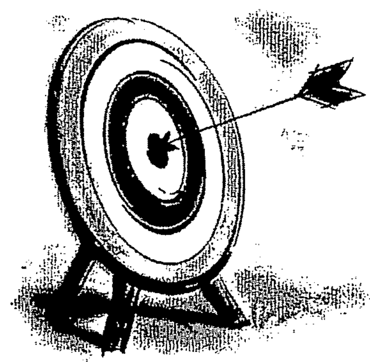
Nick Akins

President and CEO-elect

American Electric Power

My areas of strategic focus...

1. Optimize the earnings stream of the Company
   - ROE optimization
   - Resource transformation
   - Reposition transmission business
2. Achieve regulatory certainty
   - Execute Ohio strategy
   - Energy policy, EPA and environmental investments
3. Earnings and dividend growth



ROE optimization...

AEP®

ROE by Jurisdiction

Jurisdiction	Authorized ROE	Sep 2011 Proforma ROE*
AEP Ohio	NA	13.51%
APCO – Virginia	10.53%	
APCO – West Virginia	10.00%	6.88%
Wheeling	10.00%	
I&M – Indiana	10.50%	8.24%
I&M – Michigan	10.35%	
SWEPCO – Louisiana	10.57%	
SWEPCO – Arkansas	10.25%	10.05%
SWEPCO – Texas	10.33%	
AEP Texas	9.96%	14.98%
PSO - Oklahoma	10.15%	12.36%
Kentucky	10.50%	11.08%
Overall AEP Return	**NA**	**10.90%**

* Twelve Month Rolling Proforma Recurring ROE

- Strong overall system ROE with current rate cases on file for under earning utilities
- Continue to strengthen local relationships
- Concurrent recovery mechanisms
- Operating Company model refinement
  - Investment Review Committee
  - Advanced planning discussions with stakeholders

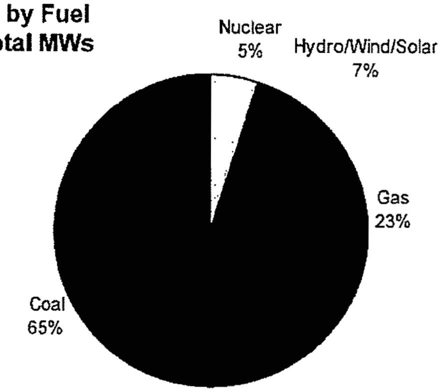
Management focused on Operating Company results and rate plans

Resource transformation . . .

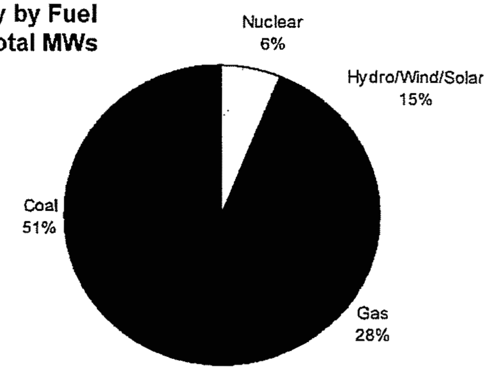
AEP®

- Grow rate base and earnings through adding environmental controls
- Retire older, uncontrolled coal units
- Add new capacity (natural gas) to rate base to replace a portion of retirements
- Transformation already occurring due to shale gas

2010 AEP Generating Capacity by Fuel 39,910 total MWs



2020 AEP Generating Capacity by Fuel 37,707 total MWs



Need more time to accomplish in order to mitigate customer costs and reliability impacts

EXHIBIT ____ (LK-9)

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, Table 1 and pages 23 to 30. Has the Company considered any other alternatives aside from Options 1-4?

a. If so, please provide detailed descriptions of all other alternatives considered, the level to which they were considered (i.e. discussion only, analysis, modeling, etc...), and any analytical work, such that it exists, that examined the cost efficacy of these other alternatives.

b. If so, please provide any analytical work that supports the non-consideration of those alternatives in the final four options presented here.

c. If not, why not?

d. Has the Company considered the cost effectiveness of replacing Big Sandy with capacity-only replacement, such as combustion turbine without combined cycle capacity?

e. Has the Company considered the cost effectiveness of replacing Big Sandy with a mixture of capacity and energy resources, such as a mix of combustion turbines and combined cycle capacity?

f. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and renewable energy purchases in either the short or long-term (i.e. immediately, up to 5 years as in Option 4A, or up to 10 years as in Option 4B)?

g. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and energy efficiency, demand response, or other demand-side management acquisitions or programs?

h. If the answer to any of (d)-(e) is yes, and as not otherwise provided in answer to (a) or (b), please provide any workpapers showing the scenario considered, the expected costs of the scenario, and any model results from comparing the scenario against other alternatives.

RESPONSE

a. An additional evaluation was performed in January of 2012, after the filing of this case. This assessment focused on the possibility of either acquiring --or entering into a purchase power arrangement-- from affiliate Ohio Power Company for a portion of the Mitchell Unit 1 and/or Unit 2 facilities. These 770 MW and 790 MW, respective coal-fired units are located in Moundsville, West Virginia and have recently been environmentally-controlled with FGDs and SCRs. The timing of this alternative evaluation was based on the recent prospect that Ohio Power Company could become corporately separated and, with that, the generation assets of that company may no longer be regulated and, hence, may be available for sale/transfer.

One of these evaluations calls for the purchase of a 20% portion of the combined Mitchell Units 1 and 2 (or, a total of 312 MW) and is under consideration as a replacement for the proposed retirement of KPCo's Big Sandy Unit 1. This evaluation is intended to be introduced as a proposed component of the 'Section 205' filing with the FERC that AEP is intending to file in early 2012 that would seek to modify the AEP Interconnection (Pool) Agreement.

Additionally, KPCo management also requested that an additional analysis be performed under which Kentucky Power would seek to receive a greater portion from Mitchell Units 1 and 2 (ostensibly, one of the 'full' Mitchell units) that would serve to effectively be substituted for the like-sized Big Sandy 2. This evaluation also assumed that in lieu of retiring Big Sandy Unit 1, it would consider converting that unit to burn solely natural gas (i.e. it would become a "gas-steam" unit).

The attachment to this response is a summary of these indicative Strategist-based evaluations performed in January 2012.

b. As indicated in the response part a of this question, this assessment was performed after this KPCo filing, but does not change the results and recommendation of the filing.

c. N/A

d. The Company has not considered the replacement of Big Sandy 2 with a combustion turbine unit. If Big Sandy Unit 2 were to be retired, KPCo would be replacing a large "baseload" facility that has historically contributed significant amounts of generated energy. As such, if it were to replaced purely with peaking capability --in the form of natural gas combustion turbine (CT) units, or as a unit simply converted to burn natural gas (i.e., a gas-steam unit)--, the Company believes it could be exposed to unacceptable levels of market (energy) purchases and, with that, potential for price volatility for the long-term life of the CTs/gas conversion due to such facilities' would very likely have very low utilization/capacity factors.

e. No. However, this option is essentially captured by, particularly, Options #4A and #4B. See the response Sierra Club 1-51, part a, for an elaboration.

f. No. The Company believes that renewable energy purchases are not substitutable for, particularly, capacity planning purposes. For instance, the PJM RTO recognizes only 13% of the nameplate MW-capacity of wind generating sources for capacity planning purposes. Further, KPCo 2009 request to recover its costs under a proposed wind renewable energy purchase agreement (REPA) was denied by the Commission following opposition by KIUC and the Attorney General.

g. No. While as indicated on Table 1-2 of Exhibit SCW-1, KPCo is projected to achieve 41 MW of demand response (DR) resource by 2016, and at least 60 MW by 2020, such amounts would likely serve to merely adjunct KPCo's resource portfolio, rather than offer a major contribution. As with peaking resources, DR would not contribute much in the way of *energy* contribution. Likewise, that same Table 1-2 of Exhibit SCW-1 also indicates as much as nearly 100 GWh of (annual) energy efficiency contribution being projected for the Company by 2016. However, that level also represents a small (< 2%) percentage of KPCo's overall internal load estimate for that year.

h. N/A

WITNESS: Scott C Weaver

EXHIBIT ____ (LK-10)

KENTUCKY POWER®
A unit of American Electric Power

AEP Interconnection Agreement (Pool) Termination and Replacement

Kentucky Power Company
Stakeholder Discussions
January 19, 2012

AEP KENTUCKY POWER
A unit of American Electric Power

Today's Topics

I. Meeting Purpose

II. Background

III. Impacts of pool termination and approach for energy and capacity needs

IV. New proposed Intercompany generation agreement

V. Estimated KYPCo retail impacts

VI. Questions and discussion

VII. Appendix with additional background information

KENTUCKY POWER
A unit of American Electric Power

I. Meeting Purpose

- Provide the KPSC with information on the latest developments
- Discuss analytical results
- Answer questions
- Gather feedback on issues or concerns
- Use meeting discussion to ensure KYPCo is complying with notice requirements before taking further actions

AEP KENTUCKY POWER
A unit of American Electric Power

II. Background

- The Interconnection Agreement (East Pool) was created in 1951 (last modified in 1980)
- Current Members are APCo, I&M, KYPCo and OPCo
  - CSP merged into OPCO December 31, 2011
  - The Pool facilitates the sharing of capacity, energy and off-system sales margins among the Members
- In December 2010, the East Pool members gave notice to AEPSC and the other members of their decision to terminate the Interconnection Agreement
- Termination based on several developments
  - AEP joined PJM RTO
  - New and anticipated environmental regulations, RPS Standards and energy efficiency mandates
  - State pool review requests
  - The current Pool no longer optimally supports AEP's operating company model which promotes planning to address unique needs of the respective operating companies
  - Impacts of Retail Choice (Ohio) on pool mechanisms

Today's East Pool does not reflect the current operating company and external environment.

AEP KENTUCKY POWER®
A unit of American Electric Power

Change in Timing

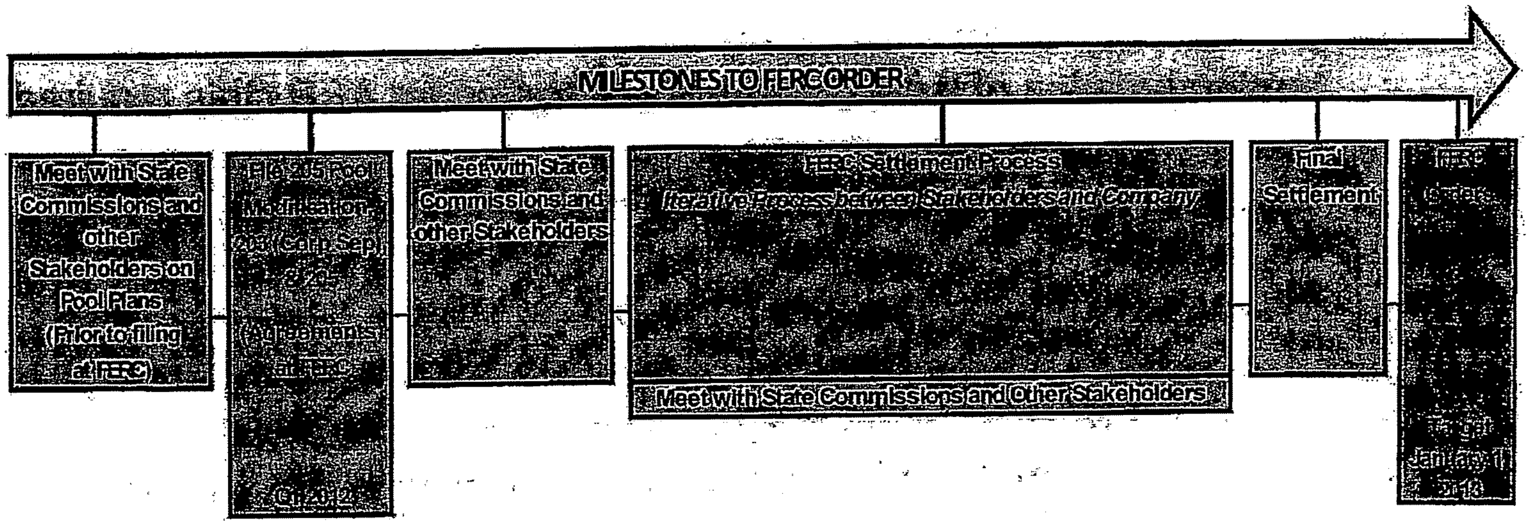
- The Ohio Commission's Order in the Electric Security Plan proceeding promotes a faster move to full competition than had previously been anticipated
  - Implementation of legal corporate separation for AEP Ohio required by Sept 30, 2013
  - Auctioning of Ohio generation load required for delivery beginning June 2015
  - Pool termination has been accelerated

- Current pool to terminate and new pool to commence with corporate separation of generation from transmission and distribution assets in Ohio
  - FERC filings currently anticipated by end of Q1 of 2012
  - Target completion date for FERC approval is January 1, 2013
  - Separation needs to occur no later than September 30, 2013

Timing of pool replacement is tied to regulatory requirements and is in the best interest of all AEP operating companies.

KENTUCKY POWER
A unit of American Electric Power

Tentative Timeline



Timeline includes communication with State commissions and other parties

AEP KENTUCKY POWER
A unit of American Electric Power

Pool-Related Agreement Provisions

Timing results in three distinct contractual periods

Member Companies of Each Agreement

	Today Until Pool Termination and Corporate Separation	Corp Sep Occurs/New Pool Begins through May 2015*	June 2015 Forward
Interconnection Agreement	APCo, I&M, KYPCo, OPCo		
New Pool Agreement		APCo**, I&M, KYPCo	APCo, I&M, KYPCo
"Bridge" Agreement		APCo, I&M, KYPCo, OPCo, AEP Generation Resources	

*Plus any additional months needed to complete transactions and/or settlements associated with this period.
**Includes merger of Wheeling Power Company into APCo.

The "Bridge" Agreement will address certain legacy pool provisions to provide a transition.

AEP KENTUCKY POWER
A unit of American Electric Power

III. Impacts of Existing Pool Termination

- **APCo and KYPCo require additional capacity & energy to be self-sufficient and meet the +15% reserve requirements in PJM**
  - Base load capacity needed by APCo & KYPCo
  - Environmentally controlled units provide the appropriate amount of energy and capacity required and compare favorably to the cost of a new combined cycle gas unit

- **Several alternatives were considered to satisfy the long-term base load generation needs of KYPCo's and APCo's customers:**
  - Short companies rely on the market; long-term concerns
  - AEP Generation Resources, Inc. can supply generation via:
    - Asset sales/transfers
    - Unit power long-term contracts

Transfer of base load units to APCo and KYPCo provides cost-effective capacity and energy to meet needs of a new 3-Company pool.

AEP KENTUCKY POWER
A unit of American Electric Power

Current Proposal – Asset Transfers

- **Solution chosen to meet KYPCo's long-term capacity and energy needs**
- **20% of an undivided interest in both Mitchell units 1 and 2 would be transferred to KYPCo**
  - Remaining 80% of Mitchell units would be transferred to APCo
  - APCo would also receive remaining portion of Amos unit 3 it does not already own
- **Mitchell Plant**
  - Located in Moundsville, WV
  - Both units in service 1971
  - Unit 1 nominal 770 MW; Unit 2 nominal 790 MW
  - KYPCo share equals nominal 154 MW (U1) and 158 MW (U2) for total of 312 MW
  - Both units have environmental controls
    - All newly Installed 2007
    - Flue gas desulfurization (FGDs)
    - Selective Catalytic Reduction (SCRs)

AEP KENTUCKY POWER
A unit of American Electric Power

Why Amos and Mitchell?

- **Good for KYPCo**
  - Along with rest of resource plan, provides sufficient capacity and base load energy needs for KYPCo customers
    - Provides "portfolio" approach for KYPCo
  - Controlled unit status will help mitigate new environmental regulations
  - Net plant book cost for KYPCo's share is (preliminary) ~$203 Million or ~$650/kW
    - Competitive with other long-term options
    - Comparable to current pool power
- **Makes sense for APCo too…**
  - Both plants located in WV – an APCo jurisdiction
  - APCo already owns Amos Units 1 and 2 and 33.3% of Unit 3

Confidential – For discussion purposes only

AEP KENTUCKY POWER
A unit of American Electric Power

IV. Proposed New Pool Agreement

- **A new, but different, pool between KYPCo, APCO and I&M is recommended to provide the following benefits**
  - Unit outage coordination
  - Risk mitigation
  - Provides flexibility to choose between PJM capacity alternatives FRR and RPM
  - Recognizes load diversity of the 3 companies
  - Works well within larger PJM pool
  - Enables optimization and trading on behalf of all members

Replacement of the existing pool with a new pool will provide benefits to the Operating Companies and facilitate more flexibility for company-specific decision making.

AEP KENTUCKY POWER
A unit of American Electric Power

Old Versus New Pool

- **The Old Pool**
  - Tightly integrated for capacity, energy and off-system sales (OSS)
  - Approach drove more centralized system planning
  - Capacity payments based on MLR and capacity position
    - Settlement at embedded cost
  - Transactions of energy at cost for Internal Load energy deficits
  - MLR sharing of OSS margins
- **The New "Pool"**
  - Operating Companies expected to be self-sufficient for capacity and energy
  - Loosely integrated, which facilitates independent decision-making by Operating Company
  - No automatic capacity payments
  - Provisions generally will provide capacity and energy as needed <u>and available</u> and allow system OSS trading

The New Pool provides benefits but also requires Operating Companies to meet their individual capacity and energy needs.

AEP KENTUCKY POWER®
A unit of American Electric Power

New Pool – Capacity Provisions

- No Monthly Capacity Payments between Companies
- Each Operating Company will be required to have or obtain capacity necessary to satisfy its internal load requirements and the required installed reserve margin
- Unassigned capacity purchases or sales, if any, will be allocated based on the capacity surplus of each Operating Company above its own requirements
  - Capacity purchases allocated to most deficit/least surplus Companies (any energy rights follow the capacity)
  - Capacity sales allocated to least deficit/most surplus Companies (any energy obligations follow the capacity)

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PJM Capacity Market

- **Companies need to elect which PJM method they will use to satisfy their capacity requirements three years in advance**
  - PJM Reliability Pricing Model (RPM) – "auction"
  - Fixed Resource Requirement (FRR) – "self-supply"

- **RPM**
  - Capacity resources offered into auction
    - Supply curve built up from these offers
  - Load obligations met by auction purchases
    - Administratively set demand curve
  - All cleared resources get market-clearing price

- **FRR**
  - Submit FRR plan that identifies resources used to satisfy load obligation and reserve margin

- **New Pool allows flexibility for either alternative**
  - It is currently anticipated the three Operating Companies will elect FRR for the PJM 2015/2016 Planning Year

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Pool Inter-Company Capacity Transactions

- If RPM is elected – STOP – any Operating Company's capacity deficit or surplus will be obtained or sold in the RPM auction
  - Once delivery year begins, each operating company responsible for any unit unavailability costs
- If FRR, new pool will provide the possibility for some limited sales and purchases between Operating Companies prior to the beginning of the delivery year
  - If an Operating Company needs more capacity, purchase can be made from one or more other Operating Companies surplus capacity, if available, at RPM clearing price
  - Once delivery year begins, unavailability costs will be managed collectively and allocated post-delivery year based on each operating company's contribution to these costs

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Old Pool - Energy

- All non-dedicated resources of each Operating Company put into one combined supply curve, i.e., "stack" and settled hourly
- The highest cost resources are assigned to OSS, regardless of Operating Company ownership *?*
  - Each Member gets allocated a MLR share of the OSS revenues and costs
- The remaining generation resources by Operating Company are then compared to its internal load obligation to determine its hourly surplus or deficit
- Operating Company surpluses are then used to satisfy the hourly energy deficit needs of the short Operating Company(ies) *?*
  - Reimbursement at cost of fuel, fuel handling and Variable O&M

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New Pool Energy

Pool supplies "Split the Savings" energy as needed and available

- **Pool Surplus Energy Sales among the members may occur when at least one Company is energy deficit in terms of meeting its own load (excluding spot purchases) and one or more others has surplus energy available**
  - To occur, transactions must be economical for the Buyer compared to Buyer's avoided spot market price
  - "Split the savings" -- Pool Surplus Energy is sold at the hourly average mid-point price between the Seller's incremental cost and Buyer's avoided market price.
- **Settlement will allocate system optimization purchases hourly among the member Companies based on each Company's hourly internal load**
- **System optimization off-system sales and other trading activity (OSS) are allocated hourly among Companies based on each Company's remaining surplus**

7 * 2

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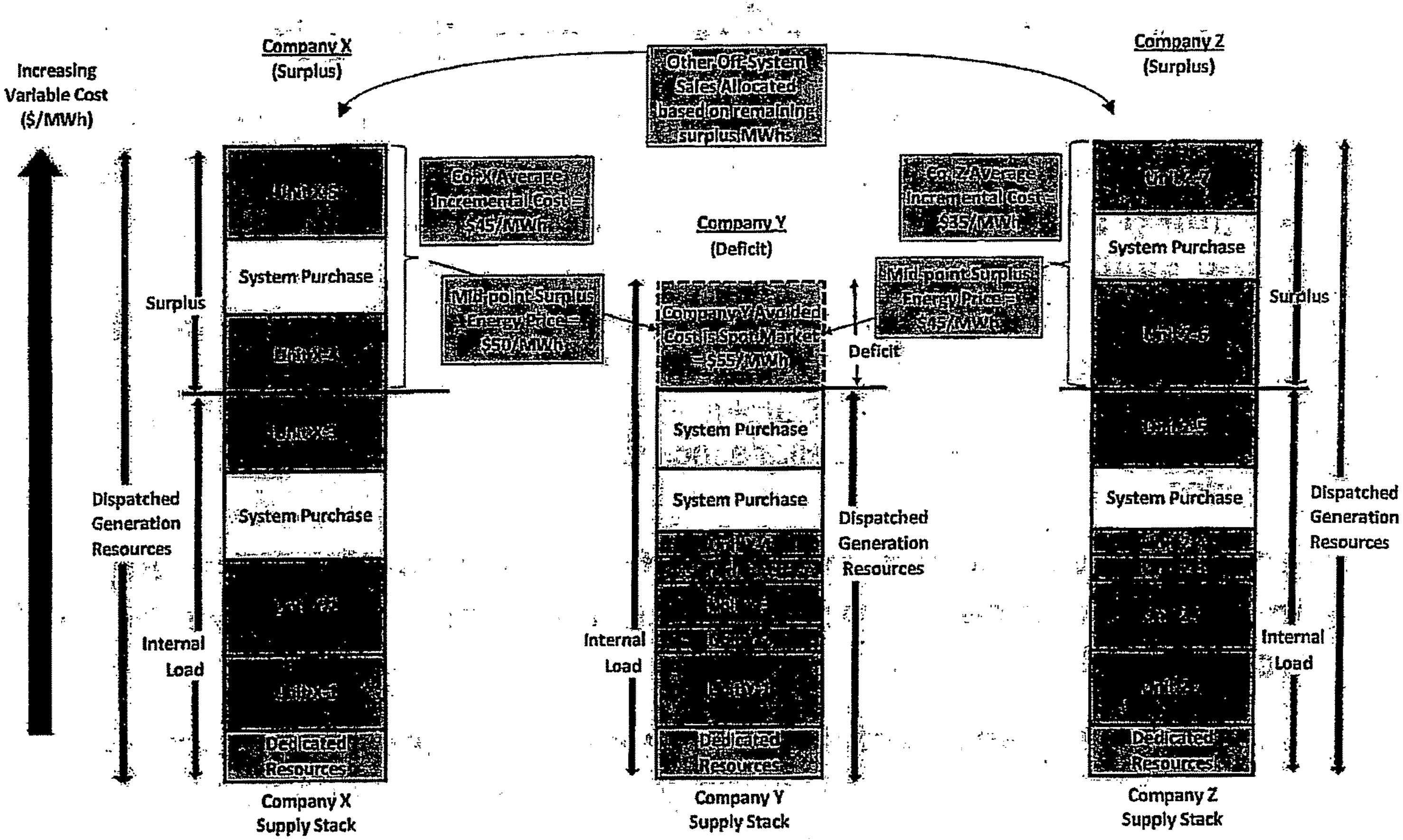
New Pool Energy – Hourly Example

New Pool Energy Allocation Hourly Example



A. Allocate system energy purchases on hourly Internal Load of each company.

B. Surplus Energy transactions at Mid-Point prices allocated from long Companies based on each Co.'s surplus MWhs.

C. Allocate other Off System Sales based on each Company's remaining energy surplus MWhs.

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Other Changes

- The Interim Allowance Agreement (IAA) will be eliminated
  - IAA currently has various provisions for settlement of Title IV SO2 emission allowances among the pool members
  - IAA is supplemental agreement to old pool and is becoming obsolete with new transactions
  - Each Operating Company will be responsible for its own emission allowance position
- **Each Operating Company will be responsible for its own charges and credits with PJM with limited exceptions**
  - PJM sub-accounts will be established for each Operating Company
- **Wheeling Power Company merged into APCO**

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V. Estimated KYPCo Retail Impacts

Line	Account		REVENUE REQUIREMENT IMPACTS ($Millions) Old Pool	New Pool	Change
1		**Revenues - Increase/(Decrease) Cost of Service**			
2	447	OSS Revenues [Note 1]	($44)	($121)	($77)
3	447	Pool Energy Sales	($32)	($23)	$9
4		**Subtotal Revenue Impacts**	($76)	($144)	($68)
5		**Expenses - Increase/(Decrease) Cost of Service**			
6	509, 411	Net Allowance Expense [Note 2]	$12	$3	($9)
7	555	Purchase Power - Pool Capacity	$55	$0	($55)
8	555	Pool Energy Purchase	$16	$10	($6)
9	555	Market Purchased Power	$4	$8	$3
10	447,555,561, 565,575	PJM Bill (Purchased Power)	$14	$45	$30
11		**Subtotal Expense Impacts**	$101	$65	($37)
12		**Mitchell Revenue Requirement**			
13	403	Depreciation	$0	$13	$13
14	5XX, 9XX	Fuel & O&M Expense	$0	$63	$63
15	408	Taxes Other Than Income	$0	$2	$2
16	NA	Return Requirement (Pre-Tax) [Note 3]	$0	$22	$22
17		**SubTotal Mitchell Revenue Requirement**	$0	$101	$101
18					
19		**Total Revenue Requirement Impact**	$25	$21	($4)
20					
21		**Kentucky Power Retail Revenue**			$579
22		**% Change**			-0.70%

A&G?

ADIT
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comm

Notes
1. Financial transactions and retained Off System Sales (OSS) margins have been removed from analysis
2. Impacts of Interim Allowance Agreement (IAA) elimination shown prior to asset transfers or pool replacement.
3. Transfer 20% of Mitchell 1&2 to KPCO (~312 MW)

Kentucky Mitchell Rate Base Retail Allocation	$203
Pre-Tax Rate of Return	11.01%
Pre-Tax Return on Mitchell Rate Base	$22

Impacts based on twelve months ended (a) September 30, 2011 for Mitchell transfer and (b) October 31, 2011 for IAA elimination and pool replacement.

Results indicate KYPCo would have been approximately neutral.

VI. Questions?

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VII. Appendix

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Old Pool MLR

- Member Load Ratio (MLR)
  - Ratio of each member company's internal load peak demand for the previous 12 months to the sum of the peak demands

Interchange Power Statement – May 2010

		APPALACHIAN			KENTUCKY			INDIANA			OHIO			COLUMBUS		
MO/YR	TOTAL	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK
04/10	15059	29	07	4556	28	07	1036	15	14	3080	29	08	3725	06	16	2662
03/10	18083	05	08	6240	05	08	1348	05	08	3364	03	09	4094	02	20	3037
02/10	19912	10	09	6952	01	09	1431	08	08	3627	08	10	4621	08	08	3281
01/10	20592	11	08	7440	08	09	1543	07	08	3680	13	08	4563	05	19	3366
12/09	19925	11	08	6613	11	08	1434	10	19	3858	10	20	4510	10	19	3510
11/09	16370	06	08	5106	06	08	1113	30	20	3373	06	10	3848	30	20	2930
10/09	16005	19	07	5341	19	08	1070	14	10	3163	19	07	3694	14	19	2737
09/09	17161	24	14	5141	22	14	1040	15	15	3559	15	14	4140	15	16	3281
08/09	19936	10	15	5786	10	16	1163	10	14	4076	10	14	4844	17	15	4067
07/09	18453	28	15	5415	27	16	1081	28	15	3803	16	16	4365	16	16	3789
06/09	19591	19	17	5362	19	16	1147	25	14	4245	25	15	4628	25	16	4209
05/09	16330	28	14	4662	22	15	1000	27	16	3400	28	13	3911	27	16	3357

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Old Pool MLR (cont.)

- **Member Load Ratio (MLR)**
  - Determines percentage of AEP East system capacity each Operating Company is financially responsible for each month
  - Allocation of total pool OSS margins

May 2010

Company	(MW)	Demand	MLR
APCO	7,440	1/11/2010	0.33392
KPCO	1,543	1/8/2010	0.06925
I&M	4,245	6/25/2009	0.19052
OPCO	4,844	8/10/2009	0.21740
CSP	4,209	6/25/2009	0.18891
Total	22,281		1.00000

MLR, while straightforward, is somewhat volatile since it is single peak driven.

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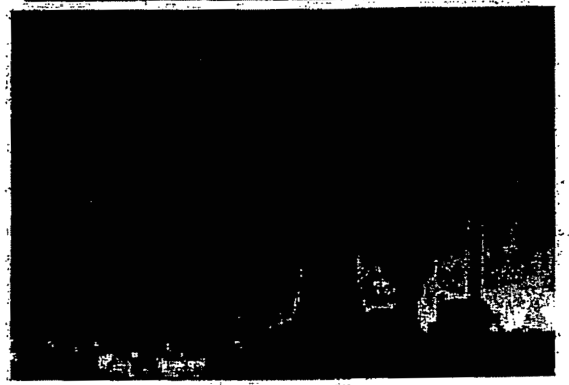
KPCo Primary Capacity

Plant	Kentucky Power Company	Capacity (kW)
Big Sandy		1,077,000
Rockport 1 (Purchase from AEG)		198,000
Rockport 2 (Purchase from AEG)		195,000
TOTAL MEMBER STEAM-ELECTRIC PRIMARY CAPACITY		1,470,000
TOTAL MEMBER PRIMARY CAPACITY		1,470,000



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Member Capacity Surplus/Deficit

Interchange Power Statement – May 2010 (Page 3)

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II) (1)	MEMBER LOAD RATIO (APPENDIX I) (2)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2) (3)	SURPLUS (DEFICIT) CAPACITY kW (4) = (1) - (3)
APCO	6,348,000	0.33392	8,878,300	(2,530,300)
KPCO	1,470,000	0.06925	1,841,200	(371,200)
I&M	5,430,000	0.19052	5,065,600	364,400
OPCO	8,483,000	0.21740	5,780,200	2,702,800
CSP	4,857,000	0.18891	5,022,700	(165,700)
TOTAL	26,588,000	1.00000	26,588,000	0

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Primary Capacity Equalization Charge

- The monthly capacity charge paid by the *deficit* (capacity short) companies is based upon a weighted average capacity rate of the *surplus* (capacity long) companies
  - Member Primary Capacity Investment Rate
  - Member Primary Capacity Fixed Operating Rate

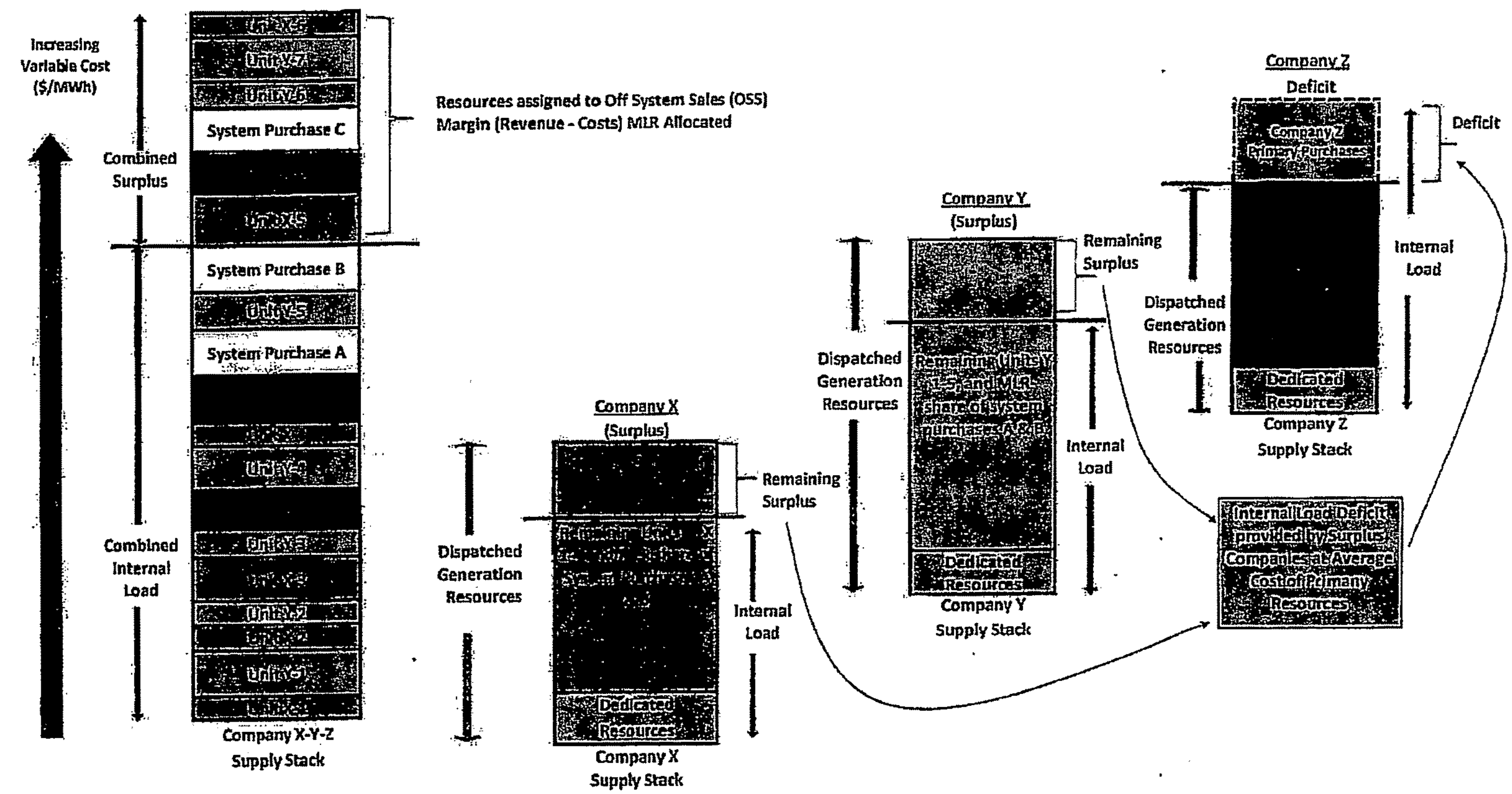
MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $	FERC ACCOUNT
	(1)		(2)		(3)	
APCO	(2,530,300)	*****	+	*****	(33,690,044)	5550004
KPCO	(371,200)	*****	+	*****	(4,942,396)	5550004
I&M	364,400	9.92	+	4.69	5,323,884	4470127
OPCO	2,702,800	10.60	+	2.54	35,514,792	4470127
CSP	(165,700)	*****	+	*****	(2,206,237)	5550004

EQUALIZATION CAPACITY RATE: 13.3146

(This is the average $/kW rate paid by deficit members.)

Old Pool - Energy

Old Pool Energy Allocation Hourly Example



A. System Purchases are MLR - Allocated and may be allocated to OSS or Internal load depending on cost.
B. Resources assigned to OSS regardless of ownership or energy position (i.e., surplus/deficit) and all Companies receive MLR-share of OSS margin.
C. Combined resources for internal load are "unbundled" and surpluses used to satisfy Internal Load deficits.

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Capacity Example - RPM

- Capacity transactions between the Operating Companies unnecessary since RPM will provide market for sells and purchases

Illustrative Example
Fulfilling PJM Capacity Obligations in the New Agreement

I. RPM Participation - 3 Operating Companies participate in auction 3 years in advance of delivery year.

	Company X	Company Y	Company Z
1. Unforced Capacity (UCAP) Resources	7,400 MW	1,800 MW	4,200 MW
2. UCAP Load Obligation including reserve margin	6,500 MW	1,500 MW	4,500 MW
3. Net Capacity Position (Ln 1 - Ln 2)	900 MW	300 MW	(300) MW

STOP - Sales and Purchases can be made directly in the RPM auctions.
Companies X and Y receive revenues auction clearing price from auction sales, assuming all their UCAP clears.
Company Z pays auction clearing price for additional capacity need.

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Contingency Capacity Example - FRR

- For capacity transactions between the Pool Operating Companies prior to the delivery year for contingency purposes only.

Illustrative Example
Fulfilling PJM Capacity Obligations in the New Agreement

II. FRR Participation - 3 Operating Companies must submit their capacity plan 3 years in advance of delivery year.

	Company X	Company Y	Company Z
1. Unforced Capacity (UCAP) Resources (MW)	7,400 MW	1,800 MW	4,200 MW
2. UCAP Load Obligation including reserve margin (MW)	6,500 MW	1,500 MW	4,500 MW
3. Net Capacity Position (Ln 1 - Ln 2)	900 MW	300 MW	(300) MW
Company Z does not have sufficient capacity to meet its portion of the capacity plan.			
4. Length of Companies X & Y above required (Ln3/Ln2)	13.85%	20.00%	
5. Allocation of Sale between Companies	(225) MW	(75) MW	300 MW
6. New Net Capacity Position	675 MW	225 MW	0 MW
7. New Capacity Percent Position	10.38%	15.00%	0.00%

EXHIBIT ____ (LK-11)

Kentucky Power Company

REQUEST

For the capital costs imbedded in the costs of the Big Sandy Unit 2 FGD system in Exhibit LPM-1, provide a breakdown of the cost for the major components in the system in total dollar amounts and in dollars per kW.

RESPONSE

The breakdown of the total Big Sandy Unit 2 DFGD system of $940,300,067 ($1,175 per kW) is as follows:

Major Component	Cost	Cost per kW
DFGD Unit #2	$604,019,623	$755
DFGD Unit #2 Assoc	241,856,603	$302
DFGD Ash Haul Road	31,042,968	$39
DFGD Landfill	63,380,873	$79
Total	$940,300,067	$1,175

WITNESS: Lila P Munsey

EXHIBIT ____ (LK-12)

Kentucky Power Company

REQUEST

Please provide a copy of all analyses that considers natural gas price alternatives at levels less than the lower band alternative scenario prices shown on Exhibit SCW-2 page 2 of 2. If the Company has not performed a sensitivity at prices less than the lower band alternative scenario, then please explain why it has not.

RESPONSE

No such analyses have been performed. The long-term forecast represents a fundamental view of the primary drivers to the energy market. Each primary driver (supply, demand, fuel, policy, etc) is developed by company experts and reflects public and non-public information. These industry views represent a sustainable outlook over the forecast period. The "base" forecast represents a sustainable view of key inputs. Upper and Lower Band forecasts measure the sensitivity of the "base" forecast to sustainable changes in fuel prices (coal and natural gas), emission prices (excluding carbon dioxide), and electricity demand.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please provide an economic analysis for a combined cycle alternative that relies on natural gas price starting at $3.00 per mmBtu in 2012 escalated at the same % rate as the lower band alternative scenario prices shown on Exhibit SCW-2 page 2 of 2.

RESPONSE

The requested analysis has not been performed.

WITNESS: Scott C Weaver

EXHIBIT ____ (LK-13)

AEP AMERICAN ELECTRIC POWER®

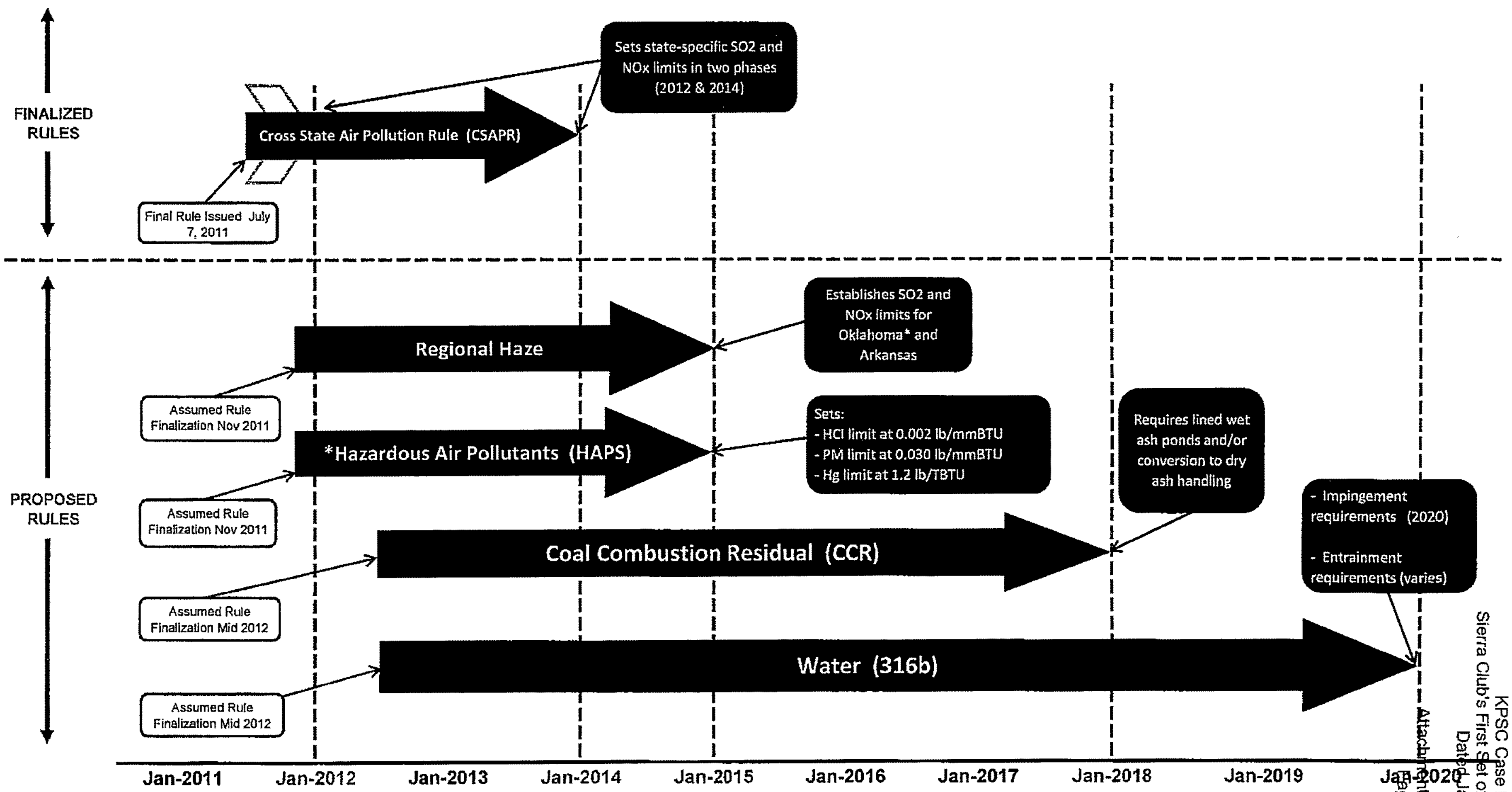
Bank of America Merrill Lynch 2011 Power & Gas Leaders Conference

New York, NY
September 20, 2011

AEP®

Nick Akins, President

EPA Regulatory Deadlines



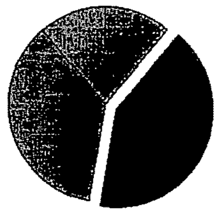
* Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.

AEP Coal Fleet Assessment

2012 – 2020

Range of Capital ($ Millions) (1)

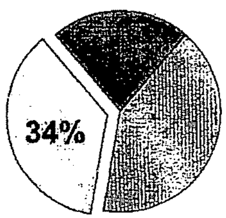
Least Exposed



Operating Company	MW
APCo	3,353
AEP Ohio	6,984
	10,337

Rules		Low		High
Water Rules (2)	$	15	$	20
CCR Rules	$	810	$	1,080
Air Rules (3)	$	1,425	$	1,900

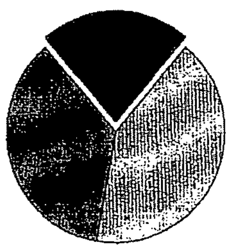
Partially Exposed



Operating Company	MW
AEP Ohio	1,385
APCo	470
I&M	3,120
PSO	1,036
SWEPCo	2,162
TNC	377
	8,550

Rules		Low		High
Water Rules (2)	$	55	$	85
CCR Rules	$	385	$	520
Air Rules (3) (4)	$	2,680	$	3,565

Fully Exposed



Operating Company	MW
AEP Ohio	2,538
APCo	1,270
I&M	495
KPCo	1,078
SWEPCO	528
	5,909

Rules		Low		High
Water Rules (2)	$	-	$	5
CCR Rules	$	30	$	45
Air Rules (3)	$	30	$	50
Replacement Generation	$	570	$	730
Grand Total	**$**	**6,000**	**$**	**8,000**

(1) The impact of all rules continues to be under review. Project scope and technical assessments are ongoing. Any change in scope will impact the capital cost ranges.

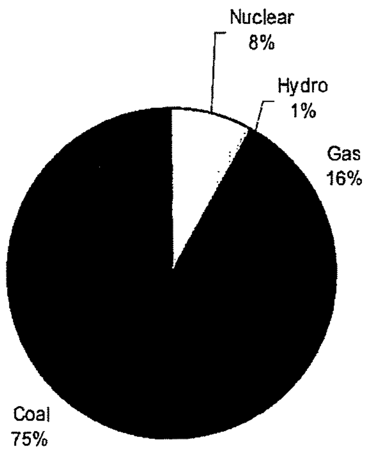
(2) Gas plants are not included in MW. Proposed 316 (b) will impact some gas facilities.

(3) Air Rules include: CSAPR as finalized and HAPs and Regional Haze Federal Implementation Plans in OK & AR, as proposed.

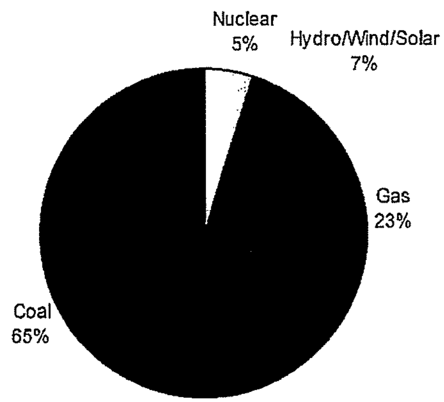
(4) Includes NSR Compliance.

Generation Transformation

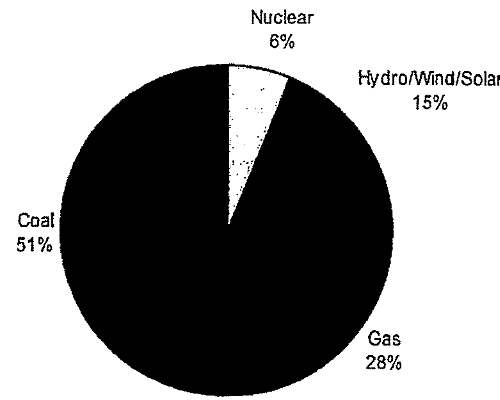
1990 AEP Generating Capacity by Fuel
37,428 total MW's



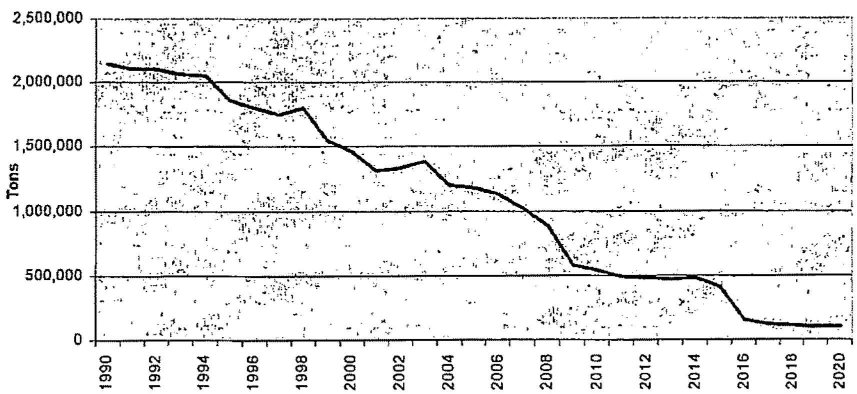
2010 AEP Generating Capacity by Fuel
39,910 total MW's



2020 AEP Generating Capacity by Fuel
37,707 total MW's



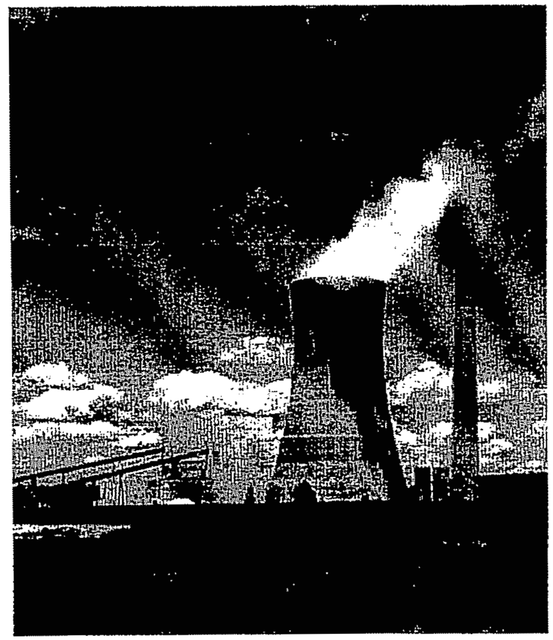
Total System NOx & SO2 (actual through 2010 and forecasted based on proposed EPA regulations)



- $7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons
- Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons

AEP Highlights

- Premier Utility Platform
- Traditional and Effective Regulatory Relationships
- Significant Investment Opportunities in Environmental Retrofits and Transmission
- Strong Value and Total Return Proposition



Mountaineer Plant (WV)

EXHIBIT ____ (LK-14)

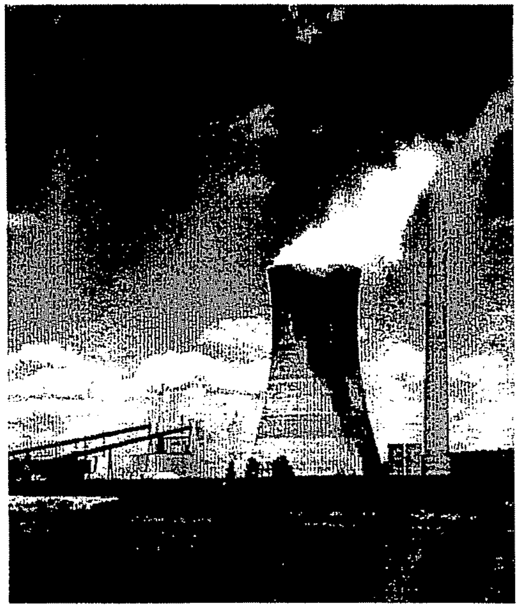
AEP AMERICAN® ELECTRIC POWER

2011 INVESTOhio Equity Conference

Columbus, OH
September 22, 2011

AEP Highlights

- ❑ Premier Utility Platform
- ❑ Traditional and Effective Regulatory Relationships
- ❑ Significant Investment Opportunities in Environmental Retrofits and Transmission
- ❑ Strong Value and Total Return Proposition



Mountaineer Plant (WV)

Retrofits/New Generation

AEP®

- The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CSAPR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
AEP Ohio	Conesville 5	400	SCR, DSI		
	Conesville 6	400	SCR, DSI		
	Muskingum River 5	510	Refuel with Natural Gas		
	Gavin 1	1320	FGD upgrade		
	Gavin 2	1320	FGD upgrade		
	Zimmer 1	330	FGD upgrade		
	Total MW	**4,280**	**Total Expected Cost**	2,100	2,800 *
APCO	Clinch River 1	211	Refuel with Natural Gas		
	Clinch River 2	211	Refuel with Natural Gas		
	Dresden	580	New Natural Gas		
	Total MW	**1,002**	**Total Expected Cost**	580	765 **
I&M	Rockport 1	1320	FGD, SCR		
	Rockport 2	1320	FGD, SCR		
	Tanners Creek 4	500	DSI, ACI		
	Total MW	**3,140**	**Total Expected Cost**	1,240	1,670 ***
KPCO	Big Sandy 1	640	New Natural Gas		
	Total MW	**640**	**Total Expected Cost**		525

*Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade

Operating Company	Plant	MW	Type of retrofit	Low Cost Estimate 2012-2020 ($MM)	High Cost Estimate 2012-2020 ($MM)
PSO	Northeastern 3	470	FGD, ACI, Baghouse		
	Northeastern 4	465	FGD, ACI, Baghouse		
	Oklaunion	101	FGD upgrade, ACI		
	Total MW	**1,036**	**Total Expected Cost**	700	940
SWEPCO	Flint Creek	264	FGD, ACI, Baghouse		
	Welsh 1	528	ACI, DSI, Baghouse		
	Welsh 3	528	ACI, DSI, Baghouse		
	Pirkey	580	ACI, Baghouse		
	Dolet Hills	270	ACI, Baghouse		
	Total MW	**2,170**			
			Total Expected Cost	900	1,200
TNC	Oklaunion	377	FGD upgrade, ACI		
	Total MW	**377**	**Total Expected Cost**	80	100

Retirements

Operating Company	Plant	MW	Expected Retirement
AEP Ohio	Sporn 5	450	2011
	Conesville 3	165	2012
	Muskingum River 1-4	840	2014
	Picway 5	100	2014
	Sporn 2-4	300	2014
	Kammer 1-3	630	2014
	Beckjord	53	2014
	Total MW	**2,538**	
APCO	Glen Lyn 5	95	2014
	Glen Lyn 6	240	2014
	Clinch River 3	235	2014
	Sporn 1	150	2014
	Sporn 3	150	2014
	Kanawha River 1	200	2014
	Kanawha River 2	200	2014
	Total MW	**1,270**	
I&M	Tanners Creek 1	145	2014
	Tanners Creek 2	145	2014
	Tanners Creek 3	205	2014
	Total MW	**495**	
KPCo	Big Sandy 1	278	2014
	Big Sandy 2	800	2014
	Total MW	**1,078**	
SWEPCO	Welsh 2	**528**	2014
	Total MW	**528**	
	Grand Total	**5,909**	

- Capacity reduction caused by retirements will create grid reliability issues particularly in the 2014-2016 time frame
- Net impact could be approx. 600 fewer jobs at AEP as well as indirect job losses affecting local vendors, contractors and service providers
- Annual lost wages of approximately $40 million
- Tax payments could decline by more than $30 million

EXHIBIT ____ (LK-15)

Kentucky Power Company
Revenue Requirement During Construction Period
For Big Sandy 2 Retrofit
Based on Using 100% CWIP in Rate Base

	As Filed Rate of Return	50% Short Term Debt	100% Short Term Debt
Construction Year 1	2,084,550	1,146,600	48,750
Construction Year 2	9,888,250	5,439,000	231,250
Construction Year 3	25,174,950	13,847,400	588,750
Construction Year 4	48,692,950	26,783,400	1,138,750
Construction Year 4 and 5/12	31,735,938	17,456,250	742,188
Total Revenue Requirement	117,576,638	64,672,650	2,749,688

Construction Adds By Year	Beg Year CWIP ($)	Direct Adds ($)	End Year CWIP ($)	Avg CWIP in RB
Const YR 1		39,000,000	39,000,000	19,500,000
Const YR 2	39,000,000	107,000,000	146,000,000	92,500,000
Const YR 3	146,000,000	179,000,000	325,000,000	235,500,000
Const YR 4	325,000,000	261,000,000	586,000,000	455,500,000
Const YR 4.5	586,000,000	253,000,000	839,000,000	712,500,000
Total		839,000,000		

Kentucky Power Company
Revenue Requirement During Construction Period
For Big Sandy 2 Retrofit
Based on Using 100% CWIP in Rate Base

Rate of Return - As Filed Traditional Financing	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.94%	6.48%	3.37%	3.37%
A/R Financing	4.12%	1.22%	0.05%	0.05%
Common Equity	43.94%	10.50%	4.61%	7.27%
Total Capital	100.00%		8.03%	10.69%

Combined Tax Rate = 36.5555%

50% STD at 0.25%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	50.00%	0.25%	0.13%	0.13%
Long Term Debt	25.00%	6.48%	1.62%	1.62%
Common Equity	25.00%	10.50%	2.63%	4.14%
Total Capital	100.00%		4.37%	5.88%

Combined Tax Rate = 36.5555%

100% STD at 0.25%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	100.00%	0.25%	0.25%	0.25%
Long Term Debt	0.00%	0.00%	0.00%	0.00%
Common Equity	0.00%	0.00%	0.00%	0.00%
Total Capital	100.00%		0.25%	0.25%

Combined Tax Rate = 36.5555%

EXHIBIT ____ (LK-16)

Kentucky Power Company

REQUEST

Based on the January 5, 2012 Conference, what is the expected impact of coal blending on the steam generator, air heaters, and SCR system?

RESPONSE

The use of a 4.5 SO2 lb/mmBTU coal blend represents a significant change from the current fuel. In order to maintain reliability and satisfactory operation, the unit will require modifications as outlined below:

1) Balanced Draft Modifications - The design of the Big Sandy Unit 2 steam generator has inherent weaknesses which can allow boiler gases to escape into the surrounding areas. The resultant boiler gases generated when burning higher sulfur coals are even more irritable. This conversion not only improves the working environment, it also improves equipment reliability by reducing ambient temperatures and lowering fugitive dust.

2) Furnace Arch Addition - The Big Sandy Unit 2 steam generator does not have a furnace arch. Higher sulfur fuels generate a greater amount of tenacious slag and adding an arch will improve the ability to maintain furnace cleanliness and thus boiler efficiency by improving gas flow distribution across the superheater surface. This addition has proven extremely successful on the "sister" 800 MW units (Amos Units 1&2 and Mitchell Units 1&2).

3) Low NOx Burners - The existing low NOx burners in place at Big Sandy 2 were designed to reduce NOx emissions by utilization of staged combustion techniques. Slag control in the combustion process is a secondary consideration when burning lower sulfur coal. Recent experience with relatively minimal increases in fuel SO2 content have led to hot burners (a safety concern) and increases in slag formation. The state of the art for Low NOx Burner technology has advanced significantly since the current burners were installed and their replacement is required to accommodate the expanded fuel sulfur range.

4) Additional furnace slag control devices – The use of NAPP coal in the blend will increase slag production in the lower furnace due to the increase in iron content. Illinois Basin coals contain even higher amounts of iron, generating even more slag. The current technology for furnace slag control, water cannons and hydro jets, has proven successful in addressing this issue.

5) Additional superheater slag blowers - Currently, the leading edge of the superheater surface does not have sootblower coverage for the control of slagging. With the move to a high slagging fuel blend, controlling the accumulations of slag in the superheater section with the addition of new sootblowers will be critical to successful and reliable operation.

6) Furnace Imaging system – The addition of a high temperature imaging system to monitor superheater slagging conditions has proven to be a successful tool in the unit operator's ability to detect slag formations. The technology of these furnace cameras continues to improve allowing clear images of the heat transfer surface deep within the furnace and on the face of the superheater. These systems can be configured to alert the operator when a region has high temperatures so that actions may be taken to help avoid costly generation curtailments and/or unit outages.

7) Furnace Overlay – The switch to a higher sulfur coal and the use of Low NOx Burners will require protection of the furnace water walls from corrosion. The amount of overlay required is expected to be 5,000 square feet utilizing inconel 622 alloy.

8) Air Heater Modifications – The air heater will require modifications to address the SO_3 dew point temperature issue associated with downstream corrosion. This is accomplished through a change in basket depth.

9) Coal Yard Modifications – The current coal yard does not have the ability to blend different coals to achieve the desired 4.5# SO2 maximum. The installation of a second coal pile as well as a blending station will be required.

WITNESS: Robert L Walton

EXHIBIT ____ (LK-17)

Kentucky Power Company

REQUEST

Refer to page 9 line 14 through page 11 line 7 of Mr. Wohnhas' Direct Testimony.

a. Please provide an estimate of the gross plant, accumulated depreciation and related ADIT that will be retired in conjunction with the boiler modifications. Provide all supporting assumptions, computations, and workpapers, including electronic spreadsheets with formulas intact.

b. Please provide the actual amounts of gross plant, accumulated depreciation, and related ADIT of the boiler and related plant at December 31, 2011 that will be retired and replaced in conjunction with the boiler modifications.

c. Please provide the average annual depreciation rate and annualized depreciation expense based on the plant in service amounts at December 31, 2011 of the boiler and related plant that will be retired and replaced in conjunction with the boiler modifications.

d. Please provide an estimate of the property tax expense based on the plant in service amounts at December 31, 2011 of the boiler and related plant that will be retired and replaced in conjunction with the boiler modifications. Provide all supporting assumptions, computations, and workpapers, including electronic spreadsheets with formulas intact.

e. Please provide the decommissioning and demolition cost of the boiler and related plant that will be retired and replaced in conjunction with the boiler modifications. In addition, please indicate if these costs are included in the Company's cost estimate for the DFGD projects.

Kentucky Power Company

f. If the Company asserts that it has not or cannot provide the information requested in response to parts (a) through (e) of this question, then provide this information for the "essentially identical work performed on four other 800 mW units on the AEP fleet, namely Amos Units 1&2 and Mitchell Units 1&2," cited as the basis for the Company's cost estimates on the boiler "upgrades" at Big Sandy 2 in response to Sierra Club 1-28(a) through (d).

RESPONSE

a-f. There are no anticipated retirements associated with the boiler modifications.

WITNESS: Ranie K Wohnhas

EXHIBIT ____ (LK-18)

Kentucky Power Company

REQUEST

Refer to the Company's response to Staff 1-45, which addresses the discontinued use of the ESPs.

a. Please provide the gross plant, accumulated depreciation, and related ADIT of the ESPs at December 31, 2011.

b. Please provide the annual depreciation rate and annualized depreciation expense on the ESPs using gross plant at December 31, 2011.

c. Please provide the actual O&M expense for the ESPs by FERC O&M expense account for 2011. Further separate these amounts into fixed, variable, and consumables expense.

d. Please provide the decommissioning and demolition cost of the ESPs and indicate if these costs are included in the Company's cost estimate for the DFGD projects.

RESPONSE

a. The detailed ESP gross plant cost and accumulated depreciation is not readily available. Property other than mass Distribution investment in accounts 364-373 is maintained in the Company's continuing property records by record unit where the record unit is defined as the account title (the record unit for account 312, Boiler Plant Equipment is defined as "Boiler Plant Equipment"). Therefore, further detailed categorization of the equipment in this account and other Steam Generation Plant accounts is not available. FERC Order No. 598 permits utility companies to keep their property records at a record unit level and book estimated retirements.

   The Company is currently developing an estimate to answer the request, however, it can not provide the estimate at this time. The Company expects to provide the information in a supplemental response no late than February 24, 2012.

b. The annual depreciation rate for equipment in Steam Production accounts 311-316 is 3.78%. The annualized depreciation expense on the ESP's is not readily available (see the Company's response a. above.

c. Big Sandy Unit 2 ESP O&M expense for 2011 was $26,958 under O&M FERC account 5120000. The Company does not classify O&M expenses into fixed or variable, but traditionally it is assumed that 50% of maintenance cost is fixed and 50% is variable.

d. The Company expects that the precipitator will not be required following the NID technology installation, and therefore would be removed as a part of this project. At this point, the costs of decommissioning and retiring the existing precipitators have not been estimated, although at current market prices the Company anticipates the scrap value will approximate the cost of decommissioning and retiring the ESP.

WITNESS: Ranie K Wohnhas

EXHIBIT ____ (LK-19)

Kentucky Power Company

REQUEST

Refer to pages 14-15 of the Wohnhas Testimony.

a. Explain the basis, whether it be a study or analysis, for the 15-year depreciation period.

b. Provide the current depreciation rates utilized for the generating equipment at the Big Sandy plant.

c. Provide, by generating plant, the depreciation periods used for the scrubbers already in service on the AEP System.

RESPONSE

a. There was no study or analysis, just the concern of recovery as stated in my testimony, page 15, lines 1-5.

b. All of the Generating equipment with the exception of the SCR Catalyst is being depreciated using a depreciation rate of 3.78%. The SCR Catalyst is being depreciated over its useful life with Catalyst Layer 1 having a retirement date of May 2018, Catalyst Layer 2 having a retirement date of May 2022 and Catalyst Layer 3 having a retirement date of May 2013.

c. Please see page 2 of this response.

WITNESS: Ranie K Wohnhas

AEP Plants with Scrubbers

Plant	AEP Affiliate Company	Depreciation Period
Gavin Units 1 & 2	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Mitchell Units 1 & 2	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Cardinal Unit 1	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Conesville Units 4 - 6	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Stuart Units 1 - 4	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Zimmer Unit 1	Ohio Power Company	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Amos Units 1 - 3	Appalachian Power Company (APCO), Unit 3 is co-owned by APCO and Ohio Power	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Mountaineer Unit 1	Appalachian Power Company (APCO)	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Oklaunion	Public Service of Oklahoma	Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Pirkey	Southwestern Electric Power Company	Company is in Arkansas, Louisana, and Texas. Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years.
Dolet Hills	Southwestern Electric Power Company	Company is in Arkansas, Louisana, and Texas. Scrubber assets are depreciated over the remaining life of the plant at the time of their installation. The plant life has been estimated to be 60 years

EXHIBIT ____ (LK-20)

Kentucky Power Company

REQUEST

Provide the expected service life of Big Sandy Unit 2 after the FGD upgrade.

RESPONSE

With appropriate ongoing maintenance and prudent and timely capital investment, the expected service life of Big Sandy Unit 2 could approach 70 years, or until at least 2040.

WITNESS: Robert L Walton

EXHIBIT ____ (LK-21)

Kentucky Power Company

REQUEST

Refer to the Company's response to Staff 1-12. Please provide a copy of all analyses that address the ability of the Big Sandy 2 plant to continue to operate as long as 70 years from commercial operation to retirement. Please provide a copy of all assumptions, computations, and source documents, including, but not limited to, internal correspondence. For all such analyses, provide a description of the reason the analyses was undertaken, by whom (names, positions, departments), and how the analyses was used or if it was not used.

RESPONSE

KPCo, on an annual basis, conducts a generating unit review where subject matter experts from Big Sandy Plant and AEP's Engineering Services organization produce a "Facilities Health Report." Please see the Company's response to Staff's First Set of Data Requests Item No. 39(g-h) Attachments 2 through 4 for this report. The report documents the existing conditions of significant unit components which could have a material effect on unit availability and longevity and provides recommendations to address any significant issues over a ten-year planning horizon.

With appropriate ongoing maintenance and prudent and timely capital investment, Big Sandy Unit 2 is expected to attain a 70 year service life. AEP currently either owns outright or has majority interest in 12 units that are 54-60 years old. Ten of these are being retrofit with FGD technology after 57 years of service. AEP also has an additional five units with greater than 60 years of service life, the oldest still generating after 68 years. It is not inconsistent with this experience to anticipate that Big Sandy Unit 2 could operate for an additional 28 years.

Attachment 1 of this response, for which confidential treatment is being sought, is an updated Facilities Health Report.

WITNESS: Robert L Walton

EXHIBIT ____ (LK-22)

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

EXHIBIT ____ (LK-23)

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-1 and the $15.212 million for Preliminary Scrubber Analysis 2004-2006.

a. Please provide a copy of all authorities relied on for the deferral of these costs, including a copy of all requests to the Commission for authorization to defer these costs and any orders from the Commission authorizing the deferrals.

b. Please provide a copy of all analyses from the approximate time period of the deferrals, including any written communications through memoranda, emails or other forms, addressing the accounting for these costs and/or whether they should be expensed or deferred.

c. Please explain why the Company has not previously sought recovery of these deferrals either in base rate proceedings or ECR proceedings.

d. Please provide a schedule showing the costs that were deferred by month, by major activity, by FERC expense account (if the costs had not been deferred), and the FERC balance sheet account used for the deferrals.

RESPONSE

a. The Company made no filings with the Commission. Because the project had not reached the stage requiring application for a certificate of public convenience and necessity the Company did not make a filing when the costs were moved from Account 107 to Account 183.

b. The Company has no such analyses.

c. The Company continued to evaluate the disposition of the Big Sandy units in light of the Consent Decree and the various EPA regulations affecting Big Sandy. Until a final decision was made (as being proposed in this application) the Company did not believe it prudent to seek recovery from its customers.

d. Please refer to the Company's response to KPSC 1-18.

WITNESS: Ranie K Wohnhas

EXHIBIT ____ (LK-24)

Kentucky Power Company
Current ECR Revenue Requirement Comparison
Based on November 2011 ECR Filing
KIUC Adjustment to Reduce ROE to 9.2%

Big Sandy ECR Rate Base - Total Company ES Form 3.10	90,394,789
Kentucky Retail Jurisdictional Allocation Factor - ES Form 1.00	83.3%
Big Sandy ECR Rate Base - Kentucky Retail	75,298,859
Annual Revenue Requirement Reduction from Reducing ROE to 9.2%	(677,690)

Big Sandy - Rate of Return - ES Form 3.15

Current Rate of Return	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	10.50%	4.61%	7.27%
Total Capital	100.00%		8.03%	10.69%

Combined Tax Rate = 36.555%

Rate of Return - Adjusted to Reflect ROE of 9.2%	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Long Term Debt	51.941%	6.48%	3.37%	3.37%
A/R Financing	4.116%	1.22%	0.05%	0.05%
Common Equity	43.943%	9.20%	4.04%	6.37%
Total Capital	100.00%		7.46%	9.79%

Kentucky Power Company
Initial Revenue Requirements Comparison
With As Filed ROE of 10.5% Compared to KIUC Adjusted ROE of 9.2%
Based on Revised Revenue Requirement - Response to Staff 1-20

	As Revised Beginning of Year 1	As Revised Adjusted for 9.2% ROE Year 1	Reduction In Initial Revenue Requirement
Eligible Plant - Placed In Service	955,512,492	955,512,492	
Less: Accumulated Depreciation			
Less: Deferred Tax Balance			
In-Service Rate Base	955,512,492	955,512,492	
Grossed Up Rate of Return	10.69%	9.79%	
Return on Revenue Requirement - Total Company	102,144,285	93,544,673	
Annual KY Jurisdiction Revenue Allocation Factor	78.91%	78.91%	
Return On Revenue Requirement - KY Jurisdiction	80,602,056	73,816,101	(6,785,954)
Revenue Requirement - Operating Expenses - KY Jurisdiction	89,750,145	89,750,145	-
Total KY Retail Revenue Requirement	170,352,201	163,566,247	(6,785,954)
KY Jurisdiction 12-month Revenue	569,593,245	569,593,245	569,593,245
Percentage Rate Increase	29.91%	28.72%	-1.19%