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PUBLIC SERVICE
COMMISSION

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December 19, 2012

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HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Application of Kentucky Power Company In Connection With The Transfer Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Certain Related Relief, Case No. 2012-______

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's application requesting all necessary approvals in connection with the transfer to Kentucky Power of a fifty percent undivided interest in the Mitchell generating station. The application also seeks certain related relief.

By copy of this letter, a copy of the application also is being served on counsel for the Attorney General, Office of Rate Intervention and Kentucky Industrial Utility Customers, Inc.

Very truly yours,

Mark R. Overstreet

MRO
cc: Counsel for Kentucky Industrial Utility Customers, Inc.
Counsel for the Office of Rate Intervention

COMMONWEALTH OF KENTUCKY

RECEIVED

DEC 19 2012

PUBLIC SERVICE
COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	)	Case No. 2012-00___

MOTION FOR CONFIDENTIAL TREATMENT

Kentucky Power Company ("Kentucky Power" or "the Company"), moves the Commission pursuant to KRS 61.878(1)(m)(1)(f), KRS 61.878(1)(k), and 804 KAR 5:001, Section 7, for an Order granting confidential treatment to information included in the Application filed by Kentucky Power in this proceeding. The information for which confidential treatment is being sought ("Confidential Information") is the redacted portions of a map included as page two of three of Exhibit 5 to the Application that includes Critical Energy Infrastructure Information ("CEII"). Such information is subject to the requirements of 18 C.F.R. § 388.112 and 18 C.F.R. § 388.113. Pursuant to 807 KAR 5:001, Section 7, three originals of the map for which confidential treatment is sought is filed under seal with this motion. Ten redacted copies of the exhibits are also being filed by Kentucky Power.

<u>Statutory Standard and Basis for Confidential Treatment</u>

KRS 61.878(1)(m)(1)(f) exempts records from public inspection that would have a reasonable likelihood of threatening the public safety by exposing a vulnerability in preventing, protecting against, mitigating, or responding to a terrorist act, including:

> Infrastructure records that expose a vulnerability referred to in this subparagraph through the disclosure of the location, configuration, or security of critical systems, including public utility critical systems. These critical systems shall include but not be limited to information technology, communication, electrical, fire suppression, ventilation, water, wastewater, sewage, and gas systems.

The Confidential Information includes infrastructure records included within the scope of the exclusion set forth in KRS 61.878(1)(m)(1)(f).

The Confidential Information is considered by the Federal Energy Regulatory Commission ("FERC") as CEII, and as such is exempt from public disclosure in accordance with FERC rules and regulations. FERC defines CEII as:

> [S]pecific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
>
> (i) Relates details about the production, generation, transportation, transmission, or distribution of energy;
>
> (ii) Could be useful to a person in planning an attack on critical infrastructure;
>
> (iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
>
> (iv) Does not simply give the general location of the critical infrastructure.

18 C.F.R. § 388.113(c)(1). The Confidential Information satisfies each of these requirements and should be treated by the Commission as CEII. The Confidential Information includes detailed information about the production, generation, transportation, transmission, or

distribution of energy, and the disclosure of such information could be useful to a person in planning an attack on critical infrastructure. The incapacity or destruction of the infrastructure at issue "would negatively affect security, economic security, public health or safety." 18 C.F.R. § 388.113(c)(2).

Additionally, KRS 61.878(1)(k) exempts from disclosure under the Kentucky Open Records Act "all public records or information the disclosure of which is prohibited by federal law or regulation." Federal law exempts CEII from disclosure under the Freedom of Information Act. 18 C.F.R. § 388.112. Accordingly, the Confidential Information should be afforded confidential treatment by the Commission.

Kentucky Power takes reasonable steps to prevent the disclosure of the Confidential Information outside the Company, and the information is available within the Company on a limited basis only to persons with a need to access it. Further, the Company treats CEII in accordance with the requirements of federal law. None of the Confidential Information is readily ascertainable by proper means by other persons. Moreover, the Company believes that independent research by persons not privy to the Confidential Information would not reveal the information for which confidential treatment is sought in this motion.

The Commission has previously afforded confidential treatment to Kentucky Power's CEII filings in *In the Matter of: Investigation Into Electric Utilities Emergency Response Plans*, Administrative Case No. 345, and *In the Matter of: 2009 Integrated Resource Plan of Kentucky Power Company*, Case No. 2009-00339. Kentucky Power respectfully requests that the Commission follow those decisions and afford the CEII confidential treatment in this proceeding.

Respectfully submitted,

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COUNSEL FOR: KENTUCKY POWER COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing was served as indicated below upon:

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

By Overnight Delivery

Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook
Kentucky Attorney General's Office
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204

By Overnight Delivery

on this the 19th day of December, 2012.

Mark R. Overstreet

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

VERIFIED APPLICATION

Kentucky Power Company ("Kentucky Power" or the "Company") moves the Public Service Commission of Kentucky ("Commission") for an Order: (1) granting the Company a Certificate of Public Convenience and Necessity pursuant to KRS 278.020(1) and 807 KAR 5:001, Section 9 in connection with the transfer of an undivided fifty percent interest in Ohio Power Company's Mitchell generating station and related assets to Kentucky Power; (2) authorizing pursuant to KRS 278.300 and 807 KAR 5:001, Section 11 the assumption by Kentucky Power of certain liabilities in connection with the transfer; (3) declaring that approval pursuant to KRS 278.020(5) and KRS 278.020(6) is not required in connection with the merger of Kentucky Power and NEWCO Kentucky as part of the transfer, (4) authorizing Kentucky Power Company in accordance with Financial Accounting Standards Board Standards Codification 980-340-25-1 ("FASB Codification 980-340-25-1") to accumulate and defer for review and recovery in its next base rate proceeding the approximately $30 million of costs incurred from 2004 through present in connection with the Company's on-going efforts to meet Federal Clean Air Act and other environmental requirements with respect to Big Sandy Unit 2; and (5) granting all other required relief or approvals. In support thereof Kentucky Power states:

Introduction

1. As a result of current and evolving environmental requirements, Kentucky Power faces important choices about how to obtain sufficient resources and base load generation to meet the capacity and energy needs of its customers over the long term. At this crossroad, and as promised earlier this year when Kentucky Power withdrew its application to retrofit Big Sandy Unit 2, the Company has conducted in-depth analyses of reasonable portfolio alternatives to determine the best path to ensure adequate and reliable capacity and energy for its customers. As described more in detail in this Application and supporting testimony, the Company's plan for the transfer of an undivided fifty percent interest in the Mitchell generating station to Kentucky Power in lieu of retrofitting the Big Sandy Unit 2 generating station with environmental controls is the least cost and best alternative.

2. The Mitchell units are attractive for many reasons. They are of a similar size, design, and capacity to Big Sandy Unit 2, and thus represent technology with which the Company and the Commission are already familiar. The units are sized to meet the needs of Kentucky Power, and are environmentally-controlled units already equipped with both flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems. The Mitchell units will be transferred at their net book value and thus at a fraction of the cost of retrofitting Big Sandy Unit 2. Taken together, and for the additional reasons set forth in this Application and

attached testimony, the transfer to Kentucky Power of a fifty percent interest in the Mitchell generating station is the right choice for the Company's customers and Kentucky Power.

3. The relief sought in this application, including the receipt of all necessary Commission approvals to consummate the transfer of an undivided fifty percent interest in the Mitchell station, along with the Mitchell generation station associated assets, contracts, liabilities and debt, to Kentucky Power, and receipt of authority to defer the Company's prudently incurred costs associated with its Phase I investigation into retrofitting Big Sandy Unit 2, represent the best alternative to address the capacity and energy needs of Kentucky Power's customers and the Company over the long term.

Applicant

4. Kentucky Power is an electric utility organized as a corporation under the laws of the Commonwealth of Kentucky in 1919. A certified copy of Kentucky Power's Articles of Incorporation and all amendments thereto was attached to the Joint Application in Case No. 99-149[1] as Exhibit 1. The post office address of Kentucky Power is 101A Enterprise Drive, P.O. 5190, Frankfort, Kentucky 40602-5190. Kentucky Power is engaged in the generation, purchase, transmission, distribution, and sale of electric power. Kentucky Power serves approximately 173,000 customers in the following 20 counties of eastern Kentucky: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike and Rowan. Kentucky Power also supplies electric power

[1] *In the Matter of: The Joint Application Of Kentucky Power Company, American Electric Power Company, Inc. And Central And South West Corporation Regarding A Proposed Merger*, P.S.C. Case No. 99-149.

at wholesale to other utilities and municipalities in Kentucky for resale. Kentucky Power is a utility as that term is defined at KRS 278.010.

5. Kentucky Power is a direct, wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP.") AEP is a multi-state public utility holding company whose operating companies provide electric utility service to customers in parts of eleven states – Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

Non-Party Entities

6. Ohio Power Company ("Ohio Power") is a corporation organized under the laws of the State of Ohio and provides electric utility service to approximately 1.5 million retail customers in Ohio. Ohio Power does not provide utility service in the Commonwealth of Kentucky and is not a utility subject to the provisions of Chapter 278 of the Kentucky Revised Statutes. Ohio Power, which is a direct, wholly-owned subsidiary of AEP, has offices located at 850 Tech Center Drive, Gahanna, Ohio 43230.

7. AEP Generation Resources Inc.[2] ("AEP Generation Resources") is a corporation organized under the laws of the State of Delaware. It is a direct subsidiary of Ohio Power and an indirect, wholly-owned subsidiary of AEP. AEP Generation Resources was created for the purpose of organizing and operating the generating assets of Ohio Power. AEP Generation Resources does not provide utility service in the Commonwealth of Kentucky and is not a utility

[2] AEP Generation Resources Inc. is a corporation distinct from AEP Generating Company, which owns a portion of the Rockport generating station.

subject to the provisions of Chapter 278 of the Kentucky Revised Statutes. Its corporate address is 1 Riverside Plaza, Columbus, Ohio 43215.

8. NEWCO Kentucky is a yet-to-be formed corporation to be organized under the laws of the State of Delaware for the limited purpose of transferring the subject assets and liabilities. It will not survive closing. NEWCO Kentucky will exist and hold assets transitorily only for a brief period immediately prior to NEWCO Kentucky's merger with Kentucky Power. It will be an indirect wholly-owned subsidiary of AEP Generation Resources. Although NEWCO Kentucky will briefly own certain generating facilities if the proposed transaction occurs, it will not provide utility service in the Commonwealth of Kentucky, and will not be a utility subject to the provisions of Chapter 278 of the Kentucky Revised Statutes.

9. Appalachian Power Company ("APCo") is a corporation organized under the laws of the Commonwealth of Virginia and provides electric utility service to approximately 1,000,000 retail customers in Virginia and West Virginia. APCo does not provide utility service in the Commonwealth of Kentucky and is not a utility subject to the provisions of Chapter 278 of the Kentucky Revised Statutes. APCo, which is a direct, wholly-owned subsidiary of AEP, maintains an office at 707 Virginia Street East, Charleston, West Virginia 25301.

10. American Electric Power Service Corporation ("AEPSC") is a corporation organized under the laws of the State of New York, AEPSC is a wholly-owned subsidiary of AEP and provides management and professional services to AEP and its utility operating subsidiaries.

Overview Of The Proposed Transaction

11. In the proposed transaction an undivided fifty percent interest in Unit 1 and Unit 2 of Mitchell generating station and associated assets will be transferred in a series of near-simultaneous transactions to Kentucky Power at their December 31, 2013 net book value. The net book value of the fifty percent interest as of December 31, 2011 was $519 million and presently is forecasted to be approximately $536 million at time of closing. The fifty percent undivided interest in the Mitchell generating station constitutes approximately 780 MW of average annual capacity.[3] In conjunction with the transaction, Kentucky Power will also assume an undivided fifty percent interest in the liabilities associated with the Mitchell Plant as well as certain related liabilities.

The Assets To Be Transferred

12. The Mitchell generating station consists of two base load coal-fired electric generating units with a total average annual capacity rating of 1,560 MW. Unit 1 of the Mitchell generating station has an average annual capacity rating of 770 MW; Unit 2 has an average annual capacity rating of 790 MW. Both units are equipped with FGD and SCR systems. The Mitchell generating station currently is owned by Ohio Power and is located approximately twelve miles south of Moundsville, West Virginia.

13. Along with the undivided fifty percent interest in the Mitchell generating station, a like share of all related equipment and facilities associated with the Mitchell generating station will be transferred to Kentucky Power, including the appurtenant interconnection facilities, the

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[3] Kentucky Power intends to issue a competitive solicitation in the first part of 2013 for up to 250 MW of long-term capacity and energy and to explore other options with respect to Big Sandy Unit 1. The Company will evaluate the results of the solicitation and study of Big Sandy Unit 1 and return to the Commission in 2013 to seek all necessary approvals.

associated real property, inventories, leases, permits, emission allowances, equipment, machinery, and the other assets described in Section 2.01 of the Form of the Asset Contribution Agreement between AEP Generation Resources and NEWCO Kentucky ("Asset Contribution Agreement").[4] Collectively the fifty percent undivided interest in the Mitchell generating station and related assets to be transferred to Kentucky Power constitute the "Transferred Assets." Excluded from the definition of Transferred Assets are the assets described in Section 2.02 of the Asset Contribution Agreement.

The Liabilities To Be Assumed

14. In conjunction with the transfer of the Transferred Assets, the Company will assume a fifty percent undivided interest in the liabilities described in Section 2.03 of the Asset Contribution Agreement between AEP Generation Resources Inc. and NEWCO Kentucky (Collectively these liabilities constitute the "Assumed Liabilities.") Excluded from Assumed Liabilities are those liabilities described in Section 2.04 of the Asset Contribution Agreement.

The Proposed Transaction

15. The Transferred Assets and Assumed Liabilities will be transferred to Kentucky Power through a series of near-simultaneous transactions described in Paragraphs 22-26 below ("Transfer and Assumption Transaction.") At the conclusion of the Transfer and Assumption Transaction, the Company will own the Transferred Assets and be subject to the Assumed Liabilities.

(a) Purpose Of The Proposed Transaction.

[4] A copy of the Asset Contribution Agreement is attached as **EXHIBIT 1** to this Application for information purposes only.

16. Kentucky Power is a party to the Interconnection Agreement dated July 6, 1951, as amended, by and between APCo, Kentucky Power, Indiana Michigan Power Company ("I&M"), Ohio Power,[5] and AEPSC, as agent, ("Pool Agreement") that defines the sharing of costs and benefits of their respective generating plants. The Pool Agreement "is a tariff that contains rates and terms of service for the wholesale sale of power and is subject to regulation by ... [the Federal Energy Regulatory Commission ("FERC")]. The members of the ... [Pool Agreement] share generating capacity and either make or receive capacity-related payments pursuant to FERC-approved rates."[6]

17. In recent years, the electric industry has undergone major regulatory, environmental, and market changes.[7] These changes have produced movement toward industry deregulation, increased competition in wholesale generation markets, and resulted in changes in Pool Agreement member costs and load, and the availability of supply and demand-side resources.

18. As result of these changes, on December 17, 2010 each member of the Pool Agreement gave notice of its decision to terminate the Pool Agreement pursuant to Section 13.2 of the Pool Agreement, effective January 1, 2014. On October 31, 2012, the members of the

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[5] Prior to its December 31, 2011 merger with Ohio Power, Columbus Southern Power Company also was a party to the Pool Agreement.

[6] Order, *In the Matter of: The Application of Kentucky Power Company for Approval of An Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities And To Amend Its Environmental Cost Recovery Surcharge Tariff*, Case No. 2006-00307 at 2-3 (Ky. P.S.C. January 24, 2007).

[7] These changes are described in greater detail in the October 31, 2012 Section 205 filing at FERC made on behalf of Kentucky Power and other AEP companies. A copy of the Section 205 filing, along with the other FERC filings described in but not attached as exhibits to this Application, may be found at http://www.aep.com/investors/currentRegulatoryactivity/regulatory/ferc.aspx .

Pool Agreement filed a notice with FERC of their intent to terminate the Pool Agreement and the AEP System Interim Allowance Agreement.

19. Following termination of the Pool Agreement, the Company will be required to have sufficient generation to meet its load and reserve obligations.

20. Big Sandy Unit 2 is an 800 MW coal-fired steam electric generating unit completed in 1969. Unless Big Sandy Unit 2 is retrofitted with extensive and costly environmental controls, including a FGD unit, the Company will be required to retire Big Sandy Unit 2 by June 2015.

21. The Transfer and Assumption Transaction is intended to permit the Company to meet its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements. It is the least cost alternative for meeting these obligations and requirements. As required by the Commission's Order dated July 24, 2012 in Case No. 2008-00408,[8] the Company fully evaluated cost-effective energy efficiency resources in determining the least cost alternative to meet its long-term capacity obligations and energy requirements.

(b) The Transfer And Assumption Process.

22. On October 31, 2012, AEPSC filed an application on behalf of Ohio Power and AEP Generation Resources pursuant to Section 203 of the Federal Power Act and Part 33 of the Regulations of FERC seeking authorization for an internal corporate reorganization that will separate Ohio Power's generation and power marketing businesses from its distribution and

[8] *In the Matter of: Consideration Of The New Federal Standards Of Energy Independence And Security Act Of 2007*, Case No. 2008-00408 at 18 (Ky. P.S.C. July 24, 2012).

transmission businesses. The full structural separation is required by Ohio restructuring law and the Ohio Power restructuring plan approved by the Public Utilities Commission of Ohio.

23. Under the corporate restructuring plan approved by the Public Utilities Commission of Ohio, Ohio Power will transfer its generation assets to AEP Generation Resources ("Corporate Separation Transaction.") Among the generation assets to be transferred is Ohio Power's 100% interest in the Mitchell generating station. The generation assets will be transferred by Ohio Power to AEP Generation Resources at Ohio Power's net book value. AEP Generation Resources also will assume the liabilities associated with the Mitchell generating station, including the Assumed Liabilities.

24. Immediately upon the closing of the Corporate Separation Transaction, a fifty percent undivided interest in the Mitchell generating station and the other Transferred Assets will be transferred in a near-simultaneous series of transactions to NEWCO Kentucky.[9] In addition, NEWCO Kentucky will assume liability for the Assumed Liabilities. These actions will all occur on or about December 31, 2013, and are designed to ensure that the transfer of the Mitchell generating station will be accomplished without incurring unintended tax consequences. The contribution of the fifty percent undivided interest in the Mitchell generating station, and assumption of the Assumed Liabilities, will be made in accordance with the terms and conditions of the Asset Contribution Agreement.

[9] The remaining fifty percent undivided interest in the Mitchell generating station will be transferred to NEWCO Appalachian. This fifty percent undivided interest in the Mitchell generating station will be transferred to APCo in a series of near-simultaneous transactions that parallel those by which the fifty percent undivided interest in the Mitchell generating station will be transferred to Kentucky Power.

25. In the final step, NEWCO Kentucky will merge with Kentucky Power, with the Company being the surviving entity. The merger will take place in accordance with the terms and conditions of the Form of Agreement and Plan of Merger of Kentucky Power Company and NEWCO Kentucky attached as **EXHIBIT 2** to this application.[10] The merger is expected to close on or about December 31, 2013.

26. At the conclusion of these transactions, Kentucky Power will own a fifty percent undivided interest in the Transferred Assets. In addition, Kentucky Power will be liable for the Assumed Liabilities. The net book value at which the fifty percent undivided interest in the Mitchell generating station will be transferred to Kentucky Power is projected to be $536 million, or approximately $687 per kW, at the time of the closing, which is expected to occur on or about December 31, 2013.

Other Agreements

(a) The Mitchell Plant Operating Agreement.

27. On October 31, 2012, AEPSC requested on behalf of APCo and Kentucky Power that FERC accept for filing without condition or modification the Mitchell Plant Operating Agreement. Under the Mitchell Plant Operating Agreement APCo will operate and maintain the Mitchell generating station in accordance with good utility practices. The Mitchell Plant Operating Agreement also provides Kentucky Power with the right to call on at any and all times its pro rata share of the available output of the Mitchell generating station. The monthly Mitchell generating station operating and maintenance costs are apportioned between APCo and

[10] Kentucky Power is seeking a declaratory ruling from the Commission in this Application that the merger of NEWCO Kentucky and Kentucky Power, with Kentucky Power being the surviving entity, does not require approval under KRS 278.020(5) or KRS 278.020(6).

Kentucky Power in accordance with their respective ownership interests. The Mitchell Plant Operating Agreement also provides for an Operating Committee, made up of representatives of APCo, Kentucky Power, and AEPSC as agent, to review and approve annual budgets, capital expenditures, and other matters regarding the operation of the Mitchell generating station. Finally, the Mitchell Plant Operating Agreement governs other aspects of the operation of the Mitchell generating station as well as relations among the parties to the agreement. An unexecuted copy of the Mitchell Plant Operating Agreement is attached to this Application as **EXHIBIT 3**.

28. In addition to the Mitchell Plant Operating agreement, the transfer of ownership of the Mitchell generating station will involve the assumption by APCo (in its role as operator of the plant) of the rights and obligations under various executory contracts necessary for the operation of Mitchell. These contracts include contracts for supplies of coal, transportation of coal, consumables for the operation of environmental control facilities (e.g., limestone, urea, and trona), and other matters. All of these contracts are existing, necessary for the operation of the Mitchell generating station, are significant in number, and may be subject to change prior to the transfer. A representative list of the principal agreements to be assumed by APCo is attached as **EXHIBIT 4** to provide a sense of the nature of the agreements to be assumed by APCo. Under the Mitchell Plant Operating Agreement, Kentucky Power will reimburse APCo for Kentucky Power's pro rata share of the expenses under the contracts assumed by APCo.[11]

(b) The Bridge Agreement.

[11] The Mitchell Plant Operating Agreement is a mechanism to fairly allocate Kentucky Power's ratable expenses in connection with its ownership of a fifty percent undivided interest in the Mitchell generating station; it is not an assumption of liability by the Company. To the extent the Commission disagrees, the Company respectfully requests all necessary approvals under KRS 278.300.

29. On October 31, 2012, AEPSC requested on behalf of APCo, I&M, Ohio Power, Kentucky Power, AEP Generation Resources, and AEPSC, as agent, that FERC accept the Bridge Agreement for filing without condition or modification. The Bridge Agreement is an interim agreement among APCo, I&M, Ohio Power, Kentucky Power, AEP Generation Resources, and AEPSC, as agent, and governs the treatment of purchases and sales made on behalf of the parties before, but that extend beyond, the termination of the Pool Agreement. In addition, the Bridge Agreement addresses the manner in which APCo, I&M, Ohio Power, and Kentucky Power will meet their collective obligation under the PJM Reliability Assurance Agreement through May 31, 2015 (PJM planning year 2014/2015). A copy of the unexecuted Bridge Agreement was filed at FERC as an exhibit to the Company's October 31, 2012 Section 205 filings. The Company's Section 205 filing may be found at the following website: http://www.aep.com/investors/currentRegulatoryactivity/regulatory/ferc.aspx.

(c) The Power Coordination Agreement.

30. On October 31, 2012 AEPSC, as agent, requested on behalf of APCo, I&M, and Kentucky Power that FERC accept the Power Coordination Agreement for filing without condition or modification. Unlike the Pool Agreement, there is no requirement under the Power Coordination Agreement for generation to be planned on a system-wide basis. APCO, I&M, and Kentucky Power individually will be required to have sufficient generation to meet their respective load and reserve obligations.[12] Consequently, there are no capacity equalization payments required under the Power Coordination Agreement. Because there are no minimum payment or take-or-pay obligations under the agreement no approval is required under KRS

[12] Parties to the Power Coordination Agreement are not precluded from jointly owning units with, or buying capacity from or selling capacity to, other parties to the agreement, through separate agreements.

278.300. A copy of the unexecuted Power Coordination Agreement was filed at FERC as an exhibit to the Company's October 31, 2012 Section 205 filings and may be found at http://www.aep.com/investors/currentRegulatoryactivity/regulatory/ferc.aspx

31. State commission approval is not required for the Bridge Agreement, the Power Coordination Agreement, or the Mitchell Plant Operating Agreement, which upon acceptance by FERC, will be FERC-filed rate schedules under Section 205 of the Federal Power Act.

32. Following their execution, Kentucky Power will file with the Commission executed copies of:

(a) the Agreement and Plan of Merger of Kentucky Power and NEWCO Kentucky; and

(b) the Mitchell Plant Operating Agreement among APCo, Kentucky Power, and AEPSC, as agent.

Compliance With The Affiliate Transaction Statute

33. To the extent the statute is applicable, the Transfer and Assumption Transaction and the Mitchell Plant Operating Agreement fully comply with the requirements of KRS 278.2207 and the other provisions of KRS 278.2201 *et seq.*[13]

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[13] To the extent the Commission concludes to the contrary, the Company respectfully requests all required waivers pursuant to KRS 278.2213

APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

34. To obtain a certificate of public convenience and necessity a utility is required to "demonstrate a need for such facilities and the absence of wasteful duplication."[14] Need in turn requires a demonstration:

> of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[15]

35. The Transferred Assets are required to permit Kentucky Power to meet its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements. The Transfer and Assumption Transaction is the least cost alternative for meeting these obligations and requirements.

36. The Transferred Assets will not result in wasteful duplication. "'Wasteful duplication' is defined as 'an excess of capacity over need' and 'an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties.'"[16] Kentucky Power performed a thorough review of reasonable alternatives to meet its capacity and

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[14] *In The Matter Of: Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity And Site Compatibility Certificate For The Construction Of A Combined Cycle Combustion Turbine At The Cane Run Generation Station And The Purchase Of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC In LaGrange, Kentucky*, Case No. 2011-00375 at 13-14 (Ky. P.S.C. May 3, 2012).

[15] *Id.* at 14.

[16] *Id.*

energy requirements, including energy efficiency resources, and determined the Transferred Assets are the least cost, reasonable alternative for meeting the Company's capacity and energy requirements.

37. Kentucky Power will submit requests to modify existing Title V permits, and other permits and licenses to reflect its transfer of an undivided fifty percent interest in the Transferred Assets. The Company is not required to seek any franchises in connection with the transfer of the Transferred Assets and hence 807 KAR 5:001, Section 9(1) is inapplicable. [807 KAR 5:001, Section 9(2)(b).]

38. The book value of the Transferred Assets will be fixed at the time of closing. The book value, net of accumulated depreciation, of the Transferred Assets as of December 31, 2011 was $678 million. The book value of the Assumed Liabilities will be also fixed at the time of closing. The book value of the Assumed Liabilities, excluding debt, as of December 31, 2011 was $159 million. Therefore, the net book value of the Transferred Assets, net of assumed liabilities and indebtedness, as of December 31, 2011 was $519 million and will initially be financed with a combination of paid-in-capital and an intercompany note. *See also* Paragraph 44 of this Application. [807 KAR 5:001, Section 9(2)(e).]

39. Using the actual 2011 cost incurred as an estimate of Kentucky Power's annual operation and maintenance cost of the Transferred Assets, these costs were $134.9 million for operations and $15.5 million for maintenance in 2011. [807 KAR 5:001, Section 9(2)(f).] In addition, using these and other 2011 values to reflect the effects of the Mitchell transfer and the termination of the current Pool Agreement on KPCo, the Company's cost of service would have increased approximately eight percent.

40. In conformity with 807 KAR 5:001, Section 9(2)(c), (d), three sets of maps to suitable scale showing the location of the Transferred Assets, including the Mitchell generating station which is located near Moundsville, West Virginia, and the location and identification of the ownership of any like facilities owned by others located within the map area are filed with this Application as **EXHIBIT 5**. The Transferred Assets will not compete with any other utility, corporation or person as described in the regulation.

APPLICATION FOR APPROVAL OF ASSUMPTION OF INDEBTEDNESS BY KENTUCKY POWER COMPANY

41. As part of the Transfer and Assumption Transaction Kentucky Power will acquire the Assumed Liabilities. The Assumed Liabilities include fifty percent of the liabilities described in Section 2.03 of the Asset Contribution Agreement. Excluded from the Assumed Liabilities are those liabilities described in Section 2.04 of Asset Contribution Agreement.

42. The book value of the Assumed Liabilities will be fixed at the time of closing. The book value of the Assumed Liabilities, excluding debt, as of December 31, 2011 was $159 million.

43. The net book value of the Transferred Assets will initially be financed with a combination of paid-in-capital and an intercompany note. Based on the net book value of $519 million at December 31, 2011, the estimate of Paid-in-Capital is $319 million and the anticipated intercompany note is $200 million. The actual capitalization will be determined at the time of closing based on the actual net assets transferred on or about December 31, 2013.

44. No new debt will be issued by Kentucky Power at the time of the Transfer and Assumption Transaction. Within six months of the closing of the Transfer and Assumption

Transaction, Kentucky Power anticipates issuing debt in the approximate amount of $275 million. The proceeds will be used to retire the intercompany note that will be assumed in connection with the Transfer and Assumption Transaction, and to recapitalize Kentucky Power to restore its debt-capital ratio to levels approximating the levels prior to the Transfer and Assumption Transaction. In addition, the rights and liabilities associated with the West Virginia Economic Development Authority ("WVEDA") Pollution Control Revenue Bond ("PCRB").[17] that partially financed the FGD units constructed at the Mitchell generating station will be transferred to Kentucky Power. This $65 million WVEDA bond for Mitchell is currently held in trust by Ohio Power and may be reissued by Kentucky Power. Kentucky Power will seek all necessary approvals under KRS 278.300 for any financing activities subsequent to the Transfer and Assumption Transaction. [807 KAR 5:001, Section 11(1)(e).]

(a) Regulatory Requirements – 807 KAR 5:001, Section 11.

45. A general description of Kentucky Power's property and its field of operation, together with the statement of its original cost and its cost to Kentucky Power, is attached as **EXHIBIT 6**. [807 KAR 5:001, Section 11(1)(a).]

46. The Assumed Liabilities in their entirety are being acquired by Kentucky Power as part of the Transfer and Assumption Transaction, which will permit Kentucky Power to meet its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements. The Transfer and Assumption Transaction, which includes the assumption of the assumed liabilities, is the least cost alternative for meeting these obligations and

[17] West Virginia Economic Development Authority $65,000,000 Series 2008A Mitchell PCRB.

requirements. The property to be acquired and the liabilities and debt to be assumed are described in more detail above. [807 KAR 5:001, Section 11(1)(c).]

47. The assets to be acquired include an undivided fifty percent interest in:

(a) the Mitchell generating station; and

(b) the assets described in Section 2.01 of the Asset Contribution Agreement.

Excluded from the assets to be acquired in connection with the assumption of indebtedness are the assets described in Section 2.02 of the Asset Contribution Agreement. Maps and drawings showing the property to be acquired are attached as **EXHIBIT 5**. No contracts have been made for the Transferred Assets or the disposition of any indebtedness or liabilities. [807 KAR 5:001, Section 11(1)(d).]

48. There are no outstanding trust deeds or mortgages relating to Kentucky Power or its property. There are no trust deeds or mortgages relating to the Transferred Assets. [807 KAR 5:001, Section 11(2)(b).]

49. The information required by 807 KAR 5:001, Section 11(2)(c) is attached as **EXHIBIT 5**.

50. Kentucky Power will not issue any stock as part of the Transfer and Assumption Transaction. [807 KAR 5:001, Section 11(1)(b).]

(b) Regulatory Requirements – 807 KAR 5:001, Section 6 (Financial Exhibit).[18]

51. Kentucky Power has the following stock authorized, issued and outstanding:

[18] 807 KAR 5:001, Section 11(2)(a).

(a) Common Stock: 2,000,000,000 shares authorized and 1,009,000 shares outstanding. [807 KAR 5:001, Section 6(1), (2)]; and

(b) Kentucky Power has no authorized preferred stock. [807 KAR 5:001, Section 6(3).]

52. There are no mortgages encumbering Kentucky Power's property or the Transferred Assets. [807 KAR 5:001, Section 6(4).]

53. The bonds identified in **<u>EXHIBIT 7</u>** to this Application constitute the Company's authorized and issued bonds. [807 KAR 5:001, Section 6(5).]

54. The note identified in **<u>EXHIBIT 7</u>** to this Application constitutes the Company's existing note. [807 KAR 5:001, Section 6(6).]

55. Kentucky Power has no other indebtedness outstanding. [807 KAR 5:001, Section 6(7).]

56. During the past five years Kentucky Power paid the dividends identified in **<u>EXHIBIT 7</u>** to this Application. [807 KAR 5:001, Section 6(8).]

57. A detailed income statement and a detailed balance sheet for Kentucky Power for the twelve month period ending September 30, 2012 are attached as **<u>EXHIBIT 8</u>** and **<u>EXHIBIT 9</u>** respectively. [807 KAR 5:001, Section 6(9).]

(c) <u>The Transfer And Assumption Transaction Satisfies The Requirements Of KRS 278.300 .</u>

58. The Assumed Liabilities are being acquired by Kentucky Power in connection with the transfer of the Transferred Assets. The Transferred Assets will permit Kentucky Power to meet its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements. The Transfer and Assumption Transaction, which includes the assumption of the assumed liabilities, is the least cost alternative for meeting these obligations and requirements. As such, the liabilities are being assumed in connection with a lawful object within the corporate purposes of Kentucky Power, and are necessary and appropriate for, and consistent with, the proper performance by the Company of its provision of electric utility service to the public. The assumption by the Company of the Assumed Liabilities as part of the Transfer and Assumption Transaction satisfies the requirements of KRS 278.300.

APPLICATION FOR DECLARATORY AND OTHER RELIEF

59. KRS 278.020(5) requires Commission approval for any acquisition or transfer of ownership of, control, or the right to control "any utility under the jurisdiction of the commission."

60. KRS 278.020(6) likewise requires Commission approval of the acquisition of control of any utility furnishing service in the Commonwealth. Excluded from the requirements of KRS 278.020(6) is the acquisition of control of a utility providing service in the Commonwealth where both the acquiring entity and the entity to be acquired are under common control. KRS 278.020(7)(b).

61. The final step of the Transfer and Assumption Transaction is the merger of NEWCO Kentucky with Kentucky Power. Through the merger, Kentucky Power will be the

surviving entity and the Transferred Assets and the Assumed Liabilities will be transferred to the Company.

62. NEWCO Kentucky will be created and briefly exist at the time of the merger to facilitate the transaction. Although during this brief period NEWCO Kentucky will own assets that could be used in connection with the generation of electricity to the public for compensation for lights, heat, power, and other uses, NEWCO Kentucky will not be a utility under the jurisdiction of the Commission. Its corporate existence will cease upon its merger with Kentucky Power. As a result, the merger is not subject to the requirements of KRS 278.020(5), which is limited to the acquisition or transfer of ownership or control of a utility under the jurisdiction of the Commission.

63. For the same reasons, NEWCO Kentucky will not be providing utility service in the Commonwealth. Accordingly, the merger is not subject to the requirements of KRS 278.020(6), which is limited to the acquisition of control of a utility furnishing service in the Commonwealth. In addition, NEWCO Kentucky will be under common control with Kentucky Power. As such, the merger of NEWCO Kentucky and Kentucky Power is not subject to the requirements of KRS 278.020(6). KRS 278.020(7)(b).

64. Kentucky Power requests that the Commission enter an Order declaring that the merger of NEWCO Kentucky and Kentucky Power is not subject to the requirements of KRS 278.020(5) or KRS 278.020(6) on or before February 15, 2013. If the Commission determines that the merger of NEWCO Kentucky and Kentucky Power is subject to review under KRS 278.020(5) or KRS 278.020(6), or, if the Commission is unable to determine by February 15, 2013 whether approval under KRS 278.020(5) or KRS 278.020(6) is required in connection with

the merge, Kentucky Power will file an application seeking approval for the merger under KRS 278.020(5) or KRS 278.020(6), or both, as the case may be. Kentucky Power will also request that this second application be consolidated with this proceeding.

APPLICATION TO ESTABLISH REGULATORY ASSETS AND LIABILITIES

(a) <u>The Company's Investigation Of Environmental And Other Controls Or Measures On Or Relating To Big Sandy Unit 2 To Meet Clean Air Act And Other Environmental Requirements</u>

65. Beginning in 2004 Kentucky Power, in collaboration with AEPSC, began a Phase I investigation into the measures necessary to permit Big Sandy Unit 2 to continue to operate in compliance with the Federal Clean Air Act and other environmental requirements. Among the environmental requirements addressed in the Phase I investigation were the former Cross-State Air Pollution Rule, the Clean Air Interstate Rule, the former Electric Generating Unit Maximum Achievable Control Technology Rule, the Mercury and Air Toxic Standards ("MATS") Rule, and the requirements imposed by the 2007 NSR Consent Decree.

66. As part of the Phase I investigation the Company engaged an architect/engineer to perform the engineering, design, and feasibility studies in connection with the investigation. In Phase I the architect/engineer, with input from a team of AEPSC engineers and managers, defined the scope of the project, prepared work plans, and developed a budgetary cost estimate and schedule for implementation. Preliminary environmental permitting work also began. Finally, because the Company was investigating the use of a "wet" FGD unit ("WFGD") a WFGD supplier was engaged to begin conceptual engineering of the WFGD unit.

67. In 2006, Kentucky Power suspended, but did not cancel, the Phase I investigation into retrofitting Big Sandy Unit 2. Work was suspended because the Company concluded the WFGD was not the most economic means of addressing the environmental requirements for the continued operation of Big Sandy Unit 2 and as a result of the decreased projected price spread between low and higher sulfur coals. At the time of suspension, the Phase I investigation and related expenditures for which deferral is sought totaled approximately $15.2 million. $1.69 million of these expenditures were related to the landfill.

68. Following further investigation into the least cost alternative for meeting Kentucky Power's capacity and energy needs in light of the environmental requirements affecting Big Sandy Unit 2, the Company reinitiated its Phase I investigation in October 2011. This work was a continuation of the work that began in 2004 and was suspended in 2006. As part of this investigation the Company evaluated the available FGD technologies and concluded that the best suitable technology was a dry FGD ("DFGD") unit. Finally, the Company also undertook the necessary engineering and other required activities to support the Company's application in Case No. 2011-00401.

69. On May 31, 2012, the Commission granted the Company's motion for leave to withdraw without prejudice its application in Case No. 2011-00401 to permit the Company to re-evaluate the continued operation of the Big Sandy generating station in light of the 2007 NSR Consent Decree, the Cross-State Air Pollution Rule, the MATS Rule, and other environmental standards.

70. Based upon the Company's re-evaluation, Kentucky Power concluded that the transfer of a fifty percent undivided interest in the Mitchell generating station and the retirement

of Big Sandy Unit 2 by June 2015 is the least cost alternative for meeting its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements. As a consequence of Big Sandy Unit 2's proposed retirement, the unit will not be retrofitted with environmental controls. The expenses incurred by the Company in connection with its Phase I investigation into the measures necessary to permit Big Sandy Unit 2 to continue to operate in compliance with the Federal Clean Air Act and other environmental requirements were necessary, proper, and prudently incurred.

(b) The Amount To Be Accumulated And Deferred.

71. As of November 30, 2012, the incremental costs associated with the Phase I investigation that would not have been incurred but for the investigation totaled $29,287,494. The expenditures through October 31, 2012 for which deferral is being sought are:

Description	Landfill[19]	WFGD	DFGD	Total
Internal Labor	$ 798	$ 81,918	$ 186,833	$ 269,549
Outside Services	$ 1,760,535	$ 11,246,162	$ 7,102,097	$20,108,794
Service Corporation Charges	$ 469,771	$ 1,306,534	$ 2,119,992	$ 3,896,297
Land Purchase	$ 630,376	$ -	$ -	$ 630,376
Overheads	$ 678,412	$ 921,489	$ 2,686,515	$ 4,286,416
Other	$ 20,130	$ 7,474	$ 68,458	$ 96,062
Total	$ 3,560,022	$ 13,563,577	$12,163,895	$29,287,494

The Company does not anticipate any additional costs will be incurred in connection with its Big Sandy Unit 2 Phase 1 investigation, but will supplement this Application with any updated

[19] A Landfill would have been required for both the WFGD and DFGD.

values.

72. Kentucky Power currently has recorded, subject to Commission approval, its total Phase I investigation expenditures with respect to Big Sandy Unit 2 on its balance sheet as an asset. If the Company is authorized to defer these Phase I investigation costs the regulatory asset will be recorded under Account No. 1823 – Other Regulatory Assets.

73. Kentucky Power's base rates currently contain no expenses relating to the Phase I investigation of Big Sandy Unit 2.

74. Kentucky Power seeks authorization from the Commission to accumulate and defer for review and recovery in Kentucky Power's next base rate proceeding the net actual costs incurred as part of the Big Sandy Unit 2 Phase I investigation from 2004 to date. The current amount to be established as a regulatory asset in Account No. 1823 is $29,287,494.

(c) Basis For The Requested Accounting Treatment

75. FASB Codification 980-340-25-1provides for the creation under prescribed circumstances of a regulatory asset such as Kentucky Power proposes. FASB Codification 980-340-25-1 states in pertinent part:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. ***An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met***:
>
> a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from the inclusion of that cost in the allowable costs for ratemaking purposes.
>
> b. Based on the available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs....[20]

[20] (emphasis supplied).

76. The Commission typically has exercised its discretion to approve a regulatory asset upon demonstration that the expenses to be deferred fall into one of four categories:

> (1) an extraordinary nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary nonrecurring expense that over time will result in a savings that fully offsets the costs.[21]

77. The Big Sandy Phase I investigation expenditures that are the subject of this application result from statutory and administrative directives, including those requirements identified in Paragraph 65 of this application.

78. In accordance with FASB Codification 980-340-25-1 and Commission precedent, Kentucky Power requests the Commission to exercise its authority under KRS 278.220 to prescribe the manner in which the Company keeps its accounts by entering an order permitting Kentucky Power to accumulate and defer for review and recovery in its next base rate proceeding the $29,287,494 in incurred by the Company in conducting its Big Sandy Unit 2 Phase I and related investigations from 2004 to present.

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[21] *In The Matter Of: The Application of East Kentucky Power Cooperative, Inc. For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To Certain Replacement Power Costs Resulting From Generation Forced Outages*, Case No. 2008-00436 at 4 (Ky. P.S.C. December 23, 2012),

Requested Date For Final Order

79. In light of the time required to consummate the transaction after all approvals are received, Kentucky Power requests that, with the exception of the request for declaratory relief for which the Company is requesting an earlier determination, the Commission issue its order granting the requested relief no later than June 30, 2013.

Exhibits And Testimony

80. The exhibits and testimony listed in the Appendix to this Application are attached to and made a part of this Application.

Communications

81. The Applicant respectfully requests that communications in this matter be addressed to:

Mark R. Overstreet
R. Benjamin Crittenden
STITES & HARBISON PLLC
P.O. Box 634
Frankfort, Kentucky 40602-0634

Kenneth J. Gish, Jr.
STITES & HARBISON PLLC
250 West Main Street, Suite 2300
Lexington, Kentucky 40507-1758

Ranie K. Wohnhas
Kentucky Power Company
P.O. Box 5190
Frankfort, Kentucky 40602-5190

ON BEHALF OF KENTUCKY POWER

WHEREFORE, Kentucky Power Company requests that the Commission issue an Order:

(a) Granting Kentucky Power a Certificate of Public Convenience and Necessity pursuant to KRS 278.020(1) and 807 KAR 5:001, Section 9 approving the transfer to Kentucky Power of an undivided fifty percent interest in the Transferred Assets;

(b) Approving pursuant to KRS 278.300 and 807 KAR 5:001, Section 11 of the assumption by Kentucky Power of the Assumed Liabilities;

(c) Declaring on or before February 15, 2013 that approval is not required pursuant to KRS 278.020(5) or KRS 278.020(6) for the merger of Kentucky Power and NEWCO Kentucky;

(d) Authorizing Kentucky Power Company in accordance with FASB Codification 980-340-25-1 to accumulate and defer for review and recovery in its next base rate proceeding before the Commission the approximately $30 million of costs incurred from 2004 through present in connection with the Company's on-going efforts to meet Federal Clean Air Act and other environmental requirements with respect to Big Sandy Unit 2; and

(e) Granting Kentucky Power such other relief or approvals as may be appropriate or required to consummate transactions set forth in this Application, including the Transfer and Acquisition Transaction, and the accounting deferral and authorization to create a regulatory asset.

Respectfully submitted,

Mark R. Overstreet
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kgish@stites.com

COUNSEL FOR:
KENTUCKY POWER COMPANY

VERIFICATION

I, Gregory G. Pauley, President and Chief Operating Officer of Kentucky Power Company, after being duly sworn, state that the facts contained in this Application are true and accurate to the best of my knowledge.

Gregory G. Pauley

Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF FRANKLIN)

Subscribed and sworn to before me by Gregory G. Pauley on this the 18th day of December, 2012.

Judy K Rosquist

Notary Public State at Large

My Commission Expires:

January 23, 2013

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing was served as indicated below upon:

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

By Overnight Delivery

Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook
Kentucky Attorney General's Office
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204

By Overnight Delivery

on this the 19th day of December, 2012.

Mark R. Overstreet

APPENDIX

TESTIMONY

Witness	Subject Matter
Gregory G. Pauley	Discusses the basis for Kentucky Power's re-evaluation of the Big Sandy generating station in light of existing and pending environmental requirements; details the decision to transfer of an undivided fifty percent interest in the Mitchell generating station to Kentucky Power; and provides an overview of this Application.
Mark A. Becker	Describes the Strategist® modeling application used by Kentucky Power.
Karl R. Bletzacker	Addresses the forecasts for natural gas prices, CO2 prices, coal prices, energy prices, and capacity values used in Company Witnesses Becker and Weaver's analyses and how the forecasts were derived.
Jeffery D. LaFleur	Describes the Mitchell generating station and its operational characteristics and compares the Big Sandy and Mitchell generating stations.
Karl A. McDermott	Provides a review of the proposed asset transfer for consistency with regulatory principles.
John M. McManus	Discusses the current and future environmental requirements affecting the Company's generating assets and the Mitchell generating station and planned compliance measures.
Scott C. Weaver	Describes the Kentucky Power generation resources modeled, the modeling process used, and the resulting analyses.
Ranie K. Wohnhas	Provides an overview of the accounting and financing activities associated with the proposed asset transfer; summarizes the estimated customer rate impact due to the transfer of the Mitchell generating station and the termination of the current Pool Agreement; explains the Company's request for the deferral of costs and establishment of a regulatory asset in connection with the Phase I investigation of the Big Sandy Unit 2 scrubber project.

List of Exhibits

EXHIBIT 1: Asset Contribution Agreement (Paragraph 13 of the Application).

EXHIBIT 2: Form of Agreement and Plan of Merger of Kentucky Power Company and NEWCO Kentucky (Paragraph 25 of the Application).

EXHIBIT 3: Unexecuted copy of the Mitchell Plant Operating Agreement among APCo, Kentucky Power, and AEPSC, as agent (Paragraph 27 of the Application).

EXHIBIT 4: Representative list of principal agreements to be assumed by APCo (Paragraph 28 of the Application).

EXHIBIT 5: Maps and drawings to suitable scale showing location and layout of Transferred Assets and the location of nearby like facilities. (Paragraphs 40, 47, and 49 of the Application).

EXHIIBT 6: General description of Kentucky Power's property, the Company's field of operation, and cost information (Paragraph 45 of the Application).

EXHIBIT 7: Information regarding bonds, note, and dividends paid (Paragraphs 53, 54, and 56 of the Application).

EXHIBIT 8: Detailed income statement of Kentucky Power for the year ended September 30, 2012 (Paragraph 57 of the Application).

EXHIBIT 9: Detailed balance sheet of Kentucky Power for the year ended September 30, 2012 (Paragraph 57 of the Application).

ASSET CONTRIBUTION AGREEMENT

BETWEEN

AEP GENERATION RESOURCES INC.

AND

[NEWCO KENTUCKY]

Dated as of __________, 201_

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EXHIBITS

SCHEDULES

ASSET CONTRIBUTION AGREEMENT

This **Asset Contribution Agreement** (this "Agreement"), dated as of ________ 201_, is between **AEP Generation Resources Inc.**, a Delaware corporation ("Transferor"), and **[NEWCO Kentucky]** a _____________ corporation ("Transferee"). Collectively, Transferee and Transferor may be referred to herein as the "Parties" and each, individually, as a "Party."

W I T N E S S E T H

WHEREAS, Transferor owns the Mitchell Power Generation Facility in Moundsville, West Virginia which is comprised of two 800 MW generating units and associated plant, equipment and facilities and certain other assets, improvements, properties (both tangible, including real and personal property, and intangible), and rights associated therewith or ancillary thereto, all as more specifically described in Schedule 1.01 (the "Mitchell Plant").

WHEREAS, Transferor desires to transfer and assign to Transferee, and Transferee desires to acquire and assume from Transferor, the Transferred Assets (as hereinafter defined) and certain liabilities, upon the terms and conditions hereinafter set forth;

WHEREAS, Transferor and Transferee intend that the transfer of the Transferred Assets contemplated herein qualify as contributions to capital under Section 351 of the Internal Revenue Code of 1986, as amended; and

WHEREAS, Transferor directly owns all of the outstanding capital stock of Transferee.

NOW, THEREFORE, in consideration of the premises and the mutual covenants, agreements, representations and warranties hereinafter set forth, the Parties, intending to be legally bound, hereby agree as follows:

ARTICLE I
DEFINITIONS

Section 1.01 Definitions.

(a) As used in this Agreement, the following terms have the following meanings:

"**Affiliate**" means a Person that directly or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the Person specified. The term "control" (including the terms "controlling," "controlled by" and "under common control with") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise.

"**Ancillary Agreements**" means the Assumption Agreement, the Asset Transfer Agreement, the Deeds, the Assignment of Easements and Rights of Way, the Assignment of Real Property Leases, the Assignment of Contracts and any other agreements or instruments entered into between the Parties with respect to the transactions contemplated by this Agreement.

"**Asset Transfer Agreement**" means the Asset Transfer Agreement to be executed and delivered at Closing by Transferor to Transferee in substantially the form attached hereto as Exhibit E.

"**Assignment of Contracts**" means the Assignment of Contracts agreement to be entered into between Transferor and Transferee at Closing, in substantially the form attached hereto as Exhibit A.

"**Assignment of Easements and Rights of Way**" means the Assignments of Easements and Rights of Way agreements to be entered into by Transferor and Transferee at Closing, in substantially the form attached hereto as Exhibit B.

"**Assignment of Real Property Leases**" means the Assignment of Real Property Leases agreements to be entered into by Transferor and Transferee at Closing, in substantially the form attached hereto as Exhibit C.

"**Assumed Liabilities**" has the meaning set forth in Section 2.03.

"**Assumed Payables**" means a certain amount of those payables owed by Transferor with respect to the Transferred Assets, as set forth in Schedule 1.02.

"**Assumption Agreement**" means the Assumption Agreement to be entered by Transferor and Transferee at Closing, in substantially the form attached hereto as Exhibit D.

"**Business Day**" means a day other than a Saturday, Sunday or day on which banks are permitted or required to remain closed in the state of Ohio.

"**CERCLA**" means the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended from time to time.

"**Closing**" has the meaning set forth in Section 3.03.

"**Closing Date**" has the meaning set forth in Section 3.03.

"**Contracts**" has the meaning set forth in Section 4.01(i).

"**CWIP**" has the meaning set forth in the definition of "Improvements."

"**Debt**" means the long-term and short-term debt owed by Transferor as described in Schedule 1.03.

"**Deeds**" means those certain deeds to be executed and delivered at Closing by Transferor to Transferee.

"**Deferred Tax Assets**" means the Transferor's deferred tax assets relating to the Transferred Assets or any assumed Liability that is carried on its books.

"**Deferred Tax Liability**" means the Transferor's deferred tax liability relating to the Transferred Assets or any assumed Liability that is carried on its books.

"**Easements and Rights of Way**" means the easements and rights of way as described in Schedule 1.04.

"**Effective Time**" has the meaning set forth in Section 3.03.

"**Emissions Allowances**" means all authorizations issued to Transferor by a Governmental Authority pursuant to a statutory or regulatory program promulgated by a Governmental Authority pursuant to which air emissions sources subject to the program are authorized to emit a prescribed quantity of air emissions.

"**Encumbrance**" means any security interest, pledge, mortgage, lien, charge, option to purchase, lease, claim, restriction, covenant, title defect, hypothecation, assignment, deposit arrangement or other encumbrance of any kind or any preference, priority or other security agreement or preferential arrangement of any kind or nature whatsoever (including any conditional sale or title retention agreement).

"**Environmental Condition**" means the presence or Release to the environment, whether at the Real Property or otherwise, of Hazardous Substances, including any migration of Hazardous Substances through air, soil or groundwater at, to or from the Real Property or at, to or from any Off-Site Location, regardless of when such presence or Release occurred or is discovered.

"**Environmental Laws**" means all (i) Laws relating to pollution or protection of the environment, natural resources or human health and safety, including Laws relating to Releases or threatened Releases of Hazardous Substances or otherwise relating to the manufacture, formulation, generation, processing, distribution, use, treatment, storage, Release, transport, remediation, abatement, cleanup or handling of Hazardous Substances; (ii) Laws with regard to recordkeeping, notification, disclosure and reporting requirements respecting Hazardous Substances; and (iii) Laws relating to the management or use of natural resources.

"**Environmental Permits**" has the meaning set forth in Section 4.01(g).

"**Excluded Liabilities**" has the meaning set forth in Section 2.04.

"**FERC**" means the Federal Energy Regulatory Commission.

"**Franklin Real Property**" means that certain real property held by Franklin Real Estate Company, a wholly owned subsidiary of the Parent, as agent for and for the benefit of Transferor's electric generation assets as more specifically described in Schedule 1.05.

"**Generation Transmission Assets**" has the meaning set forth in Section 2.01(p).

"**Good Utility Practice**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition.

"**Governmental Authority**" means any: (i) nation, state, county, city, town, village, district, or other jurisdiction of any nature; (ii) federal, state, local, municipal, foreign, or other government; (iii) governmental or quasi-governmental authority of any nature (including any governmental agency, branch, department, official, or entity and any court or other tribunal); (iv) multi-national organization or body; or (v) body exercising, or entitled to exercise, any administrative, executive, judicial, legislative, police, regulatory, or taxing authority or power of any nature.

"**Hazardous Substances**" means (i) any petrochemical or petroleum products, oil or coal ash, radioactive materials, radon gas, asbestos in any form that is or could become friable, urea formaldehyde foam insulation and transformers or other equipment that contain dielectric fluid which may contain levels of polychlorinated biphenyls; (ii) any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "contaminants," "pollutants," "toxic pollutants," or words of similar meaning and regulatory effect under any applicable Environmental Law; and (iii) any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

"**Improvements**" means all buildings, structures, machinery and equipment (including all fuel handling and storage facilities), fixtures, construction work in progress ("CWIP"), and other improvements, including all piping, cables and similar equipment forming part of the mechanical, electrical, plumbing or HVAC infrastructure of any building, structure or equipment, located on and affixed to the Real Property, the Leased Real Property and the Easements and Rights of Way.

"**Intellectual Property**" means all of the following and similar intangible property and related proprietary rights, interests and protections, however arising, (i) all software necessary to operate or maintain the Transferred Assets, (ii) confidential information, formulas, designs, devices, technology, know-how, research and development, inventions, methods, processes, compositions and other trade secrets, whether or not patentable and (iii) patented and patentable designs and inventions, all design, plant and utility patents, letters patent, utility models, pending patent applications and provisional applications and all issuances, divisions, continuations, continuations-in-part, reissues, extensions, reexaminations and renewals of such patents and applications.

"**Inventories**" means (i) all inventories of fuels and consumables owned by Transferor for use at the Mitchell Plant, whether located on Real Property, Leased Real Property or the Easements and Rights of Way associated with the Mitchell Plant or in transit thereto or stored offsite and (ii) all materials and supplies, including without limitation, spare parts, owned by Transferor for use at or in connection with the Mitchell Plant.

"**Knowledge**" means the actual and current knowledge of the corporate officer or officers of the specified Person charged with responsibility for the particular function as of the date of this Agreement, or, with respect to any certificate delivered pursuant to this Agreement, the date of delivery of the certificate, without any implication of verification or investigation concerning such knowledge.

"**Laws**" means all laws, statutes, rules, regulations, ordinances and other pronouncements having the effect of law of the United States, any foreign country and any domestic or foreign state, county, city or other political subdivision or of any Governmental Authority.

"**Leased Real Property**" has the meaning set forth in Section 4.01(e)(i).

"**Liability**" means any liability or obligation, whether known or unknown, whether asserted or not asserted, whether absolute or contingent, whether accrued or not accrued, whether liquidated or not liquidated, whether incurred or consequential, and whether due or to become due.

"**Material Adverse Effect**" means (i) any event, circumstance or condition materially impairing the ability of Transferor to perform its obligations under this Agreement or any Ancillary Agreement or (ii) any change in or effect on Transferor or the Transferred Assets that is materially adverse to the Transferred Assets, other than (a) any change resulting from changes in the international, national, regional or local wholesale or retail markets for electricity, (b) any change resulting from changes in the international, national, regional or local markets for fuel or consumables used at the Mitchell Plant, (c) any change resulting from changes in the North American, national, regional or local electric transmission system, and (d) any change in Law generally applicable to similarly situated Persons.

"**Mitchell Plant**" has the meaning set forth in the first Recital.

"**Net Book Value**" means an amount in dollars, as reflected in the corresponding line item or items of the balance sheet of Transferor as of the applicable date for all Transferred Assets and all Assumed Liabilities. With respect to the Transferred Assets, Net Book Value is equal to total Transferred Assets net of accumulated depreciation or amortization as appropriate.

"**Off-Site Location**" means any real property other than the Real Property, the Leased Real Property or real property covered by the Easements and Rights of Way.

"**Organizational Documents**" means (i) the articles or certificate of incorporation and the bylaws of a corporation; (ii) the limited liability company or operating agreement and certificate of formation of a limited liability company; (iii) the partnership agreement and any statement of partnership of a general partnership; (iv) the limited partnership agreement and the certificate of limited partnership of a limited partnership; (v) any charter or similar document adopted or filed in connection with the creation, formation, or organization of a Person and (vi) any amendment to any of the foregoing.

"**Parent**" means American Electric Power Company, Inc.

"**Party**" has the meaning set forth in the first paragraph of this Agreement.

"**Permits**" has the meaning set forth in Section 4.0l(k).

"**Permitted Encumbrances**" means: (i) mechanics', carriers', workmen's, repairmen's or other like Encumbrances arising or incurred in the ordinary course of business that would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect, (ii) Encumbrances for Taxes not yet due or which are being contested in good faith by appropriate proceedings and that would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect; (iii) imperfections of title or encumbrances, if any, that, individually or in the aggregate, do not materially impair, and would not reasonably be expected to have a Material Adverse Effect; (iv) leases, subleases and similar agreements, and liens of any landlord or other third party on property over which Sellers have easement rights or on any Leased Real Property and subordination or similar agreements relating thereto; (v) leases, mineral reservations and conveyances, easements, covenants, rights-of-way and other similar restrictions of record; (vi) any conditions that may be shown by a current, accurate survey or physical inspection of the Real Property or the Leased Real Property made prior to the Closing; (vii) zoning, planning, conservation restriction and other land use and environmental regulations by Governmental Authorities; (viii) the respective rights and obligations of the Parties under this Agreement and the Ancillary Agreements; (ix) Encumbrances resulting from legal proceedings being contested in good faith by appropriate proceedings that would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect; and (x) other Encumbrances that would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

"**Person**" means any individual, corporation (including any non-profit corporation), general or limited partnership, limited liability company, joint venture, estate, trust, association, organization, labor union, or other entity or Governmental Authority.

"**Real Property**" has the meaning set forth in Section 2.01(b).

"**Real Property Leases**" has the meaning set forth in Section 4.01(e)(i).

"**Release**" means any release, spill, leak, discharge, disposal of, pumping, pouring, emitting, emptying, injecting, leaching, dumping or allowing to escape into or through the environment.

"**Tax**" means all federal, state, local and foreign taxes, charges, fees, levies, imposts, duties or other assessments, including, without limitation, income, gross receipts, excise, employment, sales, use, transfer, license, payroll, franchise, severance, stamp, occupation, windfall profits, environmental (including taxes under Code Section 59A), premium, federal highway use, commercial rent, customs duties, capital stock, paid up capital, profits, withholding, social security, single business and unemployment, disability, real property, personal property, registration, ad valorem, value added, alternative or add-on minimum, estimated, or other tax or governmental fee of any kind whatsoever, imposed or required to be withheld by any Governmental Authority, including any interest, penalties or additions thereto, whether disputed or not.

"**Transferee**" has the meaning set in the first paragraph of this Agreement.

"**Transferor**" has the meaning set forth in the first paragraph of this Agreement.

"**Transferred Assets**" has the meaning set forth in Section 2.01.

(b) Interpretation. In this Agreement, unless otherwise specified or where the context otherwise requires:

(i) a reference, without more, to a recital is to the relevant recital to this Agreement, to an Article or Section is to the relevant Article or Section of this Agreement, and to a Schedule or Exhibit is to the relevant Schedule or Exhibit to this Agreement;

(ii) words importing any gender shall include other genders;

(iii) words importing the singular only shall include the plural and vice versa;

(iv) the words "include," "includes" or "including" shall be deemed to be followed by the words "without limitation;"

(v) reference to any agreement, document or instrument means such agreement, document or instrument as amended or modified and in effect from time to time in accordance with the terms thereof;

(vi) reference to any applicable Law means, if applicable, such Law as amended, modified, codified, replaced or reenacted, in whole or in part, and in effect from time to time, including rules and regulations promulgated thereunder;

(vii) "or" is used in the inclusive sense of "and/or";

(viii) references to documents, instruments or agreements shall be deemed to refer as well to all addenda, exhibits, schedules or amendments thereto;

(ix) the words "hereof," "herein" and "herewith" and words of similar import shall, unless otherwise stated, be construed to refer to this Agreement as a whole and not to any particular provision of this Agreement; and

(x) references to any party hereto or any other agreement or document shall include such party's successors and permitted assigns, but, if applicable, only if such successors and assigns are not prohibited by this Agreement.

ARTICLE II
TRANSFER OF ASSETS

Section 2.01 Transfer of Assets. Upon the terms and conditions set forth in this Agreement, at the Closing but effective as of the Effective Time, Transferor shall transfer, convey, assign and deliver to Transferee as a contribution to capital, and Transferee shall acquire and assume from Transferor as a contribution to capital, free and clear of all Encumbrances other than Permitted Encumbrances, an undivided fifty percent (50%) ownership interest in and to the following described assets (the "Transferred Assets"):

(a) the Mitchell Plant;

(b) the real property (including the Improvements) described in Schedule 2.01(b) (and together with the Franklin Real Property, the "Real Property");

(c) the Real Property Leases(including the Improvements) ;

(d) the Easements and Rights of Way (including the Improvements);

(e) all Inventories;

(f) the Contracts;

(g) the Permits;

(h) the Environmental Permits;

(i) the Intellectual Property;

(j) the Emissions Allowances;

(k) the Deferred Tax Assets;

(l) all vehicles, equipment, machinery, furniture and other tangible personal property used in connection with the Mitchell Plant or located on or at the Real Property, the Leased Real Property and the Easements and Rights of Way, a partial list of which is described on Schedule 2.01(l);

(m) the other assets described in Schedule 2.01(m);

(n) all unexpired, transferable warranties and guarantees from manufacturers, vendors and other third parties with respect to any Improvement or item of real or tangible personal property constituting part of the Transferred Assets;

(o) all books, purchase orders, operating records, operating, safety and maintenance manuals, engineering design plans, blueprints and as-built plans, specifications, procedures, studies, reports, equipment repair, safety, maintenance or service records, and similar items (subject to the right of Transferor to retain copies of same for its use), other than such items that are proprietary to third parties and accounting records (to the extent that any of the foregoing is contained in an electronic format, Transferor shall reasonably cooperate with Transferee to transfer such items to Transferee in a format that is reasonably acceptable to Transferee);

(p) the electrical transmission facilities associated with the Mitchell Plant located at or forming part of the Mitchell Plant, including all energized switchyard facilities on the generation asset side of the appropriate interconnection points and real property directly associated therewith, all substation facilities and support equipment, as well as all permits, contracts and warranties related thereto, including those certain assets and facilities specifically identified on Schedule 2.01(p) (the "Generation Transmission Assets");

(q) without limitation of any of the foregoing, Transferor is transferring to Transferee an undivided fifty percent (50%) ownership interest in and to all Mitchell Plant power generation function equipment including, but not limited to, generation step-up transformers, turbine-generators, plant power distribution equipment such unit auxiliary transformers, forced draft fans, coal handling facilities, precipitator facilities, and protection and control equipment and systems that are associated with the Mitchell Plant;

(r) the rights of Transferor in and to any causes of action against third parties relating to the Transferred Assets or any part thereof, including any claim for refunds (but excluding any refund, credit, penalty, payment, adjustment or reconciliation related to Taxes paid or due for periods ending prior to the Effective Time in respect of the Transferred Assets, whether such refund, credit, penalty, payment, adjustment or reconciliation is received as a payment or, subject to Section 3.02, as a credit against future Taxes payable), prepayments, offsets, recoupment, insurance proceeds, condemnation awards, judgments and the like, whether received as a payment or credit against future liabilities, relating specifically to Transferred Assets and relating to any period ending prior to, on or after the Effective Time;

(s) the rights of Transferor in, to and under all contracts, agreements, arrangements, permits or licenses of any nature and related to the Transferred Assets, which are not expressly excluded pursuant to Section 2.02 and of which the obligations of Transferor thereunder are not expressly excluded by Transferee pursuant to Section 2.04; and

(t) to the extent not otherwise described in this Section 2.01, all other assets and property, whether real or personal, tangible or intangible, that are associated with or used in connection with ownership and operation of the Mitchell Plant.

Section 2.02 Excluded Assets. Notwithstanding anything to the contrary contained in Section 2.01 or elsewhere in this Agreement, nothing in this Agreement shall constitute or be construed as conferring on Transferee, and Transferee is not acquiring, any right, title or interest in and to any properties, assets, business, operation, or division of Transferor or any of its Affiliates (other than Transferee) not expressly set forth in Section 2.01.

Section 2.03 Assumed Liabilities. On the Closing Date, Transferee shall execute and deliver the Assumption Agreement, pursuant to which, among other things, Transferee shall assume all Liabilities described therein and, in addition, Transferee shall assume fifty percent (50%) of the following Liabilities (collectively, the "Assumed Liabilities"):

(a) on the terms and subject to the conditions set forth in this Agreement, at the Closing, Transferee shall assume and become responsible for, and shall thereafter pay, perform and discharge as and when due the Liabilities arising under or related to the Transferred Assets whether arising from, or relating to, periods prior to, on or after the Effective Time;

(b) all Liability of Transferor with respect to the Assumed Payables;

(c) all Liability of Transferor with respect to the Debt to the extent relating to periods of time after the Effective Time;

(d) all Liability of Transferor with respect to the Deferred Tax Liability; and

(e) all Liability of the Transferor with respect to the property Taxes related to the Transferred Assets.

2.04 Excluded Liabilities. Notwithstanding the foregoing provisions of Section 2.03, Transferee shall not assume by virtue of this Agreement, the Assumption Agreement or any other Ancillary Agreement, or the transactions contemplated hereby or thereby, or otherwise, and shall have no liability for any of the following Liabilities or any Liability of Transferor that is not related to the Transferred Assets (the "Excluded Liabilities"):

(a) any Liabilities of Transferor in respect of any assets of Transferor that are not Transferred Assets;

(b) any Liabilities in respect of Transferor's current income Taxes and any other Taxes not otherwise assumed pursuant to Section 2.03(d) and (e);

(c) any fines and penalties imposed by any Governmental Authority resulting from any act or omission by Transferor and not related to the Transferred Assets; and

(d) any Liability of Transferor arising as a result of its execution and delivery of this Agreement or any Ancillary Agreement, the performance of its obligations hereunder or thereunder, or the consummation by Transferor of the transactions contemplated hereby or thereby.

ARTICLE III
ASSET TRANSFER; CLOSING

Section 3.01 Asset Transfer. Transferor shall transfer to Transferee an undivided fifty percent (50%) ownership interest in and to the Transferred Assets at Net Book Value as of the Effective Time. In the event that final amounts for the Net Book Value of the Transferred Assets are not available on the Closing Date, the final Net Book Value of the Transferred Assets shall be determined and agreed to by Transferee and Transferor within ninety (90) days after the

Closing Date. Transferor and Transferee agree to furnish each other with such documents and other records as may be reasonably requested in order to confirm the final Net Book Value of the Transferred Assets.

Section 3.02 Proration.

(a) Transferee and Transferor agree that all of the items normally prorated, including those listed below, relating to the business and operation of the Transferred Assets shall be prorated as of the Effective Time, with Transferor liable to the extent such items relate to any time period through the Effective Time, and Transferee liable to the extent such items relate to periods subsequent to the Effective Time:

(i) personal property, real estate, occupancy and any other Taxes, assessments and other charges, if any, on or with respect to the business and operation of the Transferred Assets. Provided, however, that the Parties shall not prorate any Taxes, assessments or charges relating to the Transferred Assets that are to be assumed by Transferee pursuant to Section 2.03;

(ii) rent, Taxes and other items payable by or to Transferor under any of the Contracts to be assigned to and assumed by the Transferee hereunder; and

(iii) sewer rents and charges for water, telephone, electricity and other utilities.

(b) In connection with such proration, in the event that actual figures are not available at the Closing Date, the proration shall be based upon the actual amount of such Taxes or fees for the preceding year (or appropriate period) for which actual Taxes or fees are available and such Taxes or fees shall be re-prorated upon request of either the Transferor or the Transferee made within ninety (90) days after the date that the actual amounts become available. Transferor and Transferee agree to furnish each other with such documents and other records as may be reasonably requested in order to confirm all adjustment and proration calculations made pursuant to this Section 3.02.

Section 3.03 Closing. The transfer, assignment, conveyance and delivery of the Transferred Assets, and the consummation of the other transactions contemplated by this Agreement, shall take place at a closing (the "Closing") to be held at the offices of American

Electric Power, 1 Riverside Plaza, Columbus, Ohio 43204 at a time mutually acceptable to the Parties on the date of the execution and delivery of this Agreement by each of the Parties (the "Closing Date"). The Closing shall be effective for all purposes as of [___________] (the "Effective Time").

Section 3.04 Closing Deliveries.

(a) At the Closing, Transferor will deliver, or cause to be delivered, to Transferee the following items:

(i) possession of the Transferred Assets;

(ii) an original of each of the Deeds, duly executed and acknowledged by Transferor;

(iii) an original of the Asset Transfer Agreement duly executed by Transferor;

(iv) an original of the Assumption Agreement duly executed by Transferor;

(v) an original of each Assignment of Easements and Rights of Way duly executed by Transferor;

(vi) an original of each Assignment of Real Property Leases duly executed by Transferor;

(vii) an original of the Assignment of Contracts duly executed by Transferor; and

(viii) such other documents as are contemplated by this Agreement or as the Transferee may reasonably request to carry out the purposes of this Agreement.

(b) At the Closing, Transferee will deliver, or cause to be delivered, to Transferor the following items:

(i) an original of the Asset Transfer Agreement duly executed by Transferee;

(ii) an original of the Assumption Agreement duly executed by Transferee;

(iii) an original of each Assignment of Easements and Rights of Way duly executed by Transferee;

(iv) an original of each Assignment of Real Property Leases duly executed by Transferee;

(v) an original of the Assignment of Contracts duly executed by Transferee; and

(vi) such other documents as are contemplated by this Agreement or as the Transferor may reasonably request, including vehicle titles, to consummate the transactions contemplated hereby.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES

Section 4.01 Representations and Warranties of Transferor. Transferor represents and warrants to Transferee as follows:

(a) Organization and Good Standing; Qualification. Transferor is a corporation duly formed, validly existing and in good standing under the laws of the state of Delaware. Transferor has all requisite power and authority to own, lease or operate the Transferred Assets and to carry on its business as it is now being conducted.

(b) Authority and Enforceability. Transferor has full power and authority to execute and deliver, and carry out its obligations under, this Agreement and each Ancillary Agreement to which it is a party and to consummate the transactions contemplated hereby and thereby. The execution, delivery and performance by Transferor of this Agreement and each Ancillary Agreement to which it is a party, and the consummation of the transactions contemplated hereby and thereby, have been duly and validly authorized by all necessary action on the part of Transferor. Assuming the due authorization, execution and delivery of this Agreement and each Ancillary Agreement to which it is a party by Transferee, this Agreement and each such Ancillary Agreement constitutes a legal, valid and binding obligation of Transferor, enforceable against it in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy, insolvency and other similar laws affecting the rights and remedies of creditors generally and by general principles of equity.

(c) No Violation; Consents and Approvals.

(i) Neither the execution, delivery and performance by Transferor of this Agreement and each Ancillary Agreement to which it is a party, nor the consummation by Transferor of the transactions contemplated hereby and thereby, will (i) conflict with or result in any breach of any provision of the Organizational Documents of Transferor; (ii) result in a default (or give rise to any right of termination, cancellation or acceleration), or require a consent, under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, material agreement or other instrument or obligation to which Transferor is a party or by which it or any of the Transferred Assets may be bound, except for any such defaults or consents (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained or which would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect; or (iii) constitute a violation of any law, regulation, order, judgment or decree applicable to Transferor, except for any such violations as would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

(ii) Transferor has obtained all consents and approvals from each Governmental Authority necessary for the execution, delivery and performance of this Agreement by Transferor or of any Ancillary Agreement to which Transferor is a party, or the consummation by Transferor of the transactions contemplated hereby and thereby, other than such consents and approvals which, if not obtained or made, would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

(d) Insurance. All material policies of property, liability, workers' compensation and other forms of insurance owned or held by, or on behalf of, Transferor and insuring the Transferred Assets are in full force and effect, all premiums with respect thereto covering all periods up to and including the date hereof have been paid (other than retroactive premiums), and no notice of cancellation or termination has been received with respect to any such policy which was not replaced on substantially similar terms prior to the date of such cancellation.

(e) Leased Real Property.

(i) Schedule 4.01(e) sets forth a description of each lease of real property held by Transferor (the "Real Property Leases") and the real property covered thereby (the "Leased Real Property") that is to be transferred as contemplated herein by Transferor to Transferee.

(ii) Each Real Property Lease (a) constitutes a legal, valid and binding obligation of Transferor and, to Transferor's Knowledge, constitutes a valid and binding obligation of the other parties thereto and (b) is in full force and effect and Transferor has not delivered or received any written notice of termination thereunder.

(iii) There is not under any Real Property Lease any default or event which, with notice or lapse of time or both, (a) would constitute a default by Transferor or, to Transferor's Knowledge, any other party thereto, (b) would constitute a default by Transferor or, to Transferor's Knowledge, any other party thereto which would give rise to an automatic termination, or the right of discretionary termination, thereof, or (c) would cause the acceleration of any of Transferor's obligations thereunder or result in the creation of any Encumbrance (other than any Permitted Encumbrance) on any of the Transferred Assets. There are no claims, actions, proceedings or investigations pending or, to the Knowledge of Transferor, threatened against Transferor or any other party to any Real Property Lease before any Governmental Authority or body acting in an adjudicative capacity relating in any way to any Real Property Lease or the subject matter thereof. Transferor has no Knowledge of any defense, offset or counterclaim arising under any Real Property Lease.

(f) Title; Condition of Assets.

(i) Subject to Permitted Encumbrances, Transferor holds title to the Real Property and the Easements and Rights of Way and has good and valid title thereto and to the other Transferred Assets that it purports to own or in which it has an interest, free and clear of all Encumbrances.

(ii) The tangible assets (real and personal) at, related to, or used in connection with Mitchell Plant, taken as a whole, (a) are in good operating and usable condition and repair, free from any defects (except for ordinary wear and tear, in light of their respective ages and historical usages, and except for such defects as do not materially interfere with the use thereof in the conduct of the normal operation and maintenance of the Transferred Assets taken as a whole) and (b) have been maintained consistent with Good Utility Practice.

(g) Environmental Matters. Except as disclosed in Schedule 4.01(g):

(i) Transferor holds, and is in compliance with, all permits, certificates, certifications, licenses and other authorizations issued by Governmental Authorities under Environmental Laws that are required for Transferor to conduct the business and operations of the Transferred Assets (collectively, "Environmental Permits"), and Transferor is otherwise in compliance with all applicable Environmental Laws with respect to the business and operations of the Transferred Assets, except for any such failures to hold or comply with required Environmental Permits, or such failures to be in compliance with applicable Environmental Laws, as would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect;

(ii) Transferor has not received any written request for information, or been notified of any violation, or that it is a potentially responsible party, under CERCLA or any other Environmental Law for contamination or air emissions at the Mitchell Plant, the Real Property, the Leased Real Property or the real property covered by the Easements and Rights of Way except for any such requests or notices that would result in liabilities under such laws as would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect, and there are no claims, actions, proceedings or investigations pending or, to the Knowledge of Transferor, threatened against Transferor before any Governmental Authority or body acting in an adjudicative capacity relating in any way to any Environmental Laws or against Transferor or Parent concerning contamination or air emissions at the Mitchell Plant, the Real Property, the Leased Real Property or the real property covered by the Easements and Rights of Way; and

(iii) there are no outstanding judgments, decrees or judicial orders relating to the Transferred Assets regarding compliance with any Environmental Law or to the investigation or cleanup of Hazardous Substances under any Environmental Law relating to the Transferred Assets, except for such outstanding judgments, decrees or judicial orders as would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

(iv) Section I of Schedule 4.01(g) lists all material Environmental Permits.

The representations and warranties made in this Section 4.01(g) are the exclusive representations and warranties of Transferor relating to environmental matters.

(h) Condemnation. There are no pending or, to the Knowledge of Transferor, threatened proceedings or governmental actions to condemn or take by power of eminent domain all or any part of the Transferred Assets.

(i) Contracts and Leases.

(i) Schedule 4.01(i) lists all written contracts, agreements, licenses (other than Environmental Permits, Permits or Intellectual Property) or personal property leases of Transferor that are material to the business or operations of the Transferred Assets (the "Contracts").

(ii) Each Contract (a) constitutes a legal, valid and binding obligation of Transferor and, to Transferor's Knowledge, constitutes a valid and binding obligation of the other parties thereto and (b) is in full force and effect and Transferor has not delivered or received any written notice of termination thereunder.

(iii) There is not under any Contract any default or event which, with notice or lapse of time or both, (a) would constitute a default by Transferor or, to Transferor's Knowledge, any other party thereto, (b) would constitute a default by Transferor or, to Transferor's Knowledge, any other party thereto which would give rise to an automatic termination, or the right of discretionary termination, thereof, or (c) would cause the acceleration of any of Transferor's obligations thereunder or result in the creation of any Encumbrance (other than any Permitted Encumbrance) on any of the Transferred Assets. There are no claims, actions, proceedings or investigations pending or, to the Knowledge of Transferor, threatened against Transferor or any other party to any Contract before any Governmental Authority or body acting in an adjudicative capacity relating in any way to any Contract or the subject matter thereof. Transferor has no Knowledge of any defense, offset or counterclaim arising under any Contract.

(j) Legal Proceedings. Except as set forth on Schedule 4.01(j) there are no actions or proceedings pending or, to the Knowledge of Transferor, threatened against Transferor before any court, arbitrator or Governmental Authority, which, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect. Transferor is not subject to any outstanding judgments, rules, orders, writs, injunctions or decrees of any court, arbitrator or Governmental Authority that, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect.

(k) Permits.

(i) Transferor has all permits, licenses, franchises and other governmental authorizations, consents and approvals (other than Environmental Permits, which are addressed in Section 4.0l(k)) necessary to own and operate the Transferred Assets (collectively, "Permits"), except where any failures to have such Permits would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. Transferor has not received any written notification that Transferor is in violation, nor does Transferor have Knowledge of any violations, of any such Permits, or any Law or judgment of any Government Authority applicable to Transferor with respect to the Transferred Assets, except for violations that would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

(ii) Section II of Schedule 4.01(k) lists all material Permits (other than Environmental Permits).

(l) Taxes. To the Knowledge of Transferor, Transferor has filed all Tax Returns that are required to be filed by it with respect to any Tax relating to the Transferred Assets, and Transferor has paid all Taxes that have become due as indicated thereon, except where such Tax is being contested in good faith by appropriate proceedings, or where any failures to so file or pay would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. There are no Encumbrances for Taxes on the Transferred Assets that are not Permitted Encumbrances.

(m) Intellectual Property. Transferor has such ownership of or such rights by license or other agreement to use all Intellectual Property necessary to permit Transferor to conduct its business with respect to the Transferred Assets as currently conducted, except where any failures to have such ownership, license or right to use would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. Transferor is not, nor has Transferor received any notice that Transferor is, in default (or with the giving of notice or lapse of time or both, would be in default) under any contract to use such Intellectual Property, and there are no material restrictions on the transfer of any material contract, or any interest therein, held by Transferor in respect of such Intellectual Property. Transferor has not received notice that it is infringing any Intellectual Property of any other Person in connection with the operation or business of the Transferred Assets.

(n) Compliance with Laws. Transferor is in compliance with all applicable Laws with respect to the ownership or operation of the Transferred Assets, except where any such failures to be in compliance would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

(o) Limitation of Representations and Warranties. **EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES SET FORTH IN THIS AGREEMENT AND IN ANY ANCILLARY AGREEMENT, TRANSFEROR IS NOT MAKING, AND HEREBY DISCLAIMS, ANY OTHER REPRESENTATIONS AND WARRANTIES, WRITTEN OR ORAL, STATUTORY, EXPRESS OR IMPLIED, CONCERNING TRANSFEROR OR THE TRANSFERRED ASSETS OR ANY PART THEREOF.**

Section 4.02 Representations and Warranties of Transferee. Transferee represents and warrants to Transferor as follows:

(a) Organization and Good Standing. Transferee is a corporation duly formed, validly existing and in good standing under the laws of the state of ___________ and has all requisite power and authority to own, lease or operate its properties and to carry on its business as it is now being conducted.

(b) Authority and Enforceability. Transferee has full power and authority to execute and deliver and carry out its obligations under this Agreement and each Ancillary Agreement to which it is a party, and to consummate the transactions contemplated hereby and thereby. The execution, delivery and performance by Transferee of this Agreement and each such Ancillary Agreement, and the consummation of the transactions contemplated hereby and thereby, have been duly and validly authorized by all necessary action by Transferee. Assuming the due authorization, execution and delivery of this Agreement and each such Ancillary Agreement by the other party or parties thereto, each of this Agreement and each such Ancillary Agreement constitutes a legal, valid and binding obligation of Transferee, enforceable against Transferee in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy, insolvency and other similar laws affecting the rights and remedies of creditors generally and by general principles of equity.

(c) No Violation; Consents and Approvals.

(i) Neither the execution, delivery and performance by Transferee of this Agreement and each Ancillary Agreement to which Transferee is a party, nor the consummation by Transferee of the transactions contemplated hereby and thereby, will (a) conflict with or result in any breach of any provision of the Organizational Documents of Transferee; (b) result in a default (or give rise to any right of termination, cancellation or acceleration), or require a consent, under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, material agreement or other instrument or obligation to which Transferee is a party or by which any of their respective material properties or assets may be bound, except for any such defaults or consents (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained or which would not, individually or in the aggregate, reasonably be expected to have a material adverse effect on the ability of Transferee to perform its obligations under this Agreement and the Ancillary Agreements; or (c) constitute a violation of any law, regulation, order, judgment or decree applicable to Transferee, except for any such violations as would not, individually or in the aggregate, reasonably be expected to have a material adverse effect on the ability of Transferee to perform its obligations under this Agreement and the Ancillary Agreements.

(ii) Transferee has obtained all consents and approvals from each Governmental Authority or other Person is necessary for the execution and delivery of this Agreement or any Ancillary Agreement by Transferee, or the consummation by

Transferee of the transactions contemplated hereby and thereby, except for any such consents and approvals which, if not obtained or made, would not, individually or in the aggregate, reasonably be expected to have a material adverse effect on the ability of Transferee to perform its obligations under this Agreement and the Ancillary Agreements.

(d) Legal Proceedings. There are no actions or proceedings pending or, to the Knowledge of Transferee, threatened against Transferee before any court, arbitrator or Governmental Authority, which, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect on the ability of Transferee to perform its obligations under this Agreement and the Ancillary Agreements. Transferee is not subject to any outstanding judgments, rules, orders, writs, injunctions or decrees of any court, arbitrator or Governmental Authority which, individually or in the aggregate, would reasonably be expected to have a material adverse effect on the ability of Transferee to perform its obligations under this Agreement and the Ancillary Agreements.

ARTICLE V
CERTAIN COVENANTS AND AGREEMENTS

Section 5.01 Transfer Tax; Recording Costs. All transfer, use, stamp, sales and similar Taxes and recording costs incurred in connection with this Agreement and the transactions contemplated hereby shall be the sole responsibility of Transferee.

Section 5.02 Further Assurances.

(a) Subject to the terms and conditions of this Agreement, Transferor and Transferee shall use commercially reasonable efforts to take, or cause to be taken, all actions, and to do, or cause to be done, all things necessary, proper or advisable under applicable Laws to consummate and make effective the transfer of the Transferred Assets pursuant to this Agreement and the assumption of the Assumed Liabilities, including using commercially reasonable efforts with a view to obtaining all necessary consents, approvals and authorizations of, and making all required notices or filings with, third parties required to be obtained or made in order to consummate the transactions hereunder, including the transfer of the Environmental Permits and the Permits to Transferee. Neither Transferor, on the one hand, nor Transferee, on the other hand, shall, without prior written consent of the other, take or fail to take any action which might reasonably be expected to prevent or materially impede, interfere with or delay the transactions contemplated by this Agreement.

(b) In the event that any portion of the Transferred Assets shall not have been conveyed to Transferee at the Closing, Transferor shall, subject to paragraphs (c) and (d) immediately below, convey such asset to Transferee as promptly as practicable after the Closing.

(c) To the extent, if any, that Transferor's rights under any Contract, Real Property Leases or Easements and Rights of Way may not be assigned without the consent of any other party thereto, which consent has not been obtained by the Closing Date, this Agreement shall not constitute an agreement to assign the same if an attempted assignment would constitute a breach thereof or be unlawful. Transferor and Transferee agree that if any consent to an assignment of any Contract, Real Property Lease or Easement and Right of Way has not been obtained at the Closing Date, or if any attempted assignment would be ineffective or would impair Transferee's rights and obligations under the Contract, Real Property Lease or Easement and Right of Way in question, so that Transferee would not in effect acquire the benefit of all such rights and obligations, Transferor, at its option and to the maximum extent permitted by law and such Contract, Real Property Lease or Easement and Right of Way , shall, after the Closing Date, (i) appoint Transferee to be Transferor's agent with respect to such Contract, Real Property Lease or Easement and Right of Way or (ii) to the maximum extent permitted by law and such Contract, Real Property Lease or Easement and Right of Way, enter into such reasonable arrangements with Transferee or take such other commercially reasonable actions to provide Transferee with the same or substantially similar rights and obligations of such Contract, Real Property Lease or Easement and Right of Way. From and after the Closing Date, Transferor and Transferee shall cooperate and use commercially reasonable efforts to obtain an assignment to Transferee of any such Contract, Real Property Lease or Easement and Right of Way.

(d) To the extent that Transferor's rights under any warranty or guaranty described in Section 2.01(r) may not be assigned without the consent of another Person, which consent has not been obtained by the Closing Date, this Agreement shall not constitute an agreement to assign the same, if an attempted assignment would constitute a breach thereof or be unlawful. The Parties agree that if any consent to an assignment of any such warranty or guaranty has not been obtained or if any attempted assignment would be ineffective or would impair Transferee's rights and obligations under the warranty or guaranty in question, so that Transferee would not in effect acquire the benefit of all such rights and obligations, Transferor shall use commercially reasonable efforts to the extent permitted by law and such warranty or guaranty, to enforce such warranty or guaranty for the benefit of Transferee to the maximum extent possible so as to provide Transferee with the benefits and obligations of such warranty or guaranty. Notwithstanding the foregoing, Transferor shall not be obligated to bring or file suit against any third party, provided that if Transferor determines not to bring or file suit after being requested by Transferee to do so, Transferor shall assign, to the extent permitted by law or any applicable agreement, its rights in respect of the claims so that Transferee may bring or file such suit.

Section 5.03 Survival. The representations and warranties of the Parties contained herein shall not survive the Closing and thereafter shall be of no further force and effect.

ARTICLE VI
MISCELLANEOUS PROVISIONS

Section 6.01 Notices. All notices and other communications hereunder shall be in writing and shall be deemed given (i) on the day when delivered personally or by e-mail (with confirmation) or facsimile transmission (with confirmation), (ii) on the next Business Day when delivered to a nationally recognized overnight delivery service, or (iii) five (5) Business Days after deposited as registered or certified mail (return receipt requested), in each case, postage prepaid, addressed to the recipient Party at its address set forth below (or to such other addresses and e-mail and facsimile numbers for a Party as shall be specified by like notice; provided, however, that any notice of a change of address or e-mail or facsimile number shall be effective only upon receipt thereof):

If to Transferor, to:

AEP Generation Resources Inc.

____

____

Attn:

Facsimile No.:

Email:

If to Transferee, to:

[NEWCO Kentucky]

____

____

Attn:

Facsimile No.:

Email:

Section 6.02 Waiver. The rights and remedies of the Parties are cumulative and not alternative. Neither the failure nor any delay by any Party in exercising any right, power, or privilege under this Agreement or the documents referred to in this Agreement will operate as a waiver of such right, power, or privilege, and no single or partial exercise of any such right, power, or privilege will preclude any other or further exercise of such right, power, or privilege or the exercise of any other right, power, or privilege. To the maximum extent permitted by applicable Law, (a) no claim or right arising out of this Agreement or the documents referred to in this Agreement can be discharged by one Party, in whole or in part, by a waiver or renunciation of the claim or right unless in writing signed by each other Party; (b) no waiver that may be given by a Party will be applicable except in the specific instance for which it is given; and (c) no notice to or demand on one Party will be deemed to be a waiver of any obligation of such Party or of the right of the Party giving such notice or demand to take further action without notice or demand as provided in this Agreement or the documents referred to in this Agreement.

Section 6.03 Entire Agreement; Amendment; Etc.

(a) This Agreement and the Ancillary Agreements, including the Schedules, Exhibits, documents, certificates and instruments referred to herein or therein, embody the entire agreement and understanding of the Parties hereto in respect of the transactions contemplated by this Agreement. There are no restrictions, promises, representations, warranties, covenants or undertakings, other than those expressly set forth or referred to herein or therein. This Agreement supersedes all prior or contemporaneous agreements, understandings or statements or agreements between the Parties, whether written or oral, with respect to the transactions contemplated hereby. Each Party acknowledges and agrees that no employee, officer, agent or representative of the other Party has the authority to make any representations, statements or promises in addition to or in any way different than those contained in this Agreement and the Ancillary Agreements, and that it is not entering into this Agreement or the Ancillary Agreements in reliance upon any reliance upon an representation, statement or promise of the other Party except as expressly stated herein or therein.

(b) This Agreement may not be amended, supplemented, terminated or otherwise modified except by a written agreement executed by Transferor and Transferee.

(c) This Agreement shall be binding upon and inure solely to the benefit of each Party hereto and nothing in this Agreement, express or implied, is intended to or shall confer upon any other Person any right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

Section 6.04 Assignment. This Agreement and all the of the provisions hereof shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and permitted assigns, but neither this Agreement nor any of the rights, interests or obligations hereunder may be assigned by, on the one hand, Transferor, and on the other hand, Transferee, in whole or in part (whether by operation of law or otherwise), without the prior written consent of the other Party, and any attempt to make any such assignment without such consent will be null and void. Notwithstanding the foregoing, Transferor or Transferee may assign or otherwise transfer its rights hereunder and under any Ancillary Agreement to any bank, financial institution or other lender providing financing to Transferor or Transferee, as applicable, as collateral security for such financing; provided, however, that no such assignment shall (i) impair or materially delay the consummation of the transactions contemplated hereby or (ii) relieve or discharge Transferor or Transferee, as the case may be, from any of its obligations hereunder and thereunder.

Section 6.05 Severability. If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any law or public policy, all other terms and provisions of this Agreement will nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in any manner materially adverse to any party hereto. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the Parties will negotiate in good faith to modify this Agreement so as to effect the original intent of the Parties as closely as possible in an acceptable manner in order that the transactions contemplated hereby are consummated as originally contemplated to the greatest extent possible.

Section 6.06 Governing Law. This Agreement, the construction of this Agreement, all rights and obligations between the Parties to this Agreement, and any and all claims arising out of or relating to the subject matter of this Agreement (including all tort and contract claims) will be governed by and construed in accordance with the laws of the state of Ohio, without giving effect to choice of law principles thereof.

Section 6.07 Counterparts: Facsimile Execution. This Agreement may be executed in one or more counterparts, all of which will be considered one and the same agreement and will become effective when one or more counterparts have been signed by each of the Parties and delivered to each other Party, it being understood that the Parties need not sign the same counterpart. This Agreement may be executed by facsimile signature(s) or signatures in portable document format.

Section 6.08 Schedules. The Schedules to this Agreement are intended to be and hereby are specifically made a part of this Agreement.

Section 6.09 Specific Performance. The Parties hereto agree that irreparable damage would occur in the event any of the provisions of this Agreement were not to be performed in accordance with the terms hereof and that the Parties will be entitled to specific performance of the terms hereof in addition to any other remedies at law or in equity.

Signatures appear on following page

IN WITNESS WHEREOF, each of the Parties has caused this Asset Contribution Agreement to be executed on its behalf by its respective officer thereunto duly authorized, all as of the day and year first above written.

AEP GENERATION RESOURCES INC.

By: ______________________________
Name: ______________________________
Title: ______________________________

[NEWCO KENTUCKY]

By: ______________________________
Name: ______________________________
Title: ______________________________

AGREEMENT AND PLAN OF MERGER
OF
KENTUCKY POWER COMPANY AND [NEWCO KENTUCKY]

This Agreement and Plan of Merger is entered into as of this __ day of ________, 201_, under Title XXIII, Section 271B.11-080 of the Kentucky Revised Statutes and Title 8, Chapter 1 of the Delaware Code, between Kentucky Power Company ("Kentucky Power"), a Kentucky corporation, and [NEWCO Kentucky], a Delaware corporation.

RECITALS

1. Kentucky Power is a corporation duly organized, validly existing and in good standing under the laws of the State of Kentucky and is a wholly owned subsidiary of American Electric Power Company, Inc., a New York corporation ("AEP"), which is a public utility holding company. Kentucky Power is a regulated public utility engaged in the business of providing electric power and related services to its customers.

2. [NEWCO Kentucky] is a corporation duly organized, validly existing and in good standing under the laws of Delaware and is a wholly owned subsidiary of AEP. [NEWCO Kentucky] owns certain electric generating facilities; however, it is not a regulated public utility.

3. Kentucky Power currently has authorized 2,000,000 shares of common stock with a par value of $50 per share, of which 1,009,000 are issued and outstanding and held by AEP.

4. [NEWCO Kentucky] currently has authorized _________ shares of common stock, no par value, of which ___________ are issued and outstanding and held by AEP.

5. The Federal Energy Regulatory Commission and the Kentucky Public Service Commission have authorized the merger of [NEWCO Kentucky] with and into Kentucky Power.

6. The Boards of Directors of Kentucky Power and [NEWCO Kentucky] have each determined that it is in the best interest of both companies and their shareholders to merge [NEWCO Kentucky] with and into Kentucky Power, and have, by resolutions, duly approved and adopted this Agreement and Plan of Merger. AEP, the sole shareholder of Kentucky Power and [NEWCO Kentucky] has approved this Agreement and Plan of Merger.

AGREEMENT

Now, therefore, in consideration of the premises and agreements contained herein, the parties agree as follows:

ARTICLE I
NAMES OF CORPORATIONS; MERGER

The names of the constituent corporations to the merger are "Kentucky Power Company" and ["NEWCO Kentucky"]. In accordance with the laws of the State of Kentucky and this Agreement and Plan of Merger, [NEWCO Kentucky] shall be merged with and into Kentucky Power which shall be, and is herein referred to as, the "Surviving Corporation."

ARTICLE II
EFFECTIVE TIME

As soon as practicable after the execution hereof, Articles of Merger shall be filed, as required by the Kentucky Business Corporation Act, in the office of the Secretary of State of the State of Kentucky and Articles of Merger shall be filed, as required by the Delaware Business Corporation Act, in the office of the Secretary of State of the State of Delaware. The merger shall become effective at [______________]. Such date and time shall be the "Effective Time" referred to in this Agreement and Plan of Merger.

ARTICLE III
EFFECT OF MERGER; ARTICLES OF INCORPORATION; BY-LAWS; DIRECTORS AND OFFICERS ON THE EFFECTIVE DATE

3.1 At the Effective Time, [NEWCO Kentucky] shall be merged with and into Kentucky Power and the separate corporate existence of [NEWCO Kentucky] shall cease, and Kentucky Power shall be the continuing and Surviving Corporation in the merger and shall continue to exist under the laws of the State of Kentucky.

3.2 The Surviving Corporation shall have all the rights, privileges, immunities and powers and shall be subject to all of the duties and liabilities of a corporation organized under the Kentucky Business Corporation Act. Title to all real estate and other property owned by Kentucky Power and [NEWCO Kentucky] shall be vested in the Surviving Corporation and the Surviving Corporation shall have all the liabilities of Kentucky Power and [NEWCO Kentucky]. Any proceeding pending against Kentucky Power or [NEWCO Kentucky] at the Effective Time may be continued as if the Merger did not occur or the Surviving Corporation may be substituted in such proceeding in the case of any such proceeding against [NEWCO Kentucky].

3.3 The Restated Articles of Incorporation of Kentucky Power, as in effect immediately prior to the Effective Time, shall be the Restated Articles of Incorporation of the Surviving Corporation until they shall thereafter be duly altered or amended.

3.4 The By-Laws of Kentucky Power, as in effect immediately prior to the Effective Time, shall be the By-Laws of the Surviving Corporation until they shall thereafter be duly altered or amended.

3.5 The directors and officers of Kentucky Power immediately prior to the Effective Time shall continue to be the directors and officers of the Surviving Corporation until changed in accordance with law.

ARTICLE IV
CONVERSION OF SHARES

The manner of carrying into effect the Merger, and the manner and the basis of converting and canceling the capital stock of the constituent companies, shall be as follows: At the Effective Time, (1) each share of capital stock of Kentucky Power then issued and outstanding shall, by virtue of the Merger and without any action by the holder, thereof, constitute one issued and outstanding share of stock of the Surviving Corporation and shall include the same rights, privileges and preferences as appertained to the capital stock of Kentucky Power immediately prior to the merger; (2) each share of capital stock of [NEWCO Kentucky] then issued and outstanding shall, by virtue of the

Merger and without any action by the holder thereof, be canceled and extinguished; and (3) no new or additional stock of the Surviving Corporation shall be issued in consummating the Merger.

ARTICLE V
MISCELLANEOUS

5.1 The parties to this Agreement and Plan of Merger shall pay the expenses incurred by each of them, respectively, in connection with the transactions contemplated herein.

5.2 The title of this Agreement and Plan of Merger and the headings herein set out are for the convenience of reference only and shall not be deemed to be part of this Agreement and Plan of Merger.

5.3 Subject to applicable law, this Agreement and Plan of Merger may be amended by agreement among the parties hereto and approved by their respective Board of Directors.

5.4 This Agreement and Plan of Merger and the legal relations among the parties hereto shall be governed by and construed in accordance with the laws of the State of Kentucky.

Signatures appear on following page

IN WITNESS WHEREOF, each of Kentucky Power and [NEWCO Kentucky] has caused this Agreement and Plan of Merger to be executed on its behalf and in its corporate name as of the date first written above.

KENTUCKY POWER COMPANY

By: ______________________________
Name: ___________________________
Title: ____________________________

[NEWCO KENTUCKY]

By: ______________________________
Name: ___________________________
Title: ____________________________

RATE SCHEDULE NO. 303

MITCHELL PLANT OPERATING AGREEMENT

APPALACHIAN POWER COMPANY

KENTUCKY POWER COMPANY

And

AMERICAN ELECTRIC POWER SERVICE CORPORATION, AS AGENT

Tariff Submitter: **Appalachian Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **APCo Rate Schedules and Service Agreements Tariffs**
Tariff Proposed Effective Date: **01/01/2014**
Tariff Record Title: **Mitchell Plant Operating Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 303**

THIS MITCHELL PLANT OPERATING AGREEMENT ("Agreement"), dated _____________ is by and among Appalachian Power Company ("Appalachian"), a Virginia corporation qualified as a foreign corporation in West Virginia; Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo") (such two parties hereinafter sometimes referred to as the "Owners"); and American Electric Power Service Corporation ("Agent"), a New York corporation qualified as a foreign corporation in West Virginia. Appalachian, KPCo and Agent may hereinafter be referred to as a "Party" or collectively as the "Parties".

WITNESSETH:

WHEREAS, Appalachian and KPCo have acquired an undivided ownership interest in the Mitchell Power Generation Facility consisting of two 800MW generating units and associated plant, equipment and real estate, located in Moundsville, West Virginia, (the "Mitchell Plant"); and

WHEREAS, Appalachian now has an undivided 50% ownership interest in the Mitchell Plant and KPCo now has an undivided 50% ownership interest in the Mitchell Plant; and

WHEREAS, the Owners desire that Appalachian shall operate and maintain the Mitchell Plant in accordance with the provisions set forth herein; and

WHEREAS, the Owners are subsidiaries of American Electric Power Company, Inc., ("AEP") the parent company in an integrated public utility holding company system, and use the services of Agent, (an affiliated company engaged solely in the business of furnishing essential services to the Owners and to other affiliated companies), as outlined in the service agreements between Agent and Appalachian Power Company and between Agent and Kentucky Power Company.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories agree as follows:

ARTICLE ONE

FUNCTIONS OF APPALACHIAN AND AGENT

1.1 Appalachian shall operate and maintain the Mitchell Plant in accordance with good utility practice consistent with procedures employed by Appalachian at its other generating stations, and in conformity with the terms and conditions of this Agreement.

1.2 Appalachian shall keep all necessary books of record, books of account and memoranda of all transactions involving the Mitchell Plant, and shall make computations and allocations on behalf of the Owners, as required under this Agreement. The books of record, books of account and memoranda shall be kept in such manner as to conform, where so required, to the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") for Public Utilities and Licensees ("Uniform System of Accounts"), and to the rules and regulations of other regulatory bodies having jurisdiction as they may from time to time be in effect.

1.3 The Owners shall establish such joint bank accounts as may from time to time be required or appropriate.

1.4 As soon as practicable after the end of the month, Appalachian shall furnish to KPCo a statement setting forth the dollar amounts associated with the operation and maintenance of the Mitchell Plant as allocated hereunder to Appalachian and KPCo for such month.

The Owners shall, on a timely basis, deposit sufficient dollar amounts in the appropriate bank accounts to cover their respective allocations of such costs.

1.5 Appalachian shall obtain such materials, labor and other services as it considers necessary in connection with the performance of the functions to be performed by it hereunder from such sources or through such persons as it may designate.

1.6 Agent, as directed by the Operating Committee and consistent with Agent's service agreements with Appalachian and KPCo, shall provide services necessary for the safe and efficient operation and maintenance of the Mitchell Plant.

ARTICLE TWO

APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The Total Net Capability of the Mitchell Plant at the Mitchell Unit 1 and Unit 2 low-voltage busses, after taking into account auxiliary load demand, is 1,600,000 kilowatts. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The Total Net Generation of the Mitchell Plant during a given period, as determined by the requirements of Appalachian and KPCo, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for the Mitchell Unit 1 and Unit 2 during such period.

2.3 In any hour, Appalachian and KPCo shall share the minimum load responsibility of Mitchell Unit 1 and Unit 2 in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time. Each Owner shall independently dispatch its share of the generating capacity between minimum and full load.

2.4 In any hour during which the Mitchell Units are out of service, the energy used by the out-of-service Units' auxiliaries during such hour shall be provided by Appalachian and KPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time.

2.5 Appalachian shall at all times accept KPCo's share of the Mitchell Plant Total Net Capability into its transmission system at the low-voltage busses of the Mitchell Plant, and shall deliver KPCo's share of energy used by the Mitchell Plant auxiliaries when the Units are out of service, as part of the energy interchange between and Appalachian and KPCo.

ARTICLE THREE

REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 Appalachian shall from time to time make or cause to be made any necessary additions to, replacements of, and retirements of capitalizable facilities associated with the Mitchell Plant as may be mutually agreed upon by the Owners.

3.2 The dollar amounts associated with any additions to, replacements of, or retirements of capitalizable facilities associated with the Mitchell Plant shall be allocated to Appalachian and KPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at the time such additions, replacements, or retirements are made.

ARTICLE FOUR

WORKING CAPITAL REQUIREMENTS

4.1 Appalachian and KPCo shall periodically mutually determine the amount of funds required for use as working capital in meeting payrolls and other expenses incurred in the operation and maintenance of the Mitchell Plant, and in buying materials and supplies (exclusive of fuel) for the Mitchell Plant.

4.2 Appalachian and KPCo shall from time to time provide their share of working capital requirements in respective amounts proportionate to their ownership interests at such time in the Mitchell Plant.

ARTICLE FIVE

INVESTMENT IN FUEL

5.1 Appalachian and Agent shall establish and maintain reserves of coal in stock pile for the Mitchell Plant of such quality and in such quantities as Appalachian and Agent shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply.

5.2 The Owners shall make such monthly investments in the common coal stock pile associated with the Mitchell Plant as are necessary to maintain the number of tons in such coal stock pile, after taking into account the coal consumption from the common coal stock pile by Mitchell Unit 1 and Unit 2 during such month.

5.3 At any time, Appalachian's and KPCo's respective shares of the investment in the common coal stock pile shall be proportionate to their ownership interests at such time in the Mitchell Plant.

5.4 Fuel oil reserves and fuel oil charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

ARTICLE SIX

APPORTIONMENT OF STATION COSTS

6.1 The allocation to the Owners of fuel expense associated with Mitchell Unit 1 and Unit 2 shall be determined by Appalachian and Agent as follows:

a. In any calendar month, the unit cost of coal received for the Mitchell Plant common coal stock pile shall be determined by dividing (i) the sum of the total delivered cost of coal received for the Mitchell Plant common coal stock pile during such month and the associated total coal storage costs, coal unloading costs and fuel handling costs incurred during such month by (ii) the total number of tons of coal delivered to the Mitchell Plant common coal stock pile during such month.

b. In any calendar month, the total cost of coal received for the Mitchell Plant common coal stock pile shall be determined by multiplying (i) the unit cost of coal received for such common coal stock pile for such month as determined by the provisions of Section 6.1(a) by (ii) the number of tons of coal received for such common stock pile during such month.

c. The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock pile shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock pile during such month. Such dollar amount shall be credited to the Mitchell Plant fuel in stock pile and charged to Mitchell Plant fuel consumed.

d. In each calendar month, Appalachian's and KPCo's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1 (c) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

e. Fuel oil reserves will be owned and accounted for in the same manner as coal stock pile, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For purposes of this Agreement, KPCo's Assigned Capacity in the Mitchell Plant shall be equal to 50% of the Total Net Capability, and Appalachian's Assigned Capacity shall be equal to 50% of the Total Net Capability.

6.3 For each calendar month, Appalachian and Agent will, to the extent practicable, determine all Mitchell Plant operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 For each calendar month, Appalachian and Agent will, to the extent practicable, determine all Mitchell Plant maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.5 In each calendar month, Appalachian's and KPCo's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with Sections 6.3 and 6.4, shall be proportionate to their respective ownership interests.

6.6 Each Owner shall bear the cost of all taxes attributable to its respective ownership interest in the Mitchell Plant.

ARTICLE SEVEN

OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, the Owners and Agent each shall name one representative ("Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement. Any Party may change its Operating Representative or alternate at any time by written notice to the other Parties. The Operating Representatives for the respective Parties, or their alternates, shall comprise the Operating Committee. All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of Appalachian and KPCo. The Operating Representative of Agent, or of any third party that provides services in replacement of Agent, shall be free to express the views of Agent or such third party on any matter, but shall not have a vote on the Operating Committee. Except as otherwise provided in Sections 11.1, 11.2 and 11.3 with respect to a dispute referred to the Operating Committee by an Owner, the failure of the Owners' respective Operating Representatives to unanimously agree with respect to a matter pending before the Operating Committee shall not be considered to be a dispute that would be subject to resolution under Article Eleven.

7.2 The Operating Committee shall have the following responsibilities:

a. Review and approval of an annual budget and annual operating plan, including determination of the emission allowances required to be acquired by Appalachian and KPCo.

b. Establishment and review of procedures and systems for dispatch, notification of dispatch, and unit commitment under this Agreement, including any commitment of Called Capacity pursuant to Section 7.6.2.

c. Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages, as well as the return to availability following an unplanned outage.

d. Decisions on capital expenditures, including unit upgrades and re-powering.

e. Determinations as to changes in the unit capability and decisions on unit retirement.

f. Establishment and modification of billing procedures under this Agreement.

g. Specification of fuels, oversight of fuel inspection and certification procedures, management of fuel inventories, and allocation of rights under fuel supply and transportation contracts.

h. Establishment of, termination of, and approval of any change or amendment to the operating arrangements between Appalachian and Agent or any replacement third party with respect to the Mitchell Plant generating units; provided, however, that Agent or any replacement third party shall participate in discussions pursuant to this subsection 7.2.h only if and to the extent requested to do so by both Appalachian and KPCo.

i. Review and approval of plans and procedures designed to insure compliance with any environmental law, regulation, ordinance or permit, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one unit for compliance.

j. Other duties as assigned by agreement of Appalachian and KPCo.

7.3 The Operating Committee shall meet at least annually, and at such other times as any Party may reasonably request.

7.4 The Parties shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 Appalachian and KPCo will each make an initial unit commitment one business day ahead of real-time dispatch.

7.6 For purposes of this Section and subsections of this Section, the terms "Party" or "Parties" refers only to Appalachian and KPCo, or both of them, as the case may be.

7.6.1 If Mitchell Unit 1 or Unit 2 is designated to be committed by both Parties, such unit will be brought on line or kept on line. If neither Party designates Mitchell Unit 1 or Unit 2 to be committed, such unit will remain off line or to be taken offline.

7.6.2 When a Mitchell Unit is designated to be committed by one Party, but designated not to be committed by the other Party, the unit will be brought on line or kept on line if the Party designating the unit for commitment undertakes to pay any applicable start-up costs for the unit, as well as any applicable minimum running costs for the unit thereafter, in which event the unit shall be brought on line or kept on line, as the case may be. The Party so designating the unit to be committed shall have the right to schedule and dispatch up to all of the Available Capacity of the unit. Available Capacity means that portion of the Owners' aggregate Assigned Capacity that is currently capable of being dispatched. The Party exercising this right shall be referred to as the "Calling Party," and the capacity called by that Party in excess of its Assigned Capacity Percentage of the Available Capacity of that unit shall be referred to as its "Called Capacity." The other Party shall be referred to as the "Non-Calling Party". The Calling Party shall provide reasonable notice to the Non-Calling Party of its call, including any start-up or shut-down time for the Unit. For purposes of this Agreement, KPCo's Assigned Capacity Percentage shall be 50%, and Appalachian's Assigned Capacity Percentage shall be 50%.

7.6.3 The Non-Calling Party can reclaim any Called Capacity attributable to its Assigned Capacity share by giving the Calling Party notice equal to the normal start-up time for the unit. At the end of the notice period, the Non-Calling Party shall have the right to schedule and dispatch the recalled capacity. At that point, the Non-Calling Party shall resume its responsibility for its share of any applicable start-up costs for the unit and prospectively shall bear its responsibility for the costs associated with its Assigned Capacity from the unit.

7.6.4 If any capacity remains available but is not dispatched from a Party's Available Capacity committed as a result of the initial unit commitment, the other Party may only schedule and dispatch such capacity pursuant to agreement with the non-dispatching Party.

7.7 Appalachian and KPCo shall be individually responsible for any fees charged by FERC on the basis of the sales or transmission by each of capacity or energy at wholesale in interstate commerce.

7.8 Emission Allowances. To the extent such assignment has not previously occurred, on or before the effective date of this Agreement, Appalachian and Agent will assign to KPCo a pro rata share of the remaining Emission Allowances for each vintage year of Emission Allowances, issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Clean Air Interstate Rule 40 CFR Parts 96 and 97, and any amendments thereto ("Emission Allowances"), that it has received from the Administrator of USEPA or the State of West Virginia with respect to the Mitchell Plant in the past and has not expended as of the date of assignment. In addition, Appalachian will assign to KPCo a pro rata share of such Emission Allowances which were purchased by Appalachian or Agent and held in any account for use at the Mitchell Plant. In each case, the number of such Emission Allowances to be assigned by Appalachian to KPCo will be determined by multiplying KPCo's Assigned Capacity Percentage, as specified in Section 7.6.2, by the total of such Emission Allowances that Appalachian or Agent has received or purchased for the Mitchell Plant and has not expended as of the date of assignment rounded to the nearest whole number. Emission Allowances received by Appalachian with respect to the Mitchell Plant will be shared by the Appalachian and KPCo in accordance with the Assigned Capacity Percentage of each of them. To the extent that additional Emission Allowances are required for operation of the Mitchell Plant, Appalachian and KPCo will each be responsible for acquiring sufficient Emission Allowances to satisfy the Emission Allowances required because of its dispatch of energy from the Mitchell Plant, and the Emission Allowances required to satisfy the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree between USEPA and Ohio Power Company entered on December 10, 2007, in Civil Action No. C2-99-1182 and consolidated cases by the U.S. District Court in the Southern District of Ohio. Agent will also determine the number and allocation of Emission Allowances to be supplied to any third-party unit operator under applicable designated representative agreements. On or before January 10 of each year, Agent shall determine and notify Appalachian and KPCo of the number of additional annual Emission Allowances consumed by each of them through December 31 of the previous year, and Appalachian and KPCo shall each transfer into the Mitchell Plant U.S. EPA Allowance Transfer System account that number of Emission Allowances with a small compliance margin by January 31 of that year. For seasonal Emission Allowance programs, Agent shall determine and notify Appalachian and KPCo of the number of additional seasonal Emission Allowances consumed by each of them during the applicable compliance period by the 10th day of the first month following the end of the compliance period, and Appalachian and KPCo shall each transfer into the appropriate Mitchell Plant U.S. EPA Allowance Transfer System Account that number of Emission Allowances with a small compliance margin by the last day of the first month following the end of the compliance period. In the event that

Appalachian or KPCo fails to surrender the required number of Emission Allowances by January 31 or the last day of the first month following any seasonal compliance period, Agent shall purchase the required number of Emission Allowances, and Appalachian or KPCo, as the case may be, shall reimburse Agent for such purchases, with interest at the Federal Funds Rate (as published by the Board of Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for the Emission Allowances required by the use of the Mitchell Plant by Appalachian and KPCo and to correct any imbalance between Emission Allowances supplied and Emission Allowances used through the end of the preceding year by settlement or payment.

7.9 Capital repairs and improvements to the Mitchell Plant will be determined by the Operating Committee pursuant to the annual budgeting process set forth in Section 7.10. Expenditures that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be assigned exclusively to that Owner.

7.10 At least 90 days before the start of each operating year, Appalachian and Agent shall submit to the Operating Committee a proposed annual budget with respect to the Mitchell Plant, a proposed annual operating plan, and an estimate and schedule of costs to be incurred for major maintenance or replacement items during the next six-year period. The annual budget shall be presented on a month-by-month basis for each month during the next operating year, and shall include an operating budget, a capital budget, an estimate of the cost of any major repairs that are anticipated will occur during such operating year with respect to the Mitchell Plant, and an itemized estimate of all projected non-fuel variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual budget and final annual operating plan. Once approved, the annual budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine.

ARTICLE EIGHT

EFFECTIVE DATE AND TERM

8.1 Subject to FERC approval or acceptance for filing, the effective date of this Agreement shall be [January 1, 2014].

8.2 Subject to FERC approval or acceptance, if necessary, this Agreement shall remain in force until such time as (i) KPCo or Appalachian has divested itself of all or any portion of its ownership interest in the Mitchell Plant, other than assignment or other transfer of such ownership interests to another AEP affiliate; or (ii) either KPCo or Appalachian is no longer a direct or indirect wholly owned subsidiary of AEP; or (iii) KPCo and Appalachian may mutually agree to terminate this Agreement.

ARTICLE NINE

GENERAL

9.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and assigns, but this Agreement may not be assigned by any signatory without the written consent of the others, which consent shall not be unreasonably withheld.

9.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

9.3 The interpretation and performance of this Agreement shall be in accordance with the laws of the State of Ohio, excluding conflict of laws principles that would require the application of the laws of a different jurisdiction.

9.4 This Agreement supercedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories or their representatives with respect to operation of the Mitchell Plant, and constitutes the entire agreement of the signatories with respect to the operation of the Plant. Notwithstanding the foregoing, this Agreement does not supercede any previous agreements among any of the signatories allocating or transferring rights to capacity and associated energy, or ownership, of the Mitchell Plant.

9.5 Each party shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, facsimile, e-mail or any similar means, properly addressed to such representative at the address specified below:

APPALACHIAN POWER COMPANY

____

____

Attn:______________________________

Phone:______________________________

Facsimile:____________________________

Email:______________________________

KENTUCKY POWER COMPANY

____

____

Attn:______________________________

Phone:______________________________

Facsimile:____________________________

Email:______________________________

AMERICAN ELECTRIC POWER SERVICE CORPORATION

____

____

Attn:______________________________

Phone:______________________________

Facsimile:____________________________

Email:______________________________

All notices shall be effective upon receipt, or upon such later date following receipt as set forth in the notice. Any Party may, by written notice to the other Parties, change the representative or the address to which such notices are to be sent.

ARTICLE TEN

LIMITATION OF LIABILITY

10.1 Notwithstanding anything in this Agreement to the contrary, neither of the Owners or Agent shall be liable under this Agreement for special, consequential, indirect, punitive or exemplary damages, or for lost profits or business interruption damages, whether arising by statute, in tort or contract or otherwise.

ARTICLE ELEVEN

DISPUTE RESOLUTION

11.1 If either Owner believes that a dispute has arisen as to the meaning or application of this Agreement, it shall present that matter to the Operating Committee in writing, and shall provide a copy of that writing to the other Owner.

11.2 If the Operating Committee is unable to reach agreement on any dispute within thirty (30) days after the dispute is presented to it, the matter shall be referred to the chief operating officers of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner involved in a dispute may invoke the arbitration provisions set forth in Section 11.3 at any time after the end of the thirty (30)day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

11.3 If the Owners are unable to resolve a dispute through the Operating Committee within thirty (30) days after the dispute is presented to the Operating Committee pursuant to Section 11.1, or through reference of the matter to the chief operating officers of the Owners pursuant to Section 11.2, either Owner may commence arbitration proceedings by providing written notice to the other Owner, detailing the nature of the dispute, designating the issue(s) to be arbitrated, identifying the provisions of this Agreement under which the dispute arose, and setting forth such Owner's proposed resolution of such dispute.

11.3.1 Within ten (10) days of the date of the notice of arbitration, a representative of each Owner shall meet for the purpose of selecting an arbitrator. If the Owner's representatives are unable to agree on an arbitrator within fifteen (15) days of the date of the notice of arbitration, then an arbitrator shall be selected in accordance with the procedures of the American Arbitration Association ("AAA"). Whether the arbitrator is selected by the Owner's representatives or in accordance with the procedures of the AAA, the arbitrator shall have the qualifications and experience in the occupation, profession, or discipline relevant to the subject matter of the dispute.

11.3.2 Any arbitration proceeding shall be subject to the Federal Arbitration Act, 9 U.S.C. §§ 1 *et seq.* (1994), as it may be amended, or any successor enactment thereto, and shall be conducted in accordance with the commercial arbitration rules of the AAA in effect on the date of the notice to the extent not inconsistent with the provisions of this Article.

11.3.3 The arbitrator shall be bound by the provisions of this Agreement where applicable, and shall have no authority to modify any terms and conditions of this Agreement in any manner. The arbitrator shall render a decision resolving the dispute in an equitable manner, and may determine that monetary damages are due to an Owner or may issue a directive that an Owner take certain actions or refrain from taking certain actions, but shall not be authorized to order any other form of relief; provided, however, that nothing in this Article shall preclude the arbitrator from rendering a decision that adopts the resolution of the dispute proposed by an Owner. Unless otherwise agreed to by the Owners, the arbitrator shall render a decision within one hundred twenty (120) days of appointment, and shall notify the Owners in writing of such decision and the reasons supporting such decision. The decision of the arbitrator shall be final and binding upon the Owners, and any award may be enforced in any court of competent jurisdiction.

11.3.4 The fees and expenses of the arbitrator shall be shared equally by the Owners, unless the arbitrator specifies a different allocation. All other expenses and costs of the arbitration proceeding shall be the responsibility of the Owner incurring such expenses and costs.

11.3.5 Unless otherwise agreed by the Owners, any arbitration proceedings shall be conducted in Columbus, Ohio.

11.3.6 Except as provided in this Article, the existence, contents, or results of any arbitration proceeding under this Article may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any agencies having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with an arbitration proceeding under pledge of confidentiality.

11.3.7 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through arbitration, as provided in this Article. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. § 791a *et seq.,* as amended from time to time, and any arbitration proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of the FERC proceedings. The arbitrator shall have no authority to modify, and shall be conclusively bound by, any decisions, findings of fact, or orders of FERC; provided, however, that to the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed to arbitration under this Article to secure such a remedy, subject to any FERC decisions, findings, or orders.

11.4 The procedures set forth in this Article shall be the exclusive means for resolving disputes arising under this Agreement and shall survive this Agreement to the extent necessary to resolve any disputes pertaining to this Agreement. Except as provided in Sections 11.3 and 11.3.7, neither Owner shall have the right to bring any dispute for resolution before a court, agency, or other entity having jurisdiction over this Agreement, unless both Owners agree in writing to such procedure.

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

APPALACHIAN POWER COMPANY

BY:______________________________

Title:________________________

KENTUCKY POWER COMPANY

BY:______________________________

Title:________________________

AMERICAN ELECTRIC POWER SERVICE CORPORATION

BY:______________________________

Title:________________________

KENTUCKY POWER COMPANY

RATE SCHEDULE NO. 303

Joint Tariff Common Name: "Mitchell Plant Operating Agreement"

Designated Filing Company: Appalachian Power Company (APCo)

Designated Filing Company Tariff Title: APCo Rate Schedules and Service Agreements Tariffs

Designated Filing Company Tariff Program: FPA (Cost Based)

Designated Filing Company Tariff Record Adopted by Reference (Record Content Description/Tariff Record Title): Rate Schedule No. 303, Mitchell Plant Operating Agreement.

No limitations: All versions of the agreement

Description of Tariff: Rate Schedule under which APCo, Kentucky Power Company, and American Electric Power Service Corporation (in an agency role) will operate and maintain the Mitchell Plant.

Attachment C

1. Certificate of Concurrence – AEP Generation Resources Inc. regarding the Sporn Plant Operating Agreement

2. Certificate of Concurrence – Kentucky Power Company regarding the Mitchell Plant Operating Agreement

CERTIFICATE OF CONCURRENCE

This is to certify that AEP Generation Resources Inc. (AEP Generation Resources), a Delaware corporation, assents to and concurs in the FERC FPA Electric Tariff described below, which Appalachian Power Company (APCo), the designated filing company, has filed in its "APCo Rate Schedules and Service Agreements Tariffs" database.

Name of Tariff Adopted by Reference: Sporn Plant Operating Agreement

APCO Tariff Record Adopted by Reference: Rate Schedule No. 302, Sporn Plant Operating Agreement

Description of Tariff: Rate Schedule under which APCo, AEP Generation Resources and American Electric Power Service Corporation (in an agency role) will operate and maintain the Sporn Plant.

By: /John C. Crespo/
John C. Crespo,
Deputy General Counsel – Regulatory Services
Dated: October 26, 2012

CERTIFICATE OF CONCURRENCE

This is to certify that Kentucky Power Company (KPCo), a Kentucky corporation, assents to and concurs in the FERC FPA Electric Tariff described below, which Appalachian Power Company (APCo), the designated filing company, has filed in its "APCo Rate Schedules and Service Agreements Tariffs" database.

Name of Tariff Adopted by Reference: Mitchell Plant Operating Agreement

APCO Tariff Record Adopted by Reference: Rate Schedule No. 303, Mitchell Plant Operating Agreement

Description of Tariff: Rate Schedule under which APCo, KPCo and American Electric Power Service Corporation (in an agency role) will operate and maintain the Mitchell Plant.

By: /John C. Crespo/
John C. Crespo,
Deputy General Counsel – Regulatory Services
Dated: October 26, 2012

REPRESENTATIVE LIST OF THE PRINCIPAL AGREEMENTS, UNDER WHICH OHIO POWER COMPANY HAS RIGHTS AND OBLIGATIONS, THAT WILL BE ASSUMED BY APPALACHIAN POWER COMPANY AND BE SUBJECT TO THE MITCHELL PLANT OPERATING AGREEMENT

Consolidation Coal Company and McElroy Coal Company	Coal
Southern Coal Sales Corporation	Coal
BPB West Virginia Inc (CertainTeed)	Gypsum Sale
Mississippi Lime Company	Hydrated Lime
O-N Minerals (Michigan) Company	Limestone
Solvay Chemicals, Inc.	Trona
Yara North American, Inc.	Urea
Bellaire Harbor Services, LLC	Urea Transportation
OPCO Statutory Trust 2004-A	Railcar Lease
First Security Trust Company of Nevada	Railcar Lease
Consolidation Coal Company and McElroy Coal Company	Construction, Operation, and Maintenance of Fly Ash Impoundment

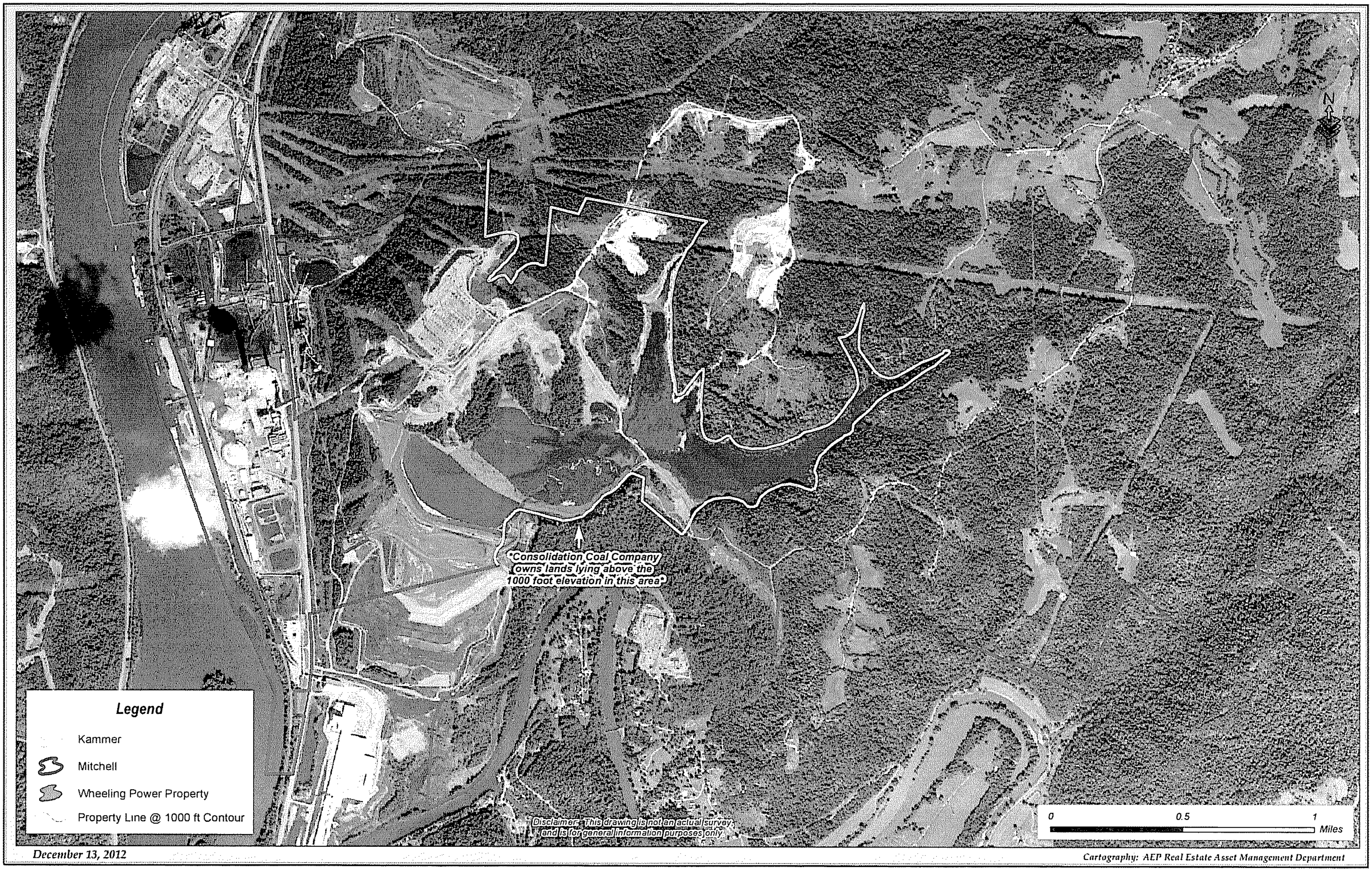


Exhibit 5
Page 1 of 3

CASE NO. 2012-00578

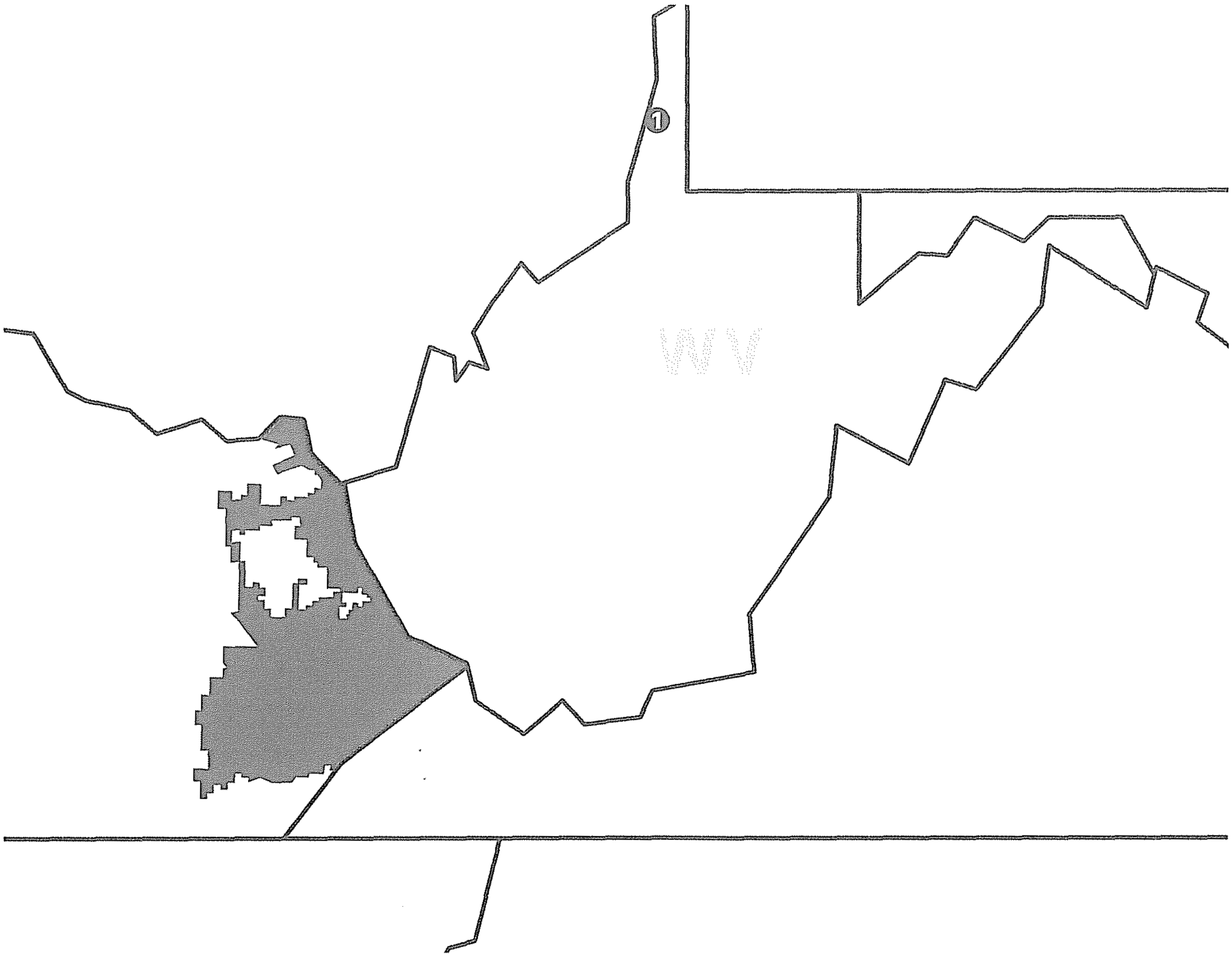
CONTAINS

LARGE OR OVERSIZED

MAP(S)

RECEIVED ON: DECEMBER 19, 2012

EXHIBIT 5
Page 2 or 3
REDACTED



Kentucky Power Company Retail Service Territory

Plant	Location
1 **Mitchell**	Moundsville, WV

Applicant's property in Kentucky includes the 1,060 megawatt Big Sandy Plant generating station located in Lawrence County, constructed in conformity with certificates of public convenience and necessity issued by this Commission; transmission lines and all appurtenant facilities; distribution lines; transmission and distribution stations and equipment; office buildings and equipment; storerooms for operation and maintenance materials; data processing equipment; metering equipment; communication equipment and motor vehicles. The total original cost and cost to Kentucky Power of Applicant's property is $1,792,590,038 as of September 30, 2012, which includes $5,987,400 of capital leases. The total original cost and cost to Kentucky Power also includes $50,792,842 of real property located in Kentucky, consisting of $20,292,063 of land and $30,500,779 of land rights.

Kentucky Power

Bonds Authorized and Outstanding

Issuing Company	Name of Bond	Issuance Date	Maturity	Amount	Coupon	Annual Interest	Secured/Unsecured
Kentucky Power	Senior Unsecured Note - Series D	6/10/2003	12/1/2032	75,000,000	5.63%	4,218,750	Unsecured
Kentucky Power	Senior Unsecured Note - Series E	9/5/2007	9/15/2017	325,000,000	6.00%	19,500,000	Unsecured
Kentucky Power	Senior Notes, Series A	6/18/2009	6/18/2021	40,000,000	7.25%	2,900,000	Unsecured
Kentucky Power	Senior Notes, Series B	6/18/2009	6/18/2029	30,000,000	8.03%	2,409,000	Unsecured
Kentucky Power	Senior Notes, Series C	6/18/2009	6/18/2039	60,000,000	8.13%	4,878,000	Unsecured

Notes Outstanding

Issuing Company	Name of Bond	Issuance Date	Maturity	Amount	Coupon	Annual Interest	Secured/Unsecured
Kentucky Power	Notes Payable to AEP	2/5/2004	6/1/2015	20,000,000	5.25%	1,050,000	Unsecured

Dividends

Year	Amounts	Total Outstanding Shares	Rate
2011	28,000,000	1,009,000	$27.75
2010	21,000,000	1,009,000	$20.81
2009	19,500,000	1,009,000	$19.33
2008	14,000,000	1,009,000	$13.88
2007	12,000,000	1,009,000	$11.89

Kentucky Power Company, Inc.
Statement on Income
Twelve Month Period Ending September 30, 2012

	12 Month Ending Sept 30, 2012
REVENUES	
Revenue - Retail Sales	512,643,428
Revenue - Transmission	8,119,950
Revenue - Sales for Resale	106,207,351
Revenue - Other Operating	13,727,734
Provision for Rate Refund	(1,635,430)
Revenue - Power Sales	402,568
TOTAL OPERATING REVENUES	639,465,601
FUEL EXPENSES	
Fuel for Electric Generation	137,845,763
Purchased Power	223,804,075
GROSS MARGIN	277,815,763
OPERATING EXPENSES	
Operational Expenses	57,987,904
Maintenance Expenses	45,836,275
Depreciation and Amortization	54,309,203
Taxes Other Than Income Taxes	13,055,485
TOTAL OPERATING EXPENSES	171,188,867
OPERATING INCOME	106,626,896
NON-OPERATING INCOME / (EXPENSES)	
Total Interest & Dividend Income	897,135
Interest & Dividend Carrying Charge	103,513
AFUDC	2,391,903
Total Interest Charges	(35,280,239)
INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	74,739,208
INCOME TAXES	
Federal Income Taxes	23,070,379
State Income Taxes	1,526,372
Total Income Taxes	24,596,751
NET INCOME	50,142,457

Kentucky Power Company, Inc.
Balance Sheet
As of September 30, 2012

	As of Sept 30, 2012
ASSETS	
Cash and Cash Equivalents	488,525
Accounts Receivable	26,615,003
Advances to Affiliates	33,736,476
Fuel, Materials and Supplies	65,289,313
Risk Management Contracts - Current	6,243,755
Margin Deposits	2,177,511
Prepayments and Other Current Assets	3,332,598
TOTAL CURRENT ASSETS	137,883,181
Electric Production	558,541,274
Electric Transmission	462,853,328
Electric Distribution	632,764,176
General Property, Plant and Equipment	64,145,262
Construction Work-in-Progress	74,285,998
TOTAL PROPERTY, PLANT and EQUIPMENT	1,792,590,038
Less: Accumulated Depreciation and Amortization	(600,481,537)
NET PROPERTY, PLANT and EQUIPMENT	1,192,108,501
Net Regulatory Assets	224,631,010
Long-Term Risk Management Assets	7,684,311
Other Non Current Assets	41,525,654
TOTAL OTHER NON-CURRENT ASSETS	273,840,975
TOTAL ASSETS	1,603,832,657
LIABILITIES	
Accounts Payable	65,866,190
Risk Management Liabilities	3,651,290
Accrued Taxes	18,185,232
Accrued Interest	6,210,934
Deposits - Customer and Collateral	22,538,942
Over-Recovered Fuel Costs - Current	2,128,455
Other Current Liabilities	21,168,230
TOTAL CURRENT LIABILITIES	139,749,273
Long-Term Debt - Affiliated	20,000,000
Long-Term Debt - Non Affiliated	530,000,000
Long-Term Debt - Premiums and Discounts Unamort	(819,731)
Long-Term Risk Management Liabilities	4,165,198
Deferred Income Taxes	351,443,519
Deferred Investment Tax Credits	425,261
Regulatory Liabilities and Deferred Credits	27,688,021
Asset Retirement Obligation	3,861,944
Employee Benefits and Pension Obligations	44,009,928
Other Non-Current Liabilities	6,671,720
TOTAL NON-CURRENT LIABILITIES	987,445,860
TOTAL LIABILITIES	1,127,195,133
COMMON SHAREHOLDERS' EQUITY	
Common Stock	50,450,000
Paid In Capital	238,750,000
Retained Earnings	187,803,715
Accumulated Other Comprehensive Income (Loss)	(366,191)
TOTAL SHAREHOLDERS' EQUITY	476,637,524
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	1,603,832,657

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

DIRECT TESTIMONY

OF

GREGORY G. PAULEY

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned Gregory G. Pauley, being duly sworn, deposes and says he is the President and COO of Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Gregory G Pauley

GREGORY G. PAULEY

COMMONWEALTH OF KENTUCKY)
) SS
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 12th day of December, 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

"Notary Public"
Judy K. Rosquist
State at Large, Kentucky
My Commission Expires on Jan. 23, 2013

DIRECT TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-______

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DIRECT TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Gregory G. Pauley. My position is President and Chief Operating Officer ("COO"), Kentucky Power Company ("Kentucky Power" or the "Company.") My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor's degree from Harding University in May 1973. I also graduated from management development programs at The Ohio State University and Virginia Polytechnic Institute and State University. I currently serve as President and COO of Kentucky Power (2010). From 2006-2010 I was Director – Public Policy for American Electric Power Service Corporation ("AEPSC") working on policy issues affecting the utility industry on a national level. Prior to that, I served as Kentucky Power's Governmental/Environmental Affairs manager from 2001-2006. I have also held positions at other American Electric Power Company, Inc. ("AEP") operating units in community affairs, manager of distribution services, human resources and accounting at various operations and generation facilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided supplemental testimony and testified in Case No. 2011-00042, *In the Matter of: The Application of AEP Kentucky Transmission Company, Inc. For A Certificate Of Public Convenience And Necessity To Operate As A Transmission Only Public Utility.*

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses five topics. First, I provide an overview of the testimony filed by the other Company witnesses in this proceeding. Next, I briefly describe my role as President and COO of Kentucky Power. Third, I provide an overview of the filings with the Federal Energy Regulatory Commission ("FERC") made on behalf of Kentucky Power and other AEP affiliates. Fourth, I describe the basis for and results of Kentucky Power's re-evaluation of the Big Sandy generating station in light of existing and pending environmental requirements. As part of this same topic, I also describe the Company's Application in this proceeding, as well as its plans for future filings. I also describe the process by which the decision to transfer a fifty percent interest in the Mitchell generating station was made and the timing of the transaction. Finally, I describe the Company's Application.

IV. WITNESSES TESTIFYING IN SUPPORT OF KENTUCKY POWER'S APPLICATION.

Q. IN ADDITION TO YOUR TESTIMONY WHAT PRE-FILED DIRECT TESTIMONY IS THE COMPANY FILING IN SUPPORT OF ITS APPLICATION?

A. In addition to my testimony, Kentucky Power presents the testimony of the following witnesses in support of this application:

Witness	Subject Matter
Mark A. Becker	Describes the Strategist® modeling application used by Kentucky Power.
Karl R. Bletzacker	Addresses the forecasts for natural gas prices, CO2 prices, coal prices, energy prices, and capacity values used in Company Witnesses Becker and Weaver's analyses and how the forecasts were derived.
Jeffery D. LaFleur	Describes the Mitchell generating station and its operational characteristics and compares the Big Sandy and Mitchell generating stations.
Karl A. McDermott	Provides a review of the proposed asset transfer for consistency with regulatory principles.
John M. McManus	Discusses the current and future environmental requirements affecting the Company's generating assets and the Mitchell generating station and planned compliance measures.
Scott C. Weaver	Describes the Kentucky Power generation resources modeled, the modeling process used, and the resulting analyses.
Ranie K. Wohnhas	Provides an overview of the accounting and financing activities associated with the proposed asset transfer; summarizes the estimated customer rate impact due to the transfer of the Mitchell generating station and the termination of the current Pool Agreement; explains the Company's request for the deferral of costs and establishment of a regulatory asset in connection with the Phase I investigation of the Big Sandy Unit 2 scrubber project.

V. MANAGEMENT OF KENTUCKY POWER

Q. WHAT ARE YOUR RESPONSIBILITIES AS PRESIDENT AND COO?

A. I am responsible for the safe, efficient and profitable operation of Kentucky Power, as well as oversight of customer services, community affairs and economic development activities. I also guide public policies in the legislative, regulatory and administrative arenas, and administer all phases of the business. Finally, I am responsible for making recommendations to, and collaborating with, the executive management of Kentucky Power's parent regarding major decisions affecting Kentucky Power.

Q. IN CARRYING OUT YOUR DUTIES FOR KENTUCKY POWER, DO YOU COLLABORATE WITH AEP EXECUTIVE MANAGEMENT AND THE MANAGEMENT OF THE OTHER AEP EAST OPERATING COMPANIES?

A. Yes. It is important to recognize that although I am the President and COO of Kentucky Power, the Company is a wholly-owned subsidiary of AEP. As a result, I am responsible to AEP for the operation and performance of Kentucky Power. In fulfilling my responsibilities, I work collaboratively with AEP executive management, the management of the other AEP East operating companies, including Charles R. Patton, President and COO of Appalachian Power Company ("APCo"), (collectively "AEP Management"), and AEPSC personnel to address those matters for which I have responsibility. I regularly meet with Robert P. Powers, Executive Vice President and COO of AEP, and have access to Nicholas K. Akins, President and Chief Executive Officer of AEP, when needed. This collaboration provides Kentucky Power access to valuable resources, but, as Mr. Akins has informed the Commission, I am in charge of the Company.

Q. WHO MADE THE DECISIONS ON BEHALF OF KENTUCKY POWER THAT ARE THE SUBJECT OF THIS APPLICATION?

A. In collaboration with AEP Management, I concluded that the transfer of an undivided fifty percent interest in the Mitchell generating station to Kentucky Power, the retirement of Big Sandy Unit 2, and the request to defer and create a regulatory asset in connection with the Big Sandy Unit 2 Phase I investigation expenditures were in the best interest of the Company and its customers.

VI. THE COMPANY'S FERC FILINGS

Q. PLEASE DESCRIBE THE FERC FILINGS MADE ON BEHALF OF KENTUCKY POWER AND OTHER AEP OPERATING COMPANIES?

A. Two sets of filings pertinent to this proceeding were made in 2012 on behalf of Kentucky Power and several other AEP operating companies. The first filings, made on February 10, 2012, were subsequently withdrawn on February 28, 2012 to permit the filing parties to consider how best to proceed in light of the February 23, 2012 Order of the Public Utilities Commission of Ohio ("Ohio Commission"). The February 23, 2012 Order withdrew the Ohio Commission's earlier approval of Ohio Power Company's ("OPCo") corporate separation plan.

Q. **WAS AN AMENDED CORPORATE SEPARATION PLAN SUBSEQUENTLY FILED WITH THE OHIO COMMISSION?**

A. Yes, and on October 17, 2012 the Ohio Commission approved the amended plan. Under the approved corporate separation plan, OPCo will transfer its generation-related assets to an unregulated affiliate. Subsequently, the unregulated affiliate will transfer certain of these assets, including, the Mitchell generating station, to Kentucky Power and APCo.

Q. **FOLLOWING THE OHIO COMMISSION'S OCTOBER 17, 2012 APPROVAL OF OPCO'S AMENDED CORPORATE SEPARATION PLAN, WERE NEW FERC FILINGS MADE ON BEHALF OF KENTUCKY POWER AND CERTAIN OF ITS AFFILIATED COMPANIES?**

A. Yes, a second set of FERC filings was made on October 31, 2012. The most pertinent of these filings to my testimony is the application for the necessary FERC authorization pursuant to Section 203 of the Federal Power Act to transfer to Kentucky Power an undivided fifty percent interest in the Mitchell generating station currently owned by OPCo. The application also provides for the transfer of the remaining fifty percent interest in the Mitchell generating station to APCo.

Q. **WHAT ARE THE REASONS FOR THE PROPOSED TRANSFER OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION TO KENTUCKY POWER?**

A. The transfer addresses the long term capacity and energy needs of the Company's customers in the least cost manner considering the termination of the

Interconnection Agreement ("Pool Agreement") effective January 1, 2014, as well as the results of the re-evaluation of the continued operation of Big Sandy Unit 2 in light of the impending environmental requirements. These environmental requirements are discussed by Company Witness McManus in his testimony.

Q. WHAT IS THE POOL AGREEMENT THAT WILL BE TERMINATED EFFECTIVE JANUARY 1, 2014?

A. Kentucky Power is a party to an agreement dated July 6, 1951, as amended, by and between APCo, Kentucky Power, Indiana Michigan Power Company ("I&M"), and OPCo. Under the Pool Agreement, Kentucky Power and the other parties to the agreement function as an integrated system by jointly satisfying their combined needs for capacity and energy. On December 17, 2010, Kentucky Power and the then four other parties[1] to the Pool Agreement gave notice in conformity with the three-year notice requirements of the Pool Agreement of the termination of that agreement effective January 1, 2014.

Q. WHY DID KENTUCKY POWER AND THE OTHER MEMBERS OF THE POOL AGREEMENT ELECT TO TERMINATE THE AGREEMENT?

A. Because of cumulative structural and regulatory changes in the electric utility industry, the Pool Agreement no longer functions as intended by the parties to the agreement. Evolving environmental regulations, differing renewable energy portfolio standards among the states where the Pool Agreement members operate, the introduction of open access to transmission facilities, the advent of regional transmission organizations, a movement in some jurisdictions toward industry

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[1] Columbus Southern Power Company, which had been a party of the agreement, subsequently merged with Ohio Power Company on December 31, 2011.

deregulation, an increased emphasis on demand-side management, and expanded competition have made it no longer feasible for the Pool Agreement members to operate in the unified and coordinated fashion provided for by the Pool Agreement. In particular, OPCo, which is a surplus member of the Pool Agreement, and whose generation resources are available to meet Kentucky Power's PJM capacity requirements along with the energy needs of its customers, is required by Ohio law to divest itself of its generating facilities. As a result, OPCo's continuing participation in the Pool Agreement has become impracticable.[2] The basis for the termination of the Pool Agreement is described in greater detail in the October 31, 2012 Section 205 filing at FERC made on behalf of Kentucky Power and other AEP companies.

Q. **YOU INDICATED EARLIER THAT A SECOND BASIS FOR TRANSFER OF A FIFTY PERCENT UNDIVIDED INTEREST IN THE MITCHELL GENERATING STATION TO KENTUCKY POWER WAS THE RESULT OF THE RE-EVALUATION OF THE CONTINUED OPERATION OF BIG SANDY UNIT 2 IN LIGHT OF IMPENDING ENVIRONMENTAL REQUIREMENTS. WHAT WAS THAT RESULT?**

A. Because of impending environmental regulations, the 800 MW Big Sandy Unit 2 cannot continue to operate without extensive additional environmental controls. As a result, and as described in detail in Company Witness Weaver's testimony, the Company determined that the transfer of an undivided fifty percent interest in the Mitchell generating station, which will close on or about December 31, 2013,

[2] Significant changes since its inception in 1994 in environmental rules and the markets associated with Title IV SO_2 emissions allowances similarly eliminated the need for the Interim Allowance Agreement.

and the retirement of Big Sandy Unit 2 by June 2015, would be the least cost long-term option for the Company. The transferred interest in the Mitchell generating station will provide average annual base load capacity of 780 MW and will effectively replace Big Sandy Unit 2.

Q. WERE ANY FERC FILINGS OTHER THAN THE SECTION 203 MITCHELL TRANSFER FILINGS MADE ON BEHALF OF KENTUCKY POWER AND OTHER AEP OPERATING COMPANIES ON OCTOBER 31, 2012?

A. Yes. In addition to the Section 203 Mitchell generating station transfer application, three agreements were filed at FERC on behalf of the Company and other AEP Operating Companies: a Bridge Agreement, a Power Coordination Agreement, and the Mitchell Plant Operating Agreement. Although state commission approval is not required for these three agreements, which upon acceptance will become FERC-filed rate schedules under Section 205 of the Federal Power Act, the agreements are described in the Application to aid the Commission's understanding of the transaction. Company Witness Wohnhas also describes the agreements in his testimony.

VII. THE RE-EVALUTION OF BIG SANDY GENERATING STATION AND THE TRANSFER OF A FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION TO KENTUCKY POWER

A. The Company's Re-Evaluation Of The Big Sandy Plant.

Q. WHY DID THE COMPANY DECIDE TO RE-EVALUATE THE CONTINUED OPERATION OF BIG SANDY UNITS 1 AND 2?

A. On December 5, 2011, Kentucky Power filed its application in Case No. 2011-00401,[3] seeking Commission approval to retrofit Big Sandy Unit 2 with a dry flue gas desulfurization ("DFGD") unit. Because of developments subsequent to the Company's filing of its application in Case No. 2011-00401, I, in collaboration with AEP Management, determined Kentucky Power should re-examine the alternatives by which the Company could meet its obligations under the 2007 AEP NSR Consent Decree,[4] the Clean Air Interstate Rule, the Mercury and Air Toxic Standards ("MATS") Rule, and other environmental standards. On May 30, 2012, Kentucky Power filed a motion seeking leave to withdraw its application without prejudice. The Commission granted the motion by Order dated May 31, 2012. As a consequence, the Commission did not rule on the Company's application in Case No. 2011-00401.

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[3] *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 Granting Of A Certificate Of Public Convenience And Necessity For The Construction And Acquisition Of Related Facilities.*

[4] The Company's obligations under the 2007 AEP NSR Consent Decree are described more fully in the testimony of Company Witness McManus.

Q. WHAT WERE THE DEVELOPMENTS AFTER THE COMPANY FILED CASE NO. 2011-00401 THAT LED THE COMPANY TO WITHDRAW ITS APPLICATION IN THAT CASE AND RE-EVALUATE THE DISPOSITION OF THE BIG SANDY PLANT?

A. There was a confluence of several events during the pendency of the application in Case No. 2011-00401 that made re-evaluation prudent. At the time of the analysis that supported the application in Case No. 2011-00401, the Mitchell generating station was not available for transfer to Kentucky Power. Subsequent to the filing, an undivided twenty percent interest in the Mitchell generating station became available to Kentucky Power for the purpose of replacing Pool Agreement-based generation. Soon thereafter, and subsequent to the withdrawal of the February 10, 2012 FERC filings, Kentucky Power, in collaboration with AEP Management, including Charles R. Patton, President and COO of APCo, and the other affected operating companies, began to re-examine the earlier decision to transfer twenty percent of the Mitchell generating station to Kentucky Power. This re-examination led to the possibility that more than twenty percent of the Mitchell generating station might be available to Kentucky Power.

Against this background, and in an effort to limit the rate increase that would be required to meet Kentucky Power's long-term generation needs, the application in Case No. 2011-00401 was withdrawn so that the Company could re-evaluate the disposition of the Big Sandy generating station.

Q. WHAT STEPS DID KENTUCKY POWER UNDERTAKE TO RE-EVALUATE ITS ALTERNATIVES WITH RESPECT TO BOTH BIG SANDY UNITS IN LIGHT OF EXISTING AND FUTURE ENVIRONMENTAL REQUIREMENTS?

A. In the time between the withdrawal of the Company's application to retrofit Big Sandy Unit 2 with a DFGD unit in May 2012 and the filing of this Application, a detailed re-evaluation of Big Sandy generating station was performed. Over the intervening months, and with the assistance of Company Witness Weaver's group, the Company examined eleven unique variations involving six discrete options assumed to be available to Kentucky Power to address the unit disposition decisions facing both Big Sandy Units 1 and 2. The Company performed this analysis in light of the availability of an ownership interest in the Mitchell generating station, as well as the major known and emerging federal rulemaking facing Kentucky Power's coal-fired generating assets. In undertaking these evaluations, the Company employed proprietary long-term resource optimization tools and examined a 30-year economic study period (2014 through 2040) to determine the relative least cost alternative. Company Witness Weaver addresses these analyses in his testimony.

B. The Mitchell Plant And Its Transfer.

Q. PLEASE DESCRIBE THE MITCHELL PLANT AND THE INTEREST IN THE PLANT TO BE TRANSFERRED TO KENTUCKY POWER.

A. The Company proposes to acquire at net book value, as of December 31, 2013, an undivided fifty percent interest (projected to be $536 million) in each of the two units of the Mitchell generating station, along with related assets and liabilities. The Mitchell generating station currently is owned by OPCo and was placed in service in 1971. It is a two-unit coal-fired power plant located south of Moundsville, West Virginia. Unit 1 of the Mitchell generating station has an average annual capacity rating of 770 MW; Unit 2 has an average annual capacity rating of 790 MW. The total average annual capacity to be transferred to Kentucky Power is 780 MW. Both units are equipped with flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems and are expected to meet the requirements of the 2007 AEP NSR Consent Decree, the Clean Air Interstate Rule, the MATS Rule, and other environmental standards at the time of their January 1, 2014 proposed transfer to the Company.

Company Witness LaFleur provides more detail concerning the Mitchell generating station in his testimony.

Q. **WHY IS A FIFTY PERCENT INTEREST IN EACH OF MITCHELL UNITS BEING TRANSFERRED TO KENTUCKY POWER INSTEAD OF 100% IN ONE OF THE NEARLY EQUALLY-SIZED MITCHELL UNITS?**

A. By diversifying the to-be-transferred generation between two units, Kentucky Power will have access to one-half of the available Mitchell generation even if one of the two units is required to be taken offline.

Q. **TO WHOM WILL THE REMAINING FIFTY PERCENT UNDIVIDED INTEREST IN MITCHELL UNIT 1 AND UNIT 2 BE TRANSFERRED?**

A. That portion of Unit 1 and Unit 2 of the Mitchell generating station not transferred to Kentucky Power will be transferred to APCo. APCo also will operate both units of the Mitchell generating station pursuant to the terms of the Mitchell Plant Operating Agreement among APCo, Kentucky Power, and AEPSC as agent.

C. The Basis For The Transfer Of A Fifty Percent Interest In The Mitchell Generating Station to Kentucky Power .

Q. **WHY IS OPCO TRANSFERRING THE MITCHELL GENERATING STATION?**

A. Under Section 4928.17 of the Ohio Revised Code and the October 17, 2012 Ohio Commission Order approving OPCo's structural corporate separation plan, OPCo is required to separate its generation and marketing businesses from its transmission and distribution businesses. As a result, on October 31, 2012 OPCo sought FERC approval pursuant to Section 203 of the Federal Power Act to transfer its generation-related assets, including the Mitchell generating station, to an unregulated affiliate, with closing on or about December 31, 2013.

Q. WHY IS THE COMPANY PROPOSING TO RETIRE BIG SANDY UNIT 2?

A. If Big Sandy Unit 2 is to run past May 2015, extensive investments in environmental control facilities will be required. Although Big Sandy Unit 2 is sufficiently large to support the environmental investment required for it to continue to operate beyond May 2015, Company Witness Weaver's analysis indicates that doing so would not be the least cost option when compared to acquiring fifty percent of the Mitchell generating station.

Q. WHY IS KENTUCKY POWER PROPOSING TO ACQUIRE A FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION?

A. Unless Big Sandy Unit 2 is retrofitted with extensive and costly environmental controls, including a DFGD unit, the Company will be required to retire Big Sandy Unit 2 by June 2015. As the testimony of Company Witness Weaver indicates, the transfer to Kentucky Power of an undivided fifty percent interest in the Mitchell generating station is the least cost option among the alternatives studied for meeting the Company's long-term capacity and energy requirements. The fifty percent interest in the Mitchell generating station will permit Kentucky Power to satisfy its capacity requirements, and to provide base load generation to meet Kentucky Power's customers' energy needs following the termination of the Pool Agreement effective January 1, 2014, and in the absence of Big Sandy Unit 2.

Q. WHY IS THE MITCHELL GENERATING STATION THE APPROPRIATE ASSET FOR COMPARISON TO THE OTHER OPTIONS AVAILABLE TO KENTUCKY POWER?

A. The Mitchell generating station is appropriate based on a number of qualitative factors. Among the factors are:

- The Mitchell units are base load units like the Big Sandy unit they will replace. The units are of the same design and approximate nominal generating capacity as Big Sandy Unit 2.
- The Mitchell units are environmentally controlled. Both Mitchell units are equipped with FGD and SCR systems, and are expected to meet obligations under the 2007 AEP NSR Consent Decree, the Clean Air Interstate Rule, and the MATS Rule.
- The two Mitchell units are appropriately sized for Kentucky Power's needs. By owning a fifty percent interest in the two units the Company is adding increased reliability to its generation by replacing Big Sandy Unit 2 with a share of two units. In addition, the Mitchell units were built subsequent to Big Sandy Unit 2 using the same proven design utilized at Big Sandy Unit 2. The two Mitchell units have provided reliable capacity and energy to Kentucky Power through the Pool Agreement.
- The fifty percent interest in the Mitchell generating station will be transferred at net book value, which is an appropriate means of pricing the transfer.

Q. DID KENTUCKY POWER ISSUE A REQUEST FOR PROPOSALS ("RFP") IN REVIEWING ALTERNATIVES TO RETROFITTING BIG SANDY UNIT 2?

A. No, it did not.

Q. PLEASE EXPLAIN THE BASIS FOR THE DECISION NOT TO ISSUE AN RFP IN CONNECTION WITH THE DETERMINATION TO TRANSFER TO KENTUCKY POWER THE UNDIVIDED FIFTY PERCENT UNDIVIDED INTEREST IN THE MITCHELL GENERATING STATION.

A. As indicated by Company Witnesses McDermott and Weaver in their testimonies, it was unnecessary for Kentucky Power to conduct a full-requirement RFP because Company Witness Weaver's analysis approximated the price bids an RFP would have elicited. Indeed, Company Witness Weaver's analysis employed the same techniques that potential bidders in an RFP process would use to evaluate and price their offers.

D. <u>The Transfer Transaction.</u>

Q. HOW WILL THE UNDIVIDED FIFTY PERCENT INTEREST IN MITCHELL UNIT 1 AND UNIT 2 BE TRANSFERRED TO KENTUCKY POWER?

A. The fifty percent interest in the Mitchell generating station, along with appurtenant interconnection facilities and related assets and liabilities, will be transferred from AEP Generation Resources Inc. ("AEP Generation Resources") to Kentucky Power through a series of near-simultaneous transactions.

Immediately prior to its merger with Kentucky Power, a fifty percent interest in the Mitchell generating station, along with the interconnection facilities and related liabilities and assets, will temporarily be held by NEWCO Kentucky, which is a yet-to-be-formed wholly-owned indirect subsidiary of AEP. NEWCO Kentucky will then immediately merge with Kentucky Power and Kentucky Power will be the surviving entity. It is through this final step, the only one to which Kentucky Power is a party, that the fifty percent undivided interest in the Mitchell generating station will be transferred to Kentucky Power. These steps will all occur on or about December 31, 2013, and are designed to ensure that the transfer of the Mitchell generating station will be accomplished without incurring unintended tax consequences.

A graphical representation of these near-simultaneous transactions is attached to Company Witness Wohnhas' testimony as Exhibit RKW-1.

Q. WHY WILL THE FIFTY PERCENT UNDIVIDED INTEREST IN THE MITCHELL GENERATING STATION BE TRANSFERRED TO KENTUCKY POWER ON OR ABOUT DECEMBER 31, 2013 WHEN BIG SANDY UNIT 2 IS EXPECTED TO CONTINUE TO OPERATE UNTIL JUNE 2015?

A. The transfer of the Mitchell generating station is timed to coincide with the termination of the Pool Agreement and the corporate separation of OPCo. The Mitchell generating station may not be available in 2015 to be transferred to Kentucky Power. It is unreasonable to expect that a valuable asset such as the Mitchell generating station would be held in waiting by AEP Generation

Resources for the benefit of Kentucky Power for the approximately seventeen months between January 1, 2014 and June 2015.

VIII. THE COMPANY'S APPLICATION.

Q. PLEASE DESCRIBE THE COMPANY'S APPLICATION.

A. The application presents the results of Kentucky Power's re-evaluation of alternatives to meet the Company's obligations with respect to Big Sandy Unit 2 under the Consent Decree, the Clean Air Interstate Rule, the MATS Rule, and other environmental standards. In particular, the application describes the plans to transfer an undivided fifty percent interest in the Mitchell generating station, along with the associated assets and liabilities to Kentucky Power and retire Big Sandy Unit 2.

Q. WHAT RELIEF IS BEING SOUGHT IN THE APPLICATION?

A. Kentucky Power is seeking:

(a) a certificate of public convenience and necessity pursuant to KRS 278.020(1) authorizing the transfer to the Company of a fifty percent interest in the Mitchell generating station;

(b) approval pursuant to KRS 278.300 for the assumption of indebtedness in connection with the transfer of the fifty percent undivided interest in the Mitchell generating station to the Company;

(c) a declaratory ruling that the merger of Kentucky Power and NEWCO Kentucky, by which AEP Generation Resources will contribute the fifty percent interest in the Mitchell generating station to Kentucky Power, is not a change of control requiring approval pursuant to KRS 278.020(5) or KRS 278.020(6);

(d) authorization for Kentucky Power, in accordance with Financial Accounting Standards Board Accounting Standards Codification 980-340-25-1, to accumulate and defer for review and recovery in its next base rate proceeding the approximately $30 million of costs incurred from 2004 through present in connection with the Company's efforts to meet Federal Clean Air Act and other environmental requirements with respect to Big Sandy Unit 2 .

Q. **IS THE DISPOSITION OF BIG SANDY UNIT 1 THE SUBJECT OF THIS APPLICATION?**

A. No. Kentucky Power intends to issue a competitive solicitation in the first part of 2013 for approximately 250 MW of long-term capacity and energy. In addition, the Company expects to explore converting Big Sandy Unit 1 to burn natural gas in its boiler in lieu of coal. The Company will evaluate the results of the solicitation and study of a Big Sandy Unit 1 conversion and return to the Commission in 2013 to seek all necessary approvals.

Q. **IS THE COMPANY REQUESTING AN ORDER IN THIS PROCEEDING BY A PARTICULAR DATE?**

A. Yes. Because of the time required to consummate the transaction after all approvals are received, Kentucky Power requests that the Commission issue its order granting the requested relief no later than June 30, 2013.

Q. **DOES KENTUCKY POWER ANTICIPATE FILING A SECOND APPLICATION IN CONNECTION WITH THE TRANSFER OF A FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION?**

A. The Company anticipates a second filing only if the Commission determines that the merger of NEWCO Kentucky and Kentucky Power is subject to review under KRS 278.020(5) or KRS 278.020(6), or, if the Commission is unable to determine by February 15, 2013 whether approval under KRS 278.020(5) or KRS 278.020(6) is required in connection with the merger. In that case, Kentucky Power plans to file an application seeking approval for the merger under KRS

278.020(5) or KRS 278.020(6), or both, as the case may be. Kentucky Power will also request that this second application be consolidated with this proceeding.

Q. **WHY IS THE TRANSACTION POSSIBLY THE SUBJECT OF TWO SEPARATE APPLICATIONS?**

A. The ultimate relief being sought by the Company, the Commission's approval of the transfer of an undivided fifty percent interest in the Mitchell generating station to Kentucky Power, is an important development for Kentucky Power and its customers, and should be fully reviewed. Although it is the Company's position that no approval is required under KRS 278.020(5) or KRS 278.020(6) in connection with the transfer to Kentucky Power of a fifty percent interest in the Mitchell generating station through the merger of NEWCO Kentucky and Kentucky Power, Kentucky Power is requesting a declaratory ruling in this application confirming the Company's understanding. If the Company also asked for approval of the merger under KRS 278.020(6) as part of this proceeding, the Commission's decision on the merger would be due no later than 120 days after the date the Company's application in this proceeding is filed. The Company believes that the 120-day period for review of applications under KRS 278.020(6) may not provide adequate time for the review of the transaction. Bifurcating the application in the fashion proposed, if necessary, provides additional time for review.

Q. **DOES THE COMPANY ANTICIPATE FILING ADDITIONAL APPLICATIONS FOLLOWING ITS RE-EVALUATION OF BIG SANDY UNIT 1?**

A. Yes. As I indicated earlier, the Company will return to the Commission in 2013 to seek any necessary approvals when the Company's review of Big Sandy Unit 1 alternatives is complete. In addition, the Company anticipates seeking authority to issue debt within six months of the transfer to refinance the AEP inter-company note assumed in connection with the transfer to Kentucky Power of a fifty percent interest in the Mitchell generating station.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

DIRECT TESTIMONY OF

MARK A. BECKER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Mark A. Becker being duly sworn, deposes and says he is the Manager, Resource Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Mark A. Becker

MARK A. BECKER

STATE OF OKLAHOMA)) CASE NO. 2012-
COUNTY OF TULSA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark A. Becker this the 5 day of December, 2012.

Angela Brown

Notary Public

My Commission Expires: 2-27-14

DIRECT TESTIMONY OF
MARK A. BECKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012- _____

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DIRECT TESTIMONY OF
MARK A. BECKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Mark A. Becker. I am employed by the American Electric Power Service Corporation ("AEPSC") as Manager - Resource Planning. My business address is 212 E. 6th Street, Tulsa, Oklahoma.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Arkansas in 1983.

I am currently employed by AEPSC as Manager - Resource Planning. I have over 28 years of experience working for municipal and investor-owned electric utilities and energy trading companies. The majority of my experience, approximately 25 years, has been related to performing utility resource planning and operational analysis functions using the proprietary long-term resource optimization software known as Strategist®. One of my responsibilities at Florida Power and Light ("FPL") in 1983-1985, was to develop the first PROSCREEN® (predecessor to Strategist®) database of the FPL system. While developing FPL's PROSCREEN® database, I also beta tested several modules of the PROSCREEN® software for its developer, New Energy Associates. In addition, I also participated in the beta testing of EPRI's Electric Generation Expansion Analysis System ("EGEAS") while at FPL. A summary of my work experience is attached as MAB- Exhibit 1.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER - RESOURCE PLANNING?

A. My primary responsibility is to oversee and perform various Strategist® analyses related to the development of Integrated Resource Plans and the evaluation of unit disposition alternatives for AEP's regulated operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided rebuttal testimony in Case No. 2011-00401, which included the Company's 2011 Environmental Compliance Plan, and request for approval of a Certificate of Public Convenience and Necessity for the construction and acquisition of related facilities.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the Strategist® modeling application and utilized by Kentucky Power Company ("KPCo", or "the Company").

IV. STRATEGIST®MODELING APPLICATION

Q. PLEASE DESCRIBE THE STRATEGIST® MODELING APPLICATION.

A. Strategist® is a proprietary software tool under lease to AEP from Ventyx, a utility industry software and data-services provider. Strategist® is a long-term resource optimization model and has been utilized by the utility industry for over

30 years. The Company utilizes three of the Strategist® simulation modules when performing resource planning related analyses (e.g. unit disposition analyses, Integrated Resource Planning, etc.) MAB- Exhibit 2 shows the flow of input and output data that is transferred between the various modules. These modules are described below:

(1) The Load Forecast Adjustment ("LFA") module allows the user to simulate a utility's peak and energy requirements, as well as model any demand-side management programs that may impact those peak and energy requirements. This peak and energy requirement data is transferred from the LFA to the Generation and Fuel ("GAF") module.

(2) The GAF module uses a probabilistic generating unit dispatch algorithm to simulate the dispatch of a utility's generating resources and estimate the energy production and related variable cost incurred in meeting those peak and energy requirements. The probabilistic generating unit dispatch algorithm used in the GAF module is similar to the one used in its sister tool PROMOD®. In addition to dispatching a utility's generating resources, the GAF module simulates a utility's ability to import (purchase) or export (sell) energy from or into a "market" when it is economic to do so based on user-defined long-term market commodity pricing profiles.

(3) The PROVIEW resource optimization module's dynamic programming optimization algorithm is used to create a "decision tree" of alternatives to determine the utility's optimal overall capacity and energy resource plan over the user-defined study period (e.g. 30 years). In developing a "decision tree",

PROVIEW determines the recovery of each resource's capital cost and energy production cost in order to determine an overall revenue requirement for that resource and the plan as a whole.

Q. PLEASE DESCRIBE THE PROCESS THAT PROVIEW'S DYNAMIC PROGRAMMING ALGORITHM USES TO CREATE A UTILITY'S OPTIMAL RESOURCE PLAN.

A. In general, PROVIEW's dynamic programming algorithm performs the following steps in determining a utility's optimal resource plan.

1. In each year of the study period, PROVIEW creates all of the possible combinations of resource alternatives defined by the user.
2. PROVIEW then determines if each of those combinations meets a user defined reliability constraint (e.g. minimum reserve margin) in that year.
3. For those combinations meeting the reliability constraint, PROVIEW uses the GAF module to determine the energy production cost for that particular combination in that year. PROVIEW also calculates the recovery of the capital cost (e.g. annual levelized fixed cost) for that combination. The energy production cost and capital cost recovery are combined to create a total "G(eneration)" cost-of-service, or revenue requirement for that combination. If a combination does not meet the reliability constraint, it is eliminated from further consideration.
4. PROVIEW moves to the next year of the study period and repeats Steps 1 through 3 building the next branch of the decision tree. In the final year of the study period, PROVIEW determines the cumulative present worth

(CPW) of revenue requirements for each branch of the decision tree. PROVIEW then uses that CPW to determine which branch of the decision tree is the least-cost optimal resource plan for the utility over the user-defined study period.

Q. HAVE YOU PROVIDED AN ILLUSTRATIVE EXAMPLE OF THE STEPS PROVIEW USES TO CREATE A UTILITY'S OPTIMAL RESOURCE PLAN?

Yes. MAB- Exhibit 3 provides an illustrative example of the steps outlined above and the process PROVIEW uses to develop the optimal resource plan.

Q. PLEASE DESCRIBE THE ILLUSTRATIVE EXAMPLE SHOWN IN MAB- EXHIBIT 3.

A. In the example illustrated in MAB- Exhibit 3, the utility needs capacity in each year of a 3-year study period. In order to meet its reliability constraint, simple-cycle combustion turbine ("CT") and combined-cycle combustion turbine ("CC") capacity can be installed to meet those reliability targets. In Year 1, two possible combinations exist, the addition of a CT and the addition of a CC. Strategist® then separately computes the revenue requirement for the system containing either the CT or CC alternative. In Year 2, CT or CC capacity can be added to those two possible Year 1 combinations. However, in Year 2 the combination that adds a CT in Year 1 and a CT in Year 2 does not meet the reliability criteria and is discarded. The combination that adds a CC in Year 1 and a CT in Year 2 is also discarded due to Bellman's Principle of Optimality. Bellman's Principle is used to help reduce the number of alternative combinations considered, but yet still arrive at the optimal plan. This principle states that if two combinations contain the same alternatives at a given point in time, the combination (Year 1 CC + Year 2 CT) with the greatest cost at that point will be discarded and the combination (Year 1 CT + Year 2 CC) with the lowest cost will continue to be considered. In Year 3, additional CTs and CCs are added to those combinations created in Year 2. In Year 3, the final CPW of each combination is compared and the combination with the lowest CPW is considered to be the optimal plan. In this example, the combination that adds a CT in Year 1, a CC in Year 2 and a CT in Year 3 is considered to be the optimal plan because it has the lowest Year 3 CPW ($7) of all of the resource combinations.

Q. HAS THE STRATEGIST® APPLICATION BEEN UTILIZED BY THE COMPANY IN CASES BEFORE THIS COMMISSION?

A. Yes. Strategist® was used to perform the economic evaluation of the Big Sandy emission retrofit and other alternative options in Case No. 2011-00401. In addition, Strategist® was used to develop the "Resource Forecast" section included in Kentucky Power Company's most recent Integrated Resource Planning filing (Case No. 2009-00339).[1] Additionally, information generated using the Ventyx-PROMOD® "sister tool" described above, is provided by the Company in connection with the Commission's two-year review of the Company's Fuel Adjustment Clause.[2]

Further, Strategist® has been utilized by other AEP operating companies in recent years to support resource planning options submitted to utility

[1] See page 4-13 and 4-14 of that filing for a description of how Strategist® was utilized in KPCO's 2009 IRP.
[2] Most recently in Case No. 2010-00490.

commissions in the states of Oklahoma, Arkansas, Texas, Louisiana, Indiana, West Virginia and Virginia.

Q. YOUR TESTIMONY DESCRIBES THAT THE STRATEGIST® MODEL CREATES A PROXY FOR A LONG-TERM "G(ENERATION)" REVENUE REQUIREMENT. WHAT ARE THE MAJOR MODEL OUTPUTS THAT ARE USED TO DETERMINE THAT?

A. The major model outputs include:

The Consumed Fuel Costs (+ attendant variable production costs) for all (KPCo) units, including the purchase entitlement share of Rockport Units 1&2 and any transferred capacity (i.e. Mitchell 1&2)

Plus: Replacement Cost of Emission Allowances Consumed for all KPCo units and KPCO's share of Rockport Units 1&2 and any transferred capacity

Plus: <Sales> / Purchases of Market Energy for KPCo

Plus: <Sales> / Purchases of Contracted Capacity and Energy for KPCo

Plus: Fixed Levelized Carrying Charges of *Incremental* KPCo Generation Capital Investment *

Plus: Fixed O&M for all KPCo units

= Total Annual Revenue Requirement

* Any on-going 'return-on' *and* 'return-of' (depreciation/amortization) capital associated with pre-existing generation plant-in-service are ignored, as such costs/revenue requirements would be assumed to be consistent across all alternatives analyzed.

These annual cost streams are then "present-valued" using KPCO's-weighted average cost of capital as of December 31, 2011, to create a CPW of (incremental) "G" revenue requirements.

Q. SPECIFICALLY, HOW DID THE STRATEGIST® MODEL PERFORM THE KENTUCKY POWER UNIT DISPOSITION ANALYSES ("UD ANALYSES") PREVIOUSLY SUMMARIZED?

A. The model incorporated the identified Kentucky Power unit disposition alternatives—and timing—as described in Company Witness Weaver's testimony, the long-term commodity pricing forecasts prepared by Company Witness Bletzacker's Fundamentals Analysis group, and the forecasted load for the Company. For instance, under the first alternative listed in TABLE 1 (Option #1A) of Company Witness Weaver's testimony, Big Sandy Unit 2 was assumed to be retrofitted with DFGD by approximately June, 2017, while Big Sandy Unit 1 was assumed to be retired by June, 2015.[3] In addition, 20% (312 MW) of Ohio Power Company's ownership interest in Mitchell units 1&2 were assumed to be transferred to KPCO. The model was set up to reflect these resources and their associated necessary input parameters, such as: capital cost to retrofit, net book value transfer cost for the Mitchell capacity, attendant fuel switch cost data, modifications to variable and fixed O&M, etc. The model utilized the (capacity) resource planning aspect of the tool to determine the capacity needs for KPCo for this option through the long-term (30-year) study period.

Q. SO YOU ARE INDICATING THAT IN ADDITION TO THE "DIRECT" COSTS ATTRIBUTABLE TO ANY UNIQUE BIG SANDY UNIT DISPOSITION OPTION, THE MODEL ALSO FACTORS IN THE IMPLICATIONS AN OPTION WOULD HAVE ON KENTUCKY POWER'S FUTURE RESOURCE REQUIREMENTS?

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[3] Although the MATS rulemaking implementation date is April (16), 2015, it is expected that these units will be able to operate an additional 45 days through the PJM 2014/15 capacity "planning year" (*i.e.*, thru May 31, 2015) after joint consultations with PJM working with several state environmental agencies responsible for overseeing the implementation of MATS.

A. Yes. This is an important aspect of this modeling process. Given that unit disposition options may not be of either equal "size" or "term", it is critical that their effects on Kentucky Power's future capacity (and energy) resource needs be determined. The Strategist® model's dynamic resource optimization capabilities allows such a holistic, overall resource planning view.

For example in a hypothetical UD Analyses, "Alternative A" proposes to retire a coal unit with 800 MW of generating capability producing 5,200 GWh of energy in any given year (roughly 75 percent average capacity factor), and replace that capacity with a smaller 650-MW gas-fired generating unit that generates only 2,900 GWh of energy due to a lower, roughly 50 percent average annual capacity factor. Contrastingly, "Alternative B" would seek to install emission retrofits and continues to operate that 800 MW coal unit. One clearly cannot perform a simple economic comparison of the *unit-specific* fixed and variable generation costs associated with alternatives with such unique attributes. Rather, those respective alternatives would need to be viewed holistically, from an overall utility portfolio perspective. In this simple hypothetical, "Alternative A" with its lower installed capacity, would require the addition of capacity to the utility's generating portfolio sooner than "Alternative B" in order to maintain required reserve margin levels. In addition, because "Alternative A" provides less energy to the utility's system it would potentially be exposed to larger and more frequent "short" energy positions that would have to be purchased from an available energy market. In the case of "Alternative A", the Strategist® tool would evaluate all of the possible combinations of new generating resource additions in order to determine the most economic resource plan for meeting this alternative's future capacity and energy requirements. A similar resource optimization would also be performed for "Alternative B" to insure that it also met its future capacity and energy requirements in the most economic manner. Once the optimal resource plans for each "Alternative" is determined, the total revenue requirements for those "Alternatives" can be compared to select the most economic unit disposition alternative.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Mark A. Becker

Education, Professional Qualifications and Business Experience

Education and Professional Qualifications

In 1983, I received a Bachelor of Science degree in Electrical Engineering from the University of Arkansas.

Business Experience

I began working for Florida Power and Light (FPL) in 1983, as an engineer in the System Planning Department. In that position, from 1983 to 1985, I performed generation planning studies, production costing studies and short-term energy supply studies using New Energy Associates PROSCREEN® (predecessor to Strategist®) and PROMOD®, as well as EPRI's Electric Generation Expansion Analysis System (EGEAS) software.

In 1986, I worked in FPL's Load Management Group. In this position, I provided engineering support during the procurement and testing of FPL's Load Management System (LMS).

In 1987, I began working for the City of Austin Electric Utility Department. In this position, I provided engineering support and project management during the City of Austin's ElectriCREDIT residential direct load control pilot project. In addition to this function, I was involved in the analysis of the City of Austin's commercial time-of-use rates.

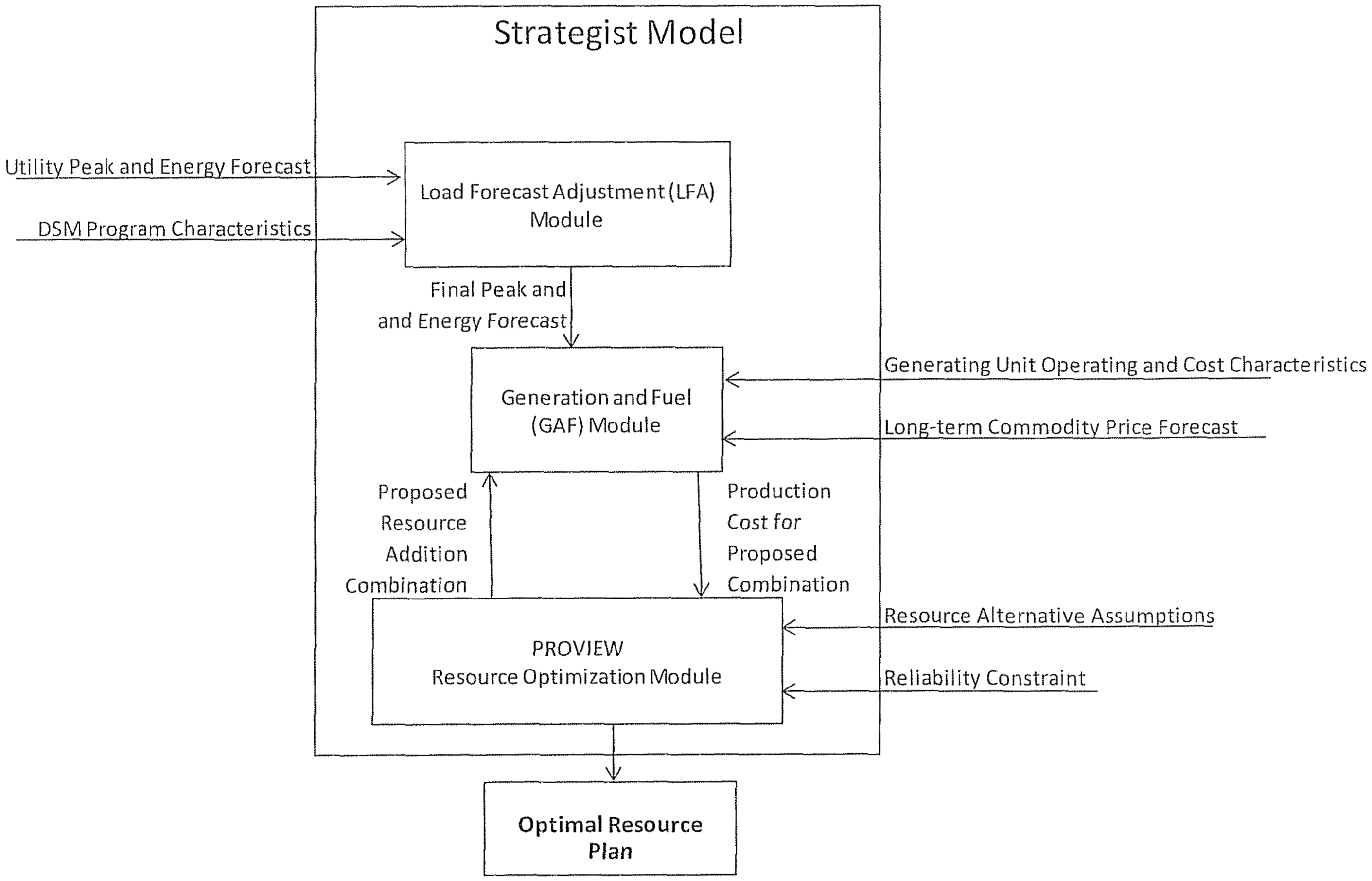
In 1989, I began working in the City of Austin Electric Utility Department's Resource Planning Division. In this position, I was responsible for developing integrated resource plans, production costing analyses and developing all-source Request for Proposals (RFP) as well as evaluating the operating and economic impacts of those proposals.

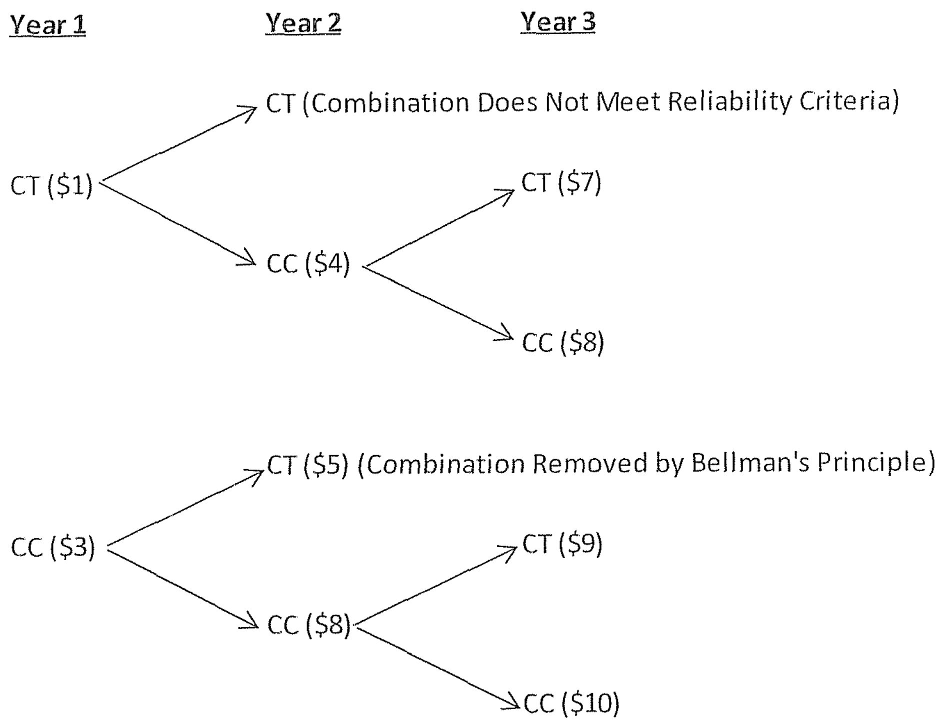
In 1997, I began working as a Project Manager in Electric Resource Planning within Central and South West Services, Inc. (CSWS). I was responsible for overseeing the price evaluation of the CSWS' Expedited Renewable RFP, the All-Source RFPs for the Central Power and Light Company's Lower Rio Grande Valley, West Texas Utilities Company and Southwestern Electric Power Company.

In 2000, I assumed the position as Staff Coordinator in the Resource Planning Section of American Electric Power Service Corporation, a subsidiary of American Electric Power Company, Inc. In this position, I oversaw AEP's production costing and resource planning functions.

In 2001, I began working for William's Energy Marketing and Trading (WEM&T). I was responsible for representing WEM&T's position in the development of various Regional Transmission Operators (RTO) and FERC's Standard Market Design. In addition, I performed analyses in support of WEM&T's transmission rights trading function.

In 2002, I returned to AEP's Resource Planning Section as a Project Manager and have since been promoted to Manager – Resource Planning. In this position, I am responsible for the development AEP's capacity resource plans and other resource planning related studies utilizing the Strategist® model.


Strategist Model
Utility Peak and Energy Forecast
DSM Program Characteristics
Load Forecast Adjustment (LFA) Module
Final Peak and and Energy Forecast
Generating Unit Operating and Cost Characteristics
Long-term Commodity Price Forecast
Generation and Fuel (GAF) Module
Proposed Resource Addition Combination
Production Cost for Proposed Combination
Resource Alternative Assumptions
Reliability Constraint
PROVIEW Resource Optimization Module
Optimal Resource Plan



($) = CPW of Total Annual Revenue Requirement

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

DIRECT TESTIMONY OF

KARL R. BLETZACKER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Karl R. Bletzacker being duly sworn, deposes and says he is Director Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Karl R Bletzacker

KARL R. BLETZACKER

STATE OF OHIO	)	
	)	CASE NO. 2012-
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker this the 7th day of December, 2012.

Ellen A McAninch

Notary Public

My Commission Expires: May 11th, 2016

NOTARIAL SEAL STATE OF OHIO

ELLEN A. MCANINCH
NOTARY PUBLIC
STATE OF OHIO
Recorded in
Franklin County
My Comm. Exp. 5/11/16

DIRECT TESTIMONY OF
KARL R. BLETZACKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-________

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**KARL R. BLETZACKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl R. Bletzacker. My position is Director, Fundamental Analysis, American Electric Power Service Corporation ("AEPSC"). AEPSC supplies engineering, financial, accounting, planning and advisory services to the eleven electric operating companies of American Electric Power Company, Inc. ("AEP"), including Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a BSMEng degree from The Ohio State University in 1980 and I have over thirty years of energy-industry experience which includes petroleum engineering and the management of the purchasing, interstate transmission and distribution of natural gas and power to both regulated and wholesale customers. I have implemented risk management strategies using New York Mercantile Exchange ("NYMEX") and over-the-counter natural gas futures, swaps, and options since the NYMEX natural gas contract was created in June of 1990. I have purchased short- and long-term natural gas supply from major and independent producers and marketing companies and I have monetized arbitrage opportunities using NYMEX futures contract, local and contract storage, pipeline imbalances and local distribution company banks. As Vice-President and Chief Operating Officer of National Gas & Oil Company (a publicly-traded Ohio natural gas utility) and Licking Rural Electrification (an Ohio electric cooperative), I was responsible for the natural gas pricing and risk management policies that ensured reliable delivery and managed customers' exposure to volatile commodity prices. As the North American Manager of Energy Procurement for Honda of America Mfg., Inc., I implemented hedging strategies utilizing NYMEX natural gas futures contracts and operated a natural gas supply pool for the benefit of Honda and its suppliers in North America. I also shared my hedging expertise while serving as Vice-Chairman of the Industrial Energy Users-Ohio which is an organization of large Ohio energy consumers that spend collectively over $3 billion per year on electricity and natural gas for their plants and facilities and whose members employ over 300,000. I joined AEP in 2005 to focus on the creation of long-term North American power market forecasts primarily to support the resource planning of its operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided rebuttal testimony and testified in Case No. 2011-00401, *In the Matter of: The 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.*

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses the North American long-term market forecast deliverables that I provided to support the unit disposition analysis performed for Kentucky Power and presents an overview on how those market forecasts are derived, in particular, the basis for the natural gas and CO_2 allowance price forecasts.

IV. FUNDAMENTALS ANALYSIS

Q. WHAT IS A FUNDAMENTALS ANALYSIS?

A. A fundamentals analysis is a long-term, weather-normalized power market forecast. There are many uses for a fundamentals analysis, but the Fundamentals Analysis Group at AEPSC primarily develops these analyses for use by AEP's regulated operating companies, including Kentucky Power, in long-term resource planning. These forecasts cover the electricity market within the Eastern Interconnect, ERCOT and the Western Electricity Coordinating Council. The forecasts developed by the AEP Fundamentals Analysis Group include: 1) monthly and annual locational power prices (in both nominal and real $), 2) prices for various qualities of Central Appalachian ("CAPP"), Northern Appalachian ("NAPP"), Illinois Basin ("ILB"), Powder River Basin ("PRB") and Colorado coals, 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub, 4) uranium fuel prices, 5) SO_2, NO_x (summer and annual) and CO_2 values, 6) locational heat rates, 7) capacity values, 8) renewable energy subsidies and 9) inflation factors.

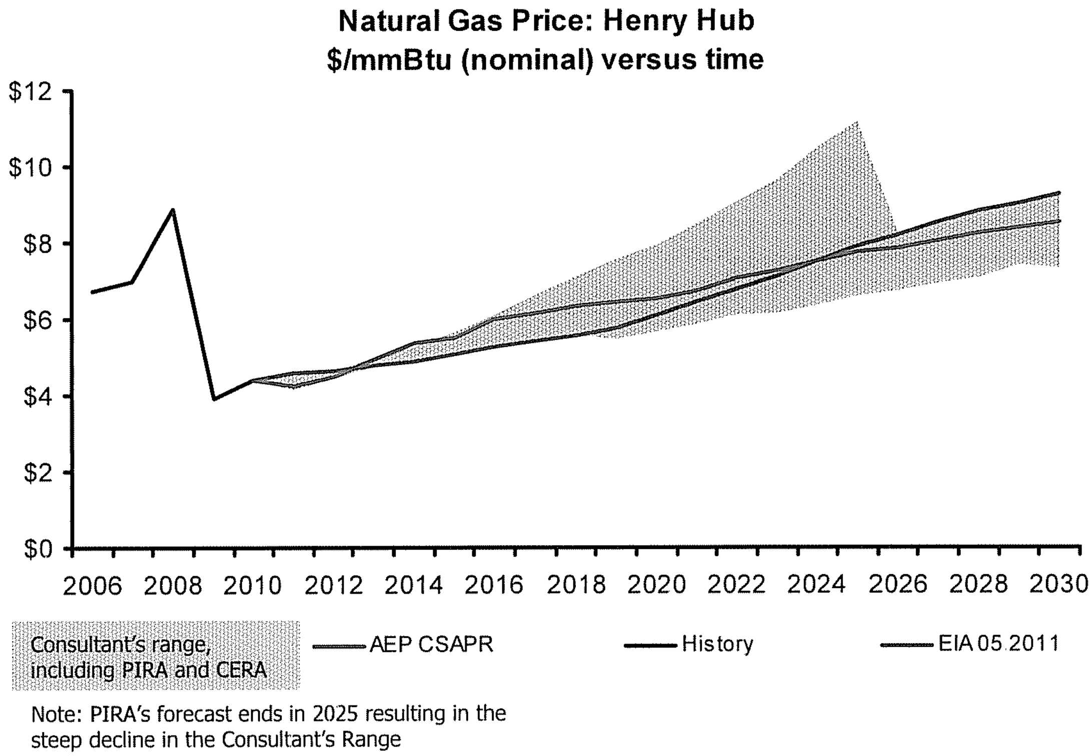
Q. WOULD YOU PLEASE DESCRIBE THE ANALYSES YOU HAVE PROVIDED KENTUCKY POWER?

A. The Fundamentals Analysis Group developed long-term, energy-related commodity pricing forecasts for use in the Kentucky Power unit disposition analysis as supported by Company witness Weaver. The long-term pricing forecasts used in this analysis include: natural gas prices, CO_2 prices, coal prices in the Northern and Central Appalachian regions, on and off-peak energy prices and capacity values within the PJM-RTO RPM construct.

Q. WHAT TOOLS DID YOU USE TO DEVELOP THE FORECASTS PROVIDED TO KENTUCKY POWER?

The primary tool the Fundamentals Group uses for developing its long-term, energy-related commodity pricing forecasts is the AuroraXMP model. The AuroraXMP model iteratively generates locational, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs, among others. In other words, it creates a weather normalized, long-term forecast of the market in which a utility would be operating over a given analysis period. More detail about the AuroraXMP model can be found in KRB-Exhibit 1.

AEPSC is also the client of many well-accepted energy consultancies including Cambridge Energy Research Associates, PIRA and WoodMackenzie. Their collective insight on fuels, energy and emissions (supply/demand and resultant price) is a key component of AEPSC's long-term North American forecasts. For example, the development of the long-term natural gas price forecast begins with an analysis of the consultancies' supply, demand and price relationship – which produces a price elasticity of supply over time. This elasticity, when applied to the AuroraXMP natural gas burn produces a corresponding change in natural gas prices – which is recycled through the AuroraXMP model iteratively until the change in natural gas burn is de minimis. Ultimately, long-term natural gas prices are compared to external peer forecasts as shown below (from Case No. 2011-00401).



Company Witnesses Becker and Weaver describe the incorporation of the long-term North American forecasts used in the unit disposition analysis performed for Kentucky Power in this case. The forecasts were input into the proprietary long-term resource optimization tool known as Strategist® allowing Kentucky Power to evaluate the relative long-term resource combinations in light of forecasted market conditions over the study period.

Q. WHY ARE NATURAL GAS PRICES IMPORTANT IN A FUNDAMENTALS ANALYSIS?

A. Natural gas prices are important because fuel prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units. Generating units with the lowest variable operating cost are the first to dispatch and plants with incrementally higher variable operating cost are called-upon sequentially as electricity demand increases.

The latest vintage of gas generators have improved efficiencies such that volatile gas prices can quickly advantage or disadvantage some coal-fired generation. A $1 per mmBtu swing in gas prices would result in a $7 to $8 per MWh swing in combined cycle natural gas generation cost.

Q. WHAT IS THE BASIS FOR KENTUCKY POWER'S NATURAL GAS PRICE FORECAST?

A. Kentucky Power has concluded that there are four major driving forces that shape the long-term outlook for natural gas.

(1). <u>Abundant, relatively low-cost natural gas supplies</u>: Natural gas reserves and productive capacity will continue to grow domestically and globally as shale gas extraction technology becomes widespread. Despite current negative reaction, the environmental impacts of shale gas development will ultimately be manageable.

(2) An increased demand for natural gas to fuel new and existing electric generation in the future is a near certainty.

(3) <u>Natural gas pipeline capacity will keep pace with the evolving locations of supply and consumption</u>: The extensive domestic natural gas transportation infrastructure is

sufficiently robust to overcome constraints through existing capacity expansions, flow reversals and new construction.

(4) The role of natural gas spans many sectors of the economy: Demand for natural gas in the expanding global economy will increase as electric generation, residential/commercial space heating and industrial processes are all advantaged with lower natural gas prices. However, the prospect of LNG exports, compressed or liquefied natural gas as a transportation fuel and postponed Renewable Portfolio Standards pose upside price threats.

Q. HOW WILL THE DEVELOPMENT OF "LIQUID-RICH" SHALE GAS AFFECT THE NATURAL GAS MARKETS?

A. The natural gas market is projected to remain disconnected from crude oil in that it will not return to historic price spreads and to pre-recession levels. Domestic producers will be led to liquid-rich shale gas plays such as the Bakken (North Dakota and Montana), Marcellus and Utica (Appalachia) and Eagle Ford (southwest Texas) which would put downward pressure on local gas prices. Ultimately, it is finding and production costs that have the most influence on the long-term natural gas price projection. Shale gas production technology has practically eliminated "dry holes" and has reduced the number of rigs necessary to develop a given volume of natural gas. Further advances in technology support an ongoing reduction in finding and production costs.

Q. DO LOW, NEAR-TERM GAS PRICES NECESSARILY MEAN PRICES WILL REMAIN LOW INTO THE FUTURE?

A. Not necessarily. Relatively low near-term natural gas prices at the benchmark Henry Hub reflect the current oversupply trend owing to an abundance of uncompleted wells intended to hold leased acreage for further development. The natural gas market is projected to come into balance mid-decade as natural gas rig counts move away from gas-only prospects. Shortly thereafter, impending environmental regulations focused on coal-fired generation (notably the Mercury and Air Toxics Standards described in witness McManus' testimony) yield a natural gas demand for electric generation which increases overall demand by 10% between 2015 and 2020. Longer-term gas prices are shaped by shale gas development costs which are balanced by advances in technology (greater productivity per well) against higher drilling and production costs from the service sector. Nearer-term natural gas prices will remain volatile as they are primarily affected by weather's deviation from normal (measured as heating degree-days) which then results in deficit or surplus levels of natural gas storage inventory. A warmer-than-normal or colder-than-normal winter has a direct effect on winter prices, but the effect also extends throughout the storage refill season until the storage inventory is fully replenished. For example, the extraordinarily mild 2011-2012 heating season caused nearby natural gas spot prices to drop to sub-$2/mmBtu levels due to high storage inventories and certain summer storage re-fill congestion. It is equally likely that, in the event of a colder-than-normal heating season, natural gas spot prices could exceed $7/mmBtu. This is quite a departure from delivered coal pricing because of the on-site coal inventory which serves to dampen any seasonal weather-related volatility. The weather-normalized, long-term projection for exploration, development and production costs for shale gas remains unchanged – thus creating a "floor" price. While natural gas prices may reflect additional environmental costs due to the process of hydro-fracturing, additional "associated gas" may be brought to market because of the economic advantage of oil/liquids-rich shale plays. But, at this time, there is no reasonable justification to alter the long-term outlook for natural gas prices used in our fundamentals analysis.

Q. PLEASE DISCUSS THE USE OF FUTURES PRICING AS A POTENTIAL BENCHMARK FOR A LONG-TERM FORECAST.

A. Although New York Mercantile Exchange natural gas futures prices may be useful for some purposes involving shorter time periods, NYMEX prices are not well-suited to the long-term, weather-normalized, price fundamental forecast that I have employed. NYMEX futures represent the price point(s) that willing buyers and sellers can realize price certainty on a given day, but those commercial expectations do not necessarily represent the fundamentals of demand, supply and the resulting future spot prices over the long-term for the entire market. While I am providing a 25-year forecast, NYMEX natural gas prices are only available for 10 years into the future. In addition, near-term natural gas prices are also uniquely sensitive to near-term weather projections, such as predictions of seasonal weather variations (e.g., predictions of a cold or warm winter that in turn affect gas storage predictions) and hurricane forecasts. Long-term forecasts using fundamentals analysis, such as we have performed, are weather-normalized. Thus, while the direction in which nearby futures prices move can indicate the direction that the nearby fundamentals-based prices could be adjusted, a proper fundamentals analysis does not over-emphasize those short-term effects, which is beneficial for a long-term forecast being used to assess comparably long-term investment decisions. Ultimately, weather affects demand and the balance of supply and demand affects price.

Q. IS COMPLETE RELIANCE UPON THE ENERGY INFORMATION ADMINISTRATION'S ("EIA") ANNUAL ENERGY OUTLOOK ("AEO") AS A LONG-TERM FORECAST BENCHMARK REASONABLE?

A. No. First and foremost, the natural gas pricing forecasts from the EIA AEO for 2012 were created under the assumption that current laws and regulations remain unchanged. That is, even reasonably known and emerging regulations are specifically excluded from the assumptions for such EIA-AEO projection purposes. The following excerpt is from the opening paragraph of the AEO2012 Executive Summary.

> *"Under the assumption that current laws and regulations remain unchanged throughout the projections, the AEO2012 Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future."*

In contrast, the AEP Fundamental Analysis group's natural gas price forecasts reflect prudent demand-induced price responses to the impending regulations that are not captured by the EIA. For example, AEP takes into consideration the recently-finalized MATS rules, as well as subsequent emerging EPA rulemaking addressing Coal Combustion Residuals, the Clean Water Act rule 316(b) later this decade, and the prospect of a future carbon tax. It is well understood that none of these subsequent emerging laws and regulations are factored into the EIA-AEO projections.

Q. WHY ARE CO_2 ALLOWANCE PRICES IMPORTANT?

A. CO_2 emission costs adversely affect the prices of electricity generated by fossil fuels - along with emission rates and implementation timing. CO_2 regulations will also affect fuel markets, e.g., an increase in natural gas consumption will result in increased natural gas prices. The direct effect of a \$10 per tonne allowance price for a coal plant is an approximate \$10 per MWh increase in plant operating costs. And likewise, a \$10 per tonne allowance price for a natural gas-fired combined cycle plant is an approximate \$4 per MWh increase in plant operating costs.

Q. PLEASE EXPLAIN KENTUCKY POWER'S CO_2 REDUCTION IMPACT ANALYSIS, INCLUDING IMPLEMENTATION TIMING AND THE APPLICATION OF ALLOWANCE PRICES, GIVEN THE ABSENCE OF ANY FINAL RULES REGULATING CO_2 EMISSIONS FROM EXISTING POWER PLANTS.

A. Kentucky Power's current assessment is that the likelihood of any successful federal climate legislation is unlikely through the tenure of the 113th Congress. With 2015-2017 as the earliest reasonable date for a climate proposal to pass through committee, reach the floor and be approved by house for eventual passage, there will likely be an implementation period of approximately five years (as seen in previous climate proposals). Thus, 2022 is the earliest reasonable projection as to when such legislation could become effective. Kentucky Power's "CO_2 Price/Tax" of approximately \$15/tonne (real) was applied to <u>all</u> CO_2 tonnes produced, whereas, in the cap-and-trade programs considered by Congress previously, there were provisions for an allocation of "free" allowances – which reduced the CO_2 costs to incumbent generators. Also, newly promulgated EPA regulations and standards such as MATS, more-stringent CAFÉ standards and others will result in an estimated 50,000 MW national reduction in inefficient coal-fired electric generation and an estimated 10% reduction in CO_2

emissions since 2010. This creates a system of CO_2 reduction that is certain to reduce CO_2 values from earlier (now outdated) cap-and-trade program models.

Q. PLEASE EXPLAIN WHY THE CO2 PRICE/TAX VALUE USED IN THE FUNDAMENTALS ANALYSIS IS APPROPRIATE.

A Kentucky Power's "CO_2 Price/Tax" is far more realistic than much higher cap-and-trade values because; 1) near-term promulgation/implementation of cap-and-trade legislation is highly unlikely, 2) in order for any federal cap-and-trade legislation to ultimately pass, the effective price will have to be moderate for the next 15-20 years, and, 3) actions to regulate CO_2 from electric generation will more likely take other forms – such as through energy efficiency standards, renewable or clean-energy standards on new power plants. Without question, the creation of a Long-Term Forecast which considers a range of CO_2 costs must include correlative changes to other input drivers. It is imprudent to ignore: 1) the effect of coal plant dispatch costs on coal prices due to changes in demand, 2) changes in gas-fired plant utilization and the effect on natural gas prices, 3) changes in plant retirement schedules, 4) the price elasticity of residential, commercial and industrial demand, for example.

Q. WOULD YOU PLEASE PROVIDE A REVIEW OF THE LONG-TERM FUNDAMENTAL COMMODITY PRICING THAT WERE INPUTS TO THE KENTUCKY POWER ANALYSES REPRESENTED BY WITNESS WEAVER.

A. I provided witness Weaver long-term commodity prices that were part of a fundamentals analysis for an array of five (5) unique, pricing views. These views consisted of a "base" view and four additional "scenario" views as described below.

- The ('BASE') "Fleet Transition-CSAPR[1]" recognizes relatively lower fuel price trending, increased natural gas price elasticity and captures a likely implementation profile of environmental regulation including MATS and potential carbon mitigation via a carbon tax beginning in 2022.

- The "Fleet Transition-CSAPR: HIGHER Band" bounds the high-end of the BASE case with plausible fuels, emissions and energy pricing—with appropriate feedback for load response - with fuel prices raised by approximately +1.0 standard deviation.

- The "Fleet Transition-CSAPR: LOWER Band" likewise bounds the low-end of the BASE case with plausible fuel, emissions and energy pricing decreased by approximately -1.0 standard deviation.

- The "Fleet Transition-CSAPR: No Carbon" assumes no carbon tax assumed throughout the entire long-term period modeled.

- The "Fleet Transition-CSAPR: Early Carbon" assumes an accelerated 2017 (versus 2022 in the Base Case) timeframe for the implementation of a CO_2/carbon tax.

These pricing scenarios allowed Kentucky Power to conduct its disposition analysis under multiple realistic market scenarios, providing a more robust evaluation of all alternatives.

Q. IS THIS THE SAME FUNDAMENTAL COMMODITY PRICING FORECAST UTILIZED IN THE COMPANY'S ANALYSIS FROM CASE NO. 20012-00401?

A. Yes.

Q. WHY HAS IT NOT BEEN UPDATED?

A. The only major factor that has changed since the analysis that was performed for Case No. 20012-00401 is the vacatur of CSAPR by decision of the U.S. Court of Appeals. Consequently, certain emission allowance values prior to 2015 will revert back to levels in line with the continued administration of the Clean Air Interstate Rule pending the

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[1] These pricing views refer to CSAPR which was vacated earlier this year. As described later in my testimony, the change from CSAPR to CAIR has no effect on the values used in the pricing views or in the forecasted market values derived during the fundamentals analysis.

promulgation of a valid replacement. The suite of forecasts would yield no changes beginning in 2015.

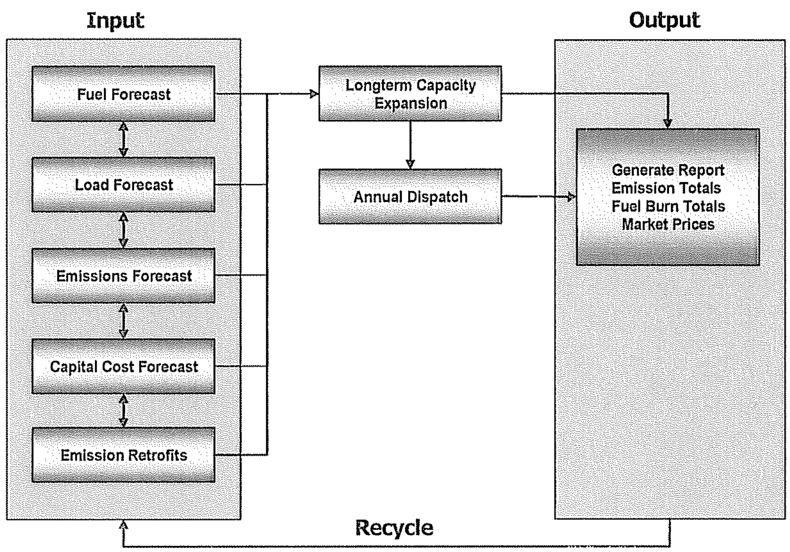
Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

APPENDIX

AURORAMXP

The primary tool used for Kentucky Power's fundamental analysis is the AuroraXMP model. The simple diagram below is indicative of the process.



The model "chooses" which capacity type and size to build and in which areas – subject to capital costs, regional fuel prices and regional reserve margin targets. The value of each resource, either existing or selected to be built, is determined and the resources are sorted by value. A small set of the lowest-valued resources are selected for retirement and a small set of new resources with the highest value are selected for inclusion. Then, the next iteration is run for the entire study period to determine the power prices and resource values. After 35 to 70 iterations, a final set of new-builds and retirements which produces the highest system-wide value is created. It is this final set of resources that is used in the annual hourly dispatch modeling runs. This analysis helps define the North American long-term power market in which Kentucky Power's units will operate and

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

DIRECT TESTIMONY OF

JEFFREY D. LAFLEUR

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jeffery D. LaFleur being duly sworn, deposes and says he is the Vice President Generating Assets for Appalachian Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

JEFFERY D. LAFLEUR

STATE OF WEST VIRGINIA)
) CASE NO. 2012-
COUNTY OF KANAWHA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey D. LaFleur this the 5th day of December, 2012.

NOTARIAL SEAL
STATE OF OHIO

Donna J. Stephens
Notary Public, State of Ohio
My Commission Expires 01-04-2014

Notary Public

My Commission Expires: 1/4/2014

DIRECT TESTIMONY OF
JEFFERY D. LAFLEUR, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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DIRECT TESTIMONY OF
JEFFERY D. LAFLEUR, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jeffery D. LaFleur. I am employed by Appalachian Power Company ("APCo") as Vice President of Generating Assets and I will be responsible for the operation of the Mitchell Plant after its transfer from Ohio Power Company ("OPCo"). APCo is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). My business address is 707 Virginia Street East, Suite 1100, Charleston, West Virginia 25301.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the Louisiana Tech University and have completed an executive management program at Louisiana State University. I joined Southwestern Electric Power Company ("SWEPCO") in 1982 as a staff engineer, progressing to various positions including maintenance supervisor, maintenance superintendent, and plant manager. I became manager of operations over all SWEPCO power plants in 1993. From 1993 through May 2008 I held several positions with Central and Southwest Corporation and other companies of the AEP system, and have been responsible for ongoing operations of generating assets including coal-fired plants, wind generating facilities, and gas-fired combined cycle and peaking units. Specifically, from 2003 to 2008 I served as Vice President of Region 2 generation assets which included the Mitchell and Big Sandy Plants. I assumed my current position in May 2008 in which I am responsible for the safe, reliable and economic operation of APCo's electric generating facilities – both fossil-fueled and hydro-powered.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have testified before the Virginia State Corporation Commission, the Public Service Commission of West Virginia, and the Public Utility Commission of Texas.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the Mitchell Plant and why it will serve as a valuable generation asset to Kentucky Power Company ("KPCo" or "Company") for meeting the capacity and energy requirements of its customers. I also describe my prior connection to Mitchell and Big Sandy Plants, and provide a brief comparison of the units comprising these generation facilities.

IV. MITCHELL PLANT OVERVIEW

Q. PLEASE DESCRIBE THE MITCHELL PLANT.

A. The Mitchell Plant is located along the Ohio River approximately 12 miles south of Moundsville, West Virginia. The plant has twin, pulverized supercritical coal-fired base load units. Each unit has a nominal capacity of 800 Megawatts ("MW"), for a total nominal capacity of 1,600 MW. Both units were placed in service in 1971. These units are of the same series and vintage as Big Sandy Unit 2 with the primary exception being the Mitchell units are fully scrubbed for SO_2 whereas Big Sandy Unit 2 is not.

As base load units, each generally provides a steady 24-hour/day, 7-days per week power supply and typically operates continuously to meet capacity and energy requirements. Base load units are commonly the most economic source of generation, thereby making the Mitchell Plant a valuable and quality generating asset. As a result, the Mitchell units receive a high-priority for operational reliability and maintenance-related expenditures. It is my understanding that the Mitchell Plant has provided capacity and energy for KPCo during deficit periods under the current Interconnection Agreement.

Q. ARE THE MITCHELL UNITS ENVIRONMENTALLY CONTROLLED?

A. The Mitchell units were retrofitted with environmental control equipment to meet the requirements of the Clean Air Interstate and Clean Air Mercury Rules. Units 1 and 2 were retrofitted in 2007 with state-of-the-art environmental pollution controls in the form of a Flue Gas Desulfurization ("FGD") system for sulfur dioxide ("SO_2") emissions reduction and a Selective Catalytic Reduction ("SCR") system for nitrogen oxides ("NO_X") emissions reductions. As discussed in detail by Company Witness McManus, these environmental controls bring the Mitchell units in compliance with the AEP 2007 Consent Decree, and are anticipated to comply with the Mercury and Air Toxics Standards ("MATS") Rule. In addition to the FGD and SCR retrofits, complementary capital investments were also undertaken at Mitchell to ensure reliable operation of the units.

Q. WHAT MAJOR ENVIRONMENTAL CAPITAL INVESTMENTS AT THE MITCHELL PLANT HAVE BEEN MADE SINCE ITS RETROFIT WITH FGD AND SCR SYSTEMS?

A. State-of-the-art fuel blending facilities were installed so that coal received by barge, rail, or conveyor can be blended to meet a target sulfur content. The Mitchell units accept a low and high sulfur coal blend of up to 4.5 lb. SO_2/MMBTU. The fuel blend typically contributes to lower fuel costs at the plant since higher sulfur coals tend to cost less than lower sulfur coals.

Units 1 and 2 have also been equipped with low NO_X burners and a FGD Trona injection system. Upgrades to the electrostatic precipitator ("ESP") are also planned at each unit. Additionally, an approximately 2-mile conveyor belt was constructed to transfer synthetic gypsum, a by-product of FGD system operation, from the Mitchell Plant to the CertainTeed Gypsum Wallboard Plant for use as wallboard feedstock. The delivery of the gypsum from Mitchell to the wallboard plant serves to reduce disposal costs since a landfill is not required for its disposal.

Q. ARE OTHER MAJOR ENVIRONMENTAL CAPITAL INVESTMENTS IN PROGRESS AT THE MITCHELL PLANT?

A. Yes. Capital projects are currently in progress to build a new landfill and an associated haul road. The landfill will allow for the disposal of dry fly ash resulting from a dry fly-ash conversion project currently in progress at the Plant. As discussed by Company Witness McManus, it is anticipated that these projects will satisfy anticipated coal combustion residual regulations. It is also anticipated that future capital investments will be made to comply with other proposed environmental regulations. These anticipated future investments are discussed by Company Witnesses McManus and Weaver.

Q. PLEASE DESCRIBE OTHER SIMILAR 800 MW COAL-FIRED UNITS IN AEP'S EASTERN FLEET.

A. KPCo's Big Sandy Unit 2 and APCo's Amos Units 1 and 2 are of similar design and nominal generating capacity (800 MW) as Mitchell Units 1 and 2. Big Sandy Unit 2 was placed in service in 1969, and Amos Units 1 and 2 were placed in-service in 1971 and 1972, respectively. However, unlike the Mitchell and Amos units, Big Sandy Unit 2 is not retrofitted with a FGD system.

Mitchell Units 1 and 2 were the first of the 800 MW units in AEP's eastern fleet to have FGD and SCR systems installed. Since the installation of these systems at the Mitchell units, plant personnel have been able to proactively optimize the performance of its equipment and manage fuel costs in an effort to provide customers with reliable and cost-effective electricity. The Mitchell units have demonstrated their value through their generating performance.

Q. **DO YOU HAVE EXPERIENCE WITH THE OPERATION OF THESE 800 MW UNITS?**

A. Yes. As previously mentioned in my testimony, I have served as Vice President of Region 2 generation assets which included the Mitchell and Big Sandy Plants, and I currently serve as Vice President of APCo's generation assets where I am responsible for the safe, reliable and economic operation of APCo's electric generating facilities, including Amos Units 1 and 2.

V. MITCHELL PLANT ANTICIPATED PERFORMANCE

Q. **PLEASE PROVIDE A GENERAL DESCRIPTION OF THE MITCHELL PLANT OPERATIONS SINCE THE INSTALLATION OF ITS ENVIRONMENTAL CONTROLS.**

A. Mitchell Units 1 and 2 are some of the most economical coal-fired plants in the AEP eastern fleet. Forced outage rates have been lowered at the plant, and APCo and KPCo, if this application is granted, will continue to make prudent capital investments in Mitchell Units 1 and 2 so that these units continue to cost effectively serve these operating companies' customers.

Q. **IS IT REASONABLE TO ASSUME THAT THE MITCHELL GENERATING UNITS CAN CONTINUE TO OPERATE THROUGH 2040?**

A. Yes. Based upon my years of experience with plant operations and my familiarity with the Mitchell Plant, the units could perform through 2040 with continued prudent investments. Given the level of ongoing capital expenditures included in the economic modeling provided by Company Witness Weaver, which in my experience is a level consistent with proper maintenance and upkeep, the Mitchell Plant should be capable of providing safe and reliable power at a reasonable cost to customers through 2040.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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DIRECT TESTIMONY OF

KARL A. MCDERMOTT, PH. D.

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Karl A. McDermott, being duly sworn, deposes and says he/she is the (Insert Title), that he/she has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his/her information, knowledge and belief

Karl A McDermott

Karl A. McDermott

Illinois)
) SS
County of Champaign)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl A. McDermott, this the 4th day of December, 2012.

"OFFICIAL SEAL"
BRADLEY M. KRALL
Notary Public, State of Illinois
My commission expires 01/04/15

Notary Public

My Commission Expires: 12/4/2012

DIRECT TESTIMONY OF
KARL A. MCDERMOTT, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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I. INTRODUCTION, PURPOSE, AND CONCLUSIONS

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND BUSINESS ADDRESS.

A. My name is Karl McDermott. I am currently the Acting Director of the Center for Business and Regulation and Ameren Distinguished Professor of Business and Government at the University of Illinois Springfield. I am also a Special Consultant to National Economic Research Associates, Inc. ("NERA"). My business address is 875 N. Michigan Ave. Suite 3650 Chicago Ill. 60611-1907.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I have been working in the field of public utility regulation for over thirty years with experience in nearly every facet of the regulation of public utilities. Prior to my current academic appointment, I was a Vice-President at NERA where I directed projects in the electric and natural gas industries. From April of 1992 until May of 1998, I served as a Commissioner on the Illinois Commerce Commission ("ICC").

From 1986 to 1992, I co-founded and served as the President of the Center for Regulatory Studies (CRS), a not-for-profit regulatory policy institute located on the campus of Illinois State University. CRS was created to provide the Illinois regulatory environment with independent third-party research and education on issues affecting the regulation of public utilities.

Before co-founding the CRS, I worked in numerous capacities including positions on the staff of the ICC, the National Regulatory Research Institute (NRRI) at the Ohio

State University, and Argonne National Laboratory.

I currently teach classes on the regulation of public utilities and I have also taught graduate and undergraduate level economics courses, including regulatory economics, at Illinois State University and undergraduate economics courses at the Ohio State University, the University of Illinois at Urbana-Champaign, and Parkland College. I am also on the faculty of the Institute for Public Utilities at Michigan State University where I am an invited lecturer at the Institute's annual Regulatory Studies Program ("Camp NARUC") as well as the annual Advanced Regulatory Studies Program.

I have testified before many state regulatory commissions, including the Kentucky Public Service Commission ("Commission"), as well as before the Federal Energy Regulatory Commission, the Federal Communications Commission, and the Iowa and Illinois General Assemblies, and in several civil courts on issues concerning public utility regulation.

I received a B.A. in Economics from Indiana University of Pennsylvania, an M.A. in Public Utility Economics from the University of Wyoming, and a Ph.D. in Economics from the University of Illinois at Urbana-Champaign.

My current Curriculum Vitae, which more fully presents my academic and work experience, is attached as **Appendix A.**

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. Kentucky Power Company ("Kentucky Power" or the "Company") has asked me to review its Asset Transfer Proposal (the "Proposal") for consistency with traditional regulatory principles. (Application of Kentucky Power Company)[1] My purpose here is not to interpret the legal requirements, but rather to provide the context for the evidence supporting a conclusion that Kentucky Power has met its burden to show that the Proposal is both necessary and furthers public convenience. I address issues relating to the reasonableness of the acquisition of a 50 percent undivided interest in Ohio Power Company's Mitchell generating station ("Mitchell"), from a regulatory policy perspective.

Q. **PLEASE SUMMARIZE YOUR CONCLUSIONS IN THIS PROCEEDING.**

A. After reviewing the regulatory environment in Kentucky and the asset transfer proposal, I conclude that:

1. Kentucky Power's Proposal is the least-cost combination of feasible and reasonable options available to meet its future obligations to customers.

2. The Proposal represents a flexible portfolio that includes employing market forces for a smaller amount of supply (250 MW) which the markets have greater capability of meeting in a cost effective manner.

3. The Proposal will allow Kentucky Power to eliminate the need to retrofit Big Sandy 2, which will avoid significant capital investments and the consequent rate impacts associate with those expenses.

4. It is unnecessary for Kentucky Power to conduct a full RFP process since the

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[1] The Proposal as I discuss it in this testimony refers to resource option 6 presented in Table 1 in Company Witness Weaver's Direct Testimony.

analysis conducted by the Company includes evaluations that approximate price bids that would result from an RFP process.

5. The Proposal maintains the Commission's regulatory and rate authority over an owned asset.

II. THE CONTEXT FOR THE PROPOSAL AND THE ISSUE BEFORE THE COMMISSION

Q. WHAT IS YOUR UNDERSTANDING OF THE CONTEXT FOR THE PROPOSAL?

A. As I understand the current situation, Kentucky Power has relied, at least in part, on a Pool Agreement within the American Electric Power ("AEP") family of eastern utilities to obtain sufficient supply to meet its customer's needs in a cost effective manner. For a number of reasons that are more thoroughly discussed by Company Witness Pauley, the pool members gave each other notice on December 17, 2010 of a termination of the Pool Agreement, effective January 1, 2014.

Q. WHAT ISSUE IS BEFORE THE COMMISSION AS IT RELATES TO THE PROPOSAL?

A. Whether the Proposal—essentially the Mitchell transfer and subsequent RFP for 250 MW—when compared to other potential resource combinations constitutes a reasonable option to meet Kentucky Power's current and future load in a cost effective, safe, and reliable manner as a result of the termination of the Pool Agreement and changes in environmental rules.

Q. WHAT IS KENTUCKY POWER REQUESTING OF THE COMMISSION?

A. While I am not a lawyer, my understanding is that Kentucky Power is requesting a Certificate of Public Convenience and Necessity pursuant to KRS 278.020(1) and 807 KAR 5:001, Section 9, among other requests, in order to transfer an undivided fifty percent interest in Mitchell from Ohio Power Company to Kentucky Power. Further, I understand the applicable statute and rules require that a utility "demonstrate a need for such facilities and the absence of wasteful duplication." (Application of Kentucky Power Company)

III. THE METHODOLOGY APPLIED TO THIS REVIEW

Q. WHAT WILL YOU DESCRIBE IN THIS SECTION OF YOUR TESTIMONY?

A. Here I describe my approach to reviewing the Company's Proposal as well as the approach the Company took in analyzing different resource options.

Q. HOW DID YOU APPROACH ANALYZING THE PROPOSAL?

A. My approach was two-fold. First, I reviewed the applicable statutes, rules, and previous Commission rulings on similar issues to familiarize myself with the approach applied by the Commission in Kentucky to such proposals. Second, I reviewed the Company's analytical framework for consistency with acceptable regulatory practice and the Commission's approach. In undertaking this analysis I reviewed the process by which the Company came to its conclusions, but I did not audit or otherwise verify the analytical results.

Q. WITH REFERENCE TO THE FIRST PART OF YOUR ANALYSIS, WHAT DO

YOU CONCLUDE WITH RESPECT TO THE APPROACH THE COMMISSION USES TO EVALUATE PROPOSALS, SUCH AS THE ONE PROPOSED BY KENTUCKY POWER?

A. As a general matter, the approach applied by the Commission is broadly consistent with the approach most regulatory bodies take when faced with these types of proposals. In brief, a public utility should acquire resources which support its ability to provide safe, adequate, and reliable service to customers at just and reasonable prices. This generally requires that a new source or sources be needed by the public utility in order to meet its obligation to serve customers and that acquiring that resource or resources will have net benefits—or at least no net harm—relative to other resource options.

Q. IN PARTICULAR, HOW DOES THE COMMISSION IMPLEMENT THIS GENERAL APPROACH?

A. The Commission recently explained its approach in its Order in Case No. 2011-00375. In that case, Louisville Gas and Electric and Kentucky Utilities proposed to purchase an existing generation asset, as well as self-build another asset, in order to meet their obligations to customers. The Commission explained that to demonstrate that a proposed facility does not result in wasteful duplication—a foundation of the analysis necessary for this type of proposal—the applicant must demonstrate that:

> …a thorough review of all reasonable alternatives has been performed. Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication. All relevant factors must be balanced. The Commission has long recognized that the

> principle of least cost is one of the fundamental foundations utilized when setting rates that are fair, just, and reasonable and that this principle is embedded in KRS 278.020(1). (Cites omitted) (Order in Case No. 2011-00375, pp. 14-16)

Q. HOW DID KENTUCKY POWER REVIEW ITS ALTERNATIVES TO MEETING ITS OBLIGATIONS GOING FORWARD?

A. Kentucky Power evaluated a number of alternatives or options to meeting its current and future obligations. (*See e.g.,* Weaver Dir.,) These options could be characterized as a portfolio of resources where combinations of refurbishments, asset transfers, market purchases, or new asset construction were combined in packages designed to meet the projected needs of Kentucky Power's customers over a thirty year planning horizon. A comparison of various options was performed using a Cumulative Present Worth (CPW) of generation cost analysis as described by Company Witness Weaver. The goal of this analysis appropriately focused on the long term relative benefits to customers of each portfolio of resources. With respect to the provision of electric service in the context of a vertically integrated utility environment, the public interest is best served by examining the long term value of resources in meeting the needs of the public, not a short-term analysis. The public utility as an institution has a responsibility to meet customers' needs cost effectively over the long term. This promotes stability for the customer base as well as not sacrificing long-term least cost service for short-term gains. The methodology articulated by Mr. Weaver in his testimony is consistent with the approach taken by most utilities and regulatory bodies in states that have not chosen to restructure their electric markets and, in my view, takes the appropriate perspective by examining the various alternatives in a fashion where the long-term costs of the options are made comparable in current terms.

IV. THE PROCESS OF EVALUATING OPTIONS HAS SHOWN THAT THE PROPOSAL MEETS THE COMMISSION'S REQUIREMENTS FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Q. HOW WOULD YOU EXPECT A UTILITY TO APPROACH THE EVALUATION OF THIS RESOURCE OPTION?

A. A utility traditionally has a planning horizon that encompasses multiple decades. In evaluating alternative supply proposals it should evaluate one against another with the goal of cost effectively meeting customer load over the planning horizon. This would include an evaluation of projected demand, an evaluation of existing resources (and potentially a reordering of the utility's exiting portfolio of resources), market procurement and a costing out of the options to meet load in the long-term. Once this process is complete each option can be compared on the basis of cost and likelihood of meeting load in a certain manner. These options should be examined for the robustness of their cost effectiveness under alternative risk scenarios in order to assure the customers and the Commission of the options' ability to serve customers under a wide variety of conditions. The utility should then choose the least-cost alternative, taking into account that it must balance the cost factors with certainty and price volatility and other factors as articulated in the Commission's Louisville Gas and Electric and Kentucky Utilities order cited earlier in this testimony.

Q. **SHOULD THE UTILITY ALWAYS CHOOSE THE LEAST-COST OPTION?**

A. The concept of least-cost is conditioned on the ability of the utility to serve customers cost effectively over a wide variety of market and asset operating conditions. The least-cost standard can only be applied to resources on a level playing field when all the relevant costs and risks of the options are taken into account. This is why all reasonable options must be analyzed and made comparable over the long term to assure that the Commission can compare alternatives appropriately. Moreover, not all demand is cost effectively served by the same generation resources. For example, base load (i.e., 24x7) is more cost effectively served by plants with high fixed costs but low operating costs as such plants produce lower total costs of serving base load than the alternative (presumably plants with low fixed costs but high operating costs). Likewise, a base load plant would not be appropriate to meet the needs of customers in excess of base load as the high fixed costs of the base load plant cannot be offset by the lower operating costs. All of these issues are balanced when a comprehensive framework of analysis is employed to evaluate the alternatives on a long run basis.

This is essentially how utility planners have operated for many years and it coincides with a portfolio approach to resource acquisition in which different resources are purchased in different quantities in order to balance out the risks associated with any one resource. For example, a utility could replace all coal-fired plants with wind power which has a very low marginal cost. Unfortunately, wind resources carry significant risks of operation, such as the inability to be dispatched, that more traditional resources do not carry.[2] Of course, other low marginal cost resources, such as demand-side resources, should be part of any evaluation as well as those resources can be cost effective at meeting load while providing somewhat of a hedge against, often volatile, fuel prices. It is my understanding that the Company has undertaken an analysis of cost-effective demand-side resources and included that in the modeling. As might be expected, the acquisition of energy efficiency does not materially alter the resources needed over the planning horizon. (Weaver, Dir.)

Q. WHAT IS YOUR UNDERSTANDING OF THE APPROACH THE COMPANY TOOK TO EVALUATING DIFFERENT OPTIONS?

A. My review of the Company's approach leads me to the conclusion that it evaluated a comprehensive portfolio of options to procure the necessary resources and came to the conclusion that the proposal—the Mitchell transfer and the 250 MW RFP—is the least-cost and viable option for meeting future load, given that there are environment restrictions facing the Big Sandy units. Essentially, the Company looked at all the reasonable options available to it as the resource procurement entity. This included building new generation, purchasing capacity and energy from the market, retrofitting Big Sandy Unit 2, energy efficiency, and various combinations of these options.

Q. DID THE COMPANY CONDUCT AN RFP FOR THE ENTIRE RESOURCE NEED?

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[2] Traditional resources do have unforced outages that can limit dispatchability. That risk, however, is fairly well understood in terms of its overall impact on the system and is lesser in degree relative to wind resources as such unforced outages occur only infrequently.

A. My understanding is that it did not.

Q. SHOULD THE COMMISSION BE CONCERNED THAT KENTUCKY POWER IS NOT COMPETITIVELY BIDDING ALL RESOURCE NEEDS?

A. No. Company Witness Weaver's analysis employs benchmarks that would be used by potential bidders into a large base load RFP. For example, any existing plant within PJM would not be willing to bid less than the value of its output in the PJM market. Mr. Weaver uses projections of those market prices over time as one of the potential options. Indeed, it is almost certain that such an approach is the lower bound of the necessary bid price as longer term contracts tend to carry risk premiums. It is also possible that bidders into a potential RFP would have chosen to build a new unit. Mr. Weaver's analysis has taken this possibility into account by examining, within the alternative portfolios, the cost of building new gas-fired plants. Gas-fired plants are almost assuredly the only type of plant that would be built. The construction proxies that Mr. Weaver employed provide the Commission with another benchmark of potential RFP bids. Once again Mr. Weaver's analysis indicates that the cost of building new plants is higher than the cost of the Proposal.

Further, it is unclear to me that a competitive bidding process would provide any additional useful information in this context. Indeed, Louisville Gas and Electric only recently attempted to obtain competitively priced power and energy through an RFP process and determined that a combination of building its own generation and purchasing an existing unit was more cost effective and the Commission agreed, as did many of the intervenors in the case. (Order in Case No. 2011-00375) This should not be entirely surprising. If an RFP amounts to duplicating what a utility would do to obtain the same capacity and energy there is every reason to believe that a regulated utility would be able to do so at a lower cost than a private-sector competitor, if only because of its capital cost advantage which is part and parcel of the regulatory paradigm.

Q. COULDN'T THE COMPANY SIMPLY ADD NEW ENVIRONMENTAL CONTROLS TO ITS EXISTING FLEET OF PLANTS AND AVOID THE COST OF THE TRANSFER OF MITCHELL?

A. This, of course, was one of the options explored by the Company, though this approach is also not without risk. While any utility will strive to undertake construction and project management in a prudent manner, the complexities of adding capital to existing plant can result in unavoidable risk. In fact the costs and risks associated with retrofit construction, new facilities, and market purchases have all been taken into account in the Company's analysis.

V. BENEFITS OF UTILITY AFFILIATE TRANSFER AND OWNERSHIP OF MITCHELL GENERATING STATION

Q. COULD YOU IDENTIFY WHAT YOU BELIEVE IS THE MOST SIGNIFICANT UNCERTAINTY FACING REGULATORS AND ELECTRICITY SUPPLIERS IN THE NEAR FUTURE?

A. To my mind the most significant factor facing regulators is the ability to reliably and cost-effectively meet customers' demand. As a former commissioner my chief concern was not simply to provide power as cheaply as possible but also to make sure that supply was available at all times and under all conditions. The Commission, in attempting to balance the issues of price and reliability, should seek to "hedge" its bets, through the use of alternative supply institutions such as the proposed transfer and use of RFPs for power procurement. Having both a vibrant wholesale market and a utility under direct control provides the Commission with greater flexibility than either reliance on the market or the utility alone.

Q. DOES THE COMMISSION MAINTAIN REGULATORY CONTROL UNDER THE PROPOSAL?

A. Because Kentucky Power will own the asset (i.e., 50 % of Mitchell) the Commission will maintain its control in determining just and reasonable costs through the traditional rate case. Further, the Commission retains its current control over Company financing as well as its review of any rate base additions. Finally, the Commission retains control over the disposition of the Company's assets, including the transfer of Mitchell ownership.

Q. DOES THE PROPOSAL ELIMINATE ALL THE RISKS TO CONSUMERS?

A. Of course not. What it does is reduce certain risks associated with the ability to control the supply of energy to serve customers. Other risks exist, such as operations risk, fuel cost risk and regulatory risk. These risks the Commission has experience with addressing through the historical regulatory process.

VI. THE PROPOSAL IS THE LEAST COST ALTERNATIVE

Q. WHAT DO YOU CONCLUDE ABOUT THE PROPOSAL?

A. In my opinion the Proposal is the least-cost approach to serving Kentucky Power customers in the long term.

Q. WHAT IS THE BASIS OF THAT CONCLUSION?

A. I have made this conclusion based on the following:

First, the transfer of Mitchell provides Kentucky Power with an asset that is in many respects identical to the Big Sandy 2 unit with the exception that Mitchell currently has the environmental controls necessary to meet the Company's obligations under its 2007 NSR Consent Decree, the Clean Air Interstate Rule, the Mercury and Air Toxic Standards, and other environmental standards expected to be in place at the time of the December 31, 2013 proposed transfer. (Pauley, Dir.) Indeed, as Company Witness Pauley testifies, making such investments in Big Sandy 2 is not as cost effective as transferring a share of Mitchell which already has these controls. (Id.)

Second, the two plants are roughly the same vintage with Mitchell being slightly newer and, as I noted above, the Proposal does not diminish the authority of the Commission over the control of operating costs or rate base additions.

Third, there are additional risks and costs associated with any new construction project, whether a new plant or a retrofit. For the most part those risks and costs are avoided here since the Mitchell units are already built and embedded in the costs of the Proposal.

Fourth, the Proposal represents a portfolio approach to resource acquisition that tends to spread risks out over multiple generation resources and even over the two units at Mitchell. (Under the Proposal, Kentucky Power receives an equal share of both units at Mitchell thereby limiting the risk of unplanned outages. (Pauley, Dir.)) This avoids the "eggs in one basket" approach of buying all power from the market or requiring the utility to build all generation.

Finally, Mr. Weaver's approach to analyzing the options takes a balanced and reasonable view of the feasible options available to Kentucky Power. Given that building a new plant engenders risk from construction and fuel prices, and buying all the power from the market is not likely to produce lower costs given the embedded cost nature of the Proposal, it not surprising that the Proposal fares well in comparison to other feasible options.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS DOCKET?

A. Yes it does.

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Education

University of Illinois at Urbana-Champaign
Ph.D., Economics, 1990
Major Fields: Monetary theory and Policy, Macroeconomic Theory, and History of Economic Thought

University of Wyoming
M.A., Public Utility Economics, 1978
Major Fields: Public Utility Economics and Industrial Organization Theory

Indiana University of Pennsylvania
B.A., Economics, 1976

Teaching Experience

University of Illinois Springfield
2008- Ameren Distinguished Professor of Business and Government
Classes taught: Regulation and the American Economy, Economics of Public Utility Regulation, macro-economics

Michigan State University, Institute for Public Utilities
2001- Faculty
Invited lecturer at Regulatory Studies Program ("Camp NARUC") held in East Lansing, Michigan. Lecture topics include performance-based regulation, rate-of-return regulation, infrastructure regulation for developing countries, and gas wholesale markets.

Illinois State University, Department of Economics
1986-1992 Lecturer in Economics
Taught both graduate and undergraduate public utility courses, Money and Banking, as well as introductory courses.

Parkland Community College, Champaign, Illinois
1984-1991 Instructor in Economics
Taught both Principles of Economics I and II.

Ohio State University, Department of Economics

Fall 1979 Lecturer in Economics
Taught Macroeconomic Principles.

Professional Experience

NERA Economic Consulting

2008- Special Consultant

1999-2008 Vice President
Directs projects in the energy and telecommunications fields. Conducts research in the design and review of performance-based regulation mechanisms. Provides strategic regulatory advice to international and domestic clients. Advises on competitive issues facing regulated firms, including regulatory policy, unbundling, corporate structure, and tariff design.

Illinois Commerce Commission

1992-1998 Commissioner
Domestic: Served as Chairman of both the Telecommunications Policy Committee and Electricity Policy Committee. Served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources and Environment Committee as the Chairman of its environmental subcommittee. Also served as NARUC representative on the President's Global Climate Change Task Force, the Federal Energy Regulatory Commission's Pipeline Competition Task Force, the National Coal Research council, and as a member of the Harvard Electric Policy Group.

International: Served as part of the United States Energy Association and USAID educational effort in Eastern Europe. Lectured in Argentina, the Czech Republic, Latvia, Poland, Romania, Russia, and Slovakia and participated in two joint USEA/USAID and World Bank seminars in Vienna providing advanced regulatory training.

Representative Publications, Conference Papers, and Reports

"The Regulatory Dilemma: Getting Over the Fear of Price," Electricity Journal Vol. 25, Issue No. 9, November 2012, pp. 6-13.

"Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation," Edison Electric Institute, June 2012.

"The Illinois Commerce Commission's Pro Forma Adjustment Rule: An Event Study of Regulatory Decision-Making," forthcoming in *Advances in Business Research.* (with C. Peterson)

"Rethinking the Implementation of the Prudent Cost Standard," in *The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries,* S. Voll and M. King (eds), 2007. (with C. Peterson and R. Hemphill).

"Mergers and Acquisitions in the US Electric Industry: State Regulatory Policies for Reviewing Today's Deals," *The Electricity Journal*, 20(1), pp. 8-25, 2007 reprinted in *The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries,* S. Voll and M. King (eds), 2007 (with C. Peterson).

"Critical Issues in the Regulation of Electric Utilities in Wisconsin," *Wisconsin Policy Research Institute Report*, 19(3), pp. 1-69, 2006 (with C. Peterson and R. Hemphill).

"The Anatomy of Institutional and Organizational Failure," in *Obtaining the Best from Regulation and Competition,* M. Crew and M. Spiegel (eds.), Kluwer Academic Publishers, London, UK, 2005, pp. 65-92 (with C. Peterson).

"Is There a Rational Path to Salvaging Competition?" *The Electricity Journal,* 15(2), 2002, pp. 15-30 (with C. Peterson).

"The Essential Role of Earnings Sharing in the Design of Successful Performance-base Regulation Programs," in *Electricity Pricing in Transition,* A. Faruqui and K. Eakin (eds.), Kluwer Academic Publishers, London, UK, 2002, pp. 315-328 (with C. Peterson).

Essential Facilities, Economic Efficiency, and a Mandate to Share: A Policy Premier, Edison Electric Institute, January 2000 (with K. Gordon, W. Taylor, and A. Ros).

The Determinants of Electric Utility Capital Structure: Re-Examining the Turbulent 1980s, presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June 2011. (with C. Peterson)

The Determinants of Commission Revenue Requirement Decisions: A Case Study of Illinois Energy Utilities, presented at Center for Research in Regulated Industries, Rutgers University, Annual Western Advanced Regulatory Conference, Monetary, CA, June 2011. (with C. Peterson and A. Everette)

Prudence: The Regulators Strike Back: A Prequel to the Revenge of the Regulator, presented at Center for Research in Regulated Industries, Rutgers University, conference held in San Diego, CA, June 2005.

The Anatomy of Institutional and Organizational Failure: Economic Reform and the Search for Institutional Equilibrium in Regulated Network Industries, preliminary draft presented at Research Seminar on Public Utilities, Center for Research in Regulated Industries, Rutgers University, October 2003 (with C. Peterson).

Distributed Resource Investment in Albania: Regulatory Options for Introducing Commercial Incentives and Promoting Solutions to Meeting Electricity Demand, white paper prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, January 2003 (with C. Peterson).

Restructuring Options for the Electric Sector in Macedonia, Report 1 and 2; prepared for the law firm of Pierce Atwood under contract with United States Agency for International Development, 2002 (with C. Peterson and R. Zarumba; report is proprietary).

Representative Testimony

In the Circuit Court of Cook County, Illinois, County Department, Law Division, *The People of the State of Illinois* ex rel. *Leon A. Greenblatt III, v. Commonwealth Edison Company,* Case No. 2007 L 004293. Expert testimony concerning the application of regulatory principles to avoided cost pricing of purchases by an electric utility from solid waste generation facilities in Illinois.

Illinois Commerce Commission, American Transmission Company LLC Application for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406.1 of the Illinois Public Utilities Act as a Transmission Public Utility to construct, operate, and maintain a new 345,000 volt electric transmission line in Lake County, Illinois, Docket No. 11-0661, expert testimony concerning the effect on electric competition of a proposed transmission line from Wisconsin to Illinois, Fall 2011.

Missouri Public Service Commission, *Proposed General Increase in Rates*, Missouri-American Water Company, Docket Nos. WR-2011-0337 and SR-201-0338, Testimony on standard tariff pricing of water services. June 2011.

Illinois Commerce Commission, *Proposed General Increase in Rates,* Commonwealth Edison Company, Docket No. 10-0527, Expert testimony on behalf of the National Resources Defense Council regarding electric decoupling. November 2010.

Indiana Utility Regulatory Commission, Rate case, Vectren Energy Delivery of Indiana, Cause No. 43839. Expert testimony on electric decoupling mechanisms. 2010.

Wyoming Public Service Commission, *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism,* Docket No. 20000-368-EA-10, Expert testimony on public interest standard for fuel adjustment mechanism, 2010.

Regulatory Commission of Alaska, *In the Matter of the Petition filed by Chugach Electric Association, Inc. for Advance Determination of Prudence for Southcentral Power Project*, U-10-41, June 2010. Expert testimony regarding preapproval of generation investment by state public utility commissions in the United States.

Utah Public Service Commission, *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism,* Docket No. 09-035-15, *Phase I and Phase II.* Expert testimony on public interest standard for fuel adjustment mechanism, 2009.

Illinois Commerce Commission, *In Re: Enbridge Pipeline (Illinois) L.L.C.* Expert testimony on the proper test for issuing a certificate of public convenience and necessity for an oil common carrier by pipeline. January 2008.

United States District Court for the Western District of Missouri, Western Division, *Travelers Property Casualty Co. v. National Union Insurance Co,* Case No. 4:06-CV-00946-REL. Expert report and testimony on behalf of Kansas City Power and Light Company calculating damages from transformer failure.

Wyoming Public Service Commission, Docket No. 20000-277-ER-07, Direct Testimony on behalf of Rocky Mountain Power on merits of utilizing marginal cost for pricing electric service to new large load customers, June 2007.

North Dakota Public Service Commission, Case No. PU-06-525, Direct and Rebuttal Testimony on behalf of Northern States Power d/b/a Xcel Energy Inc. on reasonable cost of equity for North Dakota natural gas operations, 2006-7.

Circuit court of Jackson County Missouri, *Kansas City Power and Light Company v. Bibb Associates, et. al.* Case No. 01CV207987. Expert report and testimony on behalf of Kansas City Power and Light Company calculating the damages from the explosion of its Hawthorn 5 coal-fired generation unit, 2003-2004.

Public Service Commission of Wisconsin, Docket No. 05-CE-130, Direct, Rebuttal and Surrebuttal Testimony on behalf of Wisconsin Electric Power Company regarding energy efficiency and power plant construction, 2003.

Federal Energy Regulatory Commission, Docket No. EL99-90-000, *City of Wichita, Kansas v. Western Resources, Inc.* Direct testimony on behalf of the City of Topeka, Kansas focusing on cost causation issues and rate parity, September 2000.

California Public Utilities Commission, Application A.00-06-032, Direct and rebuttal testimony on behalf of Southern California Gas Company regarding the appropriateness of peaking rate for gas services, Fall 2000.

Kentucky Public Service Commission, Case No. 2000-095, Testimony on behalf of LG&E Corp. regarding approval of a merger, March 15, 2000.

South Dakota Public Utilities Commission, Docket No. NG98-010, Testimony on behalf of MidAmerican Energy Company for continuation of its incentive gas supply procurement program, June 1999.

Iowa Utilities Board, Docket No. RPU-94-3, Request for Confidential Treatment on behalf of MidAmerican Energy Company, April 7, 1999.

Federal Communications Commission, CC Docket No. 99-24, Affidavit and Reply Affidavit of Karl McDermott and William E. Taylor on behalf of Bell Atlantic Telephone Companies for forbearance from regulation as dominant carriers in Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Washington, DC, Vermont, and Virginia, January 20, 1999 and April 8, 1999.

Dr. McDermott's full CV is available upon request.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

DIRECT TESTIMONY OF

JOHN M.MCMANUS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, John M. McManus being duly sworn, deposes and says he is the Vice President of Environmental Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

John M. McManus

JOHN M. MCMANUS

STATE OF OHIO)
) CASE NO. 2012-
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus this the 10 day of December, 2012.

Janet L. White

Notary Public

JANET L. WHITE
Notary Public, State of Ohio
My Commission Expires: My Commission Expires 02-09-2013

DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-_________

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DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is John M. McManus. I am employed by American Electric Power Service Corporation as Vice President - Environmental Services. American Electric Power Service Corporation ("AEPSC") is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent of Kentucky Power Company ("KPCo" or "the Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies there from 1976-77. I joined AEPSC's Environmental Engineering Division in September 1977. After holding various positions in the environmental division over the years, I was appointed as Manager, Environmental Services in December 2002 and remained in that position until April 2003. I was appointed to my current position as Vice President - Environmental Services in April 2003. I am also a registered professional engineer in the State of Ohio.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT-ENVIRONMENTAL SERVICES?

A. I am responsible for oversight of environmental support for all generation and energy delivery facilities owned by AEP operating companies. I am AEP's listed Designated Representative on Title IV Acid Rain Program matters and the listed NO_X Authorized Account Representative on NO_X State Implementation Plan (NO_X SIP Call) Program matters. Environmental Services provides permitting and compliance support, guidance, procedures, recommendations and training for AEP's operating companies in order to maintain and improve their environmental programs and enhance compliance with environmental laws, regulations, and policies. As part of this effort, Environmental Services is also involved in the development process for environmental regulations, coordinating with operating company staffs to support AEP's corporate strategies and values concerning the environment.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified before the Kentucky Public Service Commission on a number of occasions as well as before the Virginia State Corporation Commission, Indiana Utility Regulatory Commission, Public Service Commission of West Virginia, Public Utilities Commission of Ohio and I have submitted testimony before the Public Utility Commission of Texas.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the environmental requirements, current and future, applicable to KPCo generating assets and to Ohio Power Company's ("OPCo") Mitchell Plant. I will also discuss planned compliance strategies to meet these environmental requirements.

IV. U.S. EPA ENVIRONMENTAL REGULATIONS

Q. PLEASE DESCRIBE CURRENT REGULATORY PROGRAM DRIVERS AT THE BIG SANDY AND MITCHELL PLANTS.

A. The requirements of the 2012 Mercury and Air Toxics Standards ("MATS") Rule and the 2007 AEP Consent Decree are the primary drivers for more stringent emission limits at the Big Sandy and Mitchell Plants. The following is an overview of these requirements:

1. **MATS Rule** – The MATS Rule, originally proposed as the Electric Generating Unit Maximum Achievable Control Technology ("EGU MACT") Rule on May 3, 2011, was published in the Federal Register on February 16, 2012. The MATS Rule is a replacement for the Clean Air Mercury Rule ("CAMR") that was vacated in 2008 by the D.C. Circuit Court of Appeals. The initial compliance date for the MATS Rule is April 16, 2015. The goal of the MATS Rule is to reduce hazardous air pollutants ("HAPs") from coal- and oil-fired electric generating units. The final rule includes stringent emission limits for

mercury, particulate matter (as a surrogate for non-mercury metals), as well as hydrochloric acid or sulfur dioxide (as surrogates for acid gases).

2. **New Source Review ("NSR") Consent Decree** - In December 2007, AEP and its affiliated eastern Operating Companies entered into a Consent Decree that settled outstanding litigation with the U.S. Department of Justice, U.S. Environmental Protection Agency ("EPA"), numerous states, and other litigants that stemmed from differences in interpretation of various NSR requirements associated with coal unit maintenance practices. The AEP Companies admitted no violations of law and all claims against them were released. For KPCo's Big Sandy Units 1 and 2, the Consent Decree called for the following schedule of NOx and SO_2 controls:

- Big Sandy Unit 2: Install Flue Gas Desulfurization ("FGD") for SO_2 emission reductions by December 31, 2015
- Big Sandy Unit 2: Continue to operate the existing Selective Catalytic Reduction ("SCR") system to minimize NOx emissions
- Big Sandy Unit 1: Install Low-NO_X Burner technology and limit the sulfur content of its coal to no greater than 1.75 lb. per million British thermal units ("MMBtu"), on an annual average basis, by the effective date of the Consent Decree.

For OPCo's Mitchell Plant, the Consent Decree called for the following schedule of NOx and SO_2 controls:

- Mitchell Units 1 and 2: Install FGD for SO_2 emission reductions by December 31, 2007

- Mitchell Units 1 and 2: Install SCR system to minimize NOx emissions by January 1, 2009

Q. WHAT ARE THE IMPLICATIONS OF THE MATS RULE AT THE BIG SANDY AND MITCHELL PLANTS?

A. The MATS Rule establishes stringent unit-specific emission limits that are applicable to both plants. To comply with the MATS limits, the Big Sandy units would need to install additional emission controls, switch fuels, or be retired. The Mitchell units are expected to be able to achieve the MATS limits without any upgrades to or new installations of emission control equipment.

Q. WHAT IS THE COMPLIANCE TIMELINE FOR THE MATS RULE?

A. The initial MATS compliance date is April 16, 2015, three years after the effective date of the rule. However, a one-year administrative extension of the initial compliance date (a fourth year) can be granted by a state's Department of Environmental Protection for units undertaking major retrofit or replacement projects, or for units that will retire but are required for reliability purposes. An additional one year extension (a fifth year) via an Enforcement Order from EPA may also be available for units identified as "critical for reliability purposes".

Q. DO THE EXISTING ENVIRONMENTAL CONTROLS AT BIG SANDY UNITS 1 AND 2 FULFILL THE REQUIREMENTS OF THE 2007 AEP NSR CONSENT DECREE?

A. No. The one remaining provision of the 2007 AEP NSR Consent Decree that the Big Sandy Plant is obligated to address is the installation of an FGD system on Unit 2 by December 31, 2015.

Q. DO THE EXISTING ENVIRONMENTAL CONTROLS AT MITCHELL PLANT FULFILL THE REQUIREMENTS OF THE 2007 AEP NSR CONSENT DECREE?

A. Yes.

Q. PLEASE DISCUSS OTHER PROPOSED AND EMERGING ENVIRONMENTAL REGULATIONS THAT MAY CREATE THE NEED FOR ADDITIONAL ENVIRONMENTAL CONTROL RETROFITS AT THE BIG SANDY AND MITCHELL PLANTS.

A. The following proposed and anticipated environmental regulations have the potential to establish more stringent requirements and the subsequent need for upgrades to and/or new installation of environmental control systems at the Big Sandy and Mitchell plants:

1. **Cross States Air Pollution Rule ("CSAPR")** – EPA issued the final CSAPR in July 2011 for the purpose of reducing the interstate transport of SO_2 and NO_X emissions from 28 eastern states, including Kentucky and West Virginia. On August 21, 2012, the D.C. Circuit vacated CSAPR and ordered EPA to continue to administer the Clean Air Interstate Rule ("CAIR") until it promulgates a replacement rule. The CAIR program also regulates annual SO_2 emissions and annual and seasonal NOx emissions, utilizing emissions allowances as the compliance mechanism.
2. **New 1-hour SO_2 National Ambient Air Quality Standard ("NAAQS")** – In 2010, the EPA revised the NAAQS for SO_2, establishing a new 1-hour standard, which is significantly more stringent than the prior

standards. Final designations on whether an area meets the new standard are expected from EPA in June 2013.

States must submit proposed State Implementation Plans ("SIPs") to EPA for areas designated as "in attainment" or "unclassifiable" by June 2013, and by February 2015 for areas designated as "nonattainment". These SIPs will detail any necessary SO_2 emissions reductions to either maintain attainment or bring a non-attainment area into attainment. Non-attainment areas must then achieve attainment by August 2018. The scope and timing of potential emission reductions at the Big Sandy and Mitchell plants is uncertain.

3. **Greenhouse Gas ("GHG") Regulations** – EPA continues to move forward in implementing a regulatory approach for controlling GHG emissions from power plants. In 2010, EPA promulgated the GHG Tailoring Rule that establishes thresholds for regulating GHG emissions from new power plants or from existing units that undergo major modifications. Also, on March 27, 2012, EPA proposed New Source Performance Standards ("NSPS") for new fossil fuel power plants with a carbon dioxide ("CO_2") emission limit of 1,000 lb/MWh, which is equivalent to the rate EPA assumes for a new natural gas combined cycle unit. It is expected that EPA will propose GHG NSPS requirements for existing fossil fuel units, but the agency has indicated that it currently has no plans regarding the development or timing of this proposal.

4. **Clean Water Act "316(b)" Rule** – EPA proposed the 316(b) Rule on April 20, 2011 and recently extended the deadline for finalizing the rule to June 27, 2013. The rule is applicable to cooling water intake systems and is designed to establish technology standards around the need for, and construction of, cooling water intake structures that would lessen the impact of impingement and entrainment on fish and other aquatic organisms. The Big Sandy and Mitchell Plants could be required to upgrade cooling water system intake screens as a result of this rule.
5. **Steam Electric Effluent Limitations Guidelines ("ELG")** – EPA is currently conducting a study to update the technology-based effluent limitations guideline (40 CFR 423) for steam electric generating facilities. Updates to the guidelines could lead to more stringent wastewater discharge limitations at both Big Sandy and Mitchell Plants. EPA has indicated its intention to issue a proposed rule in April, 2013 and a final rule in May, 2014.
6. **Coal Combustion Residuals ("CCR") Rule** – EPA proposed the CCR Rule in June 2010 to address the disposal of coal combustion byproducts (coal ash, etc.). The CCR Rule could require the conversion of all "wet" ash systems to dry systems; the possible relining or closing of ash ponds; as well as the possible construction of waste water treatment facilities by approximately the end of 2018. Based on the preliminary assumption that these residual materials may be categorized as "Subtitle D", or non-

hazardous materials[1], it would be anticipated that the Big Sandy and Mitchell Plants would require plant modifications and capital expenditures to address these requirements. The issuance of a final rule is currently anticipated near the end of 2013.

Each of these environmental regulations has the potential to result in additional environmental control requirements for the Big Sandy and Mitchell Plants that would necessitate capital investments to achieve compliance. I will discuss later in my testimony the Company's plans to meet the compliance needs of the pending CCR, 316(b), and anticipated ELG rules at the Big Sandy and Mitchell Plants.

V. BIG SANDY AND MITCHELL PLANTS' REGULATORY COMPLIANCE

Q. PLEASE DISCUSS THE CURRENT STATUS OF ENVIRONMENTAL CONTROLS AT BIG SANDY UNITS 1 AND 2.

A. Big Sandy Unit 2 currently operates with SCR and low NO_X burner ("LNB") systems for NO_X control, and an electrostatic precipitator ("ESP") for particulate matter control. Big Sandy Unit 1 currently operates with LNBs with over-fire air for NO_X control, and an ESP for particulate matter control. These controls allow the Big Sandy units to operate in compliance with existing requirements, including the CAIR Rule NO_X program.

Q. WHAT ENVIRONMENTAL CONTROLS WOULD NEED TO BE INSTALLED TO BRING BIG SANDY UNITS 1 AND 2 INTO COMPLIANCE WITH THE NEW MATS REQUIREMENTS?

[1] As set forth under the current Resource Conservation and Recovery Act (RCRA)

A. The MATS Rule emission limits for mercury, particulate matter ("PM"), and hydrochloric acid will likely require some combination of FGD, dry sorbent injection ("DSI"), fabric filter baghouses, and activated carbon injection ("ACI") if the Big Sandy units continue to utilize coal. The addition of the NID™ Dry FGD technology would allow the units to meet the MATS limits. Conversion to natural gas would also allow for compliance with the MATS limits.

Q. PLEASE DISCUSS THE CURRENT STATUS OF AIR EMISSIONS CONTROLS AT MITCHELL PLANT.

A. Each Mitchell unit currently operates with a FGD system, SCR system, LNBs, ESP, and FGD Trona injection systems.

Q. DESCRIBE THE REGULATORY PROGRAMS THAT DROVE THE NEED FOR THE INITIAL INSTALLATION OF THESE CONTROLS AT MITCHELL PLANT.

A. The primary federal statute that drove the initial need for these environmental controls is the Clean Air Act ("CAA"), as implemented in the West Virginia State Implementation Plan. The electrostatic precipitators at Mitchell Plant allow the units to operate in compliance with the particulate emissions limitations in the WV SIP. The FGD systems at Mitchell allow the units to operate in compliance with the CAA Title IV and CAIR SO_2 programs. The LNBs and SCRs at Mitchell allow the plant to operate in compliance with the Title IV and CAIR NOx programs.

Q. DO THE EXISTING ENVIRONMENTAL CONTROLS AT MITCHELL PLANT CURRENTLY MEET THE COMPLIANCE NEEDS OF THE

MATS RULE?

A. Yes. The emission control systems currently in place are expected to be sufficient for the Mitchell Plant to meet the requirements of the MATS Rule.

Q. **WILL ADDITIONAL MAJOR ENVIRONMENTAL CONTROLS BE REQUIRED AT THE MITCHELL PLANT TO MEET PROPOSED AND EMERGING REGULATORY COMPLIANCE NEEDS?**

A. Currently, the following environmental projects are underway for the purpose of meeting more stringent limits in the facilities' National Pollutant Discharge Elimination System ("NPDES") permit:

- Mitchell Units 1&2 Dry Fly Ash Conversion
- Mitchell Haul Road and New Landfill

Consideration is also being given to the installation of wastewater treatment technology as a component of these projects. These projects are also expected to satisfy the anticipated requirements of the CCR Rule, although there may be a need to re-line the bottom ash pond for compliance with the CCR Rule as well.

Finally, additional waste water treatment technology may be needed at Mitchell Units 1 and 2 for compliance with the emerging ELG Rule. The Company also anticipates a need to upgrade the cooling water intake system to comply with a revised 316(b) Rule.

The expected costs associated with these projects are used in the economic modeling addressed by Company Witness Weaver.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

DIRECT TESTIMONY

OF

SCOTT C. WEAVER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Scott C. Weaver being duly sworn, deposes and says he is Managing Director Resource Planning and Operation Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

SCOTT C. WEAVER

STATE OF OHIO	)	
	)	CASE NO. 2012-
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver this the 5th day of December, 2012.

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

Notary Public

My Commission Expires: October 1, 2016

DIRECT TESTIMONY OF
SCOTT C. WEAVER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-__________

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DIRECT TESTIMONY OF SCOTT C. WEAVER, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the eleven electric operating companies of the American Electric Power System ("AEP").

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Business Administration Degree in Accounting from Ohio University in 1981, and a Master of Business Administration from the same university in 1985. In addition, in 1996 I completed the AEP Management Development Program at The Ohio State University; as well as The Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controllers Department (now Corporate Planning and Budgeting Department), and was subsequently named Assistant Financial Analyst in 1983, Financial Analyst in 1986, Senior Financial Analyst in 1987, and Senior Administrative Assistant II in 1990. In 1991, I transferred to the AEPSC Fuel Supply Department as Manager-Administration. I was subsequently named Manager-Administration and Purchasing in 1994 and Director of Power Generation Business Planning and Financial Management in 1996. I transferred to the AEP Wholesale business unit in 2000 as Manager-Business Planning and in January, 2003 transferred back to the Corporate Planning and Budgeting Department as Director of Operational Analysis. I assumed my present position in May 2003.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR–RESOURCE PLANNING AND OPERATIONAL ANALYSIS?**

A. I am responsible for the supervision and administration of long-term generation resource planning and supply-side operational analysis for AEP. In such capacity, I coordinate the use of short- and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for Kentucky Power Company ("KPCo", or "the Company") and its parent, AEP, regularly monitor actual performance, and review the preparation of forecasted information for use in regulatory proceedings.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS REGULATORY COMMISSION?**

A. Yes. I recently offered testimony in the Company's filing seeking a certificate of public convenience and necessity for the construction of environmental controls at its Big Sandy Unit 2 (Case No. 2011-00401). I have also offered testimony before this Commission on behalf of the Company's most recent base rate case (Case No. 2009-00459); as well as its renewable energy purchase agreement filing (Case No. 2009-00545). I was responsible for the development of KPCo's 2009 Integrated Resource Plan filing (Case No. 2009-00339). In addition, over the last six years I have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight other state commissions: Arkansas, Indiana, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

III. PURPOSE OF TESTIMONY

Q. WHAT ARE THE PURPOSES OF YOUR TESTIMONY IN THIS FILING AND HOW DO THEY COMPARE TO THE INTENT OF CASE NO. 2011-00401 WHICH WAS WITHDRAWN AT THE REQUEST OF THE COMPANY ON MAY 30, 2012?[1]

A. The purposes of this testimony are to:

1) discuss the pre-existing and emerging available disposition options related to KPCo's Big Sandy coal-fired generating station, which are being driven by known and emerging environmental regulations and legal requirements beginning in the nearer-term and continuing through this decade;

2) briefly describe the modeling process used to evaluate the relative economics of the various Big Sandy unit disposition options; and

[1] Subsequently formally withdrawn based on the Commission Order of May 31, 2012 granting the Company's motion to withdraw.

3) discuss the results of these economic modeling analyses which indicate that the first steps of an optimal long-term resource plan for KPCo would include;

a) retiring Big Sandy Unit 2 ("BS2") by June 2015 replacing it with an ownership transfer of a fifty percent (780 MW) undivided interest of Mitchell Units 1 and 2—which are currently owned by KPCo-affiliate Ohio Power Company ("OPCo")—in 2014; and

b) issuing a Request for Proposal ("RFP") for approximately 250 MW of long-term capacity and energy in 2013, in consideration of a potential retirement of Big Sandy Unit 1 ("BS1") by June 2015.

As will be discussed, this testimony will serve both to re-analyze all of the unit disposition options previously evaluated in Case No. 2011-00401 utilizing more up-to-date information, and introduce the results of economic modeling performed to assess additional options now available to KPCo.

Q. **WERE YOUR EXHIBITS USED TO SUPPORT YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?**

A. Yes they were. As I will describe in this testimony, it is important to realize, however, that numerous management and functional groups within KPCo and AEPSC were involved in this process. The role I served was one of coordinating the attendant economic modeling effort and, ultimately, validating, documenting, and internally communicating this process and the results.

Q. **DO THESE EXHIBITS INCORPORATE AN APPENDIX THAT SUMMARIZES OTHER RELEVANT INFORMATION?**

A. Yes. SCW- Exhibit 1 offers a broader overview of some of the other resource planning-related criteria that are necessarily introduced as part of this evaluation of alternative options surrounding the unit disposition options being considered in this filing. In addition, this Appendix offers information surrounding additional risk analyses that were undertaken to further validate the results. The following testimony focuses more specifically on the discrete economic evaluations performed that led to the Company's conclusions and recommendations.

IV. AVAILABLE ALTERNATIVES

Q. WHAT ARE THE ALTERNATIVES AVAILABLE TO KPCO TO ADDRESS THESE IMPENDING ENVIRONMENTAL AND LEGAL REQUIREMENTS AT THE BIG SANDY FACILITY?

A. As summarized on SCW- Exhibit 2 and on the following TABLE 1, eleven (11) unique variations involving six (6) alternative options were assumed to be available to KPCo to address the unit disposition decisions facing both Big Sandy Units 1 and 2, including the prospect of a specific affiliate asset transfer:

TABLE 1

Option #1: Retrofit Big Sandy Unit 2

Option #1A: Retrofit Big Sandy Unit 2 with Dry Flue Gas Desulfurization ("DFGD") technology by approximately June 2017 (and, subsequently, required "CCR and 316(b)-related" equipment by 2019); and **Retire Big Sandy Unit 1 by June 2015** replacing this unit with capacity and energy from a **twenty percent (312 MW) ownership interest of Mitchell Units 1 and 2** on January 1, 2014.

Option #1B: *same as Option "#1A" except,* assume additional capacity and energy required to replace Big Sandy 1 is purchased from projected available PJM markets for 10 years in lieu of a Mitchell unit ownership transfer; then assume a new-build combined cycle ("CC"), or simple-cycle combustion turbine ("CT") facility.

Option #2: **Retire & Replace Big Sandy 2 with a (Brownfield) CC**

Option #2A: **Retire Big Sandy Units 2 (and Unit 1) by January 2016 (and April 2015)**, respectively, and replace Unit 2 capacity and energy with a nominally-rated 762-MW (918-MW for peaking purposes with duct-firing) **New-Build natural gas CC facility**, to be located at the Big Sandy site, **by June 2017**, with additional capacity and energy required to replace Big Sandy 1 from a **twenty percent (312 MW) ownership interest of Mitchell Units 1 and 2** on January 1, 2014.

Option #2B: *same as Option "#2A" except,* assume additional capacity and energy to replace Big Sandy 1 is purchased from projected available PJM markets for 10 years in lieu of a Mitchell unit ownership transfers; then assume a new-build CC, or CT(s).

Option #3: **Retire & Replace Big Sandy 2 with a CC-Repowered Big Sandy Unit 1**

Option #3A: **Retire Big Sandy Unit 2 by January 2016** and replace it with the **Repowering of Big Sandy Unit 1** as a nominally-rated 745-MW (802-MW for peaking purposes with duct-firing) **natural gas CC unit by June 2017**, with additional capacity and energy required to replace Big Sandy 1 from a **twenty percent (312 MW) ownership interest of Mitchell Units 1 & 2** on January 1, 2014.

Option #3B: *same as Option "#3A" except,* assume additional capacity and energy to replace Big Sandy 1 is purchased from projected available PJM markets for 10 years in lieu of a Mitchell unit ownership transfer; then assume a new-build CC, or CT(s).

Option #4: **Retire & Replace Big Sandy Units 2 (and 1) with Market Purchases**

Option #4A: **Retire Big Sandy Units 1 & 2 by June 2015, and replace both units** with capacity and energy purchased from projected available **PJM markets** for an interim **period of 5 years** (through 2020), then assume a larger-tranche (700-800 MW) new-build CC and/or CT(s) capacity replacement.

Option #4B: *same as Option "#4A" except,* assume replacement capacity and energy purchases from projected available PJM markets for an interim **period of 10 years** (through 2025) before a (~700-800 MW) new-build CC and/or CT(s).

Option #5: <u>Retire Big Sandy 2 and Preserve Big Sandy 1 as a Converted Natural Gas-Fired Unit</u>

Option #5A: <u>**Retire Big Sandy Unit 2**</u> **by June 2015** replacing it with capacity and energy from a <u>**50 percent (780-MW) ownership interest of Mitchell Units 1 and 2**</u> on January 1, 2014; while <u>**converting Big Sandy Unit 1 to burn Natural Gas**</u> **by July 2015**.

Option #5B: *same as Option "#5A" except,* assume capacity and energy purchased from projected available PJM markets for an interim <u>**period of 5 years**</u> (through 2020), then assume (~700-800 MW) new-build CC and/or CT(s), in lieu of a 50% Mitchell transfer.

Option #6: <u>Retire & Replace Big Sandy Units 2 (and 1) with (50%) Mitchell Asset Transfer and Market Purchases</u>

Option #6: <u>**Retire both Big Sandy Units 1 & 2**</u> **by June 2015,** and replace with capacity and energy from a <u>**50 percent ownership interest of Mitchell Units 1 and 2**</u>, *plus* additional (~250 MW) capacity and energy purchased from available projected PJM markets for a period of 10 years, then assume new-build CC, or CT(s).

Q. **WHY ARE VARIATIONS OF THE SIX PRIMARY DISPOSITION OPTIONS BEING CONSIDERED?**

A. First, the particular focus of the six primary options is to set forth alternatives associated with the larger, 800 MW Big Sandy Unit 2. Then, as a *subset* of most of those six options, alternatives A and B were offered to consider the attendant disposition alternatives for the smaller, 278 MW Big Sandy Unit 1. The exception is Option #4 which would retire <u>both</u> Big Sandy 1 and 2 by June 2015, replacing the units, on an interim basis, solely with (PJM) market capacity and energy. Here, the attendant A and B subsets pertain to the length of the interim market purchase period; 5 years versus 10 years, respectively.

Q. OVERALL, HOW DO THESE ALTERNATIVE DISPOSITION OPTIONS COMPARE TO THOSE EVALUATED AS PART OF THE (WITHDRAWN) CASE NO. 2011-00401?

A. As summarized on SCW- Exhibit 2, Options #1B, #2B, #3B, #4A and #4B are largely identical to the disposition alternatives evaluated in Case No. 2011-00401. The only meaningful differences within this re-analysis for those options are:

- The recognized delay in the in-service dates for the Option #1 DFGD retrofit to June 2017 (from June 2016); along with the attendant cost increases associated with that change.
- Likewise, the delay in the estimated in-service date of the replacement CC options (Options #2 and #3) to the same June 2017 timeframe, along with the attendant cost estimate modifications.
- The further recognition that such in-service delays would result in the need to rely solely on PJM market capacity and energy in the period post-unit retirements (June 2015 or April 2016, depending on the option and unit), until the 'build' option is completed in June 2017 (Options #1, #2, and #3).

Options #1A, #2A, #3A, #5A, #5B and #6 represent new alternative disposition options associated with this filing. Each of these new options offers variations as to the extent/level of an affiliate generating asset transfer from a portion of the Mitchell facility.

V. PLANNING PROCESS AND IMPENDING ENVIRONMENTAL REQUIREMENTS

Q. PLEASE DESCRIBE THE IMPLICATIONS ON KPCO'S RESOURCE PLANNING PROCESS DUE TO EACH OF THE KNOWN OR

CURRENTLY-EMERGING ENVIRONMENTAL CHALLENGES FACING THE COMPANY.

A. Company Witness John McManus provides more detailed descriptions and discussions surrounding the environmental challenges facing KPCo's coal generating assets, but the following offers a summary overview of the major known and emerging federal rulemaking and previously-established requirements, and the possible implications of each on the Company's long-term planning process:

I. **Mercury and Air Toxics Standards ("MATS") Rule** Implications on Planning -- As described by Mr. McManus, the initial compliance date of the U.S. Environmental Protection Agency ("EPA") MATS rule is April 16, 2015; but also provides for a possible one-year extension which could shift implementation to April 16, 2016, if specific criteria are satisfied. Therefore, for planning purposes, it has been assumed that this one-year extension (to approximately April, 2016) would be applicable if the intent is to either retrofit (or retire and replace) a unit for purposes of achieving compliance with MATS. All resource options modeled assumed achievement of MATS rule requirements by these prescribed implementation dates.[2]

II. **Coal Combustion Residuals ("CCR") Rule** Implications on Planning – As described by Company Witness McManus, it would be anticipated that—based even on the preliminary assumption that these residual materials may be categorized as Subtitle D, or *non-*

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[2] Although the MATS rulemaking implementation date is April (16), 2015, it is expected that the AEP-East units being planned for retirement will be able to operate through the full PJM 2014/15 capacity "planning year" (*i.e.*, through May 31, 2015), after consultations with PJM working with several state environmental agencies responsible for overseeing the implementation of MATS.

hazardous materials—each coal unit in the AEP fleet, including KPCo's Big Sandy generating units as well as the Mitchell units, would require plant modifications and capital expenditures to address these requirements by, approximately, the 2018 timeframe. As will be further described later in this testimony, the necessary environmental controls to achieve the CCR Rule have been considered as part of the respective long-term Big Sandy and Mitchell unit alternative evaluations.

III. **Clean Water Act "316(b)" Rule** Implications on Planning -- KPCo's Big Sandy units as well as the Mitchell units utilize natural draft, hyperbolic cooling towers. Therefore, and as described by Mr. McManus, the most significant impact of this rule could be the potential need to install additional fish screening at the front of the water intake structure to further reduce impingement and entrainment. While representing a potential exposure, it is generally anticipated that such fish screening mechanisms would likely not be required until late this decade with any capital expenditures leading up to that point being relatively minor in nature. As will be further described later in this testimony, such project cost estimates have been incorporated into the respective Big Sandy and Mitchell unit alternative evaluations

IV. **Steam Electric Effluent Limitations Guidelines ("ELG")** Implications on Planning -- As described by Company Witness McManus, the EPA is undergoing studies that could lead to the update of guidelines for wastewater discharge limitations with rules set to be finalized in 2014. In recognition of that, wastewater treatment projects have also been considered as part of the respective long-term Big Sandy and Mitchell unit alternative evaluations discussed later in this testimony.

V. **New Source Review ("NSR") Consent Decree** -- As described by Company Witness McManus, KPCo is required under the NSR Consent Decree to perform the following:

- Big Sandy Unit 2: Install Flue Gas Desulfurization ("FGD") for SO_2 emission reductions by December 31, 2015
- Big Sandy Unit 2: Continue to operate the existing Selective Catalytic Reduction ("SCR") system to minimize NO_X emissions
- Big Sandy Unit 1: Install and operate Low-NO_X Burner technology *and* limit the sulfur content of its burn coal to no greater than 1.75 lb. per million British thermal units (MMBtu), on an annual average basis, by the effective date of the Consent Decree.

For the Mitchell units, the current owner and KPCo-affiliate, OPCo was required to perform the following under the NSR Consent Decree:

- Mitchell Units 1 and 2: Install and operate FGD by December 31, 2007
- Mitchell Units 1 and 2: Install and operate SCR system controls for NOx emissions by December 31, 2009

In fact, the Mitchell units achieved the prescribed environmental FGD and SCR retrofit dates established under the NSR Consent Decree. As described by Company Witness McManus the installation of these environmental controls is also sufficient for the Mitchell units to achieve the MATS rule implementation requirements.

Q. IN SUMMARY, FROM A PLANNING PERSPECTIVE, WHAT IMPACTS WOULD THESE KNOWN AND EMERGING U.S. EPA REQUIREMENTS HAVE ON KPCO'S COAL GENERATING ASSETS AS WELL AS THE MITCHELL FACILITY?

A. Significant environmental controls are recognized as being required to ensure the future operation of both the Big Sandy as well as the Mitchell generating units. In fact, these known and emerging EPA requirements summarized above would indicate comparable environmental controls would have been needed in lieu of—or even over-and-above—what was prescribed under the previously-established NSR Consent Decree. As part of this recognition, the economic evaluation being offered by the Company in this filing has sought to reasonably address each of these proposed or emerging regulations by way of introducing any additional environmental capital projects necessary to ensure future compliance.

Q. DID COMPANY WITNESS MCMANUS DISCUSS OTHER EMERGING ENVIRONMENTAL REGULATIONS THAT COULD POTENTIALLY IMPACT COAL PLANTS LIKE BIG SANDY AND MITCHELL?

A. Yes. He also provided overviews of a "New 1-hour SO_2 National Ambient Air Quality Standard ("NAAQS")" as well as "Greenhouse Gas ("GHG") Regulations".

Q. WHERE THESE REQUIREMENTS DIRECTLY INCORPORATED INTO THE KPCO RESOURCE OPTION MODELING YOUR ARE SPONSORING?

A. No, not specifically. As it pertains to the 1-hour SO_2 NAAQS, Mr. McManus also indicates that "The scope and timing of potential emission reductions at the Big Sandy and Mitchell plants is uncertain."[3] Given this, plus the fact that the evaluated options are already reflective of coal generation facilities that are 'fully-retrofitted' for sulfur dioxide (SO_2), nitrogen oxide (NO_X) and mercury control, at

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[3] McManus direct, at 9.

this point it is not at all certain that additional retrofit requirements would be required in any event. As it pertains to any future GHG regulation, Mr. McManus also clearly indicates, "It is expected that EPA will propose GHG NSPS requirements for existing fossil fuel units, but the agency has indicated that it currently has no plans regarding the development or timing of this proposal".[4] That said, as will be discussed later in this testimony, the Company *has* considered the impacts of CO2/carbon legislation as part of its resource option modeling process. Specific estimates for a $ per tonne of emission "carbon tax" have been incorporated into the suite of long-term commodity pricing underpinning that modeling.

Q. FOR DISPOSITION OPTION #1, PLEASE RECONCILE AND DISCUSS THE "INTERIM" IMPACTS OF AN ASSUMED BIG SANDY 2 RETROFIT IN-SERVICE DATE OF APPROXIMATELY JUNE 2017, IN THE CONTEXT OF THE REQUIRED IMPLEMENTATION DATES SET FORTH UNDER THE MATS RULEMAKING AND THE NSR CONSENT DECREE, WITH THE LATTER BEING DECEMBER 31, 2015.

A. It is anticipated that the necessary time to obtain Commission approvals, permit, engineer, procure materials and components, construct and commission a DFGD retrofit at Big Sandy Unit 2 would now place the in-service date, for economic modeling purposes, at approximately June 2017. Given that, and the limiting factors associated with the MATS rule and the NSR Consent Decree, it was then assumed that, for (Option #1) modeling purposes, Big Sandy 2 would be removed from service for the approximate 15 month period beginning January 1, 2016

[4] *Ibid.* (The acronym "NSPS" represents New Source Performance Standards.)

through the normal retrofit "tie-in" outage which would begin in approximately the April 2017 timeframe. For modeling purposes, it was assumed the Company would rely on PJM market capacity and energy during this entire interim period.

Q. **AS SUMMARIZED IN SCW- EXHIBIT 1, KPCO RECEIVES 15 PERCENT, OR APPROXIMATELY 390-MW OF THE CAPACITY AND ENERGY FROM THE CURRENTLY ENVIRONMENTALLY-UNCONTROLLED ROCKPORT UNITS 1 AND 2 AS PART OF ITS PURCHASE AGREEMENT WITH AFFILIATE AEP GENERATING COMPANY ("AEG"). WHAT UNIT DISPOSITION ASSUMPTIONS HAVE BEEN MADE AROUND THOSE UNITS FOR PURPOSE OF THIS BIG SANDY UNIT DISPOSITION MODELING?**

A. For purpose of establishing a modeling baseline, it is assumed that a single Rockport unit will be retrofitted with DFGD and SCR technology by January 1, 2016 and the other Rockport unit would be retrofitted with an FGD technology by April, 2015 and an SCR by end-of year 2019; all in-keeping with the Rockport units' MATS and unique NSR Consent Decree requirements and timing, respectively. Moreover, given that this KPCo disposition modeling focuses on decisions around Big Sandy, a broad assumption was made that this AEG-Rockport purchase agreement would be extended beyond the current term of December 7, 2022, through the end of the Strategist® long-term study period (*i.e.*, 2040). However, this in no way serves as a commitment to this course of action for either a Rockport purchase extension, *or* the attendant environmental control equipment selection and installation timing applicable to those Rockport units.

Rather it simply serves as, again, a going-in baseline for KPCo's overall resource portfolio that, in turn, impacts the modeling process for this KPCo-Big Sandy unit disposition analysis. To be clear, this would not have any bearing on this relative KPCo unit disposition analysis in any event, as *each* option evaluated would include the same Rockport-related assumptions.

VI. ECONOMIC MODELING PROCESS

Q. HOW WERE THESE IDENTIFIED ALTERNATIVES ANALYZED?

A. As more fully detailed by Company Witness Mark Becker, the Company utilized a proprietary long-term resource optimization tool known as Strategist® to perform these evaluations. Given the termination of the Interconnection Agreement ("Pool Agreement") effective January 1, 2014, as described in SCW-Exhibit 1, these economic evaluations were performed from the perspective of a "stand-alone" KPCo. Further, these evaluations were performed over a 30-year economic study period (2011 through 2040) in the Strategist® tool so as to emulate the potential life-cycle of the respective asset alternatives as well as in recognition of the various down-stream impacts on KPCo's overall resource planning needs.

As described in more detail by Mr. Becker, the alternative-specific, generation-related costs/revenue requirements were then discounted to 2011 dollars and reflected on a Cumulative Present Worth ("CPW") basis. It is also critical to understand that the framework for these evaluations was focused not on the absolute CPW results, but rather a *comparative* view of the alternative options' results. In other words, the objective of this exercise was to identify the relative least-cost alternative among those identified in TABLE 1. Finally, the results from Strategist® offer a view of these relative economics over the full, 30-year economic study period and thereby do not constitute an isolated test-year cost-of-service view.

Q. **COULD YOU PLEASE IDENTIFY SOME OF THE MORE CRITICAL INPUT PARAMETERS FOR THE UNIT DISPOSITION ANALYSES AND WHERE THAT INFORMATION WAS SOURCED?**

A. Two of the major underpinnings in this process are long-term forecasts of KPCo's energy sales and customer (peak) demand, as well as the price of various generation-related commodities, such as energy, capacity, coal, natural gas, and emission allowances, including carbon/CO_2. Both views were created internally within AEPSC. The load forecast, including projected KPCo energy sales and demand summaries offered in the SCW- Exhibit 1 information appendix, was created by the AEP Economic Forecasting organization; while the long-term commodity pricing forecast was created by Company Witness Karl Bletzacker and his AEP Fundamental Analysis group. SCW-Exhibit3 offers a table that summarizes several of the key long-term fundamental commodity pricing projections utilized in these analyses. These groups have had years of experience forecasting KPCo and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes.

Other critical input parameters include the installed cost of the environmental retrofits required and replacement capacity-build options, as well as the attendant operating costs associated with those options -- data which was sourced from the AEP Generation organization, including AEP Engineering Projects & Field Services ("EP&FS").

Q. **WOULD YOU PLEASE OFFER AN OVERVIEW OF THE FORECASTED FUNDAMENTAL COMMODITY PRICING, INCLUDING NATURAL GAS, THAT WAS USED IN THESE MODELING ANALYSES?**

A. As shown in TABLE 2 below, an array of five (5) unique, long-term commodity pricing views established and described by Company Witness Bletzacker were utilized in the Strategist®-based analysis. These profiles consisted of a Base—or most probable view—as well as four additional scenario views that served to band the Base profile:

TABLE 2

('BASE') "Fleet Transition-CSAPR" [5] ... *reflecting:*

- Recognition of relatively lower fuel price trending, increasing natural gas price elasticity and capturing of a likely implementation profile of environmental regulation including CSAPR, MATS and potential carbon mitigation via a carbon tax (latter beginning in 2022).

Commodity Price Banding Scenarios...

2. "Fleet Transition-CSAPR: HIGHER Band"... *same as the BASE case except:*
   - Bounds the high-end of the BASE case with plausible fuels, emissions and energy pricing—with appropriate feedback for load response—and with such fuel prices varying by approximately +1.0 standard deviation.

[5] The use of the term "CSAPR" in the forecast title is a naming convention based on the fact that this fundamental pricing was predicated upon several proposed and emerging EPA rules, including at the time, the Cross-States Air Pollution Rule ("CSAPR"). However, as described in the direct testimony of Company Witness Bletzacker, although the CSAPR has been vacated, certain emission allowance values (*i.e.*, SO_2 and NO_X) would expect some changes only for the years 2012-2014 in order to be in line with the replacement Clean Air Interstate Rule pending the promulgation of a valid replacement for CSAPR. Hence, the described commodity pricing (scenario) forecasts used in these long-term KPCo economic analyses would result in no changes beginning in 2015, which approximates the start-year of any relative long-term, option-specific portfolio variations.

3. "Fleet Transition-CSAPR: LOWER Band" ... *same as the BASE case except:*
    - Likewise, bounds the low-end of the BASE case with plausible fuel, emissions and energy pricing, with such fuels prices varying by approximately -1.0 standard deviation.

"Carbon/CO_2 Pricing Scenarios...

4. "Fleet Transition-CSAPR: No Carbon"... *same as the BASE case above except:*
    - No carbon tax assumed throughout the long-term period modeled.
5. "Fleet Transition-CSAPR: Early Carbon" ... *same as BASE case except:*
    - An accelerated—versus BASE view—2017 timeframe for the implementation of a CO_2/carbon tax.

Q. HAS THE SELECTION OF THE SPECIFIC BIG SANDY UNIT 2 RETROFIT TECHNOLOGY FOR "OPTION #1" BEEN MODIFIED IN THIS KPCO RE-ANALYSIS FILING, WHEN COMPARED TO THE ORIGINAL ASSESSMENT PERFORMED IN CASE NO. 2011-00401?

A. No it has not. The "NID" DFGD technology is consistent with the Big Sandy 2 retrofit design that was previously submitted in Case No. 2011-00401. This approach continues to represent the optimum FGD technology. Only the presumed in-service date—and the attendant installed (nominal) cost—have changed.

Q. LIKEWISE, IS THE REPLACEMENT NEW-BUILD (BROWNFIELD) GAS CC ALTERNATIVE AVAILABLE TO KPCO THAT YOU HAVE IDENTIFIED AS OPTION #2 CONSISTENT WITH THE ORIGINAL UNIT DISPOSITION ASSESSMENT PERFORMED IN CASE NO. 2011-00401?

A. Yes it is. The Strategist® modeling to proxy this option continues to be based on the assumed utilization of a Mitsubishi 2x1 M-501-GAC[6] design that would be nominally-rated at approximately 762 MW. Given that this CC facility would also be designed with duct-firing and chillers, the maximum capability of the unit has been determined to be 918 MW. It was further assumed to be located at the existing Big Sandy site, thereby utilizing existing site infrastructure and transmission interconnections.

Q. FURTHER, IS THE REPLACEMENT <u>BIG SANDY UNIT 1 GAS CC REPOWERING</u> ALTERNATIVE AVAILABLE TO KPCO THAT YOU HAVE IDENTIFIED AS OPTION #3 ALSO CONSISTENT WITH WHAT WAS MODELED IN CASE NO. 2011-00401?

A. Yes. The Strategist® modeling to proxy this option also continues to be based on the assumed utilization of the existing Big Sandy Unit 1 steam turbine and piping, as well as the conjoining of two (2) new Mitsubishi 501-G combustion turbines and Heat Recovery Steam Generators ("HRSGs"). The nominal rating of this CC facility then being approximately 745 MW—with duct-firing capability of up to 802 MW. As with Option #2, this modeled alternative reflected the cost and performance parameters sourced from AEP EP&FS as well as the AEP Fuel, Emissions and Logistics ("FEL") organizations, which included the utilization of 3rd party expertise in the development of each of these natural gas-fired alternative cost estimates as well as input surrounding the required natural gas pipeline infrastructure needs. Consistent with Option #2, the major changes to this Option

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[6] This represents two (2) natural gas turbines in combination with heat recovery steam generators), and single steam turbine.

#3 CC replacement alternative, versus the original filing, is the shift in the presumed in-service date and the attendant installed nominal costs.

Q. PLEASE DESCRIBE THE <u>BIG SANDY UNIT 1 GAS CONVERSION</u> ALTERNATIVE NOW BEING INITIALLY INTRODUCED AS A COMPONENT OF OPTION #5 IN THIS FILING.

A. This alternative is based on an approach which would allow the existing, smaller, Big Sandy Unit 1 to burn natural gas in its steam generator/boiler instead of coal. It would require some boiler and burner modifications and, similar to the CC alternatives (Options #2 and 3), would require the necessary gas pipeline infrastructure. Recognizing, however, that the unit would be expected to operate at approximately the same thermal efficiency/heat rate as it had as a coal unit, it would naturally be expected to economically-generate less energy (*i.e.*, operate at a lower capacity factor) as a gas-fired facility, than when previously operating as a coal-fired unit due to the relative higher projected $/MMBtu price of natural gas versus coal.

Q. WHY WAS THE LARGER BIG SANDY UNIT 2 NOT CONSIDERED FOR SUCH NATURAL GAS CONVERSION?

A. It is my understanding that such conversions would not be practical for this unit. Due primarily to its super-critical design, an attendant heat rate penalty could be more severe than what might be expected on a smaller-scale unit, hence the presumed capacity factor for a converted Unit 2 would then be even lower than anticipated for Unit 1. Further, the attendant cyclic, start-and-stop nature of its operation would likewise not lend itself to a large unit such as Big Sandy 2, compared to the more robust sub-critical steam generator/boiler design of Big Sandy Unit 1.

Q. IN SUMMARY, WHAT ARE THE COMPARATIVE ESTIMATED CAPITAL COSTS ASSOCIATED WITH THE BIG SANDY UNIT 2 FGD RETROFIT TECHONOLOGY ALTERNATIVE (OPTION #1), THE REPLACEMENT NEW-BUILD GAS CC ALTERNATIVE (OPTION #2), THE BIG SANDY 1 REPOWERED GAS COMBINED CYCLE ALTERNATIVE (OPTION #3), THE BIG SANDY UNIT 1 GAS CONVERSION ALTERNATIVE (OPTION #5), AS WELL AS THE MITCHELL TRANSFER ALTERNATIVE (OPTIONS #1, 2, 3, 5 & 6), ALL PREVIOUSLY DESCRIBED, THAT WERE UTILIZED IN THESE UPDATED KPCO UNIT DISPOSITION ECONOMIC EVALUATIONS?

A. The following TABLE 3 offers a summary of the capital costs of the options modeled in Strategists®:

TABLE 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	**Estimated "Alternative" Capital Expenditures [A]**		Direct (EPC) & Indirect Cost		KPCo Prod. Capital Overhead Alloc.	TOTAL COST *(Excluding AFUDC)*	
	(Excluding AFUDC)						
(2)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(3)	Option #1: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(4)	RETROFIT Option	(C)					
(5)	**Dry (NID™) FGD [B]**	*788*	$858	949	$90	$948	1,048
(6)	*Plus: Additional Non-Recurring BS2 Environmental*						
(7)	*Costs included in Modeling (thru 2021)*		*$45*	*48*	*$5*	*$50*	*53*
(8)	*TOTAL All Major Projects*		*$903*	*997*	*$94*	*$998*	*1,102*
(9)		*Unit Capacity*					
(10)		*(w/Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(11)	Option #2: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(12)	REPLACEMENT Option						
(13)	**New-Build CC** *(@ BS site)*	*918*	**$1,137**	**1,077**	**$97**	**$1,234**	**1,168**
(14)		*Unit Capacity*					
(15)		*(w/Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(16)	Option #3: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(17)	REPLACEMENT Option						
(18)	**BS1 CC Repowering**	*802*	**$1,072**	**1,161**	**$91**	**$1,163**	**1,260**
(19)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(20)	Option #5: Big Sandy Unit 1	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(21)	REPLACEMENT Option	(D)			(E)		
(22)	**BS1 Gas Conversion**	*268*	**$54**	**181**	*N/A*	**$54**	**181**
(23)	*Plus: Additional Non-Recurring BS1 Environmental*						
(24)	*Costs included in Modeling (thru 2021)*		*$3*	*10*	*$0.3*	*$3*	*10*
(25)	*TOTAL All Major Projects*		*$57*	*191*	*$0.3*	*$57*	*192*
(26)		*Unit Capacity*	Millions	$/kW	Millions	Millions	$/kW
(27)	Options #1,2,3,5 & 6: Big Sandy Unit 1 or 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(28)	REPLACEMENT Option		(F)			*No AFUDC would apply*	
(29)	**Mitchell 1&2 Asset Transfer @ 20%**	*312*	**$214**	**648**	*N/A*	**$214**	**648**
(30)	**Mitchell 1&2 Asset Transfer @ 50%**	*780*	**$536**	**648**	*N/A*	**$536**	**648**
(31)	*Plus: Additional Non-Recurring Mitchell Environmental*						
(32)	*Costs included in Modeling (thru 2021), post-1/2014*						
(33)	*Mitchell 1&2 Asset Transfer @ 20%*		$37	*99*	*$4*	*$40*	*110*
(34)	*Mitchell 1&2 Asset Transfer @ 50%*		$92	*99*	*$10*	*$101*	*110*
(35)	*TOTAL All Major Projects*						
(36)	*Mitchell 1&2 Asset Transfer @ 20%*		*$251*	*747*	*$4*	*$255*	*758*
(37)	*Mitchell 1&2 Asset Transfer @ 50%*		*$628*	*747*	*$10*	*$637*	*758*

(A) Represents AEP EP&FS and FEL capital cost estimates utilized for modeling purposes in Strategist®

(B)"DFGD" also includes necessary landfill and associated boiler modifications

(C) Reflects an assumed ~1.5% unit derate to compensate for assumed NID-FGD parasitic load

(D) Reflects an assumed ~3.5% unit derate; also reflects all required interconnection and gas pipeline/infrastructure costs

(E) Costs estimated were already 'fully-loaded'

(F) Reflects estimated "per book" cost @ 12/31/2013

Q. **PLEASE DESCRIBE THE COSTS NOTED IN TABLE 3 AS "ADDITIONAL NON-RECURRING ENVIRONMENTAL COSTS INCLUDED IN MODELING (THRU 2021)", AND HOW SUCH COSTS WERE ALSO FACTORED INTO THIS UNIT DISPOSITION EVALUATION PROCESS.**

A. These costs represent additional identifiable major capital spends that are expected to be incurred in the future for certain of the options modeled that are over-and-above the initial project costs. For instance, for the Option #1 Big Sandy 2 DFGD Retrofit, it was recognized that additional costs pertaining to emerging EPA regulation summarized earlier in this testimony—namely CCR and 316(b) rulemaking—could become a factor. Recognizing this, and considering the holistic nature of this evaluation process, it was necessary to consider those additional major, non-recurring capital costs that would be expected to be incurred at Big Sandy 2 beyond just the cost of the scrubber retrofit. To do otherwise would not be fair to the comparative long-term modeling exercise.

Likewise, note also in TABLE 3 that such additional, non-recurring future environmental capital costs have also been recognized for the Mitchell generating assets. Recall the transfer cost to KPCo represents the estimated AEP Generation Resources, Inc. balance sheet costs for these units as of the assumed asset ownership transfer date to be effective January 1, 2014. These additional costs reflect anticipated capital spends associated with future environmental-related requirements expected to be incurred at the Mitchell plant *beyond* that date. Such costs were then incorporated into the Strategist® modeling of the options that included such Mitchell ownership transfers.

SCW- Exhibit 4 offers project-specific detail of these major non-recurring environmental capital costs captured in the respective Big Sandy (retrofit) and Mitchell (asset transfer) resource option modeling.

Q. **WHAT WAS THE SOURCE OF THE MITCHELL ASSET TRANSFER COST DATA ALSO FOUND ON TABLE 3?**

A. KPCo's estimated Mitchell Unit Asset Transfer costs are based on estimates provided to me by Company Witness Wohnhas.

Q. **TABLE 3 DOES NOT SUMMARIZE OPTION #4 IN WHICH KPCO WOULD INITIALLY RELY ON AN ASSUMED MARKET REPLACEMENT OF <u>BOTH</u> BIG SANDY 1 AND 2 CAPACITY AND ENERGY. COULD YOU OFFER AN OVERVIEW OF THE MODELING APPROACH FOR THIS OPTION?**

A. The Strategist® modeling to proxy, specifically, Options #4A and 4B that was summarized on TABLE 1 was based on the assumption that any and all incremental capacity and energy requirements to meet KPCo native load and demand requirements, in recognition of a Big Sandy Unit 2 (and Big Sandy Unit 1) retirement by June 2015 due to MATS rule requirements, would be fully-met via market sourcing for some interim period prior to the eventual addition of CC and/or simple-cycle CT capacity resources.

To perform that analysis, the modeling utilized projections of such market values for Unforced Capacity ("UCAP") applicable to the PJM Reliability Pricing

Model ("RPM") capacity market construct, as provided by Company Witness Bletzacker and his AEP Fundamental Analysis group. Likewise, the attendant significant KPCo *energy* requirements that would emerge under this Option #4 alternative were likewise based on Mr. Bletzacker's estimates of PJM on-peak and off-peak energy pricing proxied at the AEP Generating hub. SCW- Exhibit 3 offers a summary of these respective capacity and energy forecasted values.

For purposes of the modeling exercise for this Option #4, two specific sub-options were evaluated. Option *#4A* assumed that KPCo would fully rely on PJM market capacity and energy—in lieu of the Big Sandy units, a replacement CC and/or CT-build, or an asset transfer—for a period of up to 5 years (or, through 2020) before such time that replacement CC and/or CT capacity would be added by KPCo. Option *#4B* assumed that KPCo would rely on the same (PJM) market-derived capacity and energy for a longer interim period, up to 10 years (or, through 2025). It is the Company's contention that the shorter-term full market exposure profile (Option #4A) would be the more likely option that would be considered—*if at all*—as I will discuss later in this testimony. However, in the interest of transparency, and to offer some additional banding alternatives for consideration, a longer-term (interim) PJM market solution was also chosen for modeling (Option #4B).

Q. PLEASE ALSO DESCRIBE HOW THE STRATEGIST® TOOL WAS USED IN THIS ANALYSIS TO CREATE THE REQUIRED *LONG-TERM* RESOURCE EXPANSION PLANS FOR EACH OF THE RESPECTIVE BIG SANDY UNIT DISPOSITION OPTION DESCRIBED IN TABLE 1.

A. The timing and general description of each of the eleven Big Sandy unit disposition options summarized on TABLE 1 (and SCW- Exhibit 2), and for which installed costs were summarized in TABLE 3, was modeled in Strategist®. In order to create the optimal (*i.e.*, lowest cost) generation expansion plan for each disposition option over the entire (2040) study period, the Strategist® model was then allowed to optimize subsequent KPCo capacity and energy requirements *beginning in the year 2020* from the following new generating resources options:

- In *all* of the eleven unit disposition options evaluated, it could choose from either:
  - blocks of four, new simple-cycle CTs (84 MW each, nominal rating), *or*
  - a 50% share of a new Greenfield CC-build (2x2x1 x 0.5 = 384 MW, nominal rating), *or*
  - a 100% share of a new Greenfield CC-build (2x2x1, 767 MW, nominal rating) as an available alternative capacity and energy resource block.
- In all unit disposition options <u>other than</u> those that would have already established a Brownfield CC-build in 2017 (*i.e.*, Options #2A and #2B), the model could <u>also</u> choose:
  - a 50% share of the identified new *Brownfield* CC-build (Big Sandy site) as an available alternative capacity and energy block.
- In those specific unit disposition options with larger resource needs in the period beyond 2020 that are primarily focused on nearer-term market solutions (*i.e.*, Options #4A, #4B and #5B), the model could also choose:
  - a 100% share of the identified new *Brownfield* CC-build (Big Sandy site) as an available alternative capacity and energy block during this subsequent resource optimization period.

Q. AS IT ALSO PERTAINS TO THE DEVELOPMENT OF THE COMPANY'S FUTURE RESOURCE OPTIONS, DID THE COMPANY EVALUATE COST-EFFECTIVE DEMAND-SIDE/ENERGY EFFICIENCY RESOURCES IN DETERMINING THE LEAST-COST ALTERNATIVE TO MEET ITS LONG-TERM OBLIGATIONS?

A. Yes. As described and detailed in SCW- Exhibit 1, Section II, Demand-Side Management ("DSM") in the form of both "active" and "passive" Demand Response ("DR") initiatives have been incorporated into the Company's resource planning process. Active DSM, in the form of peak-modifying DR activity has been projected as well as passive DSM in the form of Energy Efficiency ("EE") programs, which KPCo and this Commission has supported for some time.[7] While not at all trivial, it is evident, however, that such estimated DSM resource contributions from the estimated DSM activity by or around the mid-part of this decade of approximately 30-40 MW—while representing levels that are well above historical KPCo DSM contributions—are clearly well *below* the significant capacity needs that would be at issue when considering the disposition of units on the scale of Big Sandy Units 1 and 2. For example, even if it were assumed that the current modeled level of DSM activity in or around mid-decade were to perhaps *double* in scale, it would offer a relatively small offset when compared to the approximate 1,100 MW of KPCo unit disposition requirements at issue with Big Sandy Units 1 and 2.

[7] As specifically set forth in Case No. 2010-00095, which was approved by the Commission in August 2010.

VII. EVALUATION OF MODELING RESULTS

Q. **BASED ON THESE INPUT PARAMETERS, WHAT WERE THE RESULTS OF THE KPCO UNIT DISPOSITION ALTERNATIVE ANALYSES PERFORMED IN STRATEGIST®?**

A. SCW- Exhibit 5 offers a tabular summarization and comparison of the modeling results for the eleven unique KPCo disposition options for Big Sandy Units 1 and 2, while SCW- Exhibits 5A through 5E offer a broader view of the results for *each* of the five individual commodity pricing scenarios previously defined in TABLE 2.

As also previously described in this testimony these modeling results represent relative cost analyses, meaning each are compared to one another for determining the least-cost alternative outcome. Given that, SCW- Exhibit 5 reflects the costs of the various nearer-term alternative-build and (Mitchell) asset transfer options—as well as PJM market options—identified earlier (Options #1 through #6) all compared to a "Base" or reference alternative. For purpose of these economic assessments, that Base alternative was established as Option #6 from TABLE 1…

> *"Retire both Big Sandy Units 1 & 2 by June 2015, and replace with capacity and energy from a fifty percent ownership interest of Mitchell Units 1 and 2, plus additional (~250 MW) capacity and energy purchased from available projected PJM markets for a period of 10 years, then assume a new-build CC or CT(s)"*

Q. **PLEASE OFFER FURTHER ELABORATION ON THESE RESULTS SUMMARIZED ON SCW- EXHIBIT 5 (THAT WERE FURTHER SUPPORTED IN SCW- EXHIBITS 5A THROUGH SCW-5E).**

A. Focusing initially on the Company's BASE ("Fleet Transition-CSAPR") long-term fundamental commodity price forecast identified and summarized by Company Witness Bletzacker, and reflected in this testimony in TABLE 2 (and SCW- Exhibit-3), it can be concluded that the economically-optimum KPCo long-term capacity expansion plan result was clearly one that would initially include the transfer of a 780-MW, or fifty percent ownership share of the Mitchell plant by January 1, 2014.

As summarized on the first line of data found on SCW- Exhibit 5 (which is further detailed in SCW- Exhibit 5A), the relative CPW economic cost of the other options analyzed versus the Base Option #6 view—which incorporates that 780 MW (50%) ownership share transfer of Mitchell Units 1 and 2, along with an assumed smaller, approximate ~250 MW incremental need for capacity and energy from the PJM market for as long as 10 years—ranges from as high as +$697 million (+12.0%), to a <savings> for one alternative, Option #5A, of <$156 million> (<2.7>%). However, it is important to note that Option #5A *also* incorporated the same 780 MW ownership transfer of Mitchell plant; along with the assumption that Big Sandy Unit 1 would not be retired but rather converted—or "re-fueled"—as a natural gas-fired unit. In fact, setting aside the results for that comparable Option #5A, this CPW cost premium range versus the Base Option #6 would be +$258 million -to- +$697 million.

Q. **DOES THIS MODELING CONCLUSION CHANGE BASED ON THE RANGE OF LONG-TERM COMMODITY PRICING SCENARIOS ALSO EVALUATED?**

A. No it does not, but rather is reinforced. When moving down the SCW- Exhibit 5 summary, the relative CPW economic results for each of the other pricing scenarios analyzed would lead to the same conclusion. Specifically, under essentially all pricing scenarios evaluated the resource options that would include the transfer of the 780 MW (50%) ownership share of Mitchell (either the 'Base' Option #6, *or* Option #5A) offer the lowest CPW economic cost by a reasonably significant margin.

For instance, even under Fleet Transition-CSAPR: LOWER Band pricing, the relative CPW economic costs versus Base Option #6 ranges from as high as +$617 million, to a <savings> for, again, Option #5A, of <$154 million>.[8] Not surprisingly, under Fleet Transition-CSAPR: HIGHER Band pricing, the relative CPW economic costs versus Base Option #6 ranges from as high as +$1,017 million, to a <savings> for Option #5A, of <$149 million>.[9] Again, *excluding* Option #5A—which also recognizes a 50 percent Mitchell ownership transfer—the overall range of CPW <u>cost premiums</u> versus Option #6 was +$62 million -to- +$617 million, under Fleet Transition-CSAPR: LOWER Band pricing; and +$463 million -to- +$1,017 million, under Fleet Transition-CSAPR: HIGHER Band pricing.

Q. ARE THE RELATIVE SIZES OF THESE MODELED CPW COST PREMIUMS FOR THOSE OPTIONS THAT DO <u>NOT</u> REFLECT THE FIFTY PERCENT MITCHELL OWNERSHIP TRANSFER CONSISTENT

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[8] These results being further detailed in SCW- Exhibit 5C.

[9] These results being further detailed in SCW- Exhibit 5B.

WHEN VIEWED UNDER THE REMAINING PRICING SCENARIOS MODELED?

A. Yes. As also reflected on SCW- Exhibit 5, when viewed from the perspective of the additional pricing scenarios modeled that were defined on TABLE 2; namely, Fleet Transition-CSAPR: No Carbon and Fleet Transition-CSAPR: Early Carbon, the results are similar.[10] Significant relative cost savings were projected for Base Option #6 (as well as the comparable Option #5A) when compared to all of the other unit disposition options modeled. Most importantly, even under a commodity pricing scenario that would introduce a reasonable significant "carbon tax" in as early as the year 2017 (Early Carbon scenario) these modeled results offer evidence that the relative 30-year study period economics surrounding the fifty percent Mitchell asset ownership transfer continued to be significantly superior compared to the other options evaluated.

Q. YOU HAVE INDICATED THE ECONOMICS ARE BASED ON A 30-YEAR STUDY PERIOD. WHAT IS THE ULTIMATE IMPLICATION OF THESE COMPARATIVE ECONOMICS TO KPCO'S CUSTOMERS?

A. To provide some context for these relative CPW results, for every +/- $100 million CPW cost difference between any two options, there is a +/- $2.00 per Mwh levelized annual impact on KPCo's generation cost/revenue requirement over the subsequent economic life cycle analyzed—expressed in 2011 dollars. For instance, when comparing Option #6 versus Option #2B (Brownfield CC-build with PJM market purchases) costs under the BASE, or Fleet Transition-

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[10] The "No Carbon" pricing scenario modeled results are further detailed in SCW- Exhibit 5D; while the "Early Carbon" pricing scenario results are detailed in SCW- Exhibit 5E.

CSAPR pricing scenario, the resulting +$560 million CPW variance would equate to a levelized annual impact on G-revenue requirements of +$11.20 per Mwh (or 1.12 cents/kWh), in 2011 dollars.[11] Therefore assuming, for ease of demonstration, that this relative revenue requirement impact were applied equally to all tariffs, a typical KPCo Residential customer utilizing 1,000 kWh of energy per month would experience a relative G-rate impact of +$11.20 per month, every month, over the *entire* affected (*i.e.*, beginning in approximately 2016) future study period if a solution was chosen to retire Big Sandy 2 replacing it with a Brownfield CC *in lieu of* retiring the unit and replacing it rather with a 50 percent (780 MW) ownership interest in the Mitchell plant.

Q. WHAT ADDITIONAL OBSERVATIONS AND CONCLUSIONS CAN YOU DRAW FROM THE ECONOMIC COMPARISONS IN SCW-EXHIBIT 5?

A. Based even on the modeling results that were predicated on a more gas-friendly *lower* natural gas and attendant energy pricing (Fleet Transition-CSAPR: LOWER Band) and *earlier* Carbon/CO_2 (Fleet Transition-CSAPR: Early Carbon) scenarios, it would continue to strongly support the fifty percent Mitchell asset transfer. In general terms, assessing the full suite of modeled CPW differences between the evaluated disposition options summarized on SCW- Exhibit 5, that are inclusive of these hugely impactful discrete risk elements, it would indicate that a specific "metal-in-the-ground" (*i.e.*, non-market) solution calling for the transfer to KPCo of a fifty percent undivided ownership interest of the fully-

[11] 560 / 100 x 2.00 = 11.20

controlled Mitchell plant would represent the best option for KPCo and its customers.

Q. **FOCUSING SPECIFICALLY ON THE FULL MARKET-PURCHASE REPLACEMENT ALTERNATIVE (OPTIONS #4A AND #4B), WHAT CONCLUSIONS CAN ALSO BE DRAWN?**

A. The Strategist® results summarized in SCW- Exhibit 5 indicates that Option #4A (Retire and Replace Big Sandy Unit 2 with [100%] purchased capacity and energy from projected [PJM] markets for up to 5 years [through 2020] then replace with CC and/or CT-builds), would likewise reflect comparative study period economics favoring Base Option #6. Under BASE (Fleet Transition-CSAPR) pricing this largely full market solution was more costly than Option #6 by +$411 million (+$567 million if that comparison was made to the other alternative assuming the ownership transfer of a 50 percent share of Mitchell; Option #5A). To reinforce these results versus such full (PJM) market options, when comparing these Option #4A study period costs versus those of Option #6 across the *full suite* of pricing scenarios set forth in TABLE 2, the relative CPW cost premium of an Option #4A (5-year market) solution would range from as low as +$221 million (under Fleet Transition-CSAPR: LOWER Band pricing) to as high as +$*816* million (under Fleet Transition-CSAPR: HIGHER Band pricing).

Further, results for Option #4B—which would extend the full PJM market purchase period to 10 years (through 2025)—would likewise be more costly than Option #6 under BASE pricing by +$435 million. When comparing this Option #4B study period costs versus Option #6 across the full set of pricing scenarios, it would indicate a relative CPW cost range of between +$217 million (assuming the Fleet Transition-CSAPR: LOWER Band pricing scenario) to $903 million (under a Fleet Transition-CSAPR: HIGHER Band pricing scenario).

Q. **WHAT ADDITIONAL CONCERNS WOULD EXIST IF KPCO WERE TO EXERCISE AN OPTION SUCH AS #4B THAT WOULD FOREGO AN "ASSET" SOLUTION WITH ONE SOLELY DEPENDENT ON PROJECTED PJM CAPACITY AND ENERGY MARKET PRICING FOR APPROXIMATELY 1,100 MW OF GENERATION CAPACITY, AND FOR A PERIOD AS LONG AS 10 YEARS?**

A. As discussed within the testimony of Company Witness McDermott, such an approach would also potentially subject KPCo and its customers to additional cost and performance risks. Further, as summarized in my Exhibit SCW-1 information appendix, AEP and KPCo have continued to elect to opt-out of the latest annual PJM-RPM (3-year forward) capacity market/auction, and remain under the Fixed Resource Requirement ("FRR"), or "self-planning" framework. This implies that AEP and KPCo view the obligation to reliably serve its customers as paramount. The Company has no assurances that any future capacity required by PJM will be built as a result of the PJM-RPM construct. In fact, according to PJM's own <u>2015/2016 RPM Base Residual Auction Results</u> report, since the RPM's inception for the 2007/08 planning period, and through the most-recent 3-year forward (2015/16) planning period, only 13,917 MW of <u>new</u>

thermal installed capacity ("ICAP") has been offered into <u>all</u> of those nine Base Residual Auctions combined.[12]

Q. GIVEN THESE CONCERNS REGARDING THE FUTURE TIMELY AVAILABILITY OF CAPACITY UNDER THE PJM-RPM MARKET CONSTRUCT, WHAT IS YOUR CONCLUSION REGARDING OPTION #4 (RETIRE AND FULLY-REPLACE BIG SANDY UNIT 2—AND UNIT 1—WITH [PJM] MARKET PURCHASES)?

A. Based on the above observations, I conclude that while the value of PJM-RTO[13] capacity projected by the AEP Fundamental Analysis group is, in most forecast years, well below the cost of a new CC-build—as well as even PJM's established Net Cost of New Entry ("CONE") value[14]--any potential economic benefit of Option #4 could be quickly eliminated. Specifically, any perceived benefits of Option #4 could be diminished upon recognizing:

a) The price of capacity under the PJM-RPM market currently clears on a *single* incremental planning year basis, with <u>no</u> assurances—for sellers or buyers—as to the *sustainability* of those prices from year-to-year;

b) from a buyer's perspective the price of capacity under the PJM-RPM construct could begin to ultimately mirror, or exceed, Net CONE on a consistent basis[15]; and/or

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[12] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx

[13] The projection of RPM capacity value offered by the AEP Fundamentals group reflects PJM's western-most or "RTO" region.

[14] CONE is an RPM market proxy for a base/1.0 multiple capacity value based on the fixed cost associated with the construction and operation of a simple-cycle combustion turbine (SC-CT), *net* of some (small) market credits that would be subscribed to that SC-CT via the sale of energy and other ancillary products.

[15] The current Net CONE value for RTO UCAP for the most recent (2015/16) PJM forward planning year was established by PJM at approximately $321 per MW-day.

c) the price of the attendant PJM market *energy* could likewise exceed projected pricing levels.

Further, there were no modeled economic outcomes that would alter the Company's contention that—when coupled with the fact that PJM-RPM capacity market construct remains relatively immature—the inherent *year-to-year* pricing uncertainty and economic risks around being a capacity market "price-taker" are not in the best interest of KPCo's customers.

Q. COULD KPCO EXERCISE YET OTHER MARKET OPTIONS TO REPLACE THE 800 MW BIG SANDY UNIT 2 (OR, MORE SPECIFICALLY, THE FULL 1,078 MW CAPABILITY OF BOTH UNITS 1 AND 2) IN LIEU OF A PJM-RPM MARKET OPTION?

A. Yes. Recognizing the termination of the existing Pool Agreement and its capacity sharing/equalization features by and among its Member Companies, other options could theoretically be available to KPCo. For instance, assuming that KPCo would indeed effectively become a stand-alone entity from a planning perspective—in addition to retrofit, replacement-build and asset transfer replacement options (Options #1, #2, #3, #5, #6)—an option could be to enter into a market-based competitive solicitation for as much as ~1,100 MW of capacity—and attendant energy—being displaced by the potential retirement of both Big Sandy Units 1 and 2.

Q. DID KPCO ISSUE SUCH A FORMAL COMPETITIVE SOLICITATION?

A. No it did not.

Q. WHY WAS AN RFP OPTION FOR AS MUCH AS 1,100 MW OF REPLACEMENT CAPACITY AND ENERGY NOT CONSIDERED AND EVALUATED?

A. Such a market option/view *was* effectively considered. Option #2 (Retire and Replace Big Sandy 2 with a New Build CC option) offers such a market proxy. Based on discussions with AEP commercial experts, it is very reasonable to assume that a *long-term* (minimum, 10-20 year term) competitive purchase power agreement ("PPA") solicitation—for not only up to as much as 1,100 MW of replacement capacity, but for the largely baseload energy also being replaced—would likely be offered/priced at the cost of a new-build combined cycle in response to such an RFP. Based then on indicative cost-of-electricity evaluations that would assess the cost of a new-build CC, for instance, it was determined that such options would likely exceed the cost of the Mitchell generating asset transfer.

This approach is also addressed by Company Witness McDermott.

Q. COULD OTHER, PREVIOUSLY-BUILT CC CAPACITY RESIDING WITHIN THE PJM FOOTPRINT BE OFFERED AS PART OF ANY SUCH LONG-TERM, ~1,100 MW RFP UNDERTAKING BY KPCO?

A. While that is possible, such existing asset markets are extremely limited, particularly for higher-utilization CC assets. For instance, the Company is not aware of any active solicitations or informal inquiries for the sale of such comparably-sized CC generating assets. A further complication would be that any pre-existing CC asset residing within PJM that did not already have long-term, bi-lateral buyers for its capacity and energy are likely currently being offered into—and clearing in—the RPM market, meaning such assets would not be available to KPCo as part of any such bi-lateral arrangement in any event until the next PJM planning period. Given also the fact that since essentially all of any potential "merchant" CC assets residing in PJM were built early last-decade (or earlier), there is an emerging concern that these facilities could soon be facing significant, time-based turbine inspections and expensive re-builds as well as other steam-cycle and balance-of-plant maintenance issues, thereby lessening their relative economic values. Again, given this (bi-lateral) market uncertainty surrounding existing CC generating assets, it further suggests that even if one were to assume that such generating capacity and energy were available, those prices—via an asset purchase, or PPA—would likely ultimately proxy the cost of new-build replacement CC capacity and energy, as modeled under Option #2, discounted for known and measurable relative poorer efficiency and performance characteristics as well as incrementally-required, emerging life-cycle maintenance costs.

Q. WOULD THERE BE GREATER POTENTIAL FOR A SUCCESSFUL COMPETITIVE SOLICITATION OF REPLACEMENT BASELOAD CAPACITY AND ENERGY IF THE TRANCHE-SIZE WERE CLOSER TO 250 MW, OR AN AMOUNT ROUGHLY THE SIZE OF BIG SANDY UNIT 1?

A. KPCo contends that the approach of going to the market with a smaller RFP tranche size could offer a greater prospect of achieving "lower than new-build" costs as part of such a market solicitation.

Q. **IS KPCO CURRENTLY PLANNING ON ISSUING A SMALLER SOLICITATION FOR APPROXIMATELY 250 MW OF LONG-TERM CAPACITY AND ENERGY?**

A. As indicated in the testimony of Company Witness Pauley, KPCo currently plans on issuing such a competitive solicitation sometime early in 2013.

Q. **THE STRATEGIST® ANALYSIS SUMMARIZED ON SCW- EXHIBIT 4 WOULD INDICATE THAT OPTION #5A—WHICH INCLUDES THE PROSPECT OF BIG SANDY UNIT 1 *NOT* RETIRING, BUT RATHER BEING CONVERTED TO BURN NATURAL GAS—IS IN FACT THE LEAST-COST OPTION. IF SO, WHY WOULD KPCO CONTINUE TO PLAN TO SUBMIT AN RFP FOR APPROXIMATELY 250 MW OF CAPACITY AND ENERGY?**

A. The purpose of a subsequent RFP would be to obtain the best price for that *smaller* tranche of power and energy—included in Option #6—over the prescribed term. As part of the solicitation process it would be very conceivable that a Big Sandy Unit 1 natural gas conversion project (Option #5A) could be offered in as part of a formal RFP submittal. Through the subsequent RFP commercial evaluation process, if this conversion alternative were to prove out as being the least-cost approach, then the Company could then exercise such a Big Sandy 1 gas conversion option. That outcome, however, would be conditioned on the ability to quickly receive Commission approval to proceed, as well as the ability to obtain the requisite permitting and begin the required design and engineering work in time to achieve the desired approximate mid-2015 in-service date.

Q. **PLEASE SUMMARIZE YOUR CONCLUSIONS ASSOCIATED WITH THIS KPCO ALTERNATIVE RESOURCE EVALUATION PROCESS AND ITS OUTCOME.**

A. In general:

- The alternatives examined represented a well thought-out, robust set of alternative resource profiles that would seek to either continue operation *or* retire and replace Big Sandy Units 1 and 2.
- The Strategist® modeling offered a thorough, comprehensive examination of the relative generation-related costs applicable to each option across a wide array of projected commodity pricing.
- By far, the options with the least-cost attributes over the full study period examined represented those profiles (Options #6 and #5A) that would transfer a fifty percent ownership interest of the Mitchell units to KPCo.
- The recommended Option 6 alternative, would offer KPCo a balanced portfolio of sustainable, long-term low-cost baseload generating assets, coupled with the prospect of seeking a market-based solution for its remaining resource needs.

VIII. ADDITIONAL SENSITIVITY AND RISK ASSESSMENTS

Q. **WHAT ADDITIONAL STRATEGIST®-BASED SENSITIVITY ANALYSIS WAS PERFORMED?**

A. An analysis was performed to determine the extent by which the installed (or equivalent, existing unit acquisition) cost of a CC-build solution would have to change—*i.e.*, be reduced—so as to impact that option's CPW cost such that it would be equivalent to the study period CPW cost results for Option #6. Recall that the modeled economic study period CPW cost of Option #2B was $560 million more than Option #6 (under BASE pricing). Holding all other modeling variables constant, in order for that relative CPW variance to become *zero* dollars, the installed cost (excluding AFUDC) of the CC-build modeled in Option #2B would have to be reduced by $625 million (50.6%) (nominal dollars), or an "as-built" installed cost equal to only $577 per kW (2011 dollars). If one were assessing this value to any potential 3rd-party-owned (existing) CC asset purchase, that $577 per kW amount would have to be reduced *even further* in recognition of the probable poorer relative thermal efficiency and maintenance cost exposure versus a new-build CC.

Even when applying this (Option #6 vs. Option #2B) relative CPW "break-even" analysis under Fleet Transition-CSAPR: LOWER Band fundamental scenario—pricing that would favor a gas solution—the results are similar. Again, holding all other modeling variables constant, in order for that relative CPW variance of +$372 million to be zero, the installed cost of the CC-build used in Option #2B would have to be reduced by $415 million (33.6%) (nominal dollars), or an installed cost equal to $775 per kW (2011 dollars).

This sensitivity analysis would particularly support the contention that it would be highly speculative to assume that an existing, non-contracted combined cycle generating asset that may reside in the marketplace could avail itself to KPCo at a price that render the (Mitchell) asset transfer option less economic.

Q. **WHAT FURTHER RISK ASSESSMENTS WERE PERFORMED?**

A. As presented in detail in Section III of SCW- Exhibit 1, an attempt to further quantify the potential risks inherent among the potential Big Sandy unit disposition options identified in TABLE 1, an additional set of holistic economic risk analyses were executed. Using another proprietary tool known as Aurora$^{xmp®}$, this stochastic, or "Monte Carlo" modeling technique was performed to assess the relative impacts of varying driving risk factors over *multiple* forecast simulations.

Q. **WOULD YOU PLEASE SUMMARIZE THE RESULTS OF THAT ADDITIONAL MONTE CARLO RISK MODELLING DESCRIBED IN SCW- EXHIBIT 1?**

A. SCW- Exhibit 1 (*Figure 1-1*) and page 1 of SCW- Exhibit 6 offer both an optical and tabular summary of those stochastic modeling results. It indicates that the relative CPW cost of Option #3A (BS1 CC-Repower, with 20% Mitchell Transfer) was ranked first among the same full suite of eleven unique options analyzed within the discrete Strategist® tool previously described. Option #3A was ranked first by virtue of it offering the lowest relative Revenue Requirement at Risk ("RRaR") profile at +$447 million. As further described in SCW- Exhibit 1 Section III, RRaR represents the difference between the calculated generation-cost CPW 50th percentile (median) and 95th percentile outcome across the 100 simulations modeled. The 95th percentile representing a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of just 5.0 percent. Therefore, RRaR represents a measure of customer risk or uncertainty inherent in each portfolio. The *larger* the RRaR, the *greater* the level of risk that KPCo's customers could be subjected to a higher generation cost-of-service/revenue requirement. As also shown on SCW- Exhibit 6 Monte Carlo modeling result table, the RRaR for the 'Base' or, fifty percent Mitchell Transfer, with additional market capacity and energy (Option #6) was ranked 5th among the full suite of options analyzed, at a slightly higher +$517 million.

However, when examining these results more closely the top four ranked options displaying the lowest relative RRaR results (Option #3A, as well as Options #1A, #2A and #5A), each represents resource option having *no* market exposure; meaning each case represents a resource profile with some combination of "build" and (Mitchell) asset transfer. Page 2 of SCW- Exhibit 6 focuses on the remaining seven resource options in which some level of (PJM) market dependency would continue to exist. That summary indicates that the relative CPW cost of Base Option #6 was now ranked first among this suite of seven market-dependent options analyzed. In this grouping the +$417 million RRaR of Option #6 was ranked first by a relative range of 19.3 percent -to- 52.4 percent. For example, this SCW- Exhibit 6, page 2 summary indicates that for all the scenarios that would continue to reflect some level of market dependency, the RRaR for (Option #2B) was higher, at +$641 million. So when compared with Option #6, it indicates that Option #2B was determined to be "more risky" (*i.e.*, had greater cost uncertainty between the 50^{th} and 95^{th} percentile simulated results) by an order-of-magnitude of nearly 23.9 percent.[16]

When specifically comparing the attendant risk profile of Option #6 versus that of the alternative that would rely *fully* on the projected PJM capacity and energy market for 5 years (Option #4A), the relative risk associated with the latter option increases. The RRaR for Option #4A was determined to be at +$789 million; or a level higher than the Option #6 RRaR level by *52.4 percent*. That is, in addition to the discrete risk results—shown on SCW- Exhibit 5—from the Strategist®-based modeling, which point to this Option #4A as being $411 million more costly than the 'Base' Option #6, this additional Monte Carlo-based risk modeling indicates KPCo's customers would be potentially exposed to even greater cost-of-service/revenue requirement uncertainty in the future under that full-market alternative.

In summary, this additional risk modeling confirms the results and recommendations established by the Strategist® modeling process that determined that Option #6 and Option #5A—both incorporating the ownership transfer of 50 percent of the Mitchell facility—were the least-cost alternatives as set forth in SCW- Exhibit 5, as well as empirically-confirms the previous notion identified within this testimony that described the attendant price-taker risk associated with a market solution (particularly, Options #4A and #4B) would not be in the best interest of KPCo's customers.

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[16] 641 / 517 – 1 = 0.239

IX. OTHER FACTORS

Q. DO THESE MODELED KPCO UNIT DISPOSITION ANALYSES REFLECT OTHER—DIRECT AND INDIRECT—IMPACTS OVER-AND-ABOVE THOSE THAT WOULD INCREMENTALLY AFFECT THE COMPANY'S GENERATION COST-OF-SERVICE?

A. No. The analyses offered in this testimony do not incorporate other such costs. For instance, these costs do not include any and all relative local or regional socio-economic impacts tied to any disposition alternative surrounding Big Sandy Unit 2.

Likewise, as indicated in the testimony of Company Witness Becker, these disposition alternative economics focused on incremental investment only, in that any on-going 'return-on' *and* 'return-of' (depreciation/amortization) capital associated with pre-existing (Big Sandy) generation plant-in-service or other balance sheet debits and credits are ignored, as such future related costs/revenue requirements would be assumed to be consistent across all alternatives analyzed.

Q. WERE OTHER QUALITATIVE FACTORS CONSIDERED AS PART OF THIS KPCO UNIT DISPOSITION EVALUATION?

A. Yes. Chief among those factors was the consideration of both construction/performance risk as well as the ultimate pricing risk associated with the various asset-build options evaluated.

Construction/Performance Risk: Clearly, Options #1 (BS2 Retrofit), #2 (Brownfield CC-build), #3 (BS1 CC-Repower) and components of Option #5A/B (Big Sandy 1 Gas Conversion) involve yet-to-be fully-designed and engineered projects. If any were to be selected as the optimum solution for KPCo, each would be challenged to achieve expected completion dates. Conversely, the options that would transfer an ownership interest for the Mitchell plant would not face such uncertainties. As discussed in the direct testimony of Company Witness Jeffery LaFleur, theses unit are: a) successfully operating; and b) have already been retrofitted with major—FGD and SCR—environmental controls. While it would be expected that a scrubbed Big Sandy Unit 2, or replacement new-build CC, would perform as designed, greater performance risk would naturally apply to those yet-to-be-completed options.

Cost/Pricing Risk: As indicated on the TABLE 3 option cost summary reflected earlier in this testimony, when comparing the installed costs of the various build-options being evaluated—with the exception of the 268 MW Big Sandy 1 gas conversion option (Option #5), which would offer far lower energy value—the Mitchell 1&2 Asset Transfer costs at $758/kW (2011 dollars)—*inclusive* of future CCR, 316(b)-related, and ELG-related capital expenditures—are far lower than the other asset-build alternatives. The Big Sandy 2 DFGD option, with the attendant future additional future environmental costs is estimated at $1,102/kW, while the respective Brownfield CC and Big Sandy 1 CC-Repower options are $1,168/kW and $1,260/kW, respectively (all in 2011 dollars). Recognizing also that the costs identified on TABLE 3 are shown "Excluding AFUDC", those differences would only become *more* pronounced since the Mitchell asset transfer cost would not be further burdened with AFUDC.

In sum, the estimated Mitchell transfer cost is largely a bird-in-the-hand and will not likely materially fluctuate. However, the costs of the BS2 scrubber, or any replacement CC-build options could, of course, experience non-anticipated increases.

X. CONCLUSIONS BASED ON THESE ANALYSES

Q. PLEASE SUMMARIZE YOUR TESTIMONY FROM THE PERSPECTIVE OF THE UNIT DISPOSITION ANALYSES PERFORMED.

A. Several final summarizations and conclusions can be drawn from the information offered within this testimony.

(1) KPCo, AEP and other utilities will likely be subject to significant cost and (implementation) timing challenges going-forward in complying with emerging EPA rulemaking that will impact coal-based generation.

(2) KPCo has set forth alternative capacity resource options that offer a reasonable array of unit disposition alternatives, including introduction of alternatives for Big Sandy Unit 1 and 2.

(3) KPCo has performed robust economic analyses around these alternatives that would point to the ownership transfer of a fifty percent undivided interest of both Mitchell Units 1 and 2 as being the least-cost solution over the long-term economic study period.

(4) KPCo has corroborated, including through additional risk modeling, that a full (approximately 1,100 MW) replacement of Big Sandy Unit 2 (and Big Sandy Unit 1) capacity and energy by way of a market-based solution alone would

disadvantage its customers due to the potential market price and performance uncertainty—including the existing PJM-RPM construct—that could expose these customers to ultimate reliability and, possibly, year-to-year volatility in the form of price-taker risk.

(5) KPCo has demonstrated that certain "qualitative" risk factors around construction/performance and attendant potential cost favor the existing Mitchell asset transfer option.

(6) Based on the alternative least-cost and discrete price risk scenarios profiling—including the prospect for carbon/CO_2—performed in its Strategist® modeling, as well as separate Monte Carlo risk modeling, it is in the long-term interest of KPCo's customers to take advantage of the available Mitchell Units 1 and 2 generating assets by acquiring a fifty percent undivided interest in those units effective January 1, 2014 to replace Big Sandy Unit 2; while also issuing an RFP for approximately 250 MW of capacity and energy to effectively replace Big Sandy Unit 1.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

I. BACKGROUND AND GOVERNANCE

A. Overview of the historical interrelationship between KPCo and AEP for purposes of capacity resource planning

The total AEP System includes ten utility operating companies, operating in eleven states, with generation and transmission assets in, primarily, two different Regional Transmission Organization ("RTO") planning and operational regions. Those RTOs are the PJM Interconnection, L.L.C. ("PJM"), in AEP's eastern zone, and the Southwest Power Pool ("SPP") in its western zone. KPCo is a wholly-owned subsidiary of AEP—serving retail customers in eastern Kentucky—and is located in its eastern or PJM zone. In addition to KPCo, the AEP Operating Companies comprising this eastern zone (collectively, "AEP-East") consist of:

- Appalachian Power Company ("APCo"), serving large portion of West Virginia, and western Virginia;
- Indiana Michigan Power Company ("I&M"), serving portions of northern and eastern Indiana and southwestern Michigan; and
- Ohio Power Company ("OPCo"), serving portions of Ohio.[1]

In addition, two additional Operating Companies residing in this eastern zone, Kingsport Power Company and Wheeling Power Company represent non-generating affiliates.

AEP-East collectively serves about 3.6 million customers in an approximate 90,000 square-mile area of Kentucky, Virginia, West Virginia, Ohio, Indiana, Michigan, and Tennessee.

B. AEP Pool Transition

Historically, the projected capacity resource needs for KPCo were established in concert with that of AEP-East under the auspices of the Interconnection Agreement ("Pool Agreement"), which was established "(f)or the purposes of obtaining the most efficient coordinated expansion and operation of their electric power supply facilities..."[2]. This includes the coordinated and integrated determination of load and (peak) demand

[1] OPCo and the former affiliate operating company Columbus Southern Power Company ("CSP") were legally merged effective January 1, 2012.
[2] Article 4.1 of the Interconnection Agreement.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

obligations for KPCo and each of the other Member Companies defined in that agreement (APCo, CSP, I&M, and OPCo).

As more fully described by Company Witnesses Pauley and Wohnhas, on October 31, 2012, various filings were made with the Federal Energy Regulatory Commission ("FERC") which sought to, among other things:

- Terminate the previous AEP Pool and enter into a Power Coordination Agreement ("PCA"), which affords greater operating company autonomy; and
- Facilitate the asset transfer of a fifty percent undivided ownership interest of Mitchell Plant to KPCo.

II. RESOURCE NEED

A. Description of KPCo's customer base

KPCo's customer base consists of both retail and sales-for-resale customers located in eastern Kentucky. Approximately 173,000 residential, commercial, industrial and other retail, end-use customers are served by the Company. These KPCo retail customers represent nearly 99 percent of KPCo's energy sales in 2011, with the balance coming from sales to the Cities of Vanceburg and Olive Hill, for which KPCo provides wholesale service for ultimate distribution and resale to their end-use customers.

B. Overview of KPCo's peak demand requirements

To ensure the continuation of reliable service, the peak demand of its customer base represents one of the primary underpinnings of any capacity resource plan. The peak load requirement of all KPCo retail and sales for resale wholesale customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, KPCo's peak demand has been recorded in the winter season, with the all-time winter peak being 1,808 MW, which occurred on February 6, 2007. Contrastingly, the highest recorded summer peak was 1,388 MW, which occurred on August 2, 2006.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

The following **Table 1-1** offers the latest (September-2012) AEP Economic Forecasting projection of KPCo and AEP-East (summer) peak demand and internal load. Over the next 10 year period (through 2021) KPCo's summer demand is anticipated to increase by a compound annual growth rate of 0.45 percent, or by a total of 48 MW; relative results which are generally on par with those of the overall AEP-East region for the same period.

Table 1-1
Projected (Summer) Peak Demand and Internal Load
KPCo and AEP-East
(Sep-2012 Fcst)

Year	Peak Demand (MW) KPCo	Peak Demand (MW) AEP-East*	Year	Internal Load (GWh) KPCo	Internal Load (GWh) AEP-East*
2012	1,183 (A)	21,075	2012	7,444	127,337
2013	1,180	20,543	2013	7,427	123,031
2014	1,188	20,769	2014	7,464	124,329
2015	1,195	20,972	2015	7,495	125,257
2016	1,199	21,102	2016	7,528	125,985
2017	1,201	21,195	2017	7,557	126,417
2018	1,208	21,327	2018	7,592	127,023
2019	1,215	21,470	2019	7,629	127,749
2020	1,221	21,573	2020	7,661	128,435
2021	1,231	21,787	2021	7,696	129,221
2022	1,240	21,956	2022	7,736	130,030
2023	1,242	22,075	2023	7,777	130,886
2024	1,248	22,206	2024	7,820	131,769
2025	1,259	22,437	2025	7,859	132,634
2026	1,269	22,619	2026	7,905	133,538
2027	1,279	22,809	2027	7,953	134,482
2028	1,286	22,963	2028	8,002	135,457
2029	1,291	23,148	2029	8,045	136,385
2030	1,301	23,343	2030	8,091	137,352
2031	1,311	23,542	2031	8,137	138,348

10-Year (2012-2021):	KPCo	AEP-East*	10-Year (2012-2021):	KPCo	AEP-East*
Total Growth	48	712	Total Growth	253	1,885
Compound Annual Growth Rate	0.45%	0.37%	Compound Annual Growth Rate	0.37%	0.16%

20-Year (2012-2031):	KPCo	AEP-East*	20-Year (2012-2031):	KPCo	AEP-East*
Total Growth	128	2,467	Total Growth	694	11,011
Compound Annual Growth Rate	0.54%	0.58%	Compound Annual Growth Rate	0.47%	0.44%

(A) Actual KPCo summer peak demand on June 29, 2012 (@ 4PM)

* AEP-East includes Ohio-Wires customers

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

C. PJM Reserve Margin Criteria

It is assumed that the underlying minimum reserve margin criteria to be utilized in the determination of AEP-East and, ultimately, KPCo capacity needs assessment is the current PJM board-approved Installed Reserve Margin ("IRM") level of 15.4 percent.[3]

D. KPCo and AEP obligation to provide reserve margin in PJM

On October 1, 2004, AEP transferred functional control of its transmission facilities as well as its generation dispatch, including the transmission and generation facilities owned by its operating companies, including KPCo, to PJM. With that, the PJM Reliability Assurance Agreement defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity (LSE) in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's IRM requirement. This requirement is itself based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, load diversity among the LSEs and PJM, and generating asset-assumed equivalent forced outage rates ("EFOR") represent other factors impacting such required minimum reserve levels.

Further, beginning in 2007—for the initial 2010/11 "planning year"—through today—for the most recent 2015/16 Planning Year—AEPSC, as agent for its AEP-East LSEs, including KPCo, has given annual notice of its intent to elect to continue to opt-out of the PJM Reliability Pricing Model ("RPM") three-year forward capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement ("FRR") construct. FRR requires AEP and KPCo to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand *plus* IRM requirements. Further the proposed PCA offers a loosely-integrated arrangement in which the surviving operating

[3] As established by PJM beginning with the 2013/14 Reliability Pricing Model, Base Residual Auction as well as for non-auction, Fixed Resource Requirement entities such as AEP. For purpose of the modeling exercise to be discussed throughout this testimony, it is assumed this 15.4% IRM level would remain constant going-forward.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

companies (APCo, I&M and KPCo) are expected to be self-sufficient for both capacity and energy requirements.

Currently, it is AEP and KPCo's position that the interests of its customers are better preserved under that FRR framework. While KPCo and the other operating companies who will be members of the PCA—APCo and I&M—beginning with the *next* (2016/17) PJM-RPM planning year, reserve the future option of electing to participate in the RPM forward auction process.

E. KPCo's current available capacity resources

To meet the most recent projected peak demand and annual energy requirements of its customers, as part of its FRR obligations in PJM for the current, 2012/2013 Planning Year, KPCo is relying on 1,470 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability. The make-up of KPCo's PJM-recognized installed capability ("ICAP") includes a portfolio of coal facilities identified in the following table:

COAL:

- ✓ Big Sandy Unit 1 (278 MW) located in Louisa, KY. In-service 1963
- ✓ Big Sandy Unit 2 (800 MW) located in Louisa, KY. In-service 1969
- ✓ Rockport Unit 1 (197 MW) located in Spencer County, IN [4] In-service 1984
- ✓ Rockport Unit 2 (195 MW) located in Spencer County, IN [5] In-service 1989

TOTAL (2011/2012 PJM Planning Year) 1,470 MW

[4] This reflects KPCo's 30% purchase entitlement from the (50%), AEP Generating Company (AEG) ownership share of the (total) 1315-MW unit.

[5] This reflects KPCo's 30% purchase entitlement from the (50%), AEG share of the 1300-MW unit that is currently under lease to non-affiliate Lessors.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

F. KPCo's current available "demand" resource (DSM)

Demand-Side Management ("DSM") in the form of both "active" and "passive" Demand Response ("DR") initiatives have been incorporated into the Company's resource planning. Active DSM, in the form of peak-modifying DR activity have been projected as well as passive DSM in the form of Energy Efficiency ("EE") programs, which KPCo and this Commission has supported for some time. The following Table 1-2 identifies the level of KPCo (total) demand reduction initially anticipated over the forecasted time horizon based, in part, on the requirements for DSM as set forth in Case No. 2010-00095 approved in August, 2010. While not at all trivial, it is evident, however, such DR resource contributions from the estimated DSM activity by or around the mid-part of this decade of approximately 30-40 MW are clearly well below the significant capacity needs that would be at issue when considering the disposition of units on the scale of Big Sandy Units 1 and 2.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-2

Projected Demand Response (DR) and Energy Efficiency (EE)
KPCo and AEP-East
(Sep-2012 Fcst)

	+		+		=			
	(CURRENT) PJM-APPROVED INTERRUPTIBLE DEMAND RESPONSE Peak Reduction (MW)		(PROJECTED) "ACTIVE" DEMAND RESPONSE Peak Reduction (MW)		(PROJECTED) "PASSIVE" DEMAND RESPONSE Peak Reduction (MW)		TOTAL DEMAND RESPONSE Peak Reduction (MW)	
Year	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East
2012	0	581	4	50	3	146	6	777
2013	0	581	4	50	4	274	8	905
2014	0	581	11	180	6	418	17	1,179
2015	0	581	18	300	8	584	25	1,465
2016	0	581	26	450	12	732	38	1,763
2017	0	581	35	600	16	806	51	1,987
2018	0	581	36	612	17	868	53	2,061
2019	0	581	36	624	19	957	55	2,162
2020	0	581	37	637	20	1,064	57	2,282
2021	0	581	38	649	21	1,142	59	2,372
2022	0	581	39	662	21	1,202	60	2,446
2023	0	581	39	676	21	1,247	61	2,503
2024	0	581	40	689	21	1,280	62	2,550
2025	0	581	41	703	21	1,310	62	2,594
2026	0	581	41	703	21	1,319	62	2,603
2027	0	581	41	703	22	1,320	63	2,604
2028	0	581	41	703	22	1,318	63	2,602
2029	0	581	41	703	21	1,318	62	2,602
2030	0	581	41	703	22	1,319	63	2,603
2031	0	581	41	703	22	1,319	63	2,603

	(PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh)	
Year	KPCo	AEP-East
2012	19	1,006
2013	33	2,033
2014	43	2,974
2015	52	3,620
2016	77	4,135
2017	94	4,575
2018	102	4,945
2019	110	5,468
2020	116	6,103
2021	118	6,544
2022	119	6,901
2023	119	7,187
2024	119	7,410
2025	119	7,578
2026	119	7,635
2027	119	7,635
2028	119	7,635
2029	119	7,635
2030	119	7,635
2031	119	7,635

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

G. SUMMARY: KPCo's current and potential PJM capacity positions

Assuming that the KPCo LSE were viewed individually as part of a PJM-planning perspective, the following Table 1-3 offers an overview of such a KPCo "stand-alone" capacity position within PJM. This view effectively assumes that the Company would continue to elect to participate in the PJM-RPM as an FRR (*i.e.*, self-planning) entity as opposed to participating in PJM's capacity auction construct. Further it assumes, as a "going-in" or a base assumption that Big Sandy Units 1 and 2 would continue to contribute ICAP through the 2014/15 PJM Planning Year only; meaning each would be retired effective June 2015. As reflected in the Table 1-3 column identified as "Net Position w/ New Capacity" (col. 20), KPCo would ultimately become short capacity by 937 MW beginning with the 2015/16 Planning Year timeframe; or the first planning year after any presumed Big Sandy unit retirements. This demonstrates and confirms that, not surprisingly, KPCo would be significantly exposed—from a stand-alone planning perspective—should a Big Sandy disposition strategy call for the retirement of these units.

Based on the recommendations set forth in my testimony and, again, assuming that the KPCo LSE were viewed individually as part of a PJM-planning perspective, the following Table 1-4 offers another overview of such a KPCo stand-alone capacity position within PJM. Also assuming KPCo would continue to elect to be an FRR planning entity, it offers a (potential) final KPCo capacity position profile that reflects:

- Retirement of Big Sandy Units 1 and 2 effective June 2015;
- Asset transfer of 50 percent of Mitchell Units 1 and 2 effective January 1, 2014;
- the assumption of a 10-year, approximate 250 MW capacity purchase (*i.e.*, PPA) commensurate with the retirement of Big Sandy 1 and 2; and
- the potential for ownership of an approximate 300 MW combined cycle facility subsequent to the long-term capacity purchase at the end of that purchase period.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-3 "Going-In" Capacity Position

KENTUCKY POWER COMPANY

Projected Resource Capacity, Load/Peak Demands, and PJM UCAP Reserve Margins ("CLR")--PJM FRR Planning Perspective

Based on September 2012 Load Forecast

(2012/2013 - 2030/2031 PJM Planning Years)

"Going-In" Capacity Position (No New Resource Additions or Purchases)

(Assuming U.S. EPA MATS Rulemaking and NSR Consent Decree)

		Obligation to PJM									
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation
2012 /13	(k)	1,167	(3)	(1)	1,166	4	0.954	1.087	1,263	0	1,263
2013 /14	(k)	1,173	(4)	(1)	1,172	4	0.956	1.086	1,269	0	1,269
2014 /15	(k)	1,197	(6)	(1)	1,196	11	0.955	1.086	1,288	0	1,288
2015 /16	(k)	1,221	(8)	(2)	1,219	18	0.955	1.086	1,306	0	1,306
2016 /17		1,199	(12)	(3)	1,196	26	0.955	1.086	1,272	0	1,272
2017 /18		1,201	(16)	(4)	1,197	35	0.955	1.086	1,263	0	1,263
2018 /19		1,208	(17)	(6)	1,202	36	0.955	1.086	1,268	0	1,268
2019 /20		1,215	(19)	(8)	1,208	36	0.955	1.086	1,274	0	1,274
2020 /21		1,221	(20)	(12)	1,208	37	0.955	1.086	1,274	0	1,274
2021 /22		1,231	(21)	(16)	1,216	38	0.955	1.086	1,281	0	1,281
2022 /23		1,240	(21)	(17)	1,223	39	0.955	1.086	1,288	0	1,288
2023 /24		1,242	(21)	(19)	1,223	39	0.955	1.086	1,287	0	1,287
2024 /25		1,248	(21)	(20)	1,228	40	0.955	1.086	1,292	0	1,292
2025 /26		1,259	(21)	(21)	1,239	41	0.955	1.086	1,303	0	1,303
2026 /27		1,269	(21)	(21)	1,248	41	0.955	1.086	1,312	0	1,312
2027 /28		1,279	(22)	(21)	1,258	41	0.955	1.086	1,323	0	1,323
2028 /29		1,286	(22)	(21)	1,264	41	0.955	1.086	1,331	0	1,331
2029 /30		1,291	(21)	(21)	1,270	41	0.955	1.086	1,336	0	1,336
2030 /31		1,301	(22)	(21)	1,279	41	0.955	1.086	1,347	0	1,347

	Resources								I&M Position (MW)		PJM Reserve Margin				
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	
						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)	=((10)+((5)*(6)*(7)))/(1+(22))		=(20)/(21)	=(22)+(23)	
			Planned Capacity Additions												
Planning Year	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Units	MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin	
2012 /13	1,470	67				1,403	7.85%	1,293	30	30	1,096	15.60%	2.74%	18.34%	
2013 /14	1,470	54				1,416	4.65%	1,350	81	81	1,103	15.40%	7.34%	22.74%	
2014 /15	1,470	0				1,470	8.27%	1,348	60	60	1,126	15.40%	5.33%	20.73%	
2015 /16	392	0				392	5.95%	369	(937)	(937)	1,147	15.40%	-81.66%	-66.26%	(l)
2016 /17	398	0				398	5.95%	374	(898)	(898)	1,126	15.40%	-79.76%	-64.36%	
2017 /18	398	0				398	5.95%	374	(889)	(889)	1,126	15.40%	-78.96%	-63.56%	
2018 /19	398	(9)				407	5.95%	383	(885)	(885)	1,131	15.40%	-78.26%	-62.86%	
2019 /20	398	(9)				407	5.95%	383	(891)	(891)	1,137	15.40%	-78.38%	-62.98%	
2020 /21	404	(6)				410	5.95%	386	(888)	(888)	1,137	15.40%	-78.08%	-62.68%	
2021 /22	404	(4)				408	5.95%	384	(897)	(897)	1,144	15.40%	-78.40%	-63.00%	
2022 /23	404	(3)				407	5.95%	383	(905)	(905)	1,151	15.40%	-78.64%	-63.24%	
2023 /24	409	(2)				411	5.95%	387	(900)	(900)	1,151	15.40%	-78.22%	-62.82%	
2024 /25	409	0				409	5.95%	385	(907)	(907)	1,156	15.40%	-78.48%	-63.08%	
2025 /26	409	0				409	5.95%	385	(918)	(918)	1,166	15.40%	-78.73%	-63.33%	
2026 /27	409	0				409	5.95%	385	(927)	(927)	1,174	15.40%	-78.98%	-63.58%	
2027 /28	409	0				409	5.95%	385	(938)	(938)	1,183	15.40%	-79.27%	-63.87%	
2028 /29	409	0				409	5.95%	385	(946)	(946)	1,190	15.40%	-79.48%	-64.08%	
2029 /30	409	0				409	5.95%	385	(951)	(951)	1,195	15.40%	-79.61%	-64.21%	
2030 /31	409	0				409	5.95%	385	(962)	(962)	1,204	15.40%	-79.89%	-64.49%	

Notes:
(a) Based on (September 2012) Load Forecast (with implied PJM diversity factor)

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

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

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

(e) Installed Reserve Margin (IRM) = 15.6%(2012), 15.4%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2015/16: Rockport 1: 35 MW (valve)
2016/17: Rockport 1: 36 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
2023/24: Rockport 2: 35 MW (valve)
FGD DERATES:
2015/16: Rockport A: 35 MW
DSI DERATES:
2015/16: Rockport B: 0 MW
('Going In") RETIREMENTS:
2015/16: Big Sandy 1
2015/16: Big Sandy 2

(h) Includes company MLR share of:
Contractual share of remaining Mone capacity
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels --reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

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

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:
1) Remaining Mone Share => 100% to OPCo
2) SEPA => 100% to APCo

Note: o Through the 2015/16 PJM Planning Year, KPCo operates under the auspices of a ('4-Company) "FRR" capacity declaration that was inclusive of (former) AEP Pool Member Cos. APCo, I&M and OPCo
o Starting with the 2016/17 PJM Planning Year begins the potential that --under the proposed PCA-- KPCo would largely become self-sufficient for its capacity needs (i.e., a 'stand-alone' entity)

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-4 (Potential) "Final" Capacity Position

KENTUCKY POWER COMPANY

Projected Resource Capacity, Load/Peak Demands, and PJM UCAP Reserve Margins ("CLR")--PJM FRR Planning Perspective

Based on September 2012 Load Forecast

(2012/2013 - 2030/2031 PJM Planning Years)

(Potential) "Final" Capacity Position

(Assuming U.S. EPA MATS Rulemaking and NSR Consent Decree)

		Obligation to PJM										Resources								I&M Position (MW)		PJM Reserve Margin			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12)+(15))*(1-(17))-(10)	=(18)-(10)	=((10)+((5)*(6)*(7)))/(1+(22))		=(20)/(21)	=(22)+(23)
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions Units	Planned Capacity Additions MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
2012 /13	(k)	1,167	(3)	(1)	1,166	4	0.954	1.087	1,263	0	1,263	1,470	67				1,403	7.85%	1,293	30	30	1,096	15.60%	2.74%	18.34%
2013 /14	(k)	1,173	(4)	(1)	1,172	4	0.956	1.086	1,269	0	1,269	1,470	54				1,416	4.65%	1,350	81	81	1,103	15.40%	7.34%	22.74%
2014 /15	(k)	1,197	(6)	(1)	1,196	11	0.955	1.086	1,288	0	1,288	2,250	0				2,250	8.70%	2,054	766	766	1,126	15.40%	68.06%	83.46%
2015 /16	(k)	1,221	(8)	(2)	1,219	18	0.955	1.086	1,306	0	1,306	1,172	0			250	1,422	8.31%	1,304	(2)	(2)	1,147	15.40%	-0.17%	15.23% (l)
2016 /17		1,199	(12)	(3)	1,196	26	0.955	1.086	1,272	0	1,272	1,178	0			250	1,428	8.30%	1,309	37	37	1,126	15.40%	3.29%	18.69%
2017 /18		1,201	(16)	(4)	1,197	35	0.955	1.086	1,263	0	1,263	1,178	0			250	1,428	8.30%	1,309	46	46	1,126	15.40%	4.09%	19.49%
2018 /19		1,208	(17)	(6)	1,202	36	0.955	1.086	1,268	0	1,268	1,178	(9)			250	1,437	8.30%	1,318	50	50	1,131	15.40%	4.42%	19.82%
2019 /20		1,215	(19)	(8)	1,208	36	0.955	1.086	1,274	0	1,274	1,178	(9)			250	1,437	8.30%	1,318	44	44	1,137	15.40%	3.87%	19.27%
2020 /21		1,221	(20)	(12)	1,208	37	0.955	1.086	1,274	0	1,274	1,184	(6)			250	1,440	8.29%	1,321	47	47	1,137	15.40%	4.13%	19.53%
2021 /22		1,231	(21)	(16)	1,216	38	0.955	1.086	1,281	0	1,281	1,184	(4)			250	1,438	8.29%	1,319	38	38	1,144	15.40%	3.32%	18.72%
2022 /23		1,240	(21)	(17)	1,223	39	0.955	1.086	1,288	0	1,288	1,184	(3)			250	1,437	8.29%	1,318	30	30	1,151	15.40%	2.61%	18.01%
2023 /24		1,242	(21)	(19)	1,223	39	0.955	1.086	1,287	0	1,287	1,189	(2)			250	1,441	8.28%	1,322	35	35	1,151	15.40%	3.04%	18.44%
2024 /25		1,248	(21)	(20)	1,228	40	0.955	1.086	1,292	0	1,292	1,189	0			250	1,439	8.28%	1,320	28	28	1,156	15.40%	2.42%	17.82%
2025 /26		1,259	(21)	(21)	1,239	41	0.955	1.086	1,303	0	1,303	1,189	0	300 MW KP -CC	300	0	1,489	8.28%	1,366	(212)	63	1,166	15.40%	5.40%	20.80%
2026 /27		1,269	(21)	(21)	1,248	41	0.955	1.086	1,312	0	1,312	1,189	0				1,489	8.22%	1,367	(221)	55	1,174	15.40%	4.69%	20.09%
2027 /28		1,279	(22)	(21)	1,258	41	0.955	1.086	1,323	0	1,323	1,189	0				1,489	8.22%	1,367	(232)	44	1,183	15.40%	3.72%	19.12%
2028 /29		1,286	(22)	(21)	1,264	41	0.955	1.086	1,331	0	1,331	1,189	0				1,489	8.22%	1,367	(240)	36	1,190	15.40%	3.02%	18.42%
2029 /30		1,291	(21)	(21)	1,270	41	0.955	1.086	1,336	0	1,336	1,189	0				1,489	8.22%	1,367	(245)	31	1,195	15.40%	2.60%	18.00%
2030 /31		1,301	(22)	(21)	1,279	41	0.955	1.086	1,347	0	1,347	1,189	0				1,489	8.22%	1,367	(256)	20	1,204	15.40%	1.66%	17.06%

Notes: (a) Based on (September 2012) Load Forecast (with implied PJM diversity factor)

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

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

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

(e) Installed Reserve Margin (IRM) = 15.6%(2012), 15.4%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2015/16: Rockport 1: 35 MW (valve)
2016/17: Rockport 1: 36 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
2023/24: Rockport 2: 35 MW (valve)
FGD DERATES:
2015/16: Rockport A: 35 MW
DSI DERATES:
2015/16: Rockport B: 0 MW
RETIREMENTS:
2015/16: Big Sandy 1
2015/16: Big Sandy 2

ASSET TRANSFERS:
2014/15: Mitchell Unit 1: 395 MW (790-MW x 50%)
2014/15: Mitchell Unit 2: 385 MW (770-MW x 50%)

(h) Includes company MLR share of:
Contractual share of remaining Mone capacity
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels
--reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

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

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:
1) Remaining Mone Share => 100% to OPCo
2) SEPA => 100% to APCo

Note: o Through the 2015/16 PJM Planning Year, KPCo operates under the auspices of a ('4-Company) "FRR" capacity declaration that was inclusive of (former) AEP Pool Member Cos. APCo, I&M and OPCo
o Starting with the 2016/17 PJM Planning Year begins the potential that --under the proposed PCA-- KPCo would largely become self-sufficient for its capacity needs (i.e., a 'stand-alone' entity)

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

III. ADDITIONAL RISK ANALYSIS

Once the discretely-modeled Strategist® resource alternative resource portfolios identified in Exhibits SCW- 5A though 5E were established, they were subjected to risk "stress-testing" to ensure that none of the plans had outcomes that were economically-exposed—versus the other plans—under an array of input variables.

A. The Aurora^{XMP} Model

The proprietary Aurora$^{XMP®}$ model was developed by EPIS, Inc. in the mid 1990's and has been licensed for use by AEP since 2002. Aurora^{XMP} is primarily a production costing model using a fundamentals-based, multi-area, transmission-constrained dispatch logic in order to simulate real market conditions. At AEP it used by the AEP Fundamental Analysis group primarily as a long-term optimization tool to forecast mid- and long-term power prices and other industry commodity pricing for all regions within the Eastern Interconnect and ERCOT.

One of the features of the Aurora$^{XMP®}$ model is its endogenous risk analysis capabilities for stochastic or random-variable ("Monte Carlo") simulations. For the purposes of this study, a commonly accepted sampling method (*i.e.*, the Latin-Hypercube) is employed by the tool in order to generate a plausible distribution of risk factors with a relatively small number of samples or risk iterations.

This study focused solely on the KPCo portfolio of generating units. One hundred (100) risk iteration runs were simulated with five key risk factors being sampled. The results take the form of a distribution of possible generation-related cost-of-service/revenue requirement outcomes for each plan portfolio. The input variables, or key risk factors considered by Aurora$^{XMP®}$ within this analysis were:

- coal prices ($/MMBtu);
- natural gas prices ($/MMBtu);
- (SPP) on-peak and off-peak energy prices ($/Mwh)
- CO_2 emission (allowance) price/tax ($/tonne); and
- full requirements KPCo load (Gwh)

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

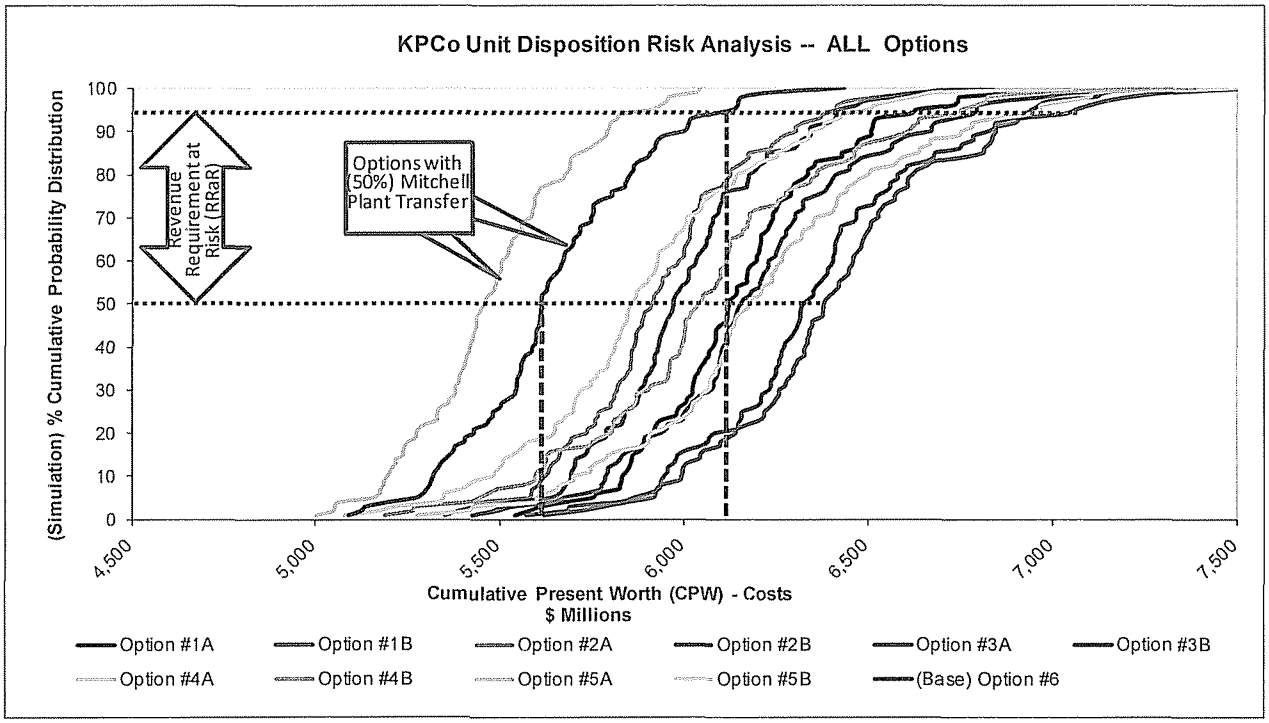
B. Modeling Process and Results

For each portfolio, the modeled *difference* between the calculated generation cost cumulative present worth ("CPW") at the 50th (median) and 95th percentile outcomes across the 100 simulations was identified as Revenue Requirement at Risk ("RRaR"). The 95th percentile represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of only 5.0 percent. Thus, the RRaR represents a measure of customer risk or uncertainty inherent in each portfolio. The *larger* the RRaR, the *greater* the level of risk that KPCo's customers could be subjected to a higher generation cost-of-service/revenue requirement.

Figure 1-1 that follows shows the distribution of outcomes for each of the plans that were evaluated (Options #1 through #6). Note that these CPW results are largely consistent with the CPW values calculated using the Strategist® tool, with the Option #5A (50% Mitchell Transfer, with BS1 gas conversion) case being the lowest cost plan. The importance of this evaluation, however, is not in matching the discrete Strategist® results, but rather in examining the *relative risk* among the portfolios. As *Figure 1-1*—including the supporting table—indicates, the RRaR (difference between the 50th and 95th probability percentile simulated result) is also nearly the lowest for Option #5A. This reinforces the conclusions from the Strategist® optimization analysis that, an option inclusive of the fifty percent Mitchell Asset Transfer would produce relative reduced cost risk exposure to KPCo's customers over the long-term study period.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Figure 1-1: KPCo-Unit Disposition – Simulation Risk Distribution, ALL Options



	Cumulative Distribution Percentile	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	(Base) Option #6
CPW ($Millions)	50	6,123	6,380	5,912	6,153	5,972	6,325	6,178	6,037	5,458	5,856	5,612
	95	6,633	7,061	6,412	6,794	6,418	6,942	6,967	6,751	5,910	6,504	6,129
'RRaR' ($Millions)	*95th vs. 50th*	**510**	**681**	**500**	**641**	**447**	**617**	**789**	**714**	**451**	**648**	**517**
RELATIVE RRaR RANK		***4***	***9***	***3***	***7***	***1***	***6***	***11***	***10***	***2***	***8***	***5***

'RRaR' DELTAS:

(Base) Option #6 versus...

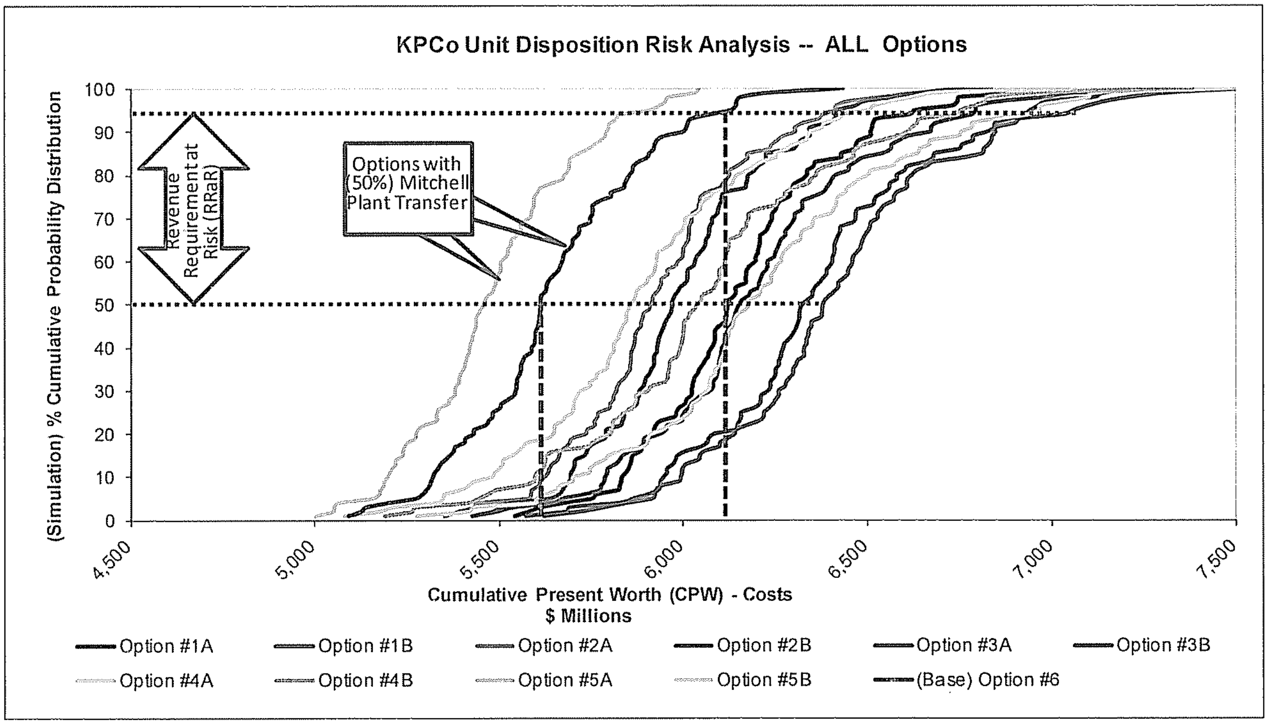
	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B
($Millions)	*7*	*(164)*	*17*	*(124)*	*71*	*(100)*	*(271)*	*(197)*	*66*	*(131)*
	1.4%	*-31.7%*	*3.3%*	*-23.9%*	*13.7%*	*-19.3%*	*-52.4%*	*-38.0%*	*12.8%*	*-25.3%*

Option #5A (Also Inclusive of a '50% Mitchell 1&2 Transfer) versus...

	Option #1A	Option #1B	*Option #2A*	*Option #2B*	*Option #3A*	*Option #3B*	*Option #4A*	Option #4B	Option #5B	(Base) Option #6
($Millions)	*(59)*	*(230)*	*(49)*	*(190)*	*5*	*(166)*	*(337)*	*(263)*	*(197)*	*(66)*
	-13.1%	*-50.9%*	*-10.9%*	*-42.0%*	*1.1%*	*-36.8%*	*-74.7%*	*-58.2%*	*-43.6%*	*-14.6%*

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Figure 1-1: KPCo-Unit Disposition – Simulation Risk Distribution, ALL Options



	Cumulative Distribution Percentile	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	(Base) Option #6
CPW ($Millions)	50	6,123	6,380	5,912	6,153	5,972	6,325	6,178	6,037	5,458	5,856	5,612
	95	6,633	7,061	6,412	6,794	6,418	6,942	6,967	6,751	5,910	6,504	6,129
'RRaR' ($Millions) *95th vs 50th*		**510**	**681**	**500**	**641**	**447**	**617**	**789**	**714**	**451**	**648**	**517**
RELATIVE RRaR RANK		***4***	***9***	***3***	***7***	***1***	***6***	***11***	***10***	***2***	***8***	***5***

'RRaR' DELTAS:

(Base) Option #6 versus...

	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	
($Millions)	*7*	*(164)*	*17*	*(124)*	*71*	*(100)*	*(271)*	*(197)*	*66*	*(131)*	
	1.4%	*-31.7%*	*3.3%*	*-23.9%*	*13.7%*	*-19.3%*	*-52.4%*	*-38.0%*	*12.8%*	*-25.3%*	

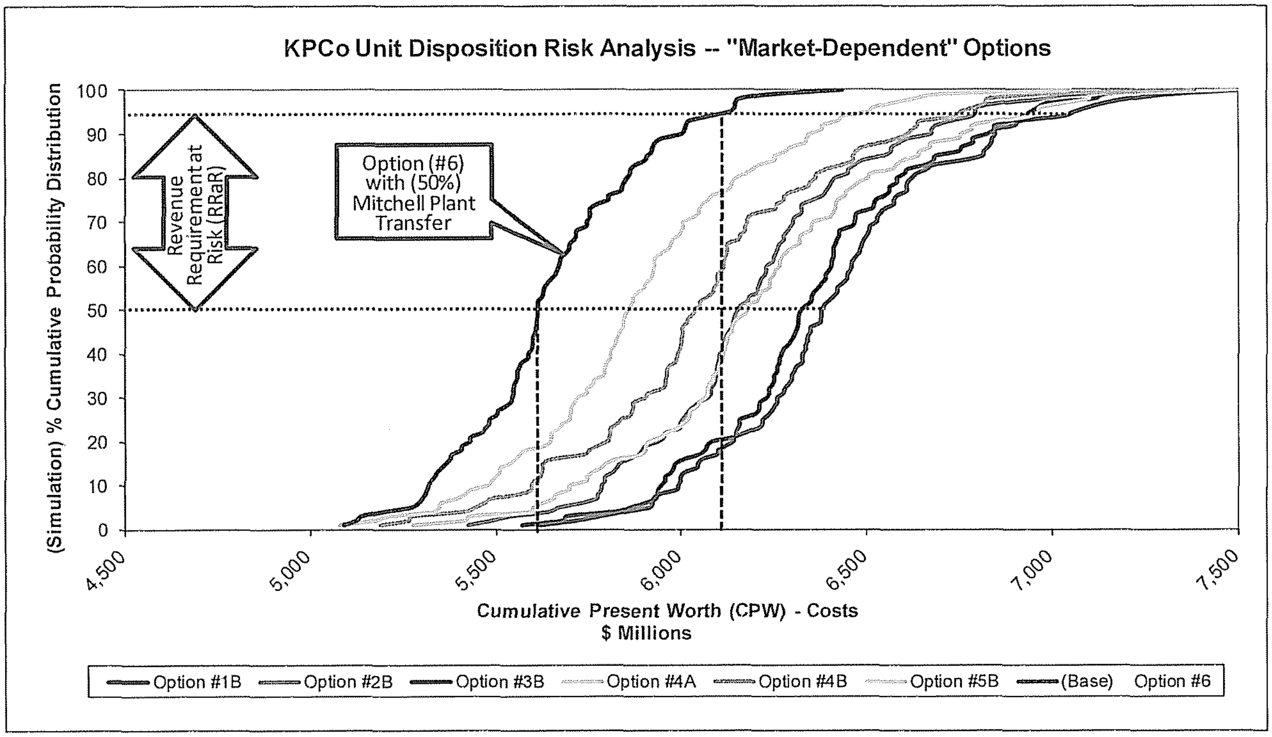
Option #5A (Also Inclusive of a '50% Mitchell 1&2 Transfer) versus...

	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B		Option #5B	(Base) Option #6
($Millions)	*(59)*	*(230)*	*(49)*	*(190)*	*5*	*(166)*	*(337)*	*(263)*		*(197)*	*(66)*
	-13.1%	*-50.9%*	*-10.9%*	*-42.0%*	*1.1%*	*-36.8%*	*-74.7%*	*-58.2%*		*-43.6%*	*-14.6%*

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

However, when examining these results more closely, the top four ranked options displaying the lowest relative RRaR from *Figure 1-1* (Option #3A, as well as Options #1A, #2A and #5A), each represents a resource option having no market exposure; meaning each case represents a resource profile with some combination of asset-build and (Mitchell) asset transfer. ***Figure 1-2*** focuses on the remaining seven resource options in which some level of (PJM) market dependency would continue to exist. That summary indicates that the relative RRaR of the Base Option #6 was now ranked first among this suite of seven "market-dependent" options.

Figure 1-2: KPCo-Unit Disposition – Simulation Risk Distribution, "Market-Dependent" Options



	Cumulative Distribution Percentile	Option #1B	Option #2B	Option #3B	Option #4A	Option #4B	Option #5B	(Base) Option #6
CPW ($Millions)	50	6,380	6,153	6,325	6,178	6,037	5,856	5,612
	95	7,061	6,794	6,942	6,967	6,751	6,504	6,129
'RRaR' ($Millions)	*95th vs. 50th*	**681**	**641**	**617**	**789**	**714**	**648**	**517**
	RELATIVE RRaR RANK	***5***	***3***	***2***	***7***	***6***	***4***	***1***

'RRaR' DELTAS:

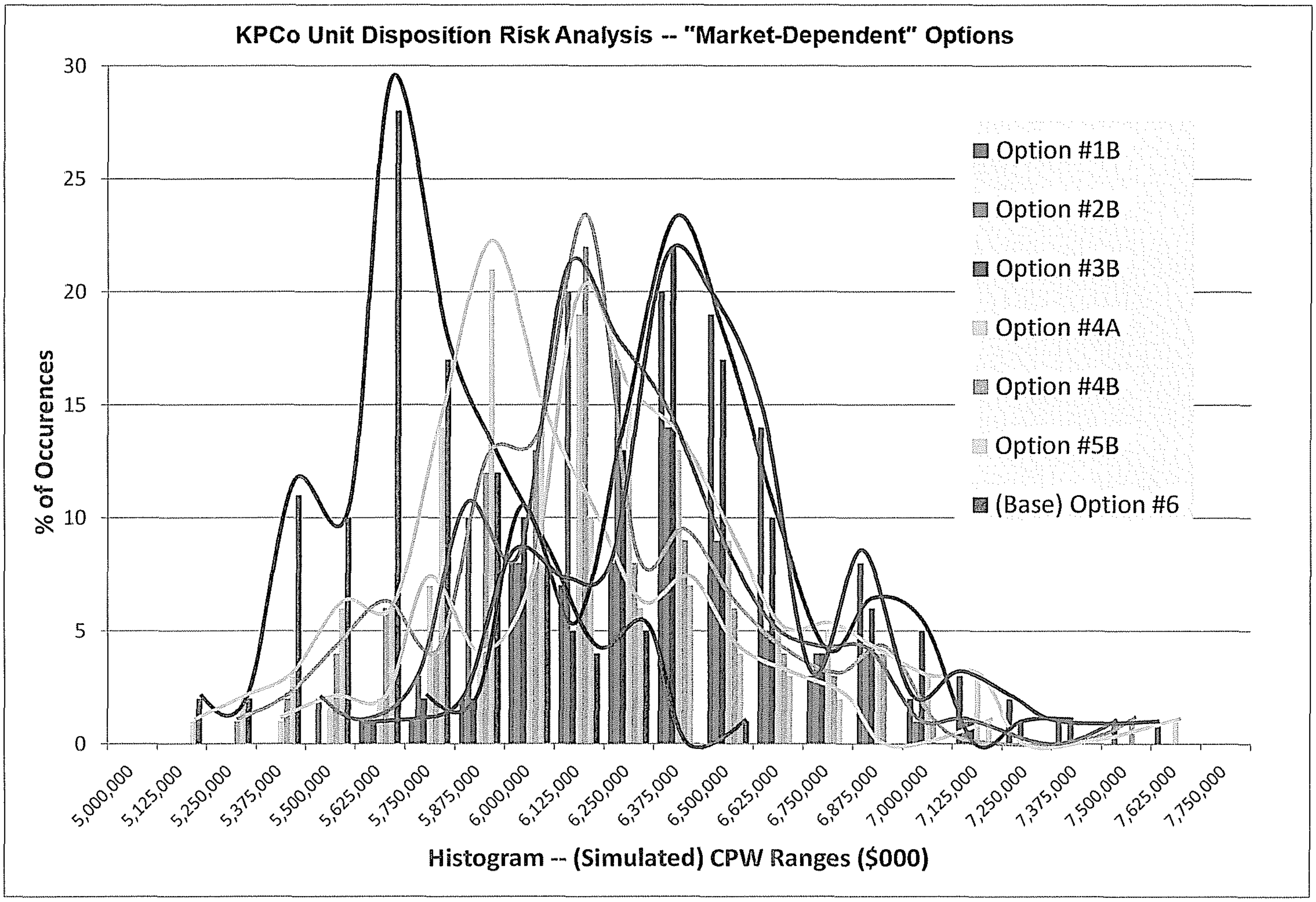
(Base) Option #6 versus...

	Option #1B	Option #2B	Option #3B	Option #4A	Option #4B	Option #5B
($Millions)	***(164)***	***(124)***	***(100)***	***(271)***	***(197)***	***(131)***
	-31.7%	***-23.9%***	***-19.3%***	***-52.4%***	***-38.0%***	***-25.3%***

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Finally, ***Figure 1-3*** offers a histogram—bell curve plotting—of these same Monte Carlo-simulated results for those market-dependent options. This optic of the Aurora[XMP®] modeled results indicates that the 100 simulated CPW outcomes for Option #6 are slightly more "symmetrical". This means there is approximately an equal probability that any randomly-simulated outcome would be above or below the highest occurring range of outcomes. However, the simulated outcomes for the full-market Options #4A and #4B --in addition to having a higher RRaR-- are slightly less symmetrical, with those portfolio profiles indicating a greater percentage of CPW outcomes above the highest-occurring range of results (*i.e.*, approaching that "tail" outcome). This would continue to point to Options #4A and 4B as having the greatest level of (RRaR) cost uncertainty/risk.

Figure 1-3: KPCo Unit Disposition-Simulation Histogram, "Market-Dependent" Options



KPCo Big Sandy Unit Disposition Options [A]

(Evaluated in the Strategist® long-term resource cost/optimization model; study period thru 2040):

Options "#1" thru "#4" from the recent (Big Sandy) CPCN Filing (Docket No. 2011-00401)...

	Option#	Unit Dispositions [B]: Big Sandy 2	Unit Dispositions [B]: Big Sandy 1	Approx. Resulting KPCo Capacity Need (MW)	*Effective BS2 Replacement*	Approx. Remaining KPCo Capacity Need (MW)	*Effective BS1 Replacement*	*Additional Comments/Definition...*
1	#1A	Retrofit (DFGD; 6/2017)	Retire (6/2015)	~250	*n/a*	~250	20% Mitchell Transfer [312-MW] (1/2014)	o Assumes a <u>6/2017</u> retrofit in-svc date (1-Yr delay), with BS2 idled 1/2016 (assumes MATS "+1"/NSR), BS1 ret 6/2015. o Assumes an approx. 25-Yr. operating life for BS2 as well as Mitchell transfer capacity (thru 2040 study period)
2	#1B	*same as Option #1A except...*					Market Proxy (Using Forecasted Pricing)	o This 'market proxy' approach would be in lieu of issuing a formal long-term Request for Proposals (RFP). o PJM capacity & energy market would be proxied by utilizing AEP Fundamental Analysis' latest long-term fcst o Such (~250 MW) add'l (market) replacement capacity & energy would be for a 10-yr period (thru 2025), then like-size CC or CT-build.
3	#2A	Retire (1/2016)	Retire (6/2015)	up to 1,100	CC (Brownfield) (6/2017)	~250	20% Mitchell Transfer [312-MW] (1/2014)	o Assumes a consistent, <u>6/2017</u> Brownfield CC in-svc date, with BS2 idled 1/2016 (MATS+1/NSR), BS1 idled 6/2015. o Assumes a 30-Yr service life for BS2 CC Replacement and an approx. 25-yr life for Mitchell transfer capacity (thru 2040).
4	#2B	*same as Option #2A except...*					Market Proxy (Using Forecasted PJM Pricing)	*(See also comments re Option #1B)*
5	#3A	Retire (1/2016)	(CC) Repower	~250	CC (BS1 Repower) (6/2017)	~250	20% Mitchell Transfer [312-MW] (1/2014)	o Assumes a consistent <u>6/2017</u> BS1-Repowered CC in-svc date, with BS2 idled 1/2016 ('MATS+1'/NSR). o Assumes a 20-Yr. service life for a 'CC-repowered' BS1 (thru 2036), followed by new CC-build @ ~800-MW.
6	#3B	*same as Option #3A except...*					Market Proxy (Using Forecasted PJM Pricing)	*(See also comments re Option #1B)*
7	#4A	Retire (6/2015)	Retire (6/2015)	up to 1,100	Market *(for <u>5 yrs</u>)... then replace with ~700-800 MW CC-build tranche by 1/2021*	up to 1,100	Market Proxy (Using Forecasted PJM Pricing)	o Assumes a <u>5-Yr</u> exposure to a 'full' market... followed by a new (~700-800 MW) CC-build by approx. 2021. *(See also comments re Option #1B)*
8	#4B	*same as Option #4A except...*			Market *(for <u>10 yrs</u>)... then replace with ~700-800 MW CC-build tranche by 1/2021*	up to 1,100	Market Proxy (Using Forecasted PJM Pricing)	o Assumes a <u>10-Yr</u>. exposure to a 'full' market... followed by a new (~700-800 MW) CC-build by approx. 2026. *(See also comments re Option #1B)*

Options "#5" and "#6" that were NOT considered in that filing...

	Option#	Big Sandy 2	Big Sandy 1	Approx. Resulting KPCo Capacity Need (MW)	Effective BS2 Replacement	Approx. Remaining KPCo Capacity Need (MW)	Effective BS1 Replacement	Additional Comments/Definition...
9	#5A	Retire (6/2015)	Convert/Fuel-Switch to Gas (7/2015)	up to 800	<u>50%</u> Mitchell Transfer [780-MW] (1/2014)	*assume zero*	*n/a*	o Assumes a <u>15-Yr</u> incremental service life for a BS1 Conversion (thru 2030), followed by like-size CC or CT-build. o BS2 assumed idled 6/2015; assumes an approx. 25-Yr service life for transferred Mitchell capacity (thru 2040)
10	#5B	*same as Option #5A except...*			<u>NO</u> Mitchell Transfer... Market *(for <u>5 yrs</u>)... then replace w/ ~700-800 MW CC-build by '21*	up to 800	Market Proxy (Using Forecasted PJM Pricing)	o Assumes a <u>5-Yr</u>. exposure to a 'full' market... followed by a new (~700-800 MW) CC-build by approximately 2021. *(See also comments re Option #1B)*
11	#6	Retire (6/2015)	Retire (6/2015)	up to 1,100	<u>50%</u> Mitchell Transfer [780-MW] (1/2014)	~250	Market Proxy (Using Forecasted PJM Pricing)	*(See also comments re Option #1B)*

[A] *<u>ALL</u> modeling scenarios continue to assume the extension of KPCo's current (390-MW, total) purchase entitlement share of Rockport Units 1 and 2 through the full (2040) study period.*

[B] *Although the MATS rulemaking implementation date is April (16), 2015, it is expected that these units will be able to operate through the PJM 2014/15 capacity "planning year" (thru <u>May 31</u>, 2015) after joint consultations with PJM working with several state environmental agencies responsible for overseeing the implementation of MATS.*

Summary of Long-Term Commodity Price Forecast Scenarios Used in Strategist® Modeling

(Source: AEP Fundamental Analysis)

Unless otherwise note, all Annual-Average pricing is represented in 'Nominal' Dollars

Exhibit SCW-3

NATURAL GAS (Henry Hub)
($/MMBtu)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	4.48	4.48	3.94	4.48	4.48
2013	4.94	5.43	4.35	4.94	4.94
2014	5.38	6.02	4.73	5.38	5.38
2015	5.52	6.29	4.86	5.52	5.52
2016	5.99	6.94	5.27	5.99	5.99
2017	6.13	7.23	5.39	6.42	6.13
2018	6.32	7.46	5.56	6.60	6.32
2019	6.46	7.62	5.68	6.73	6.46
2020	6.52	7.69	5.73	6.78	6.52
2021	6.75	7.97	5.94	7.06	6.60
2022	7.07	8.34	6.22	7.22	6.68
2023	7.26	8.57	6.39	7.35	6.86
2024	7.51	8.86	6.61	7.51	7.10
2025	7.75	9.14	6.82	7.75	7.32
2026	7.85	9.26	6.91	7.85	7.42
2027	8.04	9.49	7.08	8.04	7.60
2028	8.22	9.78	7.23	8.22	7.77
2029	8.41	10.08	7.40	8.41	7.94
2030	8.52	10.48	7.50	8.52	8.05

CO2
($/Metric Tonne)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	15.08	0.00
2018	0.00	0.00	0.00	15.28	0.00
2019	0.00	0.00	0.00	15.47	0.00
2020	0.00	0.00	0.00	15.68	0.00
2021	0.00	0.00	0.00	15.88	0.00
2022	15.08	15.48	15.48	16.08	0.00
2023	15.28	15.67	15.67	16.29	0.00
2024	15.48	15.88	15.88	16.50	0.00
2025	15.67	16.08	16.08	16.72	0.00
2026	15.88	16.29	16.29	16.94	0.00
2027	16.08	16.50	16.50	17.16	0.00
2028	16.29	16.72	16.72	17.38	0.00
2029	16.50	16.94	16.94	17.60	0.00
2030	16.72	17.12	17.16	17.84	0.00

NAPP (6.0#)
($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	56.75	64.13	53.91	56.75	56.75
2013	58.00	66.70	53.36	58.00	58.00
2014	60.00	69.00	53.40	60.00	60.00
2015	62.36	72.34	55.50	62.36	62.36
2016	64.72	75.08	57.60	64.72	64.72
2017	65.92	76.47	58.67	64.00	65.92
2018	67.18	77.93	59.79	65.22	67.18
2019	68.45	79.40	60.92	66.46	68.45
2020	69.71	80.87	62.05	67.68	69.71
2021	71.18	82.57	63.35	69.10	71.18
2022	70.90	82.24	63.10	70.55	72.67
2023	72.37	83.95	64.41	72.02	74.18
2024	73.87	85.69	65.74	73.51	75.71
2025	75.38	87.44	67.09	75.01	77.26
2026	76.91	89.22	68.45	76.54	78.84
2027	78.46	91.02	69.83	78.08	80.43
2028	80.04	92.85	71.24	79.65	82.04
2029	81.65	94.71	72.66	81.25	83.69
2030	83.27	96.60	74.11	82.87	85.36

CAPP (1.6#)
($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	79.97	91.46	75.97	79.97	79.97
2013	83.46	97.95	75.11	83.46	83.46
2014	84.83	101.44	74.65	84.83	84.83
2015	85.21	102.25	74.98	85.21	85.21
2016	85.52	102.62	75.26	85.52	85.52
2017	85.31	102.37	75.07	82.83	85.31
2018	86.94	104.33	76.51	84.41	86.94
2019	88.58	106.30	77.95	86.00	88.58
2020	90.22	108.26	79.39	87.59	90.22
2021	92.07	110.48	81.02	89.38	92.07
2022	91.66	109.99	80.66	91.21	93.95
2023	93.52	112.22	82.30	93.07	95.86
2024	95.41	114.49	83.96	94.94	97.79
2025	97.31	116.77	85.63	96.84	99.74
2026	99.24	119.09	87.33	98.76	101.72
2027	101.19	121.43	89.05	100.70	103.72
2028	103.18	123.81	90.80	102.68	105.76
2029	105.19	126.23	92.57	104.68	107.82
2030	107.24	128.69	94.37	106.72	109.92

NATURAL GAS (Henry Hub) (REAL, 2010 $)
($/MMBtu)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	4.22	4.22	3.71	4.22	4.22
2013	4.57	5.03	4.02	4.57	4.57
2014	4.84	5.42	4.26	4.84	4.84
2015	4.86	5.54	4.27	4.86	4.86
2016	5.18	6.01	4.56	5.18	5.18
2017	5.22	6.16	4.60	5.47	5.22
2018	5.30	6.26	4.67	5.54	5.30
2019	5.34	6.30	4.70	5.56	5.34
2020	5.31	6.26	4.67	5.52	5.31
2021	5.42	6.39	4.77	5.67	5.30
2022	5.59	6.59	4.92	5.70	5.28
2023	5.66	6.68	4.98	5.73	5.35
2024	5.76	6.80	5.07	5.76	5.45
2025	5.86	6.91	5.15	5.86	5.53
2026	5.85	6.90	5.15	5.85	5.53
2027	5.90	6.96	5.19	5.90	5.58
2028	5.94	7.07	5.23	5.94	5.62
2029	5.99	7.18	5.27	5.99	5.66
2030	5.99	7.36	5.27	5.99	5.66

ON-Peak Energy (PJM-AEP Gen Hub)
($/Mwh)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	50.57	55.16	47.59	49.73	50.30
2013	50.14	55.48	44.98	48.59	47.85
2014	54.24	62.03	49.26	54.28	54.45
2015	56.71	65.49	53.60	56.42	56.79
2016	63.56	71.80	58.75	62.42	63.74
2017	63.48	71.72	59.20	71.84	64.41
2018	64.18	73.15	60.06	72.73	65.25
2019	65.44	74.08	60.90	73.21	66.31
2020	66.33	75.16	60.86	73.82	66.55
2021	67.64	77.00	62.38	75.75	67.28
2022	76.79	85.88	72.64	77.34	68.31
2023	78.33	87.97	74.25	78.43	70.32
2024	80.34	89.78	74.99	79.55	71.04
2025	82.18	92.27	76.25	81.48	73.07
2026	83.23	93.67	77.71	82.70	73.94
2027	84.57	95.54	79.22	84.24	75.28
2028	86.25	98.14	80.55	86.25	76.51
2029	87.64	100.30	81.53	87.32	77.70
2030	89.34	103.70	82.78	88.75	78.95

OFF-Peak Energy (PJM-AEP Gen Hub)
($/Mwh)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	30.92	33.66	29.07	30.33	30.27
2013	30.55	35.01	28.55	30.15	29.97
2014	33.26	38.84	31.15	32.95	33.34
2015	33.89	40.47	32.16	33.73	34.34
2016	39.57	45.94	36.16	38.65	40.12
2017	41.57	48.09	38.59	51.00	41.67
2018	42.57	49.48	39.25	52.03	42.70
2019	43.60	50.18	40.01	52.82	43.47
2020	44.18	51.40	40.52	53.54	44.35
2021	45.76	53.01	41.76	55.14	45.22
2022	55.93	63.44	52.41	56.56	46.22
2023	56.84	65.25	53.42	57.35	47.67
2024	58.85	66.65	54.17	58.69	48.94
2025	60.37	68.79	55.93	60.38	50.72
2026	61.06	70.11	56.67	61.28	51.59
2027	62.64	72.07	58.15	62.85	53.19
2028	64.05	74.08	59.05	64.56	54.40
2029	65.66	76.20	60.20	65.80	55.78
2030	67.49	78.87	61.12	66.82	56.65

Capacity Value (PJM-RTO RPM) *
($/MW-Day)

	'BASE' Fleet Transition: CSAPR (Carbon in 2022)	Alternative Scenarios: FT-CSAPR: HIGHER Band (Carbon in 2022)	FT-CSAPR: LOWER Band (Carbon in 2022)	FT-CSAPR: Early Carbon (Carbon in 2017)	FT-CSAPR: No Carbon
2012	55.44	55.44	55.44	55.44	55.44
2013	23.03	23.03	23.03	23.03	23.03
2014	85.05	85.05	85.05	85.05	85.05
2015	215.25	215.25	215.25	215.25	215.25
2016	281.92	281.92	281.92	281.92	281.92
2017	235.98	199.63	230.85	210.98	240.98
2018	200.39	166.43	179.76	180.39	205.39
2019	224.57	211.40	186.64	214.57	230.57
2020	253.47	253.86	212.57	243.47	261.47
2021	280.05	293.65	238.70	265.05	295.05
2022	304.18	330.64	264.71	289.18	322.18
2023	325.73	364.68	288.14	310.73	345.73
2024	344.58	391.96	308.40	329.58	364.58
2025	360.58	405.21	325.58	345.58	380.58
2026	373.61	411.28	340.04	358.61	394.61
2027	383.50	417.45	350.60	363.50	405.50
2028	390.13	423.72	358.23	370.13	413.13
2029	392.94	430.07	362.96	372.94	416.94
2030	392.16	436.27	361.29	372.16	418.16

* Represents forecasted PJM-RTO Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years

Exhibit SCW-4

Estimated Non-Recurring Major Environmental Capital Expenditures Associated with Emerging and Proposed U.S. EPA Rulemaking

- o Mercury and Air Toxics Standards (MATs) Rule
- o Coal Combustion Residuals (CCR) Rule
- o Clean Water Act "316(b)" Rule
- o Steam Electric Effluent Limitations Guidelines (ELG)
- o NPDES Permit Limits (Mitchell only)

Included in Strategist® KPCo-Resource Modeling for either Big Sandy or Mitchell Plants 'Options'

All Costs Exclude AFUDC
($000)

	2012 Est. *	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Option #1 (Big Sandy 2 Retrofit)											
(Excluding DFGD & Assoc. Projects)											
BS U2 Ash Waste Water Treatment System	0	0	0	781	9,621	17,336	6,934	0	0	0	34,672
BS U2 316(b)	0	0	0	17	35	178	1,157	0	0	0	1,387
BS U2 Bottom Ash Pond Reline	0	0	0	0	883	4,089	4,213	0	0	0	9,185
TOTAL	*0*	*0*	*0*	*798*	*10,539*	*21,603*	*12,304*	*0*	*0*	*0*	*45,244*

	2012 Est. *	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Option #5 (Big Sandy 1 Convert to Gas)											
BS U1 316(b)		0	71	160	200	356	2,312	0	0	0	*3,099*

	2012 Est. *	2013	2014	2015	2016	2017	2018	2019	2020	2021	Subtotal (2014-2021)	Total
Options #1A, 2A, 3A, 5A & 6 (Mitchell Asset Transfer)	(A)	(A)										(A)
100% of Est. Unit Costs												
ML U1&2 Dry Fly Ash Conversion	29,219	54,798	20,780	0	0	0	0	0	0	0	20,780	104,796
ML U1&2 Bottom Ash Pond Reline	0	0	0	0	1,442	6,417	6,785	0	0	0	14,644	14,644
ML U1 Ash Waste Water Treatment System	566	1,529	4,346	3,336	0	0	0	0	0	0	7,681	9,776
ML U1 Electro-static Precipitator Upgrades (Ph 1)	1,224	4,527	0	0	0	0	0	0	0	0	0	5,751
ML U1 316(b)	0	0	40	72	88	27	42	1,143	0	0	1,412	1,412
ML U1 ELG Waste Water Treatment System	0	0	0	1,631	4,128	6,753	7,613	0	0	0	20,125	20,125
ML U1 Electro-static Precipitator Upgrades (Ph 2)	0	0	0	0	0	0	5,697	19,173	0	0	24,870	24,870
ML U2 Ash Waste Water Treatment System	566	1,529	4,346	3,336	0	0	0	0	0	0	7,681	9,776
ML U2 Electro-static Precipitator Upgrades (Ph 1)	0	0	881	4,190	0	0	0	0	0	0	5,071	5,071
ML U2 316(b)	0	0	40	72	89	27	42	1,143	0	0	1,413	1,413
ML U2 ELG Waste Water Treatment System	0	0	0	1,631	4,128	6,753	7,613	0	0	0	20,125	20,125
ML U2 Electro-static Precipitator Upgrades (Ph 2)	0	0	0	0	0	12,361	10,041	0	0	0	22,402	22,402
ML U0 New Haul Road and Landfill Expansion	10,108	11,673	13,734	0	805	3,884	5,755	4,194	4,446	4,241	37,059	58,840
TOTAL	*41,683*	*74,056*	*44,166*	*14,268*	*10,680*	*36,222*	*43,588*	*25,653*	*4,446*	*4,241*	*183,264*	*299,003*
20% of TOTAL Mitchell (KPCo Options: #1A, 2A & 3A)	*8,337*	*14,811*	*8,833*	*2,854*	*2,136*	*7,244*	*8,718*	*5,131*	*889*	*848*	*36,653*	*59,801*
50% of TOTAL Mitchell (KPCo Options: #5A & 6)	*20,842*	*37,028*	*22,083*	*7,134*	*5,340*	*18,111*	*21,794*	*12,827*	*2,223*	*2,120*	*91,632*	*149,501*

* *Note: 2012 represents a full-year forecast estimate*

(A) Estimated Costs incurred prior to 1/1/2014 were incorporated into the overall "Asset Transfer" Cost

Exhibit SCW-5

Kentuc. er Co.

Big Sandy Unit Disposition Analysis

Life-Cycle Study Period (30-Year, 2011-2040) Economics

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS>)

$ Millions

	Option #1: RETROFIT Big Sandy Unit 2; RETIRE & REPLACE Big Sandy Unit 1 (6/2015) Retrofit BS2 with Dry (NID) FGD Technology (6/2017)		Option #2: RETIRE & REPLACE Big Sandy Units 1 and 2 (6/2015 & 1/2016, respectively) Replace BS2 with "Brownfield New-Build" NG-Combined Cycle (@ Big Sandy site) (7/2017)		Option #3: RETIRE & REPLACE Big Sandy Unit 2 (1/2016) "CC-Repowered" Big Sandy Unit 1 (7/2017)		Option #4: RETIRE & REPLACE Big Sandy Units 1 and 2 (6/2015) Replace with Purchased Capacity & Energy		Option #5: RETIRE & REPLACE Big Sandy Unit 2 (1/2016) "Gas-Converted" Big Sandy Unit 1 (7/2015)	
	Option #1A: Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Option #1B: Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Option #2A: Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Option #2B: Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Option #3A: Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Option #3B: Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Option #4A: Capacity from (PJM) Market Purchases for 5-yrs, then ~700-800 MW CC and/or CT-build	Option #4B: Capacity from (PJM) Market Purchases for 10-yrs, then ~700-800 MW CC and/or CT-build	Option #5A: Capacity from 50% (780-MW) Mitchell Asset Transfer (1/2014)	Option #5B: Capacity from (PJM) Market Purchases for 5-yrs, then ~700-800 MW CC and/or CT-build
all versus... ("BASE") Option #6: RETIRE & REPLACE Big Sandy 1 and 2 (6/2015) with 50% (780-MW) Mitchell Units Ownership Transfer (1/2014) plus (PJM) Market Purchases (for 10-yrs)										
BASE: "Fleet Transition-CSAPR"	490	697	347	560	423	633	411	435	(156)	258
% Relative Variance	*8.5%*	*12.0%*	*6.0%*	*9.7%*	*7.3%*	*10.9%*	*7.1%*	*7.5%*	*-2.7%*	*4.5%*
'Commodity Price Banding' Scenarios...										
2. "Fleet Transition-CSAPR: HIGHER Band"	463	844	553	934	636	1,017	816	903	(149)	673
3. "Fleet Transition-CSAPR: LOWER Band"	506	617	252	372	324	440	221	217	(154)	62
'Carbon/CO_2 Pricing' Scenarios...										
4. "Fleet Transition-CSAPR: No Carbon"	482	727	403	651	478	723	498	537	(168)	341
5. "Fleet Transition-CSAPR: Early Carbon (2017)"	493	661	297	473	371	543	333	345	(144)	183

Note:

-- A "POSITIVE" value above would favor the 50% Mitchell Transfer (Option #6)... a "<NEGATIVE>" value would favor the alternative option

-- Every $100 Million change in CPW is equivalent to a $2.00 per Mwh (0.200 cents/kWh) impact on levelized annual KPCo G-revenue requirements (2011$) over the entire affected (2016-2040) period

Additional Notes:

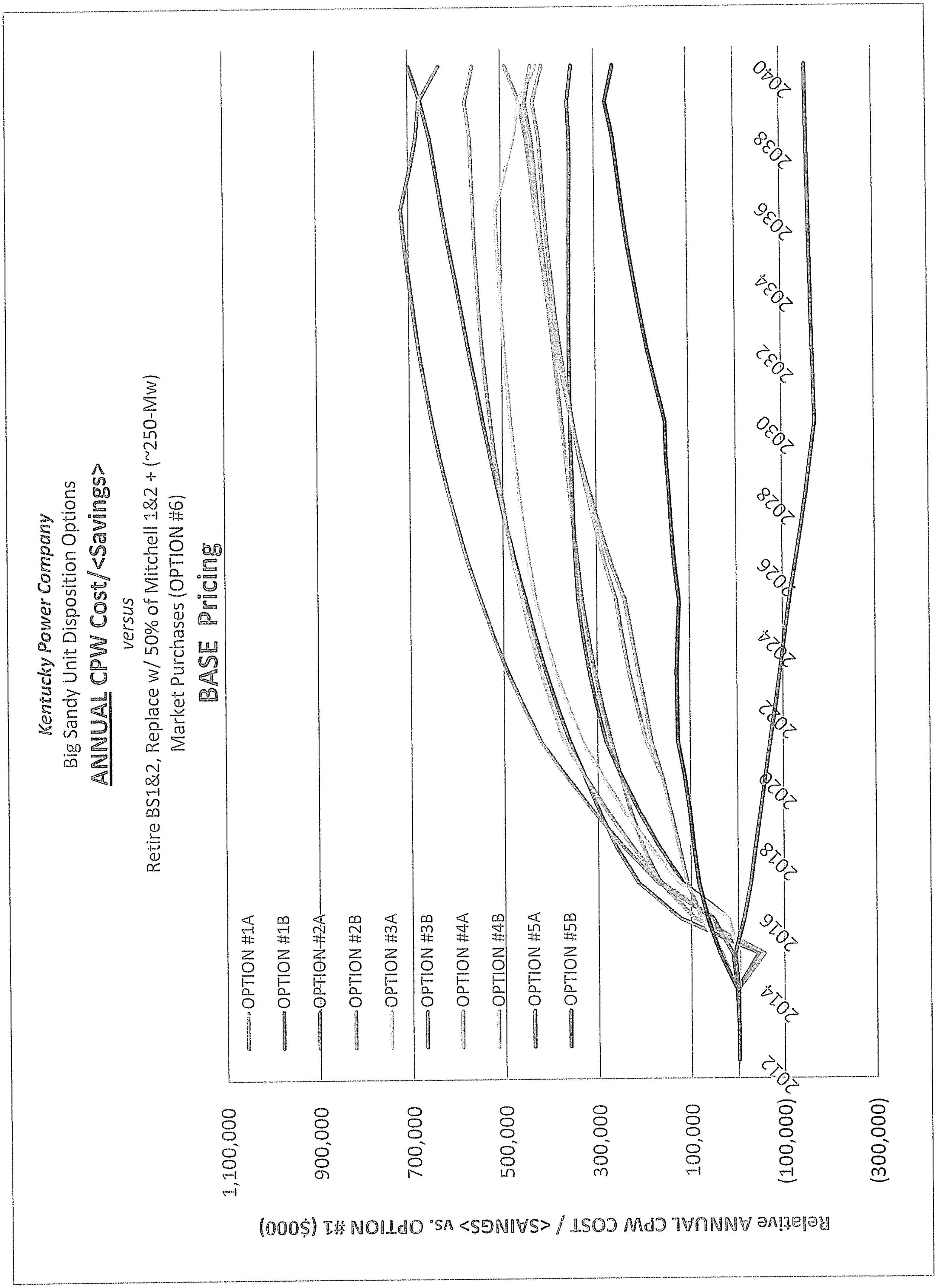
- 'BASE' ("Fleet Transition-CSAPR") pricing scenario --as well as "HIGHER Band" and "LOWER Band" pricing scenarios-- assumes carbon/CO2 pricing is effective in 2022
- Any (short-term) "interim" requirements post-Big Sandy unit retirement dates that would *precede* the in-service date of the DFGD, or replacement CC-builds (Options #1, #2, #3) would be met w/ PJM market purchases
- Option #1 (RETROFIT Big Sandy 2) assumes the unit would operate and recovery costs through the full study period
- Option #2 (RETIRE & REPLACE BS2 w/ "New-Build CC") assumes a 30-year operation and capital cost recovery period for the CC in all analyses
- Option #3 (RETIRE & REPLACE BS2 w/ "CC-Repowered BS1") assumes a 20-year operation and capital cost recovery period for the CC in all analyses (i.e., thru 2035)
- Option #4 (Gas Convert Big Sandy 1) assumes the unit would operate and recovery capital costs for the subseqent 15 period (i.e., thru 2030)
- Options #1, #2, #4 and #6 assume Big Sandy Unit 1 is retired 6/2015 (Option #3 assumes that unit is repowered as a CC unit; Option #5 assumes the unit is 'converted' to burn natural gas in the existing boiler)
- All options analyses include KPCo's 30% purchase entitlement share of AEG's 50% portion of Rockport Units 1 and 2 (or, collectively, ~393-MW of capacity and energy)
  (i.e. resulting in effectively no relative impact on any of these Big Sandy 2 disposition analyses)
- Big Sandy 2 "Retirement" Options #2, #3, #4, #5 and #6 also conservatively exclude costs associated w/ socio-economic impacts to the region
  (i.e. resulting in effectively no relative impact on any of these BS2 disposition analyses)
- "G" Revenue Requirements established on a KPCo "stand-alone" basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs being inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits on coal unit and/or new-build/repowered NG-CC capacity)

KPCO Big Sandy Unit Disposition Options

"BASE" ('Fleet Transition-CSAPR') Commodity Pricing

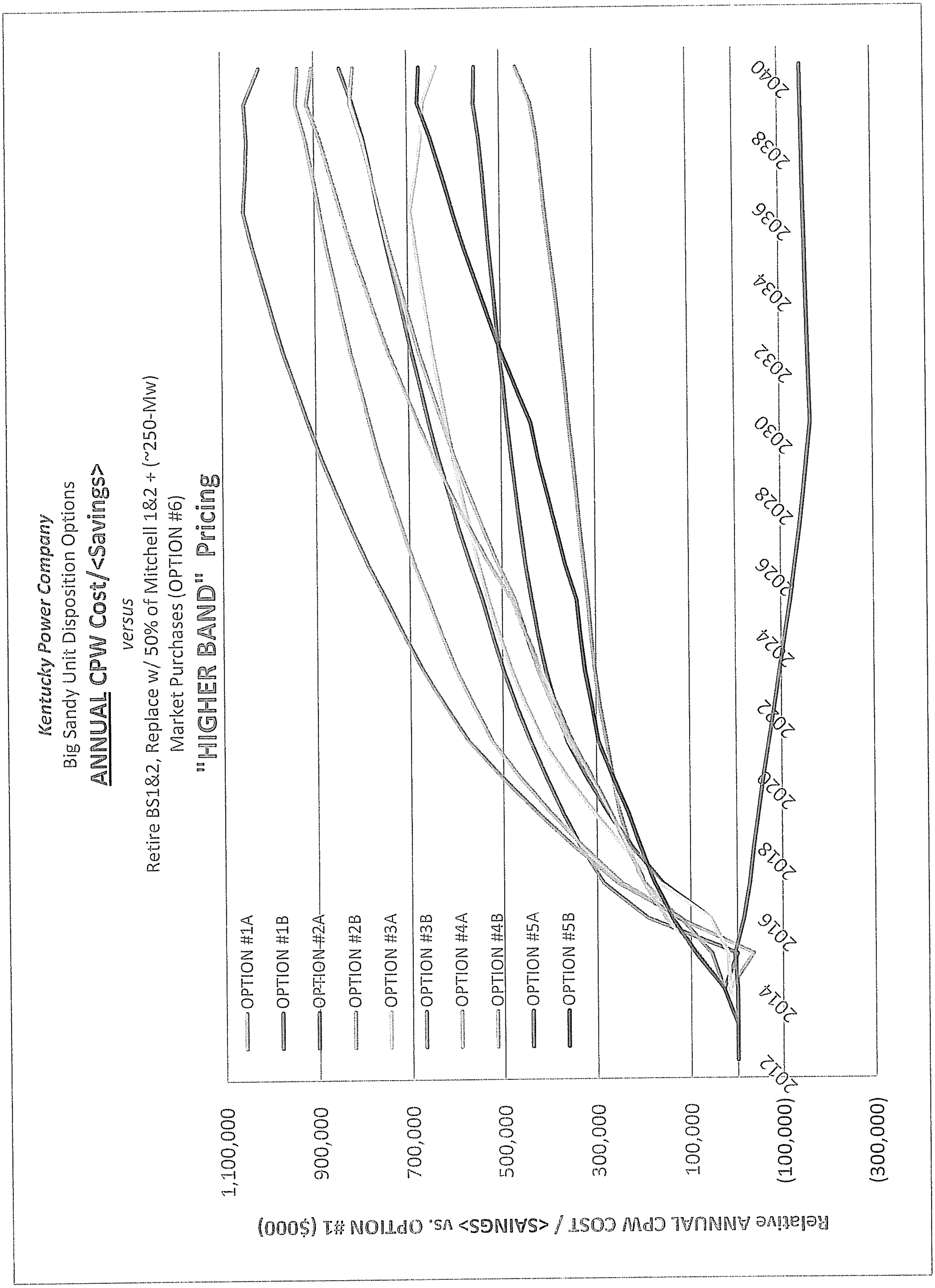
Expansion Plan Summary and Costs

Option	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B	#6
Big Sandy 1 Disposition	Retire 6/2015		Retire 6/2015		(CC) Repower 6/2017		Retire 6/2015		Gas Conversion 7/2015		Retire 6/2015
Big Sandy 2 Disposition	Retrofit 6/2017 (Idling 1/2016)		Retire 1/2016		Retire 1/2016		Retire 6/2015		Retire 6/2015		Retire 6/2015
Mitchell 1&2 Transfer (1/2014)	20%	0%	20%	0%	20%	0%	0%	0%	50%	0%	50%
BS Repl-Build Capacity at Big Sandy Site	None		Combined-Cycle (6/2017)		(Repowered) Combined-Cycle (6/17)		None (thru 2025)	None (thru 2025)	None (thru 2030)	None (thru 2020)	None (thru 2025)
BS Repl-Build Capacity at Generic Site	None	None (thru 2025)	None	None (thru 2025)	None	None (thru 2025)	None (thru 2020)	None (thru 2025)	None	None (thru 2025)	None
Market Puchase Duration	None	To '26 (~250 MW)	None	To '26 (~250 MW)	None	To '26 (~250 MW)	To '21(~1050 MW)	To '26(~1050 MW)	None	To '21(~800 MW)	To '26 (~250 MW)
2011											
2012											
2013											
2014	2- 20% ML,		2- 20% ML,		2- 20% ML,				2- 50% ML,		2- 50% ML,
2015									1- 260 MW BSGAS	1- 260 MW BSGAS	
2016											
2017	1 -788 MW Retrofit	1 -788 MW Retrofit	1- 762 MW BFCC,	1- 762 MW BFCC,	1- 745 MW RPWR	1- 745 MW RPWR					
2018											
2019											
2020							4 -85 MW CTs, 1- 352 MW CC1,				
2021										1- 381 MW BFCC,	
2022											
2023											
2024											
2025											
2026		4 -85 MW CTs,		4 -85 MW CTs,		4 -85 MW CTs,	1- 381 MW BFCC,	4 -85 MW CTs, 1- 762 MW BFCC,		4 -85 MW CTs,	1- 381 MW BFCC,
2027											
2028											
2029											
2030									1- 381 MW BFCC,	1- 352 MW CC1,	
2031											
2032-2040											
2011- 2040 CPW ($000)											
KPCO Production and Capital Cost	6,256,539	6,322,529	6,214,342	6,286,130	6,209,935	6,278,564	5,972,503	5,815,008	5,680,947	5,855,373	5,752,470
Less: Value of ICAP Revenue	(20,560)	(161,628)	79,997	(61,071)	(205)	(141,273)	(225,245)	(406,986)	50,313	(189,484)	(34,601)
Total KPCO Revenue Requirement, Net	6,277,099	6,484,157	6,134,344	6,347,201	6,210,140	6,419,837	6,197,747	6,221,994	5,630,634	6,044,857	5,787,072
Cost / <Savings> vs. "Option #6"	**490,027**	**697,085**	**347,273**	**560,129**	**423,068**	**632,765**	**410,676**	**434,922**	**(156,437)**	**257,786**	-
	8.5%	12.0%	6.0%	9.7%	7.3%	10.9%	7.1%	7.5%	-2.7%	4.5%	


Kentucky Power Company
Big Sandy Unit Disposition Options
ANNUAL CPW Cost/<Savings>
versus
Retire BS1&2, Replace w/ 50% of Mitchell 1&2 + (~250-Mw)
Market Purchases (OPTION #6)
BASE Pricing
OPTION #1A
OPTION #1B
OPTION #2A
OPTION #2B
OPTION #3A
OPTION #3B
OPTION #4A
OPTION #4B
OPTION #5A
OPTION #5B
Relative ANNUAL CPW COST / <SAINGS> vs. OPTION #1 ($000)
1,100,000
900,000
700,000
500,000
300,000
100,000
(100,000)
(300,000)
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040

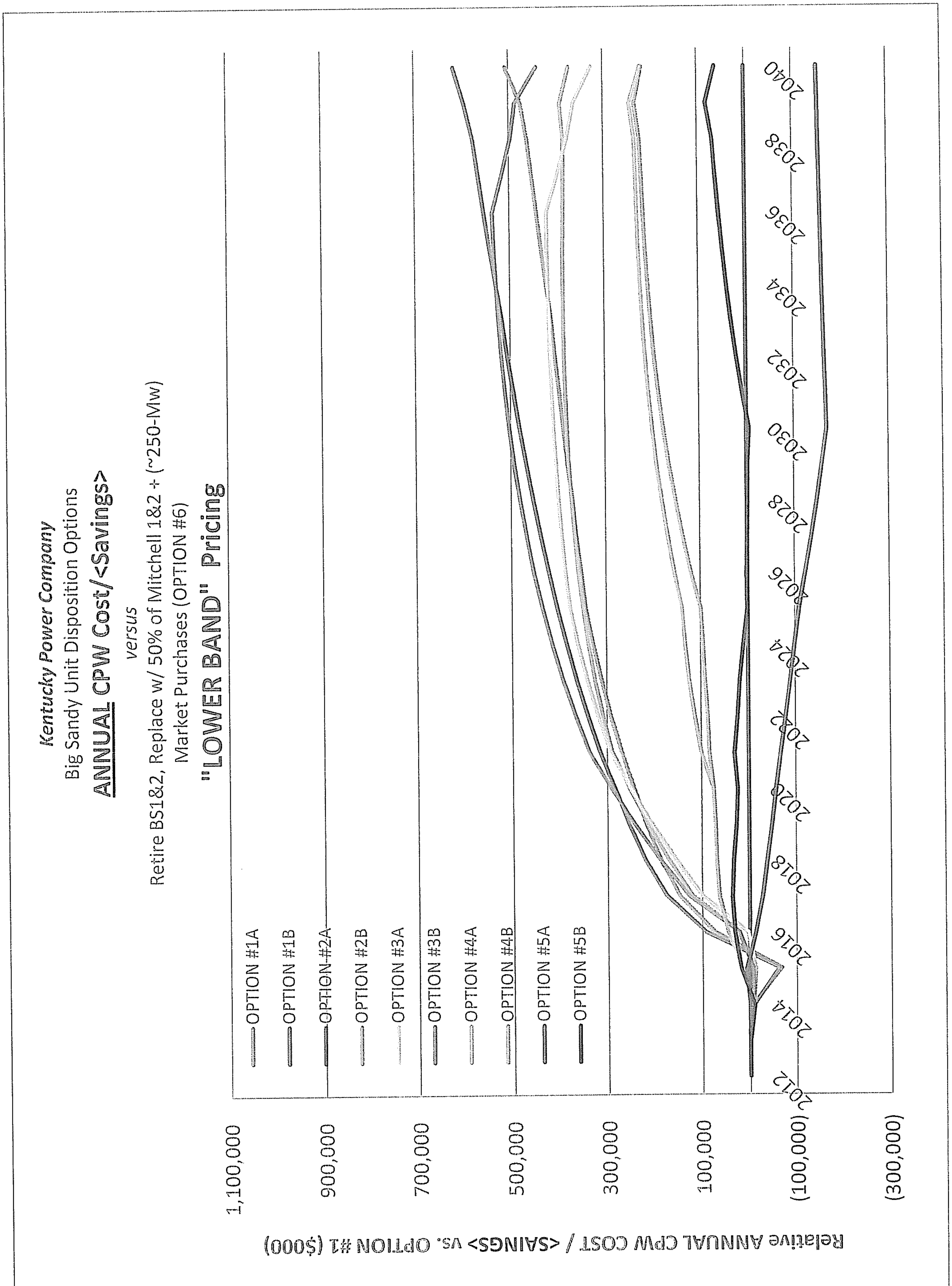
KPCO Big Sandy Unit Disposition Options
HIGHER Band Commodity Pricing
Expansion Plan Summary and Costs

Option	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B	#6
Big Sandy 1 Disposition	Retire 6/2015		Retire 6/2015		(CC) Repower 6/2017		Retire 6/2015		Gas Conversion 7/2015		Retire 6/2015
Big Sandy 2 Disposition	Retrofit 6/2017 (Idling 4/2016)		Retire 1/2016		Retire 1/2016		Retire 6/2015		Retire 6/2015		Retire 6/2015
Mitchell 1&2 Transfer (1/2014)	20%	0%	20%	0%	20%	0%	0%	0%	50%	0%	50%
BS Repl-Build Capacity at Big Sandy Site	None		Combined-Cycle (6/2017)		(Repowered) Combined-Cycle (6/2017)		None (thru 2025)	None	None (thru 2030)	None (thru 2020)	None (thru 2025)
BS Repl-Build Capacity at Generic Site	None	None (thru 2025)	None	None (thru 2025)	None	None (thru 2025)	None (thru 2020)	None (thru 2025)	None	None (thru 2025)	None
Market Puchase Duration	None	To '26 (~250 MW)	None	To '26 (~250 MW)	None	To '26 (~250 MW)	To '21(~1050 MW)	To '26(~1050 MW)	None	To '21(~800 MW)	To '26 (~250 MW)
2011											
2012											
2013											
2014	2- 20% ML,		2- 20% ML,		2- 20% ML,				2- 50% ML,		2- 50% ML,
2015									- 260 MW BSGAS	- 260 MW BSGAS	
2016											
2017	1 -788 MW Retrofit	1 -788 MW Retrofit	1- 762 MW BFCC,	1- 762 MW BFCC,	1- 745 MW RPWR	1- 745 MW RPWR					
2018											
2019											
2020											
2021							4 -85 MW CT's, 1- 352 MW CC1,			1- 381 MW BFCC,	
2022											
2023											
2024											
2025											
2026		1- 352 MW CC1,		1- 352 MW CC1,		1- 352 MW CC1,	1- 381 MW BFCC,	3- 352 MW CC1,		4 -85 MW CT's,	1- 381 MW BFCC,
2027											
2028											
2029											
2030											
2031									1- 381 MW BFCC,	1- 352 MW CC1,	
2032-2040											
2011- 2040 CPW ($000)											
KPCO Production and Capital Cost	6,262,415	6,520,045	6,462,165	6,718,308	6,457,637	6,714,493	6,426,335	6,268,785	5,717,874	6,312,312	5,784,381
Less: Value of ICAP Revenue	(13,789)	(137,974)	95,252	(28,932)	8,331	(115,853)	(202,860)	(448,064)	53,780	(174,526)	(29,153)
Total KPCO Revenue Requirement, Net	6,276,204	6,658,019	6,366,913	6,747,240	6,449,306	6,830,347	6,629,195	6,716,849	5,664,095	6,486,838	5,813,534
Cost / <Savings> vs. "Option #6"	462,670 8.0%	844,485 14.5%	553,379 9.5%	933,707 16.1%	635,772 10.9%	1,016,813 17.5%	815,661 14.0%	903,315 15.5%	(149,439) -2.6%	673,304 11.6%	-


Kentucky Power Company
Big Sandy Unit Disposition Options
ANNUAL CPW Cost/<Savings>
versus
Retire BS1&2, Replace w/ 50% of Mitchell 1&2 + (~250-Mw)
Market Purchases (OPTION #6)
"HIGHER BAND" Pricing
OPTION #1A
OPTION #1B
OPTION #2A
OPTION #2B
OPTION #3A
OPTION #3B
OPTION #4A
OPTION #4B
OPTION #5A
OPTION #5B
1,100,000
900,000
700,000
500,000
300,000
100,000
(100,000)
(300,000)
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Relative ANNUAL CPW COST / <SAINGS> vs. OPTION #1 ($000)

KPCO Big Sandy Unit Disposition Options
"LOWER BAND" Commodity Pricing
Expansion Plan Summary and Costs

Option	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B	#6
Big Sandy 1 Disposition	Retire 6/2015		Retire 6/2015		(CC) Repower 6/2017		Retire 6/2015		Gas Conversion 7/2015		Retire 6/2015
Big Sandy 2 Disposition	Retrofit 6/2017 (Idling 1/2016)		Retire 1/2016		Retire 1/2016		Retire 6/2015		Retire 6/2015		Retire 6/2015
Mitchell 1&2 Transfer (1/2014)	20%	0%	20%	0%	20%	0%	0%	0%	50%	0%	50%
BS Repl-Build Capacity at Big Sandy Site	None		Combined-Cycle (6/2017)		(Repowered) Combined-Cycle (6/2017)		None (thru 2025)	None (thru 2025)	None (thru 2030)	None (thru 2020)	None (thru 2025)
BS Repl-Build Capacity at Generic Site	None	None (thru 2025)	None	None (thru 2025)	None	None (thru 2025)	None (thru 2020)	None (thru 2025)	None	None (thru 2025)	None
Market Puchase Duration	None	To '26 (~250 MW)	None	To '26 (~250 MW)	None	To '26 (~250 MW)	To '21(~1050 MW)	To '26(~1050 MW)	None	To '21(~800 MW)	To '26 (~250 MW)
2011											
2012											
2013											
2014	2- 20% ML,		2- 20% ML,		2- 20% ML,				2- 50% ML,		2- 50% ML,
2015									- 260 MW BSGAS	- 260 MW BSGAS	
2016											
2017	1 -788 MW Retrofit	1 -788 MW Retrofit,	1- 762 MW BFCC,	1- 762 MW BFCC,	1- 745 MW RPWR	1- 745 MW RPWR					
2018											
2019											
2020							4 -85 MW CT's,				
2021							1- 352 MW CC1,			1- 381 MW BFCC,	
2022											
2023											
2024											
2025											
2026		4 -85 MW CT's,		4 -85 MW CT's,		4 -85 MW CT's,	1- 381 MW BFCC,	4 -85 MW CT's, 1- 762 MW BFCC,		4 -85 MW CT's,	1- 381 MW BFCC,
2027											
2028											
2029											
2030											
2031									1- 381 MW BFCC,	1- 352 MW CC1,	
2032-2040											
2011- 2040 CPW ($000)											
KPCO Production and Capital Cost	6,190,321	6,172,346	6,027,448	6,018,345	6,026,169	6,013,930	5,718,627	5,556,551	5,602,371	5,592,636	5,680,225
Less: Value of ICAP Revenue	(25,305)	(154,304)	65,588	(63,410)	(6,900)	(135,899)	(211,507)	(370,124)	46,899	(178,634)	(29,216)
Total KPCO Revenue Requirement, Net	6,215,627	6,326,650	5,961,859	6,081,755	6,033,069	6,149,828	5,930,134	5,926,675	5,555,471	5,771,270	5,709,441
Cost / <Savings> vs. "Option #6"	**506,186** 8.9%	**617,209** 10.8%	**252,419** 4.4%	**372,315** 6.5%	**323,628** 5.7%	**440,388** 7.7%	**220,693** 3.9%	**217,235** 3.8%	**(153,970)** -2.7%	**61,829** 1.1%	-

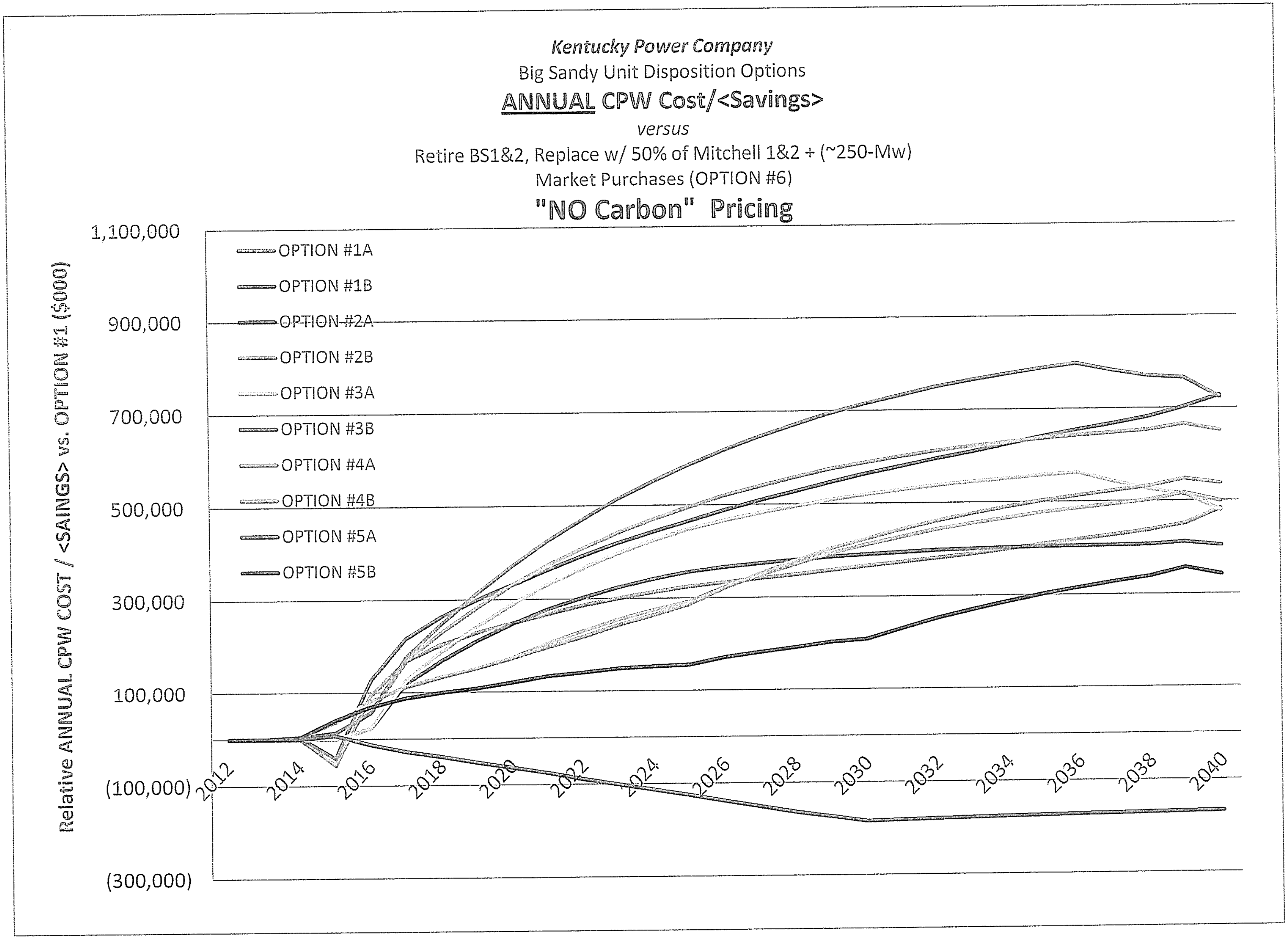

Kentucky Power Company
Big Sandy Unit Disposition Options
ANNUAL CPW Cost/<Savings>
versus
Retire BS1&2, Replace w/ 50% of Mitchell 1&2 + (~250-Mw)
Market Purchases (OPTION #6)
"LOWER BAND" Pricing
OPTION #1A
OPTION #1B
OPTION #2A
OPTION #2B
OPTION #3A
OPTION #3B
OPTION #4A
OPTION #4B
OPTION #5A
OPTION #5B
1,100,000
900,000
700,000
500,000
300,000
100,000
(100,000)
(300,000)
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Relative ANNUAL CPW COST / <SAINGS> vs. OPTION #1 ($000)

KPCO Big Sandy Unit Disposition Options

"No Carbon" Commodity Pricing

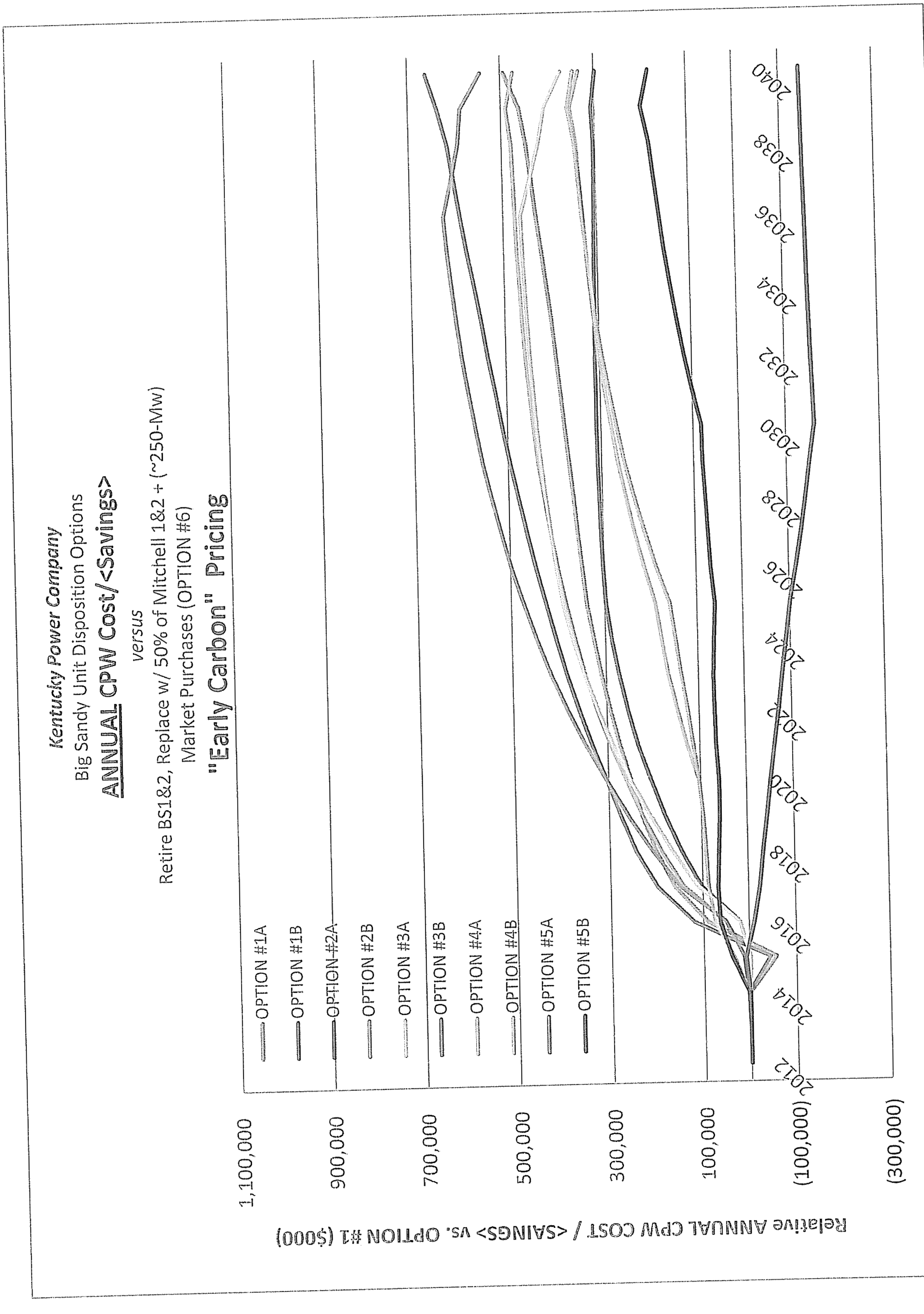
Expansion Plan Summary and Costs

Option	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B	#6
Big Sandy 1 Disposition	Retire 6/2015		Retire 6/2015		(CC) Repower 6/2017		Retire 6/2015		Gas Conversion 7/2015		Retire 6/2015
Big Sandy 2 Disposition	Retrofit 6/2017 (Idling 4/2016)		Retire 1/2016		Retire 1/2016		Retire 6/2015		Retire 6/2015		Retire 6/2015
Mitchell 1&2 Transfer (1/2014)	20%	0%	20%	0%	20%	0%	0%	0%	50%	0%	50%
BS Repl-Build Capacity at Big Sandy Site	None		Combined-Cycle (6/2017)		(Repowered) Combined-Cycle (6/2017)		None (thru 2025)	None (thru 2025)	None (thru 2030)	None (thru 2020)	None (thru 2025)
BS Repl-Build Capacity at Generic Site	None	None (thru 2025)	None	None (thru 2025)	None	None (thru 2025)	None (thru 2020)	None (thru 2025)	None	None (thru 2025)	None
Market Puchase Duration	None	To '26 (~250 MW)	None	To '26 (~250 MW)	None	To '26 (~250 MW)	To '21(~1050 MW)	To '26(~1050 MW)	None	To '21(~800 MW)	To '26 (~250 MW)
2011											
2012											
2013											
2014	2- 20% ML,		2- 20% ML,		2- 20% ML,				2- 50% ML,		2- 50% ML,
2015									- 260 MW BSGAS	- 260 MW BSGAS	
2016											
2017	1 -788 MW Retrofit	1 -788 MW Retrofit,	1- 762 MW BFCC,	1- 762 MW BFCC,	1- 745 MW RPWR	1- 745 MW RPWR					
2018											
2019											
2020											
2021							4 -85 MW CT's, 1- 352 MW CC1,			1- 381 MW BFCC,	
2022											
2023											
2024											
2025											
2026		4 -85 MW CT's,		4 -85 MW CT's,		4 -85 MW CT's,	1- 381 MW BFCC,	4 -85 MW CT's, 1- 762 MW BFCC,		4 -85 MW CT's,	1- 381 MW BFCC,
2027											
2028											
2029											
2030									1- 381 MW BFCC,	1- 352 MW CC1,	
2031											
2032-2040											
2011- 2040 CPW ($000)											
KPCO Production and Capital Cost	5,824,397	5,923,545	5,850,549	5,953,666	5,841,385	5,940,893	5,632,701	5,479,052	5,245,131	5,511,565	5,326,027
Less: Value of ICAP Revenue	(19,095)	(164,294)	86,411	(58,788)	2,267	(142,932)	(226,506)	(418,872)	52,137	(191,098)	(35,146)
Total KPCO Revenue Requirement, Net	5,843,492	6,087,838	5,764,139	6,012,454	5,839,118	6,083,825	5,859,207	5,897,924	5,192,994	5,702,664	5,361,172
Cost / <Savings> vs. "Option #6"	**482,320** 9.0%	**726,666** 13.6%	**402,966** 7.5%	**651,282** 12.1%	**477,945** 8.9%	**722,652** 13.5%	**498,034** 9.3%	**536,752** 10.0%	**(168,178)** -3.1%	**341,491** 6.4%	-


Kentucky Power Company
Big Sandy Unit Disposition Options
ANNUAL CPW Cost/<Savings>
versus
Retire BS1&2, Replace w/ 50% of Mitchell 1&2 + (~250-Mw)
Market Purchases (OPTION #6)
"NO Carbon" Pricing
Relative ANNUAL CPW COST / <SAINGS> vs. OPTION #1 ($000)
1,100,000
900,000
700,000
500,000
300,000
100,000
(100,000)
(300,000)
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
OPTION #1A
OPTION #1B
OPTION #2A
OPTION #2B
OPTION #3A
OPTION #3B
OPTION #4A
OPTION #4B
OPTION #5A
OPTION #5B

KPCO Big Sandy Unit Disposition Options
"Early Carbon" Commodity Pricing
Expansion Plan Summary and Costs

Option	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B	#6
Big Sandy 1 Disposition	Retire 6/2015		Retire 6/2015		(CC) Repower 6/2017		Retire 6/2015		Gas Conversion 7/2015		Retire 6/2015
Big Sandy 2 Disposition	Retrofit 6/2017 (Idling 4/2016)		Retire 1/2016		Retire 1/2016		Retire 6/2015		Retire 6/2015		Retire 6/2015
Mitchell 1&2 Transfer (1/2014)	20%	0%	20%	0%	20%	0%	0%	0%	50%	0%	50%
BS Repl-Build Capacity at Big Sandy Site	None		Combined-Cycle (6/2017)		(Repowered) Combined-Cycle (6/2017)		None (thru 2025)	None (thru 2025)	None (thru 2030)	None (thru 2020)	None (thru 2025)
BS Repl-Build Capacity at Generic Site	None	None (thru 2025)	None	None (thru 2025)	None	None (thru 2025)	None (thru 2020)	None (thru 2025)	None	None (thru 2025)	None
Market Puchase Duration	None	To '26 (~250 MW)	None	To '26 (~250 MW)	None	To '26 (~250 MW)	To '21(~1050 MW)	To '26(~1050 MW)	None	To '21(~800 MW)	To '26 (~250 MW)
2011											
2012											
2013											
2014	2- 20% ML,		2- 20% ML,		2- 20% ML,				2- 50% ML,		2- 50% ML,
2015									- 260 MW BSGAS	- 260 MW BSGAS	
2016											
2017	1 -788 MW Retrofit	1 -788 MW Retrofit,	1- 762 MW BFCC,	1- 762 MW BFCC,	1- 745 MW RPWR,	1- 745 MW RPWR,					
2018											
2019											
2020											
2021							4 -85 MW CTs, 1- 352 MW CC1,			1- 381 MW BFCC,	
2022											
2023											
2024											
2025											
2026		4 -85 MW CTs,		4 -85 MW CTs,		4 -85 MW CTs,	1- 381 MW BFCC,	4 -85 MW CTs, 1- 762 MW BFCC,		4 -85 MW CTs,	1- 381 MW BFCC,
2027											
2028											
2029											
2030											
2031									1- 381 MW BFCC,	1- 352 MW CC1,	
2032-2040											
2011- 2040 CPW ($000)											
KPCO Production and Capital Cost	6,536,921	6,569,751	6,436,637	6,477,538	6,434,613	6,471,916	6,180,972	6,019,708	5,967,265	6,064,617	6,031,075
Less: Value of ICAP Revenue	(19,224)	(154,321)	76,272	(58,825)	113	(134,984)	(215,660)	(388,936)	48,130	(181,941)	(32,445)
Total KPCO Revenue Requirement, Net	6,556,145	6,724,072	6,360,365	6,536,363	6,434,500	6,606,899	6,396,632	6,408,644	5,919,135	6,246,559	6,063,521
Cost / <Savings> vs. "Option #6"	492,624	660,552	296,845	472,842	370,979	543,379	333,111	345,123	(144,386)	183,038	-
	8.1%	10.9%	4.9%	7.8%	6.1%	9.0%	5.5%	5.7%	-2.4%	3.0%	


Kentucky Power Company
Big Sandy Unit Disposition Options
ANNUAL CPW Cost/<Savings>
versus
Retire BS1&2, Replace w/ 50% of Mitchell 1&2 + (~250-Mw)
Market Purchases (OPTION #6)
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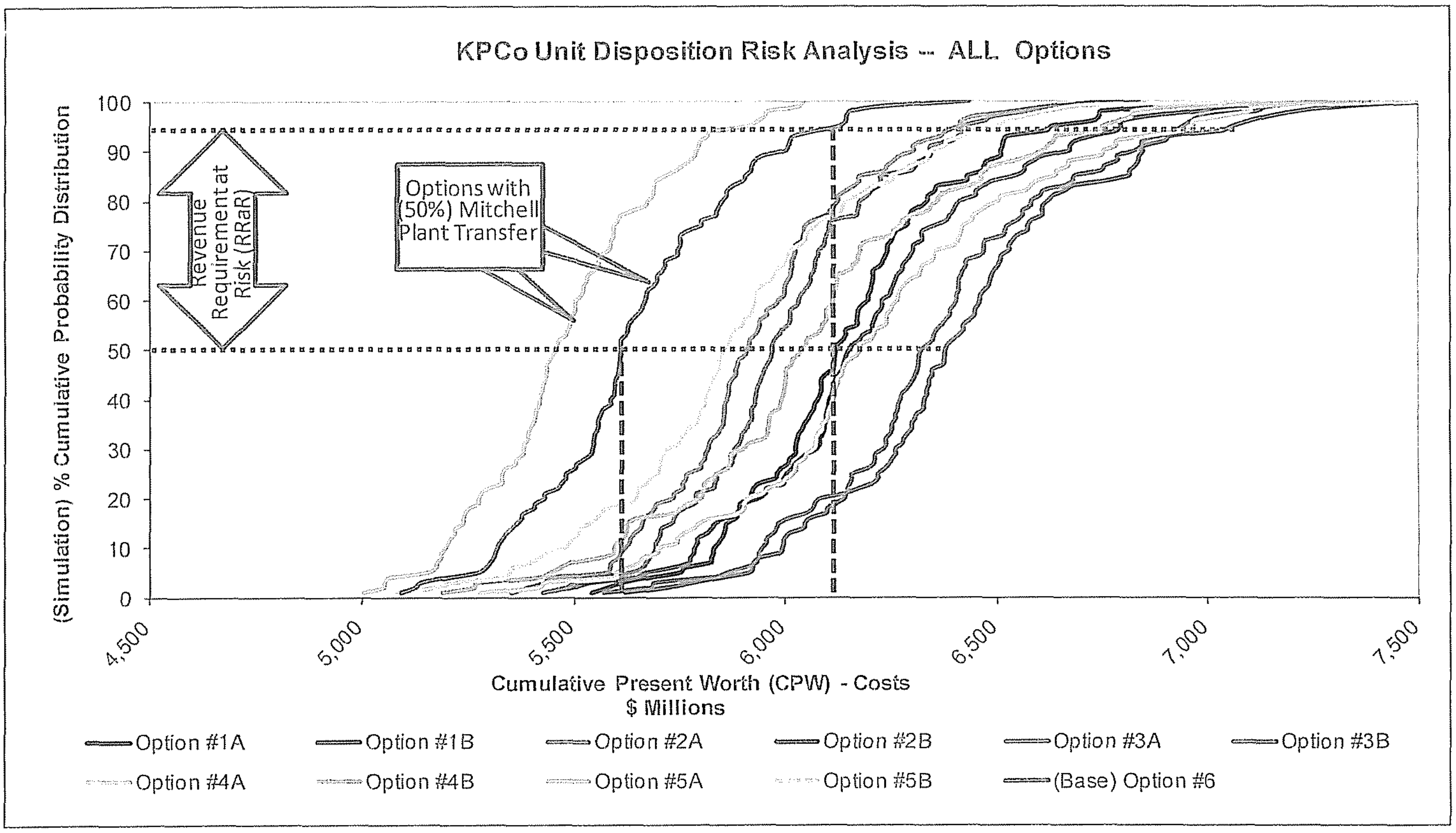
OPTION #1A
OPTION #1B
OPTION #2A
OPTION #2B
OPTION #3A
OPTION #3B
OPTION #4A
OPTION #4B
OPTION #5A
OPTION #5B
Relative ANNUAL CPW COST / <SAINGS> vs. OPTION #1 ($000)
1,100,000
900,000
700,000
500,000
300,000
100,000
(100,000)
(300,000)
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040



	Cumulative Distribution Percentile	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	(Base) Option #6
CPW ($Millions)	50	6,123	6,380	5,912	6,153	5,972	6,325	6,178	6,037	5,458	5,856	5,612
	95	6,633	7,061	6,412	6,794	6,418	6,942	6,967	6,751	5,910	6,504	6,129
'RRaR' ($Millions)	*95th vs. 50th*	510	681	500	641	447	617	789	714	451	648	517
RELATIVE RRaR RANK		*4*	*9*	*3*	*7*	*1*	*6*	*11*	*10*	*2*	*8*	*5*

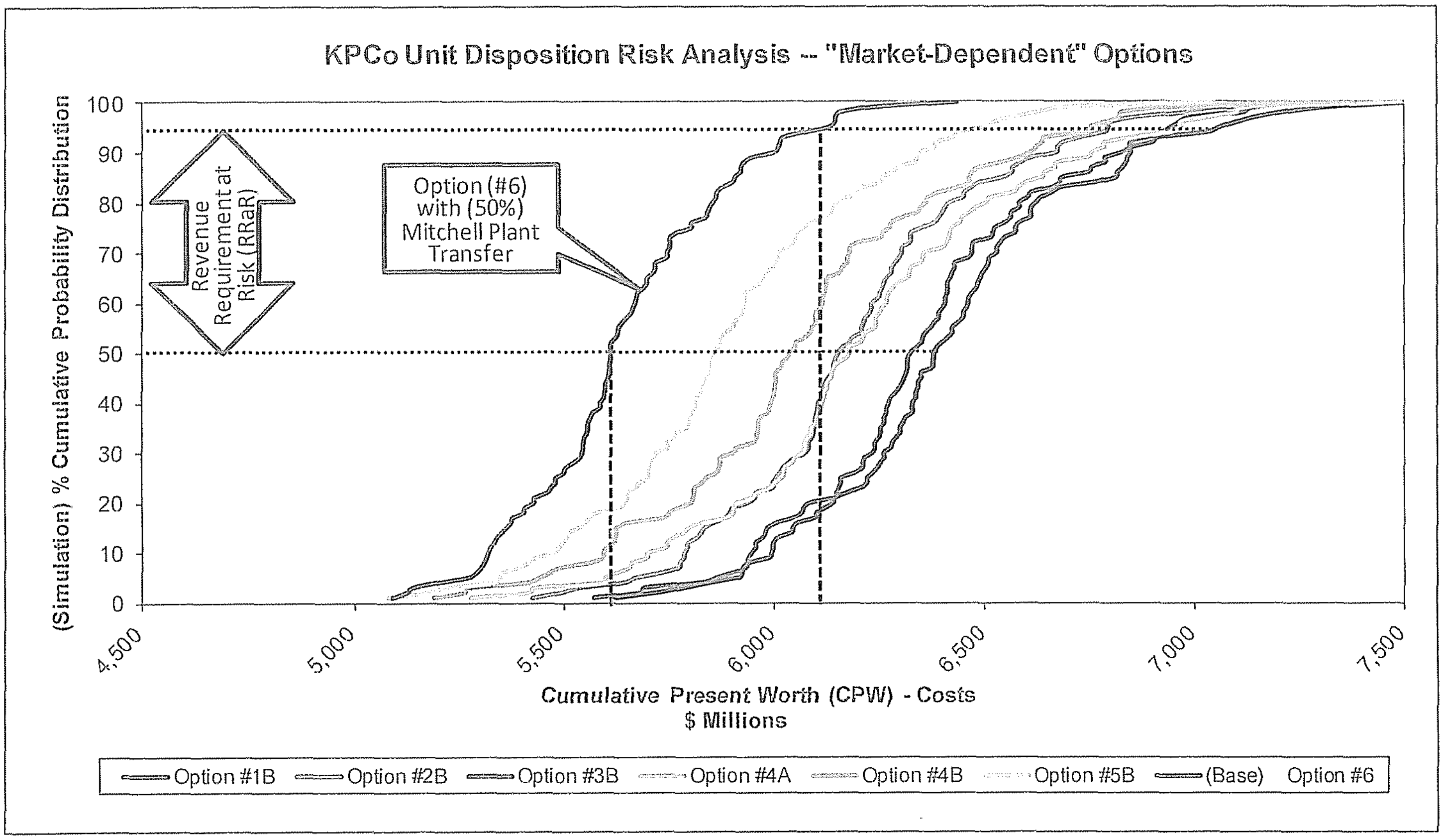
'RRaR' DELTAS:

(Base) Option #6 versus...

	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	
($Millions)	*7*	*(164)*	*17*	*(124)*	*71*	*(100)*	*(271)*	*(197)*	*66*	*(131)*	
	1.4%	*-31.7%*	*3.3%*	*-23.9%*	*13.7%*	*-19.3%*	*-52.4%*	*-38.0%*	*12.8%*	*-25.3%*	

Option #5A (Also Inclusive of a '50% Mitchell 1&2 Transfer) versus...

	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B		Option #5B	(Base) Option #6
($Millions)	*(59)*	*(230)*	*(49)*	*(190)*	*5*	*(166)*	*(337)*	*(263)*		*(197)*	*(66)*
	-13.1%	*-50.9%*	*-10.9%*	*-42.0%*	*1.1%*	*-36.8%*	*-74.7%*	*-58.2%*		*-43.6%*	*-14.6%*

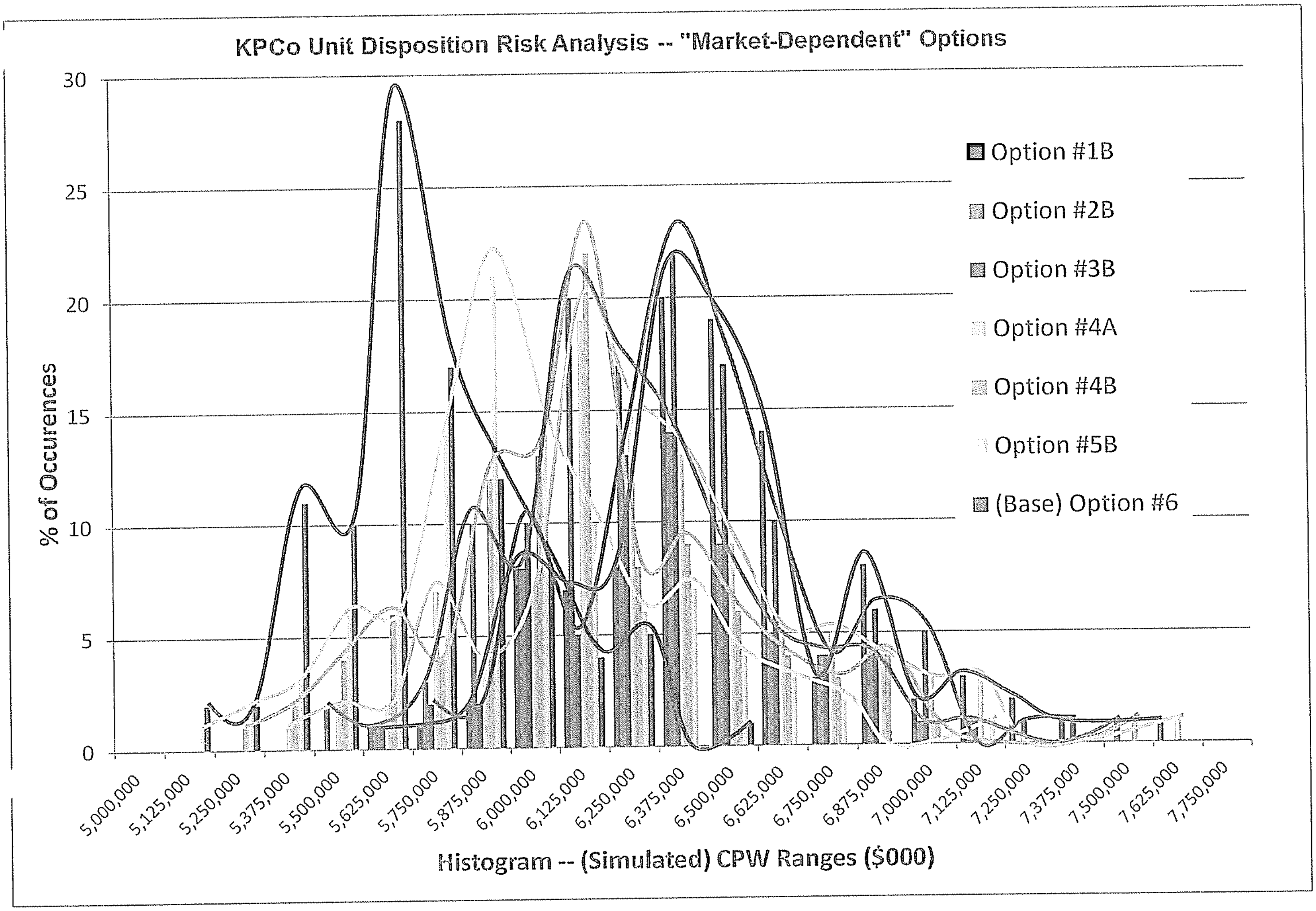


	Cumulative Distribution Percentile	Option #1B	Option #2B	Option #3B	Option #4A	Option #4B	Option #5B	(Base) Option #6
CPW ($Millions)	50	6,380	6,153	6,325	6,178	6,037	5,856	5,612
	95	7,061	6,794	6,942	6,967	6,751	6,504	6,129
'RRaR' ($Millions)	*95th vs. 50th*	**681**	**641**	**617**	**789**	**714**	**648**	**517**
	RELATIVE RRaR RANK	***5***	***3***	***2***	***7***	***6***	***4***	***1***

'RRaR' DELTAS:

(Base) Option #6 versus...

	Option #1B	Option #2B	Option #3B	Option #4A	Option #4B	Option #5B
($Millions)	***(164)***	***(124)***	***(100)***	***(271)***	***(197)***	***(131)***
	-31.7%	***-23.9%***	***-19.3%***	***-52.4%***	***-38.0%***	***-25.3%***


KPCo Unit Disposition Risk Analysis -- "Market-Dependent" Options
% of Occurences
30
25
20
15
10
5
0
Option #1B
Option #2B
Option #3B
Option #4A
Option #4B
Option #5B
(Base) Option #6
5,000,000
5,125,000
5,250,000
5,375,000
5,500,000
5,625,000
5,750,000
5,875,000
6,000,000
6,125,000
6,250,000
6,375,000
6,500,000
6,625,000
6,750,000
6,875,000
7,000,000
7,125,000
7,250,000
7,375,000
7,500,000
7,625,000
7,750,000
Histogram -- (Simulated) CPW Ranges ($000)

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter Of:

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

DIRECT TESTIMONY

OF

RANIE K. WOHNHAS

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

RANIE K. WOHNHAS

COMMONWEALTH OF KENTUCKY)
) SS
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Ranie K. Wohnhas, this the 12th day of December 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

"Notary Public"
Judy K. Rosquist
State at Large, Kentucky
My Commission Expires on Jan. 23, 2013

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00XXX

TABLE OF CONTENTS

DIRECT TESTIMONY OF RANIE K. WOHNHAS, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company ("Kentucky Power", "KPCo" or "Company"). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power Company in 1978 working in various customer services and accounting positions. In 1983, I transferred to Kentucky Power working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 overseeing all billing and collection activity for the Company. In 1998, I transferred to Appalachian Power Company ("APCo") working in rates. In 2001, I transferred to the American Electric Power ("AEP") Service Corporation ("AEPSC") working as a Senior Rate Consultant. In July 2004, I assumed the position of Manager, Business Operations Support with KPCo and was promoted to Director in April 2006. I was promoted to my current position as Managing Director, Regulatory and Finance effective September 1, 2010.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR, REGULATORY AND FINANCE?**

A. I am primarily responsible for managing the regulatory and financial strategy for KPCo. This includes planning and executing rate filings for both federal and state regulatory agencies and certificate of public convenience and necessity ("CPCN") filings before this Commission. I am also responsible for managing the Company's financial operating plans including various capital and O&M operational budgets that interface with all other AEP organizations affecting the Company's performance. As part of the financial strategy, I work with various AEPSC departments to ensure that adequate resources such as debt, equity and cash are available to build, operate, and maintain Kentucky Power's electric system assets providing service to our retail and wholesale customers. In my role as Managing Director, Regulatory and Finance, I report directly to Gregory G. Pauley, President and Chief Operating Officer of Kentucky Power.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. Yes. I have testified before this Commission in various fuel proceedings and provided written testimony in the last two base rate case filings (Case Nos. 2005-00341 and 2009-00459). I also provided written testimony and testified in the pending filing by AEP Kentucky Transmission Company, Inc. seeking for public utility status (Case No. 2011-00042), and provided written testimony in support of the Company's application for a CPCN to construct the proposed Bonnyman-Soft

Shell 138 kV transmission line and related facilities (Case No. 2011-00295). In addition, I provided written testimony and testified in Case No. 2011-00401, which included the Company's 2011 Environmental Compliance Plan, and request for approval of a CPCN for the construction and acquisition of related facilities. Most recently, I provided testimony in Case No. 2012-00226, which requested the withdrawal of Tariff RTP and approval of Rider RTP.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an overview of the financial and accounting activities associated with the transfer to KPCo of an undivided fifty percent interest in the Mitchell generating station, as well as to describe the capital structure of the Company subsequent to the asset transfer. I will also be summarizing the estimated customer rate impact of the Mitchell plant transfer coincident with the termination of the Interconnection Agreement ("Pool Agreement"). Finally, I will explain the Company's request for the deferral and establishment of a regulatory asset of the approximately $30 million of costs incurred from 2004 through present in connection with the Phase I investigation of the Big Sandy Unit 2 retrofit projects as part of the Company's on-going efforts to meet Federal Clean Air Act and related environmental requirements.

IV. FINANCIAL AND ACCOUNTING ACTIVITY OVERVIEW

Q. **PLEASE DESCRIBE THE TRANSACTIONS BY WHICH A FIFTY PERCENT INTEREST IN THE MITCHELL PLANT WILL BE TRANSFERRED TO KENTUCKY POWER AT NET BOOK VALUE.**

A. Exhibit RKW-1 provides a graphical representation of the near-simultaneous transactions required for the transfer of the Mitchell plant from Ohio Power Company ("OPCo") to KPCo without incurring unintended tax consequences. First, pages 1 through 4 of Exhibit RKW-1 show how OPCo will, as part of its corporate separation, transfer its generation related assets, including the Mitchell generating station to AEP Generation Resources Inc. ("AEP Generation Resources"). AEP Generation Resources will then contribute a fifty percent undivided interest in the Mitchell generating station to its yet-to-be formed direct subsidiary, NEWCO Kentucky. NEWCO Kentucky will be created solely for the purpose of effectuating the transfer of a fifty percent interest in the Mitchell generating station and the associated assets and liabilities to Kentucky Power and will not survive the transfer. Second, page 5 of Exhibit RKW-1 illustrates how AEP Generation Resources will contribute its shares of NEWCO Kentucky to its direct parent (which will be an intermediate holding company between AEP Generation Resources' ultimate parent, AEP, and AEP Generation Resources). Next, page 6 of Exhibit RKW-1 illustrates that the intermediate holding company will distribute its shares of NEWCO Kentucky to its direct parent, AEP. Finally, page 7 of Exhibit RKW-1 shows the merger of NEWCO Kentucky with and into Kentucky Power, with Kentucky Power being the surviving entity. This step completes the transfer of the fifty percent undivided interest in the Mitchell generating station from Ohio Power to Kentucky Power and is shown on page 8 of Exhibit RKW-1. These near-simultaneous transactions will all occur on or about December 31, 2013

Q. **PLEASE DESCRIBE THE PROPOSED ACCOUNTING ENTRIES FOR THE ASSET TRANSFER.**

A. Exhibit RKW-2 provides book balances reflecting the proposed transfer of an undivided fifty percent interest in the Mitchell generating station. The book balances displayed on Exhibit RKW-2 are based on account balances on OPCo's books as of December 31, 2011. While these balances reasonably represent the expected assets, liabilities and total capitalization to be transferred, the actual account balances at the time of the asset transfer will be different and more precisely detailed. The Company will submit final book balances within six months of the closing of the Mitchell transfer reflecting all entries made on the books and records of Kentucky Power.

Q. **IS IT APPROPRIATE TO TRANSFER THE MITCHELL PLANT AT NET BOOK VALUE?**

A. Yes. As recognized by the Public Utilities Commission of Ohio in Case No. 12-1126-EL-UNC, "[b]ecause OP seeks only to transfer its generating assets to an affiliate within the same parent corporation, in compliance with the mandate of section 4928.17, Revised Code, we agree that it is appropriate for OP to transfer the assets at net book value…"[1] This establishes the value at which OPCo will

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[1] Case No. 12-1126-EL-UNC *In the Matter of the Application of Ohio Power Company for Approval of an Amendment to its Corporate Separation Plan*, Finding and Order (October 17, 2012) ¶ 42

transfer the Mitchell Plant to AEP Generation Resources. As a member of the Pool Agreement Kentucky Power has been paying a share of the costs associated with the Mitchell plant since the plant was placed in service and the Company became a party to the Pool Agreement. Because payments through the Pool Agreement are cost based, it is appropriate to transfer the Mitchell plant at that same net book value to KPCo because the transaction is equivalent to a transfer from Ohio Power to Kentucky Power.

Q. **ARE THESE BALANCES AS OF DECEMBER 31, 2011 USED ELSEWHERE IN THIS FILING?**

A. Yes. Exhibit RKW-3 provides the beginning Mitchell plant net book value used by Company Witness Weaver in his analysis of the Mitchell plant alternative. The column "Ohio Power Co. Actual 12/31/2011" ties to the numbers in Exhibit RKW-2 but are presented in a different format. Exhibit RKW-3 then adds estimated activity for 2012 and 2013 to arrive at an estimated Mitchell plant balance as of 12/31/2013. Company Witness Weaver includes additional capital costs estimated over the remaining life of the Mitchell plants for his comparative analysis of the options he modeled.

Q. **WILL KENTUCKY POWER BE REQUIRED TO ISSUE DEBT TO CONSUMMATE ITS ACQUISITION OF A FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION?**

A. No. However, within six months of the close of the transaction, Kentucky Power will issue debt to repay inter-company notes associated with the asset transfer and to restore its debt-capital ratio to levels approximating the levels prior to the

Transfer and Assumption transaction. The transferred Mitchell plant liabilities are anticipated to include an inter-company note. Additionally, there will be a surplus of assets over liabilities that will be treated as a paid in capital contribution for accounting purposes. As such, a dividend of approximately $75 million may be necessary to return Kentucky Power's equity as a percentage of capitalization to the level immediately prior to the contribution.

Q. WHO WILL OPERATE THE MITCHELL GENERATING STATION?

A. After the OPCo corporate separation is complete and upon transfer of ownership of the Mitchell Plant, a new operating agreement will be executed between APCo and KPCo. Under the agreement, APCo, which will receive the remaining fifty percent interest in the Mitchell generating station, will operate the Mitchell plant. This agreement will address the operation and maintenance of the plant, maintaining the books and records, allocation of costs, the apportionment of capacity and energy between KPCo and APCo, and the formation and role of an Operating Committee among the parties. An unexecuted copy of the Mitchell Plant Operating Agreement is attached to the application as Exhibit 3.

V. KENTUCKY POWER COST OF SERVICE IMPACTS

Q. HAS THE COMPANY ESTIMATED THE RELATIVE IMPACT ON THE COST OF SERVICE DUE TO THE TRANSFER OF THE MITCHELL GENERATING STATION AND THE TERMINATION OF THE POOL AGREEMENT?

A. Yes, the Company has calculated an estimated impact on the cost of service using actual results for calendar year 2011. This analysis includes the effects attributable to both the Mitchell transfer and elimination of the current Pool Agreement and is shown in Exhibit RKW-4. As illustrated in Exhibit RKW-4, the overall cost of service impact would have been approximately 8% for 2011.

Q. WHEN DOES THE COMPANY ANTICIPATE SEEKING TO INCLUDE THE FIFTY PERCENT SHARE OF THE MITCHELL UNITS AND THE IMPACT OF THE TERMINATION OF THE POOL AGREEMENT IN BASE RATES?

A. Based upon the termination of the Pool Agreement on January 1, 2014 and the request in the filings made on behalf of the Company at the Federal Energy Regulatory Commission to transfer the Mitchell units on or about December 31, 2013, the Company will need to file an application for a base rate change no later than June 28, 2013, with new rates to be effective January 1, 2014.

Q. HOW DOES THE CALCULATION ILLUSTRATED IN EXHIBIT RKW-4 TREAT THE BIG SANDY UNITS?

A. The analysis reflects the Big Sandy units running at the level they did in 2011.

Q. DOES THIS ANALYSIS TAKE INTO CONSIDERATION THE COSTS OF RETIRING BIG SANDY UNIT 2?

A. No. The retirement of Big Sandy Unit 2 would occur independent of any particular generation resource option that leads to its eventual retirement, including the transfer of a fifty percent interest in the Mitchell plant. The costs associated with the Big Sandy Unit 2 retirement will be addressed in the Company's next base rate case.

Q. WHAT ARE THE COMPANY'S PLANS FOR BIG SANDY UNIT 1?

A. As discussed by Company Witnesses Pauley and Weaver, the Company anticipates issuing in early 2013 a Request for Proposals (RFP) for up to 250 MW to replace Big Sandy Unit 1.

Q. **DOES THIS MEAN THAT BIG SANDY UNIT 1 IS TO BE RETIRED?**

A. No. The responses to the RFP will be evaluated against the option of converting Big Sandy Unit 1 to gas. After the evaluations have been completed, the Company will then determine if and when Big Sandy Unit 1 would be retired.

VI. REGULATORY RECOVERY OF ENVIRONMENTAL COMPLIANCE EFFORTS

Q. **WHAT PLANNING EFFORTS HAS KENTUCKY POWER UNDERGONE TO ASSURE COMPLIANCE WITH EVOLVING ENVIRONMENTAL REQUIREMENTS?**

A. Company Witness McManus details in his testimony the current and future environmental requirements affecting the continued operation of KPCo's Big Sandy Unit 2. The Company began its preliminary Phase I investigation into installing a Flue Gas Desulfurization ("FGD") system at Big Sandy Unit 2 as early as 2004. That work was suspended in 2006 because of increases in the estimated cost of the wet FGD system then being investigated, and a decrease in the price spread between low and higher sulfur coal. The Company restarted the Phase I conceptual and analytical work in support of a CPCN filing in the first quarter of 2010 in light of the changing environmental requirements, the purported abundance of shale gas, and the availability of new dry FGD technology. The Company filed for approval of the installation of a dry FGD on

Big Sandy Unit 2 in Case No. 2011-00401. Kentucky Power subsequently requested that the application be withdrawn without prejudice and that request was granted by the Commission. The Phase I investigation represents the Company's efforts to evaluate the least-cost pollution control alternatives for Big Sandy Unit 2 in light of evolving environmental requirements and technologies.

Q. **AS PART OF THIS FILING, IS THE COMPANY PROPOSING TO RECOVER THE COSTS INCURRED TO DATE FOR THE EFFORTS INVOLVED IN EXPLORING THE SCRUBBER ALTERNATIVES FOR BIG SANDY UNIT 2?**

A. No, the Company is not requesting such cost recovery as part of this Application. However, because the transfer of the Mitchell generating station is the best alternative for the customers of Kentucky Power, and therefore retrofitting Big Sandy Unit 2 with a dry FGD is no longer being recommended, the Company requests that the Commission issue an order pursuant to KRS 278.030 and KRS 278.220 permitting Kentucky Power to defer and establish a regulatory asset for review and recovery in its next base rate proceeding before the Commission for those costs incurred by Kentucky Power in connection with its exploration of retrofit alternatives for Big Sandy Unit 2.

Q. **HOW MUCH HAS THE COMPANY SPENT AS A RESULT OF THESE EFFORTS?**

A. The Company has incurred costs of nearly $30 million on these efforts. The Company accumulated expenditures of $15.2 million in connection with the wet FGD and landfill from 2004 through April 2006 before the Phase 1 investigation was suspended. An additional $14.1 million was spent on the recent dry FGD and landfill efforts. A detailed break down of these expenditures is shown on Exhibit RKW-5.

Q. **SHOULD THE COMMISSION APPROVE THE DEFERRAL OF THE $30 MILLION AND THE ESTABLISHMENT OF A REGULATORY ASSET FOR THE COSTS OF SYSTEMS THAT WILL NOT BE INSTALLED?**

A. Yes. The Company, in its efforts to reach the most cost effective alternative to meet the requirements of emerging environmental regulations, prudently evaluated various alternatives and reacted to changing conditions and requirements. The Phase I work on the wet FGD system was suspended in 2006 due to significant increases in labor and material costs and the reduction in the projected price spread between low and high sulfur coals. The dry FGD system is no longer the least cost alternative when compared to the transfer of a fifty percent interest in the Mitchell generating station. The ultimate outcome of evaluating the changing alternatives provides a solution that benefits our customers through a lesser rate impact. Denying the Company's request to establish a regulatory asset for prudently incurred Phase I costs will impede the Company's ability to react to changing regulatory, technological, business and economic requirements.

VII. OTHER AGREEMENTS

Q. **ARE THERE OTHER AGREEMENTS THAT THE COMPANY WILL ENTER INTO WITH THE ELIMINATION OF THE POOL AGREEMENT?**

A. Yes, the Bridge Agreement and Power Coordination Agreement ("PCA") are new agreements for Kentucky Power.

Q. **WHAT IS THE PURPOSE OF THE BRIDGE AGREEMENT?**

A. The Bridge Agreement is an interim agreement between KPCo, APCo, Indiana Michigan Power Company ("I&M"), OPCo, AEP Generation Resources and AEPSC, as agent, to address legacy Pool Agreement issues. The Bridge Agreement addresses the treatment of off-system purchases and sales made under the existing Pool Agreement that extend beyond the termination of the Pool Agreement. It also addresses the parties' fulfillment of their combined Fixed Resource Requirement (FRR) obligation in PJM through the planning year ending May 31, 2015, including AEP Generation Resources' commitment to make generating assets it acquires and retains from OPCo available to contribute toward the fulfillment of this FRR obligation.

Q. **PLEASE PROVIDE AN OVERVIEW OF THE PCA.**

A. The PCA is designed to provide KPCo, APCO and I&M (jointly referred to as the "Operating Companies") and AEPSC, as agent, with the opportunity to (a) participate collectively under a common FRR capacity plan in PJM, and (b) to participate in collective off-system sales and purchase activities. The PCA requires that each Operating Company have sufficient generation to meet their respective load and reserve obligations; it does not impose capacity equalization charges on deficit members.

As with the existing Pool Agreement, AEPSC will continue to act as agent for the Operating Companies with responsibility to (1) assist each Operating Company in its evaluation of power supply resources to meet load requirement, (2) assist in the coordination and operation of each Operating Company's power supply resources, (3) conduct off-system purchases and sales on behalf of the Operating Companies, and (4) coordinate the procurement of fuel, consumables, emission allowances, and transportation services.

Q. **HOW WILL THE PCA BE GOVERNED?**

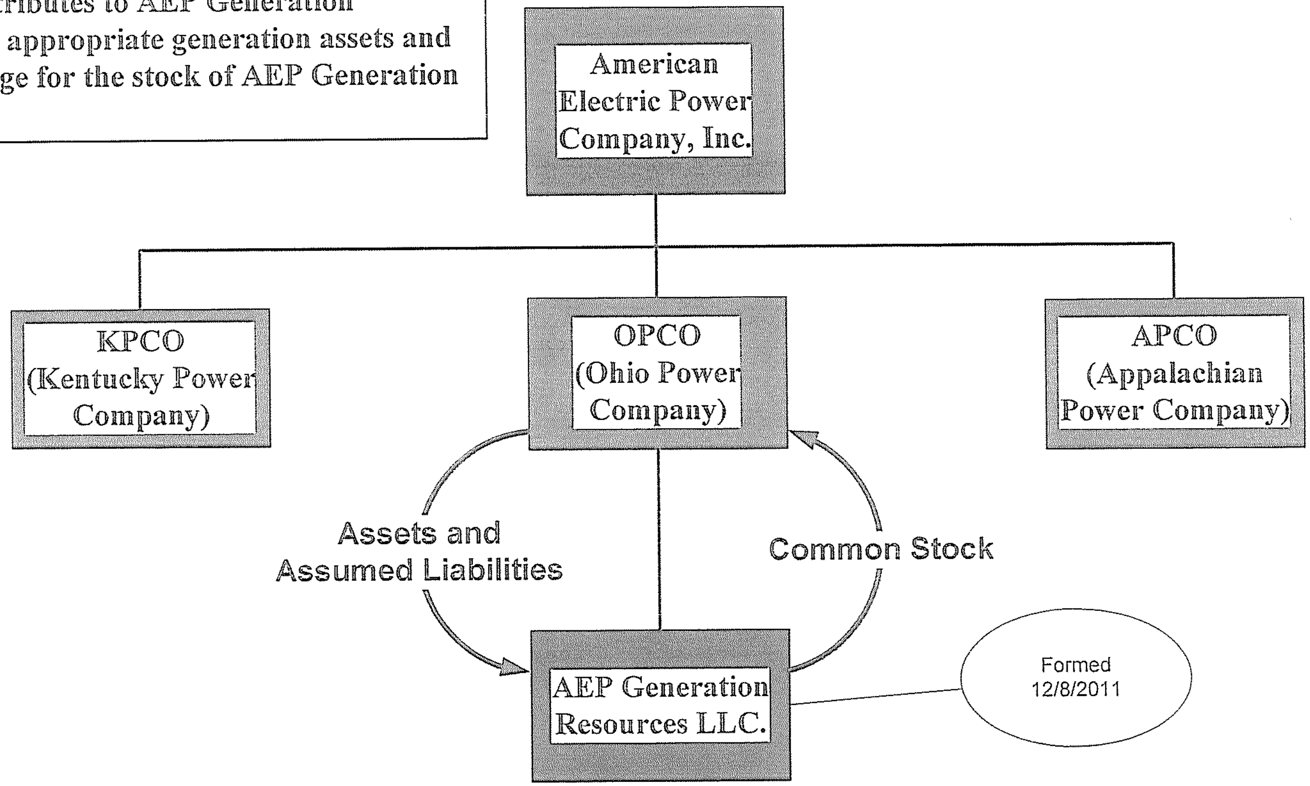
A. Governance will be accomplished through an Operating Committee consisting of representatives of each Operating Company, with AEPSC acting as agent. The primary duty of the Operating Committee will be to review procedures for cost and benefit allocations under the agreement and to coordinate efforts to implement measures necessary for the reliable and economic use of the Operating Companies' respective power supply resources. The utilization of such an Operating Committee is the same as the use of the Operating Committee under the current Pool Agreement, which will terminate effective January 1, 2014.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

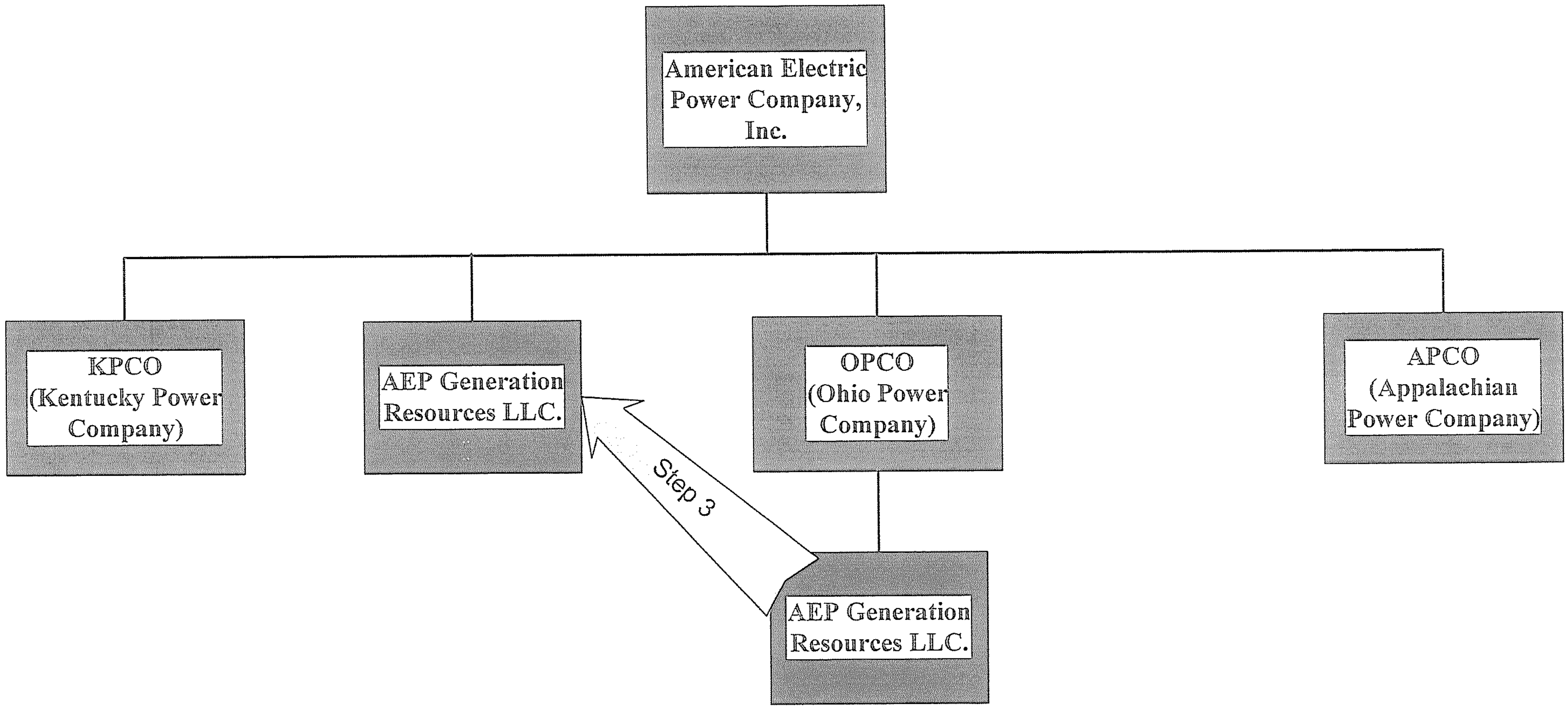
AMERICAN ELECTRIC POWER

Step 1. OPCO forms AEP Generation Resources LLC.
Step 2. OPCO contributes to AEP Generation Resources LLC the appropriate generation assets and liabilities in exchange for the stock of AEP Generation Resources LLC.



AMERICAN ELECTRIC POWER

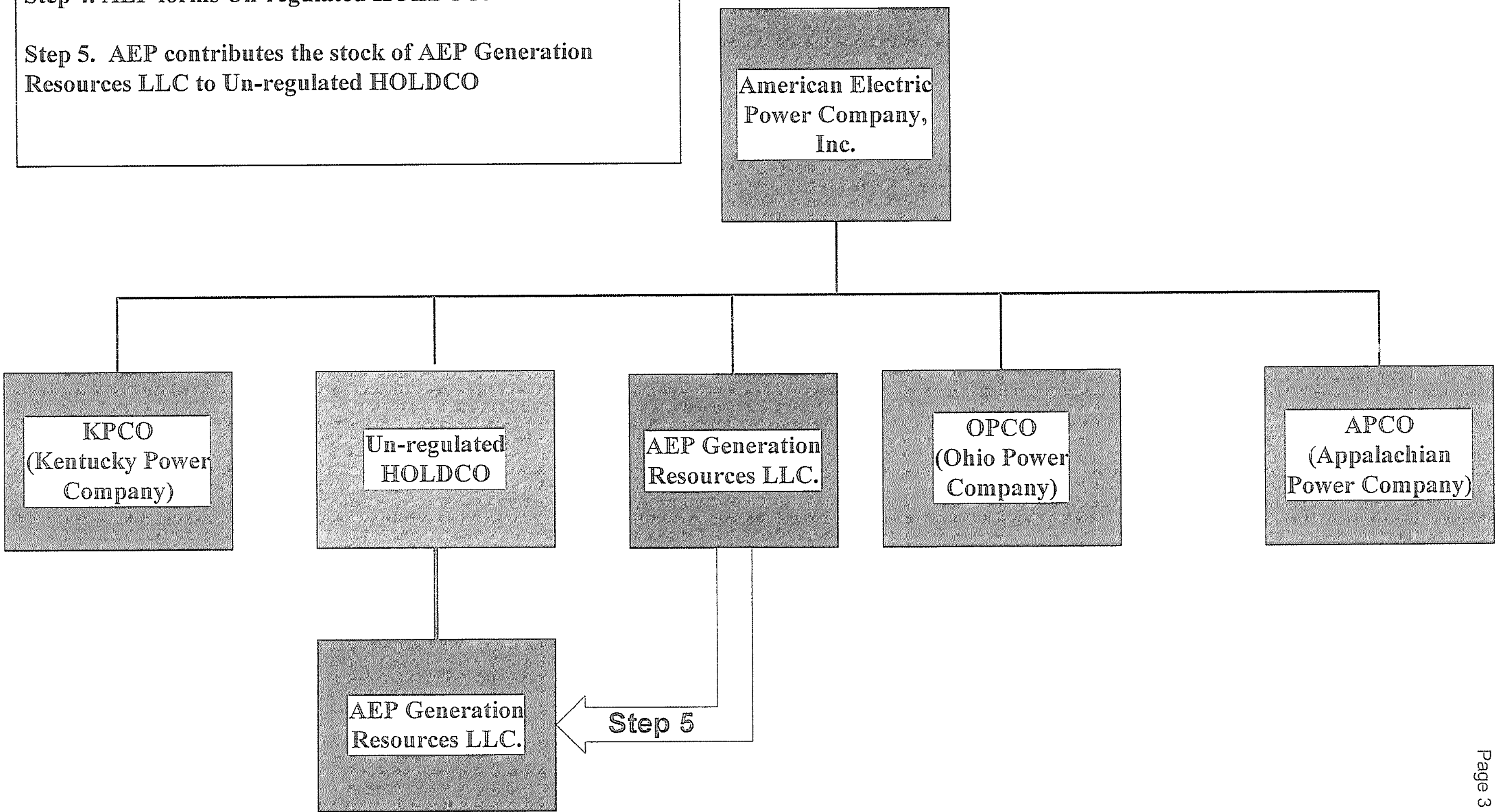
Step 3. OPCO distributes the stock of AEP Generation Resources LLC to AEP.



AMERICAN ELECTRIC POWER

Step 4. AEP forms Un-regulated HOLDCO.

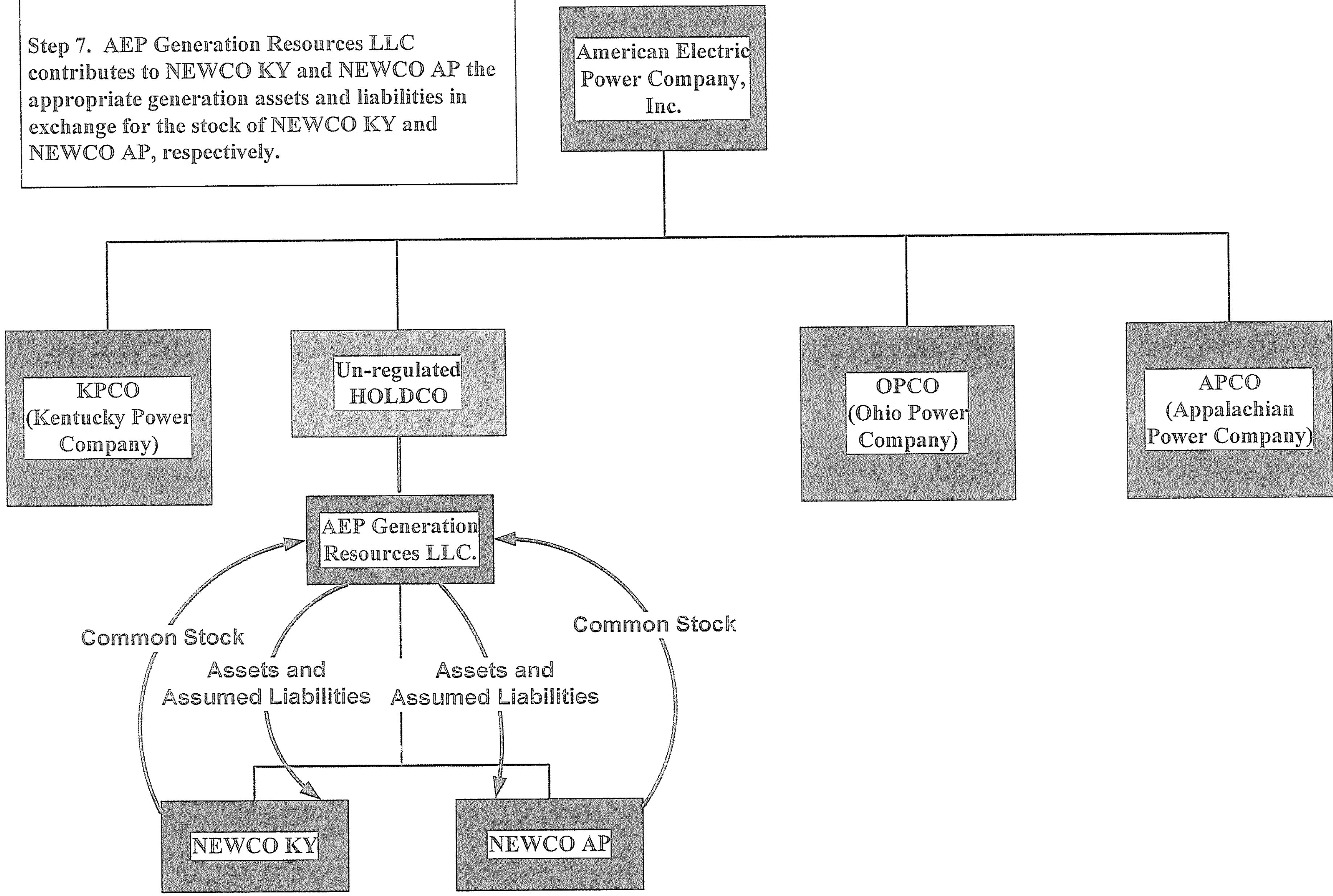
Step 5. AEP contributes the stock of AEP Generation Resources LLC to Un-regulated HOLDCO



AMERICAN ELECTRIC POWER

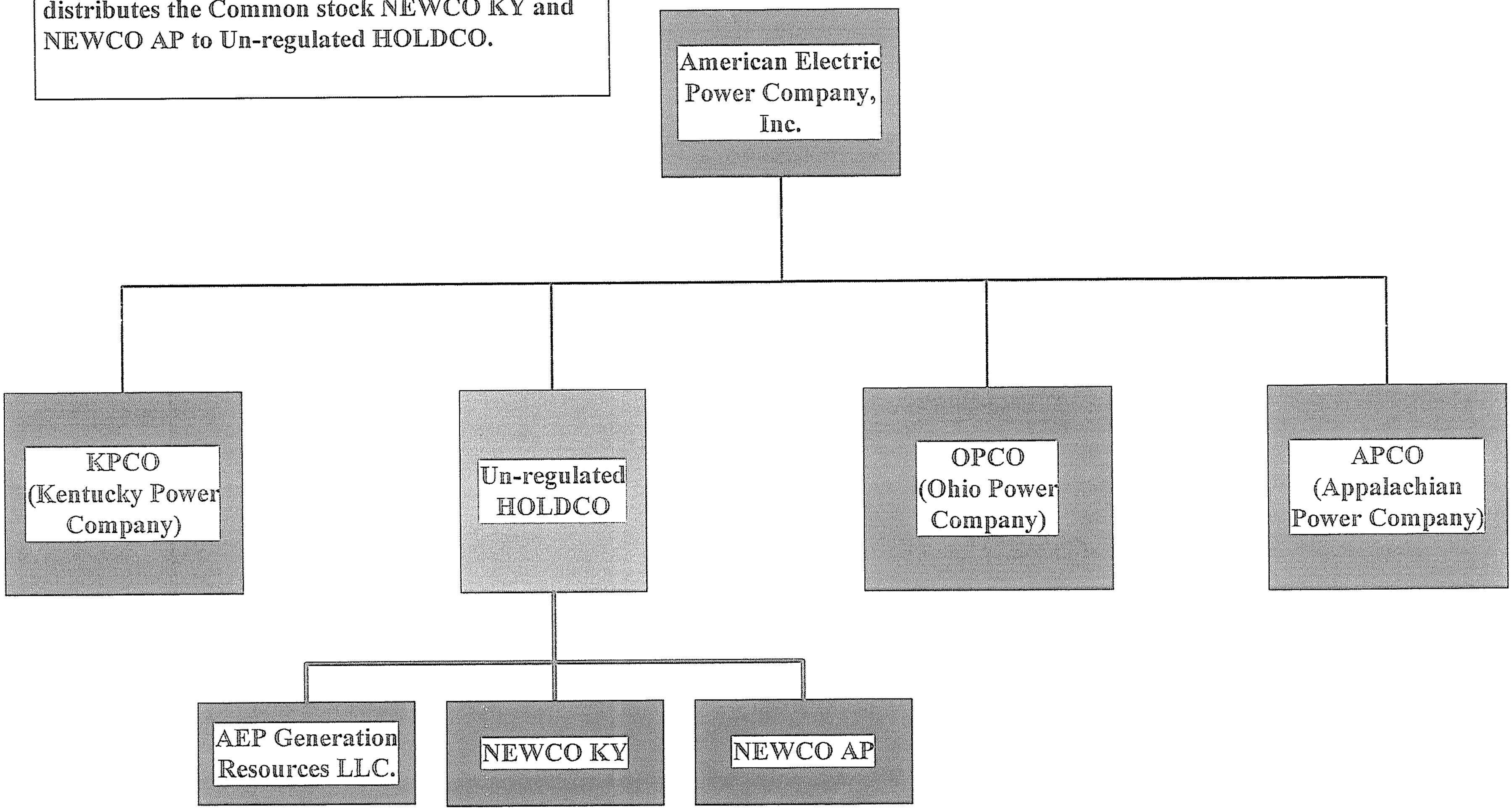
Step 6. AEP Generation Resources LLC forms NEWCO KY and NEWCO AP.

Step 7. AEP Generation Resources LLC contributes to NEWCO KY and NEWCO AP the appropriate generation assets and liabilities in exchange for the stock of NEWCO KY and NEWCO AP, respectively.



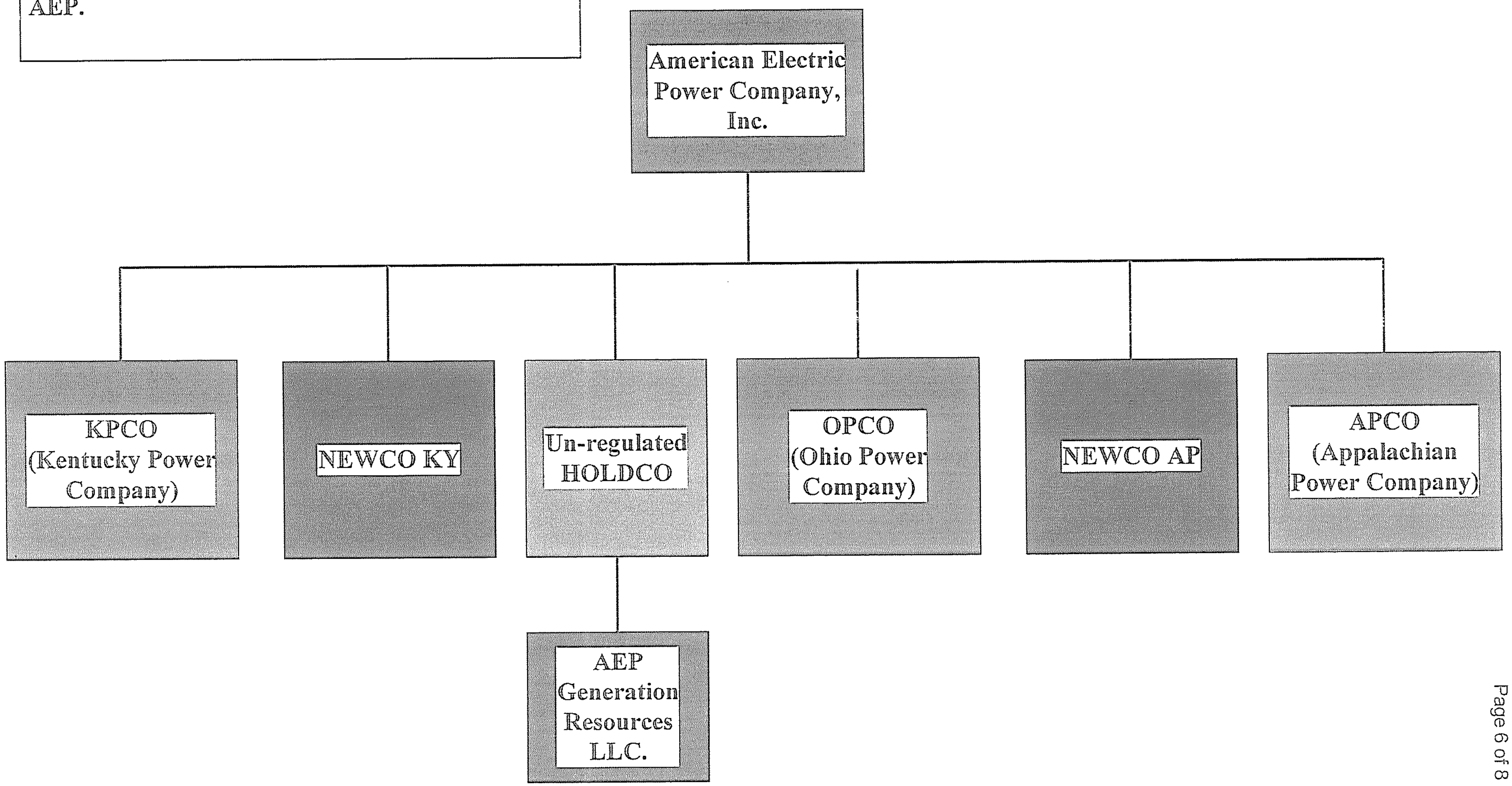
AMERICAN ELECTRIC POWER

Step 8. AEP Generation Resources LLC distributes the Common stock NEWCO KY and NEWCO AP to Un-regulated HOLDCO.



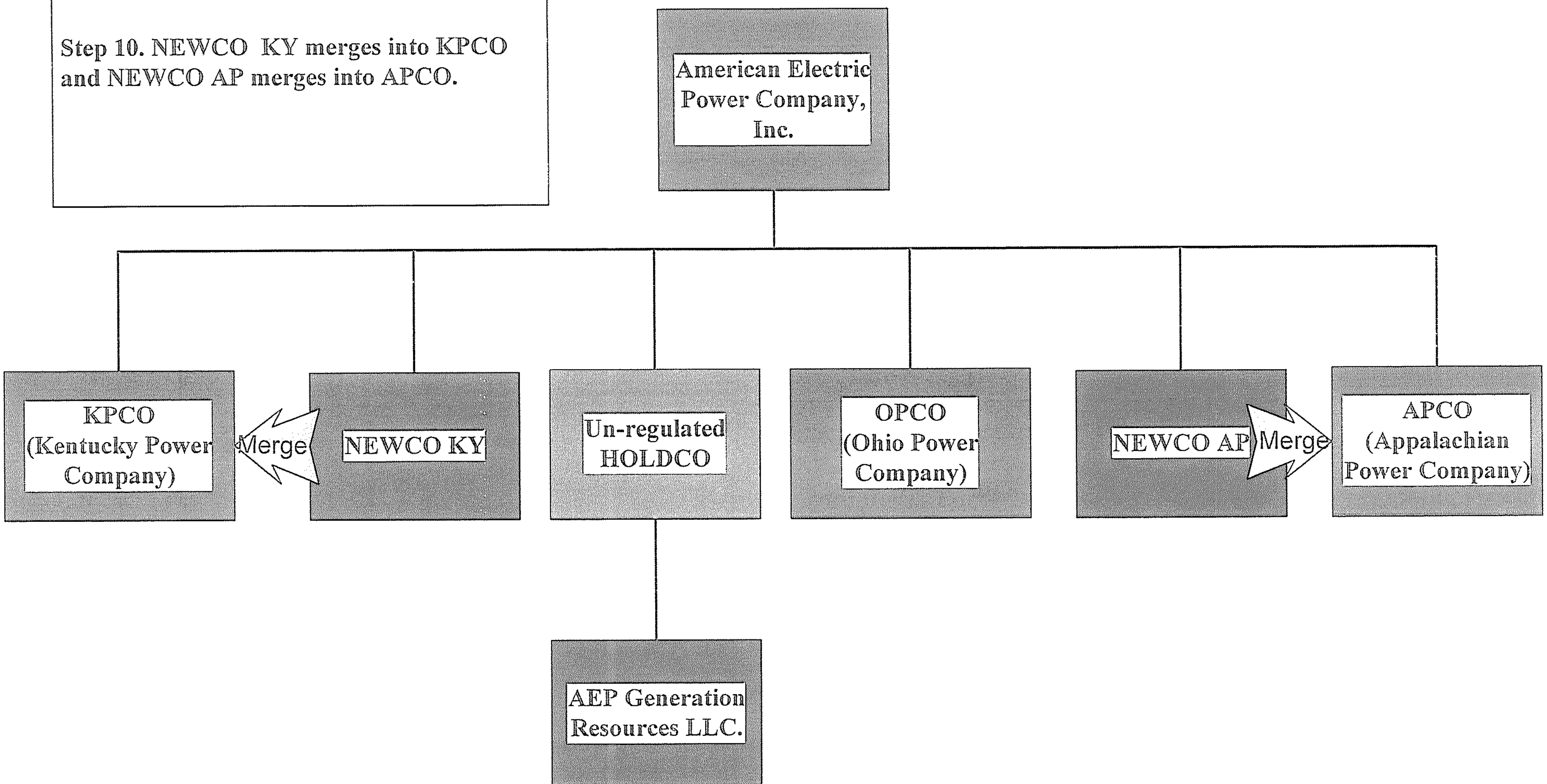
AMERICAN ELECTRIC POWER

Step 9. Un-regulated HOLDCO distributes the Common stock NEWCO KY and NEWCO AP to AEP.



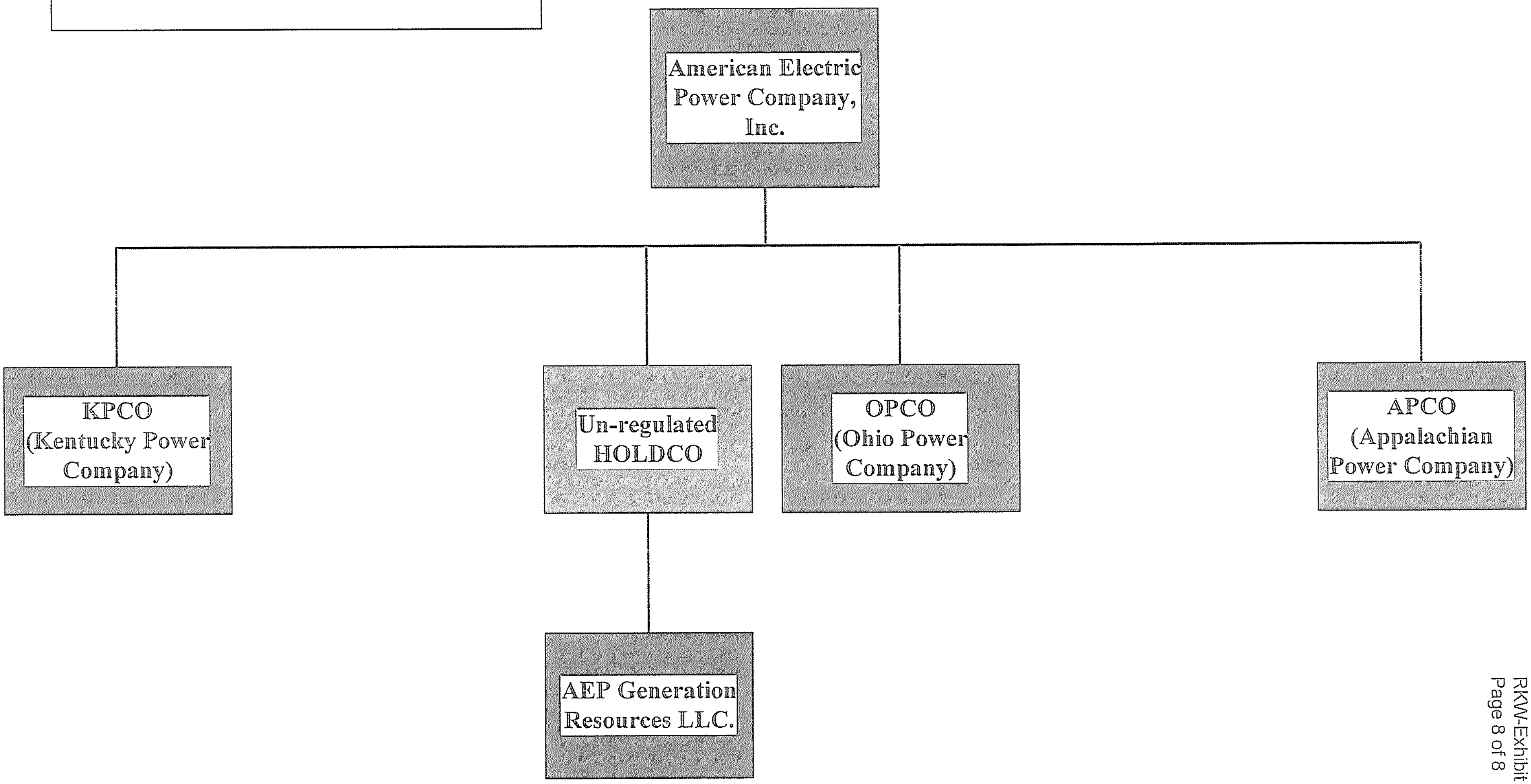
AMERICAN ELECTRIC POWER

Step 10. NEWCO KY merges into KPCO and NEWCO AP merges into APCO.



AMERICAN ELECTRIC POWER

FINAL STRUCTURE



Kentucky Power Company
Transfer Of The
Mitchell Generation Assets To Kentucky Power Company
Based On Book Balances Of Ohio Power Company As Of 12/31/11

Account	Account Description	Assets (in thousands)	Liabilities & Equity (in thousands)
101-106, 114	Utility Plant	874,397	
107	Construction Work in Progress	16,372	
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(251,188)	
124	Other Investments	1,303	
151	Fuel Stock	15,914	
152	Fuel Stock Expenses Undistributed	371	
154	Plant Materials and Operating Supplies	10,345	
158.1, 158.2	Allowances	4,270	
186	Miscellaneous Deferred Debits (Property Taxes)	3,784	
190	Accumulated Deferred Income Tax	1,980	
201-226	Proprietary Capital & Long-term Debt		519,072
230	Asset Retirement Obligations		4,978
236	Taxes Accrued		3,784
242	Miscellaneous Current and Accrued Liabilities (W/C)		595
282	Accum. Deferred Income Taxes - Other Property		147,624
283	Accum. Deferred Income taxes - Other		1,495
	Total	677,548	677,548

Kentucky Power Company
Determination of Estimated Mitchell Asset Ownership "Transfer Cost/Price" @ 12/31/2013
Included in Strategist ® KPCo Resource Modeling for Mitchell 'Options'

Account	Description	Ohio Power Co. Actual 12/31/2011 ($000)	Estimated 2012-2013 Activity ($000)	Estimated 12/31/2013 ($000)
50% of Mitchell Plant:				
(KPCo Options: #5A & 6)				
101-106, 114	Utility Plant	874,397	78,482	940,675
107	Construction Work in Progress	16,372		28,576
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(251,188)	(62,538)	(313,726)
	Subtotal -- Net Book Value, including CWIP	*639,581*	*15,944*	*655,524*
124	Other Investments	1,303	299	1,601
151	Fuel Stock	15,914	7,226	23,140
152	Fuel Stock Undistributed	371	0	371
154	Plant Materials and Operating Supplies	10,345	8,358	18,703
158.1, 158.2	Allowances	4,270	(717)	3,553
186	Miscellaneous Deferred Debits (Property Taxes)	3,784	0	3,784
190	Accumulated Deferred Income Tax	1,980	0	1,980
230	Asset Retirement Obligations	(4,978)	(683)	(5,661)
236	Taxes Accrued (Property Taxes)	(3,784)	0	(3,784)
242	Miscellaneous Current and Accrued Liabilities	(595)	(1,452)	(2,047)
282	Accum. Deferred Income Taxes-Other Property	(147,624)	(12,135)	(159,759)
283	Accum. Deferred Income Taxes-Other	(1,495)	0	(1,495)
	TOTAL -- 50% of Mitchell Plant	519,072	16,840	**535,911**
20% of Mitchell Plant:				
(KPCo Options: #1A, 2A & 3A)				
	TOTAL -- 20% of Mitchell Plant *('TOTAL' above / 0.5 x 0.2)*			**214,364**

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

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

Notes:

1. Current case represents 2011 actual results, including the current Pool Agreement, unadjusted for asset transfers. Excludes amounts which do not differ between cases.
2. Asset Transfers and Pool Elimination case includes the impact of transferring 50% of Mitchell Units 1 and 2 to KPCo, termination of the Pool Agreement, implementation of the Power Coordination Agreement (PCA), and Big Sandy still operating.
3. Off-System Sales (OSS) revenues include PJM capacity sales, and are net of the PJM bill and OSS margin sharing.
4. Includes the impact of eliminating the Interim Allowance Agreement (IAA).
5. Depreciation, Fuel, O&M, and Taxes represent Ohio Power's actual 2011 costs. Return Requirement uses KPCo rate of return on 12/31/11 net rate base.

Kentucky Power Company
Summary by Major Cost Component
Preliminary Engineering Analyses Costs For Scrubbing Options On Big Sandy Unit 2
As of November 30, 2012

Line	Description	Landfill (1)	WFGD	DFGD	Total
1	Internal Labor	$ 798	$ 81,918	$ 186,833	$ 269,549
2	Outside Services	$ 1,760,535	$ 11,246,162	$ 7,102,097	$ 20,108,794
3	Service Corporation Charges	$ 469,771	$ 1,306,534	$ 2,119,992	$ 3,896,297
4	Land Purchase	$ 630,376	$ -	$ -	$ 630,376
5	Overheads	$ 678,412	$ 921,489	$ 2,686,515	$ 4,286,416
6	Other	$ 20,130	$ 7,474	$ 68,458	$ 96,062
7	Total	$ 3,560,022	$ 13,563,577	$ 12,163,895	$ 29,287,494

(1) A Landfill would have been required for both the WFGD and DFGD.