COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR A CPCN AUTHORIZING THE TRANSFER OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS *ET AL*) CASE NO. 2012-00578

ATTORNEY GENERAL'S PETITION FOR REHEARING

The Attorney General for the Commonwealth of Kentucky, Jack Conway ("Attorney General"), by and through counsel of the Office of Rate Intervention, petitions the Kentucky Public Service Commission ("Commission") pursuant to KRS 278.400 *et al* and 807 KAR 5:001, Section 9 *et al* for rehearing of the Commission's order dated October 7, 2013 ("Commission Order"), granting Kentucky Power Company's ("KPCo" or "the Company") request to acquire an undivided fifty (50) percent interest in the Mitchell Generating Station ("Mitchell Plant") and related assets currently owned by an affiliate, Ohio Power Company ("OPCo"). In support of this petition applying for rehearing ("Petition"), the Attorney General states as follows:

The Attorney General as the only intervenor applicant[1] having not joined the non-unanimous, partial settlement of these proceedings, seeks rehearing on two (2) essential matters, which relate to the specific issues outlined below:

[1] The Lawrence County Judge/Executive by and through the Lawrence County Attorney also sought intervention in these proceedings. By Order dated June 28, 2013, the Commission denied the Lawrence County motion to intervene. Since this Petition seeks a rehearing including the introduction of new evidence, the Attorney General assert that Lawrence County's opportunity to appeal the final order of the Commission with respect to intervention should be tolled consistent with the deadlines provided under KRS 278.400. Further, if rehearing is granted, the Attorney General would support the application of Lawrence County to intervene and present evidence consistent with the issues identified herein.

ISSUE (1)

The Commission's erroneous reliance on KPCo's "stacking analysis"[2] of the conforming responses to the Big Sandy Unit 1 request for proposals ("RFP") to support its finding that the acquisition of a 50 percent interest in the Mitchell Plant was the best and least-cost option for KPCo's ratepayers was unreasonable and contrary to Kentucky law regarding affiliate transactions (KRS 278.2207 *et seq.*), and rehearing is required to afford the Attorney General and the ratepayers procedural due process.

ISSUE (2)

The Commission failed to consider whether the new Mitchell Plant Operating Agreement,[3] violates Kentucky state law and/or federal law regarding affiliate transactions or otherwise creates the potential for a Kentucky regulated utility, such as KPCo, to be joined with a market-regulated power sales affiliate, AEP Generation Resources, in a manner that will transfer benefits to the affiliate and its stockholders to the detriment of KPCo's captive, retail ratepayers. Further, rehearing is required to afford the Attorney General and the ratepayers procedural due process.

On the foregoing issues, the Attorney General asserts that additional evidence is necessary to meet the requirements of due process, for full consideration of the questions by the Commission and, pursuant to KRS 278.400, that this evidence "could not with reasonable diligence have been offered on the former hearing" held in this matter. The following exhibits are filed herewith and incorporated by reference in support of this Petition:

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[2] Commission Order at 21-22.

[3] *See* American Electric Power ("AEP"), KPCo and related affiliates filed the Mitchell Plant Operating Agreement and related tariff filings with the Federal Energy Regulatory Commission ("FERC") on October 15, 2013, (FERC Docket Nos. ER13-238, ER13-239 and ER14-86) and by letter with this Commission on October 22, 2013 (Case No. 2013-00578).

AG REHEARING EXHIBIT A:

Direct Testimony and Exhibits of Scott Norwood on behalf of the Virginia Attorney General's Division of Consumer Counsel ("TE Norwood"), *In Re: Application of Appalachian Power Company for Approval of Transactions to Acquire Interests in the Amos and Mitchell Generation Plants and to Merge with Wheeling Power Company*, Virginia State Corporation Commission, Case No. PUE-2012-00141.

AG REHEARING EXHIBIT B:

Kentucky Attorney General Motion for Leave to Intervene, *In RE: AEP Service Corporation*, FERC Docket No. ER14-86-000 (October 30, 2013)

The matters identified for rehearing are discussed below in further detail.

***Issue 1:* The Commission's Use of KPCo's Stacking Analysis Was Erroneous, Unreasonable and Contrary to Kentucky Law**

A. Summary of the Stacking Analysis

By Order dated May 28, 2013, more than five (5) months after KPCo's filing of its application in this matter and after the scheduling of discovery and pre-filed testimony, the Commission required KPCo to file "an analysis of the bids received in response to the March 28, 2013 solicitation."[4] KPCo's solicitation or request for proposals ("RFP") sought "250 MW of long-term capacity and energy" to replace, retrofit, repower or refuel the Big Sandy Unit 1.[5] The Commission stated generally that the bids in response to the Big Sandy Unit 1 RFP "will assist the Commission in investigating the reasonableness of Kentucky Power's proposed purchase of 50 percent of the Mitchell Generating Station."[6]

Further, the Commission, *nunc pro tunc*, continued the public hearing scheduled in this matter to accommodate KPCo's filing of the partial settlement and stipulation and to further

[4] Case No. 2012-00578, Order (May 28, 2013) at 3.
[5] *Id.*, *see also*, KPCo's Supplemental Testimony of Joseph A. Karrasch, Exhibit JAK-1S (June 28, 2013)
[6] Commission Order (May 28, 2013) at 3.

fulfill its mandated analysis of the Big Sandy Unit 1 bids by KPCo.[7] However, the Commission did not expand the procedural schedule for discovery or testimony related thereto. Therefore, the Attorney General -- the only non-signatory to the partial settlement – was not afforded an opportunity to seek discovery and/or file rebuttal testimony in response to the resulting stacking analysis submitted by KPCo.

On June 28, 2013, just two (2) weeks prior to hearing, KPCo tendered the conforming responses along with a stacking analysis,[8] which the Commission describes in its most recent Order as follows:

> Kentucky Power argues that its stacking analysis of the conforming responses to the Big Sandy Unit 1 RFP also demonstrates that the NBV of the Mitchell Station is less than its fair market value. Because the generation bid into the Big Sandy Unit 1 RFP could be substituted for the Mitchell proposal, an analysis of the CPW of the Big Sandy Unit 1 RFP conforming bids' costs to CPW (*cumulative present worth*) of the Mitchell proposal's costs would provide evidence of the relationship between the NBV (*net book value*) and the fair market value of the Mitchell Station. Kentucky Power stated that it performed such an analysis by first creating a substitute for the Mitchell acquisition by combining, or stacking, the least-cost conforming Big Sandy Unit 1 RFP bids and then comparing, by utilizing Strategist modeling, the CPW of the substitute generation stack's costs against the CPW of the Mitchell acquisition costs.[9]

Similar to Kentucky Power's original cost analysis of the options for the Big Sandy Unit 2, on which the scope of this matter pertained, the stacking analysis of the Big Sandy Unit 1 bids employed by KPCo in response to the Commission's directive was created using proprietary modeling software, which could not be independently verified by the Commission.[10]

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[7] *Id.*
[8] KPCo's Supplemental Testimony of Scott C. Weaver (June 28, 2013).
[9] Commission Order (October 7, 2013) at 21; *see also* Supp TE Weaver at 10.
[10] Testimony of Weaver on Cross-Examination, Case No. 2012-00578, Video Transcript of Evidence ("VTE") July 12, 2013 generally and at 2:51:25-2:53:25.

B. <u>KPCo's Stacking Analysis Cannot Replace an RFP for the Big Sandy Unit 2</u>

The Commission erred when it presumed to and directed the use of proposals to supply power to replace Big Sandy Unit 1 as the basis for determining the reasonableness of the cost of replacing Big Sandy Unit 2 with a 50 percent interest in the Mitchell Plant. The product requested in the RFP to replace the Big Sandy Unit 1 ***<u>is not in any way equivalent to ownership of Mitchell</u>***, even if adjusted to reflect a comparable level of generation in megawatt (MW) capacity. For example, the RFP for Big Sandy Unit 1 required bidders to assume transmission costs, guarantee pricing and availability of the units, and assume responsibility for all future compliance related costs.[11] These assumptions are inapplicable to the Mitchell Plant option, which KPCo – as a presumptive owner of Mitchell -- would simply pass through its rates.

<u>The stacking analysis used by KPCo and accepted by the Commission is simply an apples to oranges comparison.</u> Such an approach would never be considered reasonable even by AEP, if it were instead evaluating acquisition of the Big Sandy Unit 2 and/or Mitchell Plant capacity from a third party bidder. Therefore, use of the stacking analysis by the Commission constitutes clear error, especially since this analysis was not subject to discovery by the Attorney General, thus depriving him of meaningful participation in the hearing given the lack of due process.

C. <u>KPCo's Stacking Analysis Does Not Supply a Market Alternative</u>

Even if the acquisition of the Mitchell assets was found to be a reasonably low cost alternative for replacing the Big Sandy Unit 2, the stacking analysis does not change the clear fact that KPCo presented ***<u>no evidence that the transfer price meets the "lower of cost or market</u>***

[11] Supplemental Testimony of Karrasch, Exhibit JAK-1S at pp. 9-10.

value" standard for affiliate transfers.[12] A survey of information regarding recent coal plant sales, which was presented as part of pre-filed testimony tendered by the Virginia Attorney General's expert witness to the Virginia State Corporation Commission ("Virginia Commission), strongly suggests that AEP through its affiliate OPCo would not be able to get the proposed transfer price of greater than $1 billion if it sold the Mitchell assets (total) in the open market, due to the age of the units and the significant regulatory risk attached to coal plants.[13]

Moreover, the failure by KPCo and its parent company, AEP, to solicit market alternatives or present adequate evidence regarding the market value of the Mitchell generating assets violates the statutes governing affiliate transactions in both Virginia ***and Kentucky.***[14] As stated by the expert for Virginia's Attorney General:

> ...the Company must show that the proposed transactions will not impair or jeopardize adequate service to the public at just and reasonable rates ... [the company] bears the burden of demonstrating that the proposed acquisitions are in the public interest and priced at the lower of cost or market value.[15]

This standard is the same in Kentucky. KRS 278.2201 *et seq.* also requires pricing that shall be at lower of cost or market. Further, deviation from this standard may only be granted and the pricing determined reasonable if the Commission finds that the price deviation ***is in the public interest***[16] ***– not the interest of the utility's parent company's shareholders.*** Therefore, KPCo failed to meet its burden to demonstrate this required evidence.

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[12] KRS 278.2207(1)(b) requires that transactions between a utility and its affiliates shall be priced "at the affiliate's fully distributed cost but in no event greater than market." Further, deviation from this "lower-of-cost-or-market-value" standard may only be granted if the Commission "determines the deviation is in the public interest." KRS 278.2207(2).

[13] *See* Exhibit SN-21, Direct Testimony and Exhibits of Scott Norwood on behalf of the Virginia Attorney General's Division of Consumer Counsel ("TE Norwood"), *In Re: Application of Appalachian Power Company for Approval of Transactions to Acquire Interests in the Amos and Mitchell Generation Plants and to Merge with Wheeling Power Company*, Virginia State Corporation Commission, Case No. PUE-2012-00141, attached as "AG Rehearing Exhibit A".

[14] KRS 278.2207.

[15] TE Norwood, AG Rehearing Exhibit A at 9.

[16] *See also* KRS 278.020(1), which provides that the Commission "when considering an application for certificate to construct a base load electric generating facility, may consider the policy of the General Assembly to foster and

D. Additional Evidence is Required to Afford Adequate Due Process

Under KRS 278.020(8), the Commission is permitted to "utilize the provisions of KRS 278.255(3) if, in the exercise of its discretion, it deems it necessary to hire a competent, qualified and independent firm to assist it in reaching its decision." The Commission elected to seek expert assistance in this matter, employing Vantage Energy Consulting ("Vantage") to assist it in reaching its decision. In fact, Vantage Principle Walter Drabinski attended the hearing in this matter and provided real-time consulting to the Commission and staff regarding the stacking analysis presented by KPCo.[17] However, Mr. Drabinski was not offered as a witness by the Commission for cross-examination by the Attorney General, or any other party, nor was Mr. Drabinski's "competent, qualified and independent" assessment of the stacking analysis presented during the public hearing or thereafter. Due process requires that expert evidence relied upon by the Commission to arrive at its final decision be made public by way of presenting the Commission's own retained expert and subjecting him/her to examination by the intervening parties, including the Attorney General.[18]

Therefore, the Attorney General seeks a rehearing on the issue of whether the Commission erred in relying on KPCo's stacking analysis to support its finding that the acquisition of a 50 percent interest in the Mitchell Plant was the best and least-cost option for KPCo's ratepayers. Additional evidence, including but not limited to discovery, testimony, depositions and/or cross-examination of all witnesses and experts upon whom the Commission

encourage use of Kentucky coal by electric utilities serving the Commonwealth." Via public comment and testimony presented at the hearing and during the course of the Commission's consideration of KPCo's application for a REPA, Case No. 2013-00144, the great weight of evidence demonstrated that retirement of the Big Sandy Unit 2 would have a detrimental impact on the public interest and would contribute to the rapid declining use of Kentucky coal by KPCo.

[17] Case No. 2012-00578, VTE generally July 10-12, 2013.

[18] *See e.g.*, Kentucky Rules of Evidence (KRE) 706, regarding court-appointed expert witnesses who "shall be subject to cross-examination by each party."

relied, is needed to determine the market value of the Mitchell assets and whether the transfer does indeed meet Kentucky's legal standards.

Issue 2: AEP's New Operating Agreement Does Not Conform to Federal & State Law Governing Affiliate Transactions

A rehearing is also required due to the chain of events occurring after the July 10-12, 2013 hearing on this matter, which reversed the functional operating plans and affiliate transactions related to the Mitchell Plant. Most significantly, the proposed ownership and operating structure of the proposed Mitchell Plant transfers, which the Commission considered and approved as to KPCo, have been substantively altered due to the Virginia Commission's disallowance of the Mitchell transfer to APCo, and the possibility that the West Virginia Public Service Commission will take similar action. Further, subsequent to the Commission's Order in this matter, AEP filed with the Federal Energy Regulatory Commission ("FERC") an entirely new and superseding Mitchell Operating Agreement among KPCo, AEP Generation Resources and AEP Service Corporation ("Superseding Operating Agreement").[19]

The new ownership structure presented in the Superseding Operating Agreement introduces significant additional risk for KPCo's customers and presents a transaction under which KPCo, a franchised regulated utility, will co-own the Mitchell Plant with a deregulated market affiliate. Therefore, a rehearing before this Commission is necessary to address the issues arising from this new ownership structure that could have a bearing on costs, benefits and risks of the Mitchell transfer ***<u>that have not yet been evaluated</u>***. Further, rehearing is required to afford to and protect the due process interests of the Attorney General and the ratepayers he represents.

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[19] *See In Re: AEP Service Corporation, Request of AEP Service Corporation for Waiver of Certain Affiliate Restrictions and Expedited Treatment,* FERC Docket No. ER14-86-000 (October 15, 2013) and filed in KY PSC Case No. 2012-00578 (October 22, 2013).

A. The Commission Did Not Consider the Superseding Operating Agreement

In its Order dated October 7, 2013, the Commission foresaw an operational structure change as a result of the VSCC Order, but did not consider any specific terms or conditions concerning an operating agreement under which KPCo would co-own the Mitchell Plant with its unregulated, market affiliate. Specifically, the Commission stated as follows:

> Kentucky Power advises that if the remaining 50 percent undivided interest in the Mitchell Station is not ultimately transferred to APCo, that interest will likely remain with AEP Generation Resources. Under those circumstances, Kentucky Power states that a revised Mitchell Operating Agreement will be filed with FERC providing that Kentucky Power will operate the Mitchell Station on behalf of itself and AEP Generating Resources. The revised operating agreement will continue to reflect the costs attendant to Kentucky Power's ownership and operation of the undivided 50 percent interest in the Mitchell Station.[20]

As such, the Commission did retain jurisdiction of this matter to the extent that it required KPCo to "provide the Commission a copy of the FERC application and apprise the Commission of FERC's final decision on the application."[21]

However, the Commission erred in not exercising its full authority to consider whether the Superseding Operating Agreement would comport with Kentucky state law governing utility transactions with unregulated affiliates.[22] By neglecting this oversight role, the Commission risks abdicating its duty to protect ratepayers from a new ownership structure that could impact costs, benefits and risks associated with ownership of the Mitchell Plant.

2. Federal Law May Prohibit the Superseding Operating Agreement and Co-Ownership of the Mitchell Plant by Kentucky Power and an Unregulated Affiliate of AEP

In order to protect Kentucky's ratepayers from the impacts described above, the Attorney General is intervening in the pending FERC proceedings to consider whether AEP's proposal

[20] Commission Order at 41.
[21] *Id.*
[22] *See, e.g.,* KRS 278.2201 (banning a utility from subsidizing nonregulated activity), KRS 278.2207 (imposing pricing requirements relating to transactions between a utility and its affiliate); and KRS 278.2213 (requiring separate recordkeeping for a utility and affiliate and prohibiting certain business practices).

seeking waiver of federal law regarding affiliate restrictions with respect to the operation of the Mitchell Plant is lawful. The Attorney General's motion is submitted herewith, and will be filed nearly simultaneously to the date and time of this filing for rehearing.[23]

Specifically, 18 C.F.R. 35.39 codifies affiliate restrictions mandated by FERC that are intended "to protect captive customers from the potential for a franchised public utility to interact with a market-regulated power sales affiliate in ways that transfer benefits to the affiliate and its stockholders to the detriment of the captive customers."[24] Further, within the context of this analysis, "[c]aptive customers are defined as 'any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation.'[25] Finally, FERC has recently denied a waiver of these requirements where a company has failed to satisfy its burden to show (1) that the proposed interaction of the companies will not result in harm to captive customers,[26] and (2) that there is satisfactory oversight by state authorities sufficient to prevent the affiliates from interacting in way that would be at the expense of captive customers.[27]

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[23] *See* Kentucky Attorney General Motion for Leave to Intervene, FERC Docket No. ER14-86-000, attached as "AG Rehearing Exhibit B" and incorporated by reference herein.
[24] *See Virginia Elec. & Power Co. Dominion Energy Mktg., Inc. Dominion Nuclear Connecticut, Inc. Dominion Energy Kewaunee, Inc. Dominion Energy Brayton Point, LLC Dominion Energy Manchester St., Inc. Dominion Energy New England, Inc. Dominion Energy Salem Harbor, LLC Dominion Retail, Inc. Elwood Energy, LLC Fairless Energy, LLC Kincaid Generation, L.L.C. Nedpower Mt. Storm, LLC State Line Energy, L.L.C. Fowler Ridge Wind Farm LLC*, 142 FERC ¶ 61103 (Feb. 8, 2013)
[25] *Id.* (internal citations and references omitted).
[26] *Id.* ("We will deny the Dominion Companies' request for waiver of the requirement in section 35.39(c)(2)(i) of the Commission's regulations. The Dominion Companies have not satisfied us that the sharing of the three groups of resource planning employees as proposed in their application will not result in harm to captive customers.")
[27] *Id.* ("The Dominion Companies assert that state oversight would be sufficient to prevent the Dominion Marketing Affiliates from building or acquiring generation in Virginia, North Carolina and West Virginia at the expense of Dominion Virginia Power's captive customers. However, the Dominion Companies' discussion of the oversight exercised by the Virginia and North Carolina Commissions focuses on the ability of these commissions to review the resource planning activities of Dominion Virginia Power, and fails to explain the extent to which they would be in a position to review the resource planning activities of the Dominion Marketing Affiliates to see if and how resource decisions that were foregone by Dominion Virginia Power might affect captive customers (e.g., if Dominion Virginia Power passed over opportunities to build generation or purchase power that could be used for low-cost power for native load or off-system sales in order to allow the Dominion Marketing Affiliates to build and make those sales).")

The Commission need look no further than the four corners of AEP's request for federal waivers from these affiliate restrictions to identify the risk potential. In its request, AEP seeks to:

> (1) share (a) certain KPCo employees who will provide operating and maintenance ("O&M") services for the Mitchell Plant (and to recover from AEP Generation Resources the actual cost of those services), and (b) certain AEPSC employees who, as agent for KPCo and AEP Generation Resources, will be engaged in the fuel procurement function for the Mitchell Plant; and
> (2) have access to certain limited operating information about the Mitchell Plant that could be considered 'market information.'

Decisions about fuel procurement in the form of coal contracts for the Mitchell Plant and dispatch decisions regarding market sales of capacity and energy from the Mitchell Plant carries the risk of having significant impacts on Kentucky ratepayers as well as the residents of Kentucky's eastern counties that KPCo serves.

Therefore, at a minimum, rehearing is necessary to ensure that the Commission exercise its duty as state regulator to ensure that the Superseding Operating Agreement and the related transactions and waivers proposed by KPCo and AEP will not result in harm to at the expense of Kentucky ratepayers.

WHEREFORE, the Attorney General respectfully requests that the Commission issue an order granting the Attorney General's application for rehearing on the matters described in this Petition, and granting the Attorney General all other relief requested or to which the law requires for a full and fair hearing on these matters.

Respectfully submitted,

JACK CONWAY
ATTORNEY GENERAL

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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Jeff Derouen, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

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This 30th day of October, 2013,

Assistant Attorney General

AG REHEARING EXHIBIT A

DIRECT TESTIMONY OF SCOTT NORWOOD

VSCC – CASE NO. PUE-2012-00141

April 23, 2013

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April 23, 2013

Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
1300 East Main Street
Richmond, Virginia 23219

Re: ***Application of Appalachian Power Company, For approval of transactions to acquire interests in the Amos and Mitchell generation plants and to merge with Wheeling Power Company***
Case No. PUE-2012-00141

Dear Mr. Peck:

Pursuant to the Commission's Order issued March 14, 2013, please find enclosed for filing in the above-styled case, the Direct Testimony and Exhibits of Scott Norwood on behalf of the Office of the Attorney General's Division of Consumer Counsel ("Consumer Counsel").

Mr. Norwood's Exhibits contain confidential information. Accordingly, pursuant to Rule 5-20-170, an original and 15 copies of the confidential version of the Exhibits, along with an original and 1 copy of the public, redacted version of the Exhibits, are being simultaneously hand-delivered to the clerk to be filed under seal.

Very truly yours,

/s/ Charles Mitchell Burton, Jr.

Charles Mitchell Burton, Jr.
Assistant Attorney General

Enclosure

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing was, this 23rd day of April, 2013, served by first-class mail, postage prepaid, to:

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF APPALACHIAN POWER COMPANY	CASE NO. PUE-2012-00141

For approval of transactions to acquire interests in the Amos and Mitchell generation plants and to merge with Wheeling Power Company

DIRECT TESTIMONY

OF

SCOTT NORWOOD

ON BEHALF OF

THE OFFICE OF THE ATTORNEY GENERAL

DIVISION OF CONSUMER COUNSEL

APRIL 23, 2013

DIRECT TESTIMONY OF SCOTT NORWOOD

TABLE OF CONTENTS

EXHIBITS (continued)

SN-9	Industry Average Performance Statistics for Coal Plants
SN-10	PSO Testimony on Coal Unit Service Lives/Future Environmental Risk, Excerpt – Pages 1 and 45
SN-11	Carbon Tax Forecast, APCo Response to OAG 3-057
SN-12	APCo Responses to OAG 2-016 and OAG 2-018
SN-13	AEP Press Release on Waterford Plant Acquisition
SN-14	Estimated Reduction in Cost Savings from 20% Reduction in Combined Cycle Capital Cost
SN-15	**CONFIDENTIAL** – Estimated Reduction in Cost Savings from Adjusting Generating Asset Capacity Factors
SN-16	**CONFIDENTIAL** – AEP Coal Plant Retirement Dates, Confidential Response to OAG 3-043
SN-17	Estimated Reduction in Cost Savings from Adjusting Generating Asset Lives to 60 Years
SN-18	OSS Margins, APCo Response to OAG 8-122
SN-19	**CONFIDENTIAL** – Estimated Reduction in Cost Savings due to Exclusion of Retained Margins
SN-20	APCo Responses to OAG 2-013 and OAG 2-015
SN-21	Information on Coal Plant Sales: APCo Response to OAG 3-046 and Electric Power Daily Article

I. INTRODUCTION

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

A. My name is Scott Norwood. I am President of Norwood Energy Consulting, L.L.C. My business address is 9408 Bell Mountain Drive, Austin, Texas 78730.

Q. WHAT IS YOUR OCCUPATION?

A. I am an energy consultant specializing in the areas of electric utility regulation, resource planning, and energy procurement.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have over 30 years of experience in the electric utility industry. After graduating from the University of Texas in 1980 with a Bachelor of Science degree in electrical engineering, I began my career as a power plant engineer for the City of Austin's Electric Utility Department where I was responsible for electrical maintenance and design projects for the City's three gas-fired power plants. In January 1984, I joined the staff of the Public Utility Commission of Texas as Manager of Power Plant Engineering. In that capacity, I was responsible for addressing resource planning, fuel and purchased power cost issues presented in regulatory filings before the Texas Commission. In 1986, I joined GDS Associates, Inc., a Marietta, Georgia-based consulting firm that specializes in electric utility regulatory consulting and resource planning. I was elected a Principal of GDS in 1990 and directed the firm's Deregulation Services Department until January

2004, when I left GDS to form Norwood Energy Consulting, LLC. The focus of my current consulting practice is energy planning, procurement, and regulation. Exhibit SN-1 provides a more detailed summary of my background and experience.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Office of the Attorney General, Division of Consumer Counsel ("Consumer Counsel").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE STATE CORPORATION COMMISSION?

A. Yes. I have testified on behalf of Consumer Counsel in numerous past regulatory proceedings before the State Corporation Commission ("Commission") on power plant certification, base rate, and fuel recovery matters, including cases involving Appalachian Power Company ("APCo" or "Company"). Outside of Virginia, I also have testified in proceedings involving base rate, fuel, and power plant certification matters before state regulatory commissions in Arkansas, Georgia, Illinois, Iowa, Michigan, Missouri, New Jersey, Louisiana, Oklahoma, Texas, Washington and Wisconsin.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present my evaluation and recommendations regarding APCo's application for approval of the proposed ownership transfer of approximately 1,647 MW of the Mitchell and Amos Unit 3 coal-fired generating assets (hereinafter referred to jointly as the "Generating Assets" or "proposed asset transfers") from its affiliate, Ohio Power Company ("Ohio Power") through a series of transactions as described in the Company's application, and the Company's proposed merger with Wheeling Power Company ("Wheeling").

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. I have prepared 21 exhibits, which are attached to my testimony.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. APCo is seeking approval of the proposed transfer of ownership of 867 MW from Amos Unit 3 and 780 MW of Mitchell Units 1 and 2 from its affiliate Ohio Power, along with its proposed merger with Wheeling, another affiliate. The proposed transfer price for the Generating Assets is approximately $1.15 billion, or approximately $700/kW. (See Exhibit SN-2, Response to OAG 2-006.) APCo claims that the Generating Assets would produce total system production cost benefits of approximately $1.28 billion on a present value basis when compared to an optimized plan excluding the Generating Assets over the forecasted remaining lives of the assets. (Torpey Direct Testimony, page 15.) The Company further asserts that the Wheeling merger will have a minimal impact on APCo's Virginia jurisdictional cost of service and rates. (Martin Direct Testimony, page 3.)

I have analyzed APCo's asset transfer and Wheeling merger proposals and have reached the following major findings and conclusions regarding these proposed transactions:

- The forecasted total Company revenue requirement for the Generating Assets is approximately $566 million ($58/MWh) in 2014, the first full year of commercial operations under APCo. The total Company revenue requirement of the Generating Assets is forecasted to be approximately $16.5 billion on a nominal basis over the estimated remaining life of the assets. (See Exhibit SN-3.)

- APCo's base case peak demand forecast generally appears reasonable. The proposed Generating Asset transfers are expected to result in a short-term surplus of excess capacity on APCo's system until certain older coal-fired generating units are retired in 2015; however, based on APCo's analysis, the Company expects the transfers to produce cost savings for customers over the life of the assets even after considering this initial surplus.

- The Generating Assets would provide certain cost and schedule advantages over new generation resource alternatives, and are likely to offer lower fuel costs and reduced fuel price volatility for the foreseeable future. However, the Generating Assets also have certain disadvantages for APCo and its customers. Of particular concern, the proposed asset transfers would significantly reduce the fuel diversity of APCo's system and leave the Company heavily dependent on older coal-fired units to supply the vast majority of its energy needs at a time of great uncertainty regarding future environmental regulations.

- The Generating Assets would reduce APCo's market purchases and therefore reduce exposure to market price volatility. However, much of the forecasted cost savings attributable to the Generating Asset transfers are related to increased sales of excess coal-fired energy and capacity into the PJM market. To the extent these sales opportunities do not materialize as forecasted by APCo, or if the market prices for these sales are lower than forecasted by the Company, the projected benefits of the Generating Assets would be significantly diminished.

- APCo did not solicit offers or otherwise attempt to identify possible market alternatives to the proposed Generating Assets. For this reason, the Company does not really know whether there may have been other suppliers who were willing to sell power from existing or new generation projects at a lower cost than the proposed asset transfers from APCo's affiliate.

- APCo's economic analysis of the Generating Asset transfers incorporates a number of unreasonable assumptions, including overly optimistic performance assumptions, very long assumed coal unit service lives, and the inclusion of off-system sales margins that are retained by the Company. These assumptions generally serve to overstate the forecasted cost savings attributable to the proposed asset transfers. After reasonable adjustments for these modeling problems are made, it appears that the forecasted cost savings from the Generating Asset transfers (when compared to costs under an optimized resource plan without the assets) would drop to approximately $365 million on a cumulative present value basis. This amount, while not insignificant, represents less than 1.3% of the approximately $28.5 billion total modeled production costs of the APCo system over the remaining life of the Generating Assets. (See Exhibit SN-4.)

- APCo has not presented evidence to establish the market value of the Generating Assets to demonstrate the reasonableness of the price at which it seeks to acquire such assets from its affiliate. The Company did not solicit market offers which could have eliminated uncertainty that exists regarding the market value of the Generating Assets. Other recent coal plant sales appear to indicate that market values of existing coal plants may be significantly lower than the $700/kW transfer price proposed by APCo in this case.

Based on the above findings and conclusions, I have serious unresolved questions as to whether the Generating Assets transfers represent the best alternative for supplying APCo's future capacity and energy requirements. My recommendations to the Commission regarding the proposed asset transfers are as follows:

- Due to APCo's failure to solicit market alternatives, my concerns regarding the ownership risks associated with older coal plants, my concerns regarding the diminished fuel diversity which would result from the proposed asset transfers, and the lack of evidence regarding the market value of the generating assets, I do not recommend approval of APCo's request for approval of the Generating Asset transfers.

- The proposed Wheeling merger appears likely to have minimal impact on APCo's retail rates and over time should benefit the Virginia jurisdiction by increasing the assignment of fixed costs to the West Virginia jurisdiction and away from Virginia. For these reasons, I do not oppose this merger.

III. SUMMARY OF APCO'S APPLICATION

Q. **WHAT IS APCO REQUESTING IN THIS CASE?**

A. APCo is requesting approval to enter into a series of affiliate transactions under which the Company would: 1) acquire a two-thirds ownership interest (approximately 867 MW) in the Amos Unit 3 coal-fired generating unit from its affiliate AEP Generation Resources; 2) acquire a fifty percent interest (approximately 780 MW) in the Mitchell Units 1 and 2 coal-fired generating units from Ohio Power; and 3) merge with Wheeling, an affiliate which provides retail electric service in West Virginia. (Application, page 1.) In addition, APCo requests approval of an operating agreement under which the Company would operate and maintain the Mitchell coal units. (Application, page 3.)

Q. WHAT IS THE PROPOSED ACQUISITION PRICE FOR THE GENERATING ASSETS?

A. APCo proposes to acquire the Generating Assets at net book value, which is estimated by the Company to be approximately $1.15 billion. (See Exhibit SN-2.) This equates to an average price of $700/kW for the 1,647 MW of capacity supplied from the transferred assets.

Q. WHAT IS THE FORECASTED ANNUAL REVENUE REQUIREMENT FOR THE PROPOSED GENERATING ASSET TRANSFERS?

A. APCo estimates that the total Company annual revenue requirement for the Generating Assets would be approximately $566 million in 2014, the first full year of operations after the transfers are made. (See Exhibit SN-3.) Based on APCo's forecast, the average cost of power delivered from the transferred assets would be approximately $58/MWh in 2014.

Q. WHY IS APCO PROPOSING THESE GENERATING ASSET TRANSFERS AT THIS TIME?

A. APCo indicates that the Generating Assets are needed to supply future load obligations arising from the planned termination of the AEP East Interconnection Agreement in January of 2014, the planned retirement of approximately 1,243 MW of older APCo coal-fired generating units in 2015, and increased load arising from the Wheeling merger. (Torpey

Direct Testimony, page 4 and LaFleur Direct Testimony, page 4.) The Company further claims that the Generating Assets represent the least cost option for meeting these future capacity and energy requirements. (Application, page 2.)

Q. WHY IS APCO PROPOSING TO MERGE WITH WHEELING POWER COMPANY?

A. APCo indicates that its merger with Wheeling was motivated by a 2009 order from the West Virginia Public Service Commission ("WVPSC") which encouraged APCo to take steps to merge with Wheeling due to the fact that both companies provide retail service in West Virginia and are direct and wholly-owned affiliates of AEP. (Patton Direct Testimony, page 10.) The Company admits that any efficiencies resulting from the merger are likely to be relatively small since Wheeling serves only 41,000 customers while APCo currently serves almost a million customers, and because Wheeling is already structured to operate as a district office rather than as a separate operating company. (Patton Direct Testimony, page 10.) APCo asserts that the Wheeling merger will have a minimal effect on APCo's Virginia retail rates. The Company's estimate of the impact of the Wheeling merger upon APCo's Virginia jurisdictional revenue requirement is approximately $3.3 million, or 0.29% of total revenues for the twelve months ending June 30, 2012. (Martin Direct Testimony, page 3 and Schedule 1.)

Q. WHAT ARE THE STANDARDS APCO MUST SATISFY TO OBTAIN APPROVAL OF THE PROPOSED GENERATING ASSET TRANSFERS AND WHEELING MERGER?

A. APCo has requested approval of its acquisition of the Generating Assets pursuant to the Utility Transfers Act, Virginia Code Sections 56-88 et seq. ("Transfers Act") and will be seeking approval under the Affiliates Act, Virginia Code Sections 56-76 et seq. ("Affiliates Act"). It is my understanding that under the Transfers Act the Company must show that the proposed transactions will not impair or jeopardize adequate service to the public at just and reasonable rates, while under the Affiliates Act APCo bears the burden of demonstrating that the proposed acquisitions are in the public interest and priced at the lower of cost or market value.

Q. WHAT ARE THE PRIMARY FACTORS CITED BY APCO AS SUPPORT FOR ITS PROPOSED ACQUISITION OF THE TRANSFERRED GENERATING ASSETS?

A. APCo asserts that the Generating Asset transfers are in the public interest and lists four primary factors in support of its proposed acquisition of these assets:

1) The Company has a need for the capacity and energy to be supplied from the Generating Assets due to termination of the Interconnection Agreement, upcoming retirements of older coal-fired units, and additional load arising from the proposed Wheeling merger (Application, page 12.);

2) Because the Generating Assets have already been constructed, have operated at or above industry standards, use a plentiful and secure fuel and meet existing environmental regulations, the assets have lower cost escalation, schedule and

performance risks when compared to the construction of a new generating plant (Application, page 13.);

3) The Generating Assets will increase APCo's ownership of generation and thereby reduce the Company's exposure to future volatility of the energy and capacity markets (Application, page 13.); and

4) The proposed Generating Asset transfers represent the least cost option for meeting APCo's forecasted capacity and energy requirements (Application, page 12.).

Q. **HOW HAVE YOU EVALUATED APCO'S CLAIMS THAT THE PROPOSED TRANSFER OF GENERATING ASSETS AND MERGER WITH WHEELING ARE IN THE PUBLIC INTEREST?**

A. With regard to the Generating Asset transfers, I have evaluated APCo's underlying analysis and evidence for each of the four major factors cited by the Company in support of its claim that the transfers are in the public interest. In addition, I have evaluated evidence presented by APCo and from other sources to assess the Company's claim that the proposed acquisition price for the Generating Assets is reasonable and reflective of fair market value for the assets. It is my understanding that the Commission has historically applied a "lower of cost or market value" standard under the Affiliates Act in deciding the recoverable price for assets purchased by regulated utilities from affiliates.

Finally, I have evaluated APCo's impact analysis for the Wheeling merger and have considered other potential future impacts arising from this proposed combination in assessing the Company's claim that the proposed merger is in the public interest.

IV. NEED FOR CAPACITY

Q. WHAT INFORMATION HAS APCO PROVIDED TO DEMONSTRATE THAT THERE IS A NEED FOR THE CAPACITY SUPPLIED BY THE GENERATING ASSETS?

A. APCo witness Mr. Torpey has summarized the Company's forecasted capacity obligations in Figure 1 on page 5 of his direct testimony and a similar forecast has been provided on page 4 of Exhibit 10 of the Company's application. These forecasts indicate that, without the proposed Generating Asset transfers and assuming the termination of the Interconnection Agreement and Wheeling merger occur, APCo would be capacity deficit by 98 MW in 2014 and this deficit would grow to 1,244 MW after the planned retirements of APCo's Clinch River, Glen Lyn, Kanawha River, and Sporn coal units in 2015.

Q. DOES THE PEAK DEMAND FORECAST UNDERLYING APCO'S CAPACITY OBLIGATION FORECAST APPEAR TO BE REASONABLE?

A. I have not conducted a detailed analysis of APCo's peak demand forecast. The Company's forecast indicates average peak demand growth of approximately 0.5% per year for the period 2015-2030 (i.e., after reflecting the Wheeling merger), which is somewhat lower than the 1.3% per year average growth in peak demand actually experienced on APCo's system over the last ten years. (See Exhibit SN-5.) This lower level of forecasted demand growth is generally consistent with other recent industry forecasts I have seen, which apparently are reflective of the slow economic growth being experienced in most parts of the country as well as the anticipated effects of future energy efficiency and demand-side management programs. All other things being equal, the relatively low level of demand growth forecasted by APCo would tend to lower the forecasted economic benefits of the proposed asset transfers by reducing and delaying the replacement capacity and energy costs associated with alternatives to the Generating Assets.

Q. HOW DOES THE PROPOSED WHEELING MERGER AFFECT THE NEED FOR THE GENERATING ASSETS?

A. The Wheeling merger contributes significantly to the need for the Generating Assets. APCo's peak demand forecast includes approximately 475 MW for the peak demand of the Wheeling system in 2014, and the Wheeling load is forecasted to increase to approximately 508 MW by 2040. (See Exhibit SN-6, Response to OAG 8-125.) Assuming a 15% reserve obligation, this means that the Wheeling merger will increase APCo's need for capacity by approximately 546 MW by 2014, which represents nearly one-third of the 1,647 MW of capacity supplied from the Generating Assets. If the Wheeling merger did not occur, APCo would have approximately 1,974 MW of excess capacity in 2014, and approximately 750 MW to 850 MW of excess capacity between 2015 and 2020. Under these circumstances, APCo would not need to acquire the full 1,647 MW supplied by the Generating Assets in order to meet its system capacity obligations.

Q. HAS APCO CONDUCTED AN ANALYSIS TO DETERMINE WHETHER ACQUISITION OF THE GENERATING ASSETS WOULD BE JUSTIFIED IF THE WHEELING MERGER WAS NOT IMPLEMENTED?

A. Yes. In response to a data request from the Staff, APCo conducted a series of analyses that indicate there would still be significant cost savings for customers arising from acquisition of the Generating Assets even if the Wheeling merger was not implemented. (See Exhibit SN-7, Supplemental Response to Staff 08-162.)

Q. ARE YOU CONCERNED WITH THE FACT THAT THE PROPOSED GENERATING ASSET TRANSFERS COULD RESULT IN SURPLUS CAPACITY ON APCO'S SYSTEM?

A. Not necessarily. It is important to recognize that some short-term surplus will arise from the proposed Generating Asset transfers and this creates certain economic risk for APCo's customers to the extent that the Company is unable to sell the surplus capacity or if prices received from the sale of surplus capacity and energy are not sufficient to offset the cost of the transfers. However, APCo's peak demand forecast appears relatively low; therefore, it is also possible that the surplus will not be as large as forecasted. Moreover, the costs and benefits of the Generating Assets should be evaluated over the remaining useful lives of the assets (as APCo has done), and if the analysis indicates that the transfers are the lowest reasonable cost alternative (with due consideration to attendant risks), they should be approved even if the Generating Asset transfers may cause a short-term surplus.

V. COST ESCALATION, SCHEDULE, AND PERFORMANCE RISKS

Q. APCO CLAIMS THAT THE PROPOSED GENERATING ASSET TRANSFERS WILL RESULT IN LOWER COST ESCALATION, SCHEDULE AND PERFORMANCE RISKS WHEN COMPARED TO CONSTRUCTION OF A NEW PLANT. DO YOU AGREE?

A. Not entirely. I do agree that the Generating Assets will essentially eliminate the risks of construction cost increases or construction schedule delays that might otherwise result if the Company constructed a new plant, since the plants are already operational. However, construction cost and schedule risks could also be eliminated by acquiring existing assets or entering into long-term purchased power agreements.

There is good reason to expect that the proposed transfers could also provide a fuel cost advantage over gas-fired resource options due to the fact that coal prices have historically tended to be lower and less volatile than natural gas prices. However, many energy analysts are predicting generally lower and more stable natural gas prices in the future due to the "shale gas revolution," and should this occur, the cost and price volatility advantages of coal over natural gas could be diminished in the future. On balance, due to the declining demand for coal and increasing demand for natural gas in the future, I think it is reasonable to assume that coal will maintain a cost and price volatility advantage over natural gas for the foreseeable future. The extent to which this coal price advantage benefits APCo's customers depends on a number of factors, including the future level of natural gas prices, future federal environmental regulations or legislation, as well as the future operating performance of the Generating Assets.

Q. WOULD THE ACQUISITION OF THE GENERATING ASSETS ENHANCE THE FUEL DIVERSITY OF APCO'S SYSTEM?

A. No. As summarized in Table 1, the proposed asset transfers would significantly reduce the existing fuel diversity of APCo's system and leave the Company heavily dependent upon coal-fired generation for meeting future energy requirements.

Table 1

APCo System Energy Supply Mix

	Coal	Gas	Purchases	Wind	Hydro
2012 Actual	47.0%	6.2%	43.4%	2.2%	1.2%
Optimization Portfolio (2020)	56.2%	16.0%	22.5%	3.5%	1.8%
Asset Transfer (2020)	87.1%	8.2%	0.0%	3.8%	1.1%

Sources: APCo's Responses to OAG 2-021 and OAG 7-108.

Q. SHOULD THE PROPOSED ASSET TRANSFERS BE REJECTED IN ORDER TO PRESERVE GREATER FUEL DIVERSITY ON APCO'S SYSTEM?

A. Not necessarily. While I believe that maintaining fuel diversity is particularly important given uncertainty that presently exists in energy markets, the cost of maintaining fuel diversity must be weighed against the potential benefits of acquiring resources (such as the Generating Assets) that reduce fuel diversity. In APCo's case, unless the Generating Assets are reasonably certain to provide a significant economic advantage over other alternatives, it would be appropriate for the Company to pursue a diversification strategy because (as noted by the results of the Optimization Portfolio in Table 1) over 56% of

APCo's total system energy requirements would still be supplied by coal even if the asset transfers do not occur.

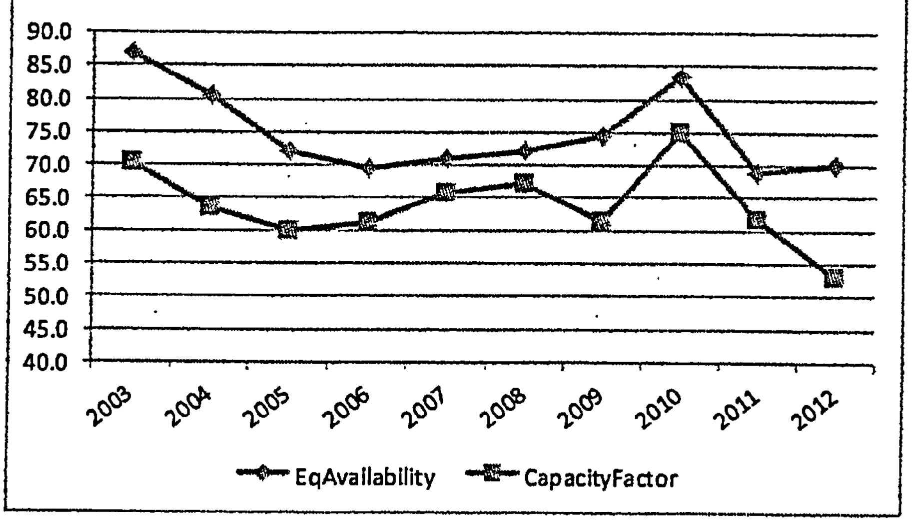
Q. WHAT EVIDENCE HAS APCO PROVIDED TO SUPPORT ITS CLAIM THAT THE GENERATING ASSETS ARE IN GOOD OPERATING CONDITION?

A. The Company has provided summaries of major outage events and historical performance statistics, but apparently has not commissioned an independent engineering assessment of the condition of the proposed transferred generating assets. (See Exhibit SN-8, Responses to OAG 2-033 and OAG 3-061.) The Company states that it was not necessary to have an independent condition assessment performed since it has operated the Amos 3 unit for years and is familiar with Ohio Power's Mitchell generating units, which are similar in design to the Amos coal-fired units. An independent assessment of the condition of the Generating Assets, or even a formal AEP analysis, would have been useful and appropriate to demonstrate that there are no significant potential operating liabilities or risks that APCo will be assuming if the proposed transfers are implemented. The lack of any such condition assessment creates additional uncertainty with regard to APCo's proposed acquisition of the Generating Assets, which is a concern due to the direct linkage that exists between forecasted savings and operating performance of the units.

Q. DO THE HISTORICAL PERFORMANCE STATISTICS FOR THE AMOS AND MITCHELL PLANTS SUPPORT APCO'S CLAIM THAT THE ASSETS HAVE BEEN OPERATED AT OR ABOVE INDUSTRY STANDARDS?

A. No. As shown in Figure 1 below, the equivalent availability and capacity factor performance of the transferred generating assets generally have declined over the last 10 years; the average equivalent availability during this historical period was slightly below 75%, while the average capacity factor was approximately 64%.

Figure 1
Average Performance Statistics for Amos 3, Mitchell 1 & 2



Source: APCo's Response to OAG 2-017.

While I have not analyzed availability performance for a peer group of older coal units (i.e., 40 years or older) such as the transferred assets, other performance surveys I have reviewed suggest that the average equivalent availability performance for coal units typically approaches 85%, and the transferred assets have performed below this level for 8 of the last 10 years. (See Exhibit SN-9.) Moreover, the historical equivalent availability performance of the transferred assets is well below performance of new combined cycle generating units, which typically approach 90% on an annual average basis.

Q. APCO ASSERTS THAT ONE ADVANTAGE OF THE GENERATING ASSETS OVER NEW SUPPLY RESOURCES IS THAT THE ASSETS MEET EXISTING ENVIRONMENTAL REGULATIONS. DO YOU AGREE?

A. No. While the Generating Assets may meet existing environmental regulations, this would not represent an advantage over most new generation resource options or existing gas-fired generating assets, since coal units have higher air emissions and therefore typically have inherently higher environmental risk than gas-fired units. Moreover, the EPA is expected to issue new regulations in the coming years under the Clean Air Act's New Source Performance Standard program that could apply carbon emissions standards to existing generating facilities. Although the timing and final form and impact of any such carbon regulations on the Generating Assets cannot be predicted with certainty at this time, additional carbon emissions standards or fees could make the operation of these units more costly than forecasted by APCo.

Q. HAS APCO ADDRESSED THE RISK OF FUTURE EPA REGULATIONS ON COAL IN ITS ANALYSIS OF THE TRANSFERRED ASSETS?

A. To some extent APCo has addressed future environmental risk of the Generating Assets in its Strategist analysis. For example, the Company has included approximately $195 million in capital costs for certain anticipated environmental retrofits to comply with future regulations and has also included costs of forecasted future carbon taxes, beginning in year 2022, in all scenarios it evaluated. (See Torpey Direct Testimony, Schedules 1 and 2.) These forecasted compliance costs create a disadvantage for the Generating Assets when compared to gas-fired generation alternatives.

Q. IS THE COMPANY'S TREATMENT OF FUTURE ENVIRONMENTAL RISK CONSISTENT WITH AEP'S TESTIMONY IN OTHER PENDING REGULATORY CASES?

A. No. APCo has not attempted to forecast the impact of other future unknown environmental risks upon the Generating Assets as other AEP operating companies have in other pending regulatory cases involving disposition of existing coal units. For example, in a pending case before the Oklahoma Corporation Commission ("OCC"),[1] APCo's affiliate Public Service Company of Oklahoma ("PSO") has argued that the financial risk associated with future EPA regulations that have not yet been identified or implemented would likely result in the retirement of PSO's Northeastern coal units after 50 years of service, whereas in this case APCo has assumed that the Generating Assets will operate for nearly 70 years in its base case Strategist analysis. (See Exhibit SN-10.) Under PSO's analysis of future environmental risk, the Generating Assets would have only approximately 7 to 9 years of remaining life after the transfer to APCo since the assets will be 41 to 43 years old when the transfers occur. This shortened operating life would reduce the forecasted cost advantage of the Generating Assets over other alternatives. In this respect, AEP's treatment of future environmental risk for coal units

[1] Cause No. PUD 2012000054

in Oklahoma appears to directly and significantly conflict with APCo's treatment of future environmental risk faced by the Generating Assets.

Q. ARE YOU SUGGESTING THAT APCO SHOULD HAVE INCLUDED ADDITIONAL COSTS FOR FUTURE EPA REGULATIONS THAT DO NOT EXIST IN ITS BASE CASE EVALUATION OF THE GENERATING ASSETS?

A. No. However, it would have been appropriate for APCo to have conducted sensitivity analyses with higher carbon taxes in order to assess the cost impact associated with the risk that unknown future environmental regulations could be more stringent than assumed in the Company's base case analysis. Unfortunately, APCo did not conduct either a "high carbon tax" or a "no carbon tax" sensitivity analysis as other AEP operating companies have done when evaluating major coal plant investments in other recent regulatory cases. (See Exhibit SN-11, Response to OAG 3-057.)

Q. HOW DO FORECASTED NON-FUEL OPERATING COSTS OF THE GENERATING ASSETS COMPARE TO OPERATING COSTS FOR A NEW GAS-FIRED COMBINED CYCLE PLANT?

A. The forecasted non-fuel operating costs of the Generating Assets are much higher than costs of new or existing gas-fired generation alternatives, simply due to the fact that the Amos and Mitchell units are relatively old coal-fired plants and have greater exposure to future environmental compliance costs than gas-fired plants. For example, the total forecasted non-fuel operating cost of the Generating Assets is approximately 35% higher than the forecasted non-fuel operating expense for new gas-fired combined cycle units in

APCo's Strategist analyses. In order for the Generating Assets to overcome this significant non-fuel operating cost disadvantage (and be beneficial to customers), the assets must maintain consistently good operating performance in the future.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COST, SCHEDULE AND PERFORMANCE RISKS OF THE GENERATING ASSETS?

A. I agree with APCo that the Generating Assets would provide certain cost and schedule advantages over new generation resource alternatives, and are likely to offer lower fuel costs and reduced fuel price volatility for the foreseeable future when compared to gas-fired generation options. However, the Generating Assets also have certain disadvantages for APCo and its customers, including higher non-fuel operating costs, lower operating availability and higher environmental risk than new or existing gas-fired resources. Of particular concern, the proposed asset transfers would reduce the fuel diversity of APCo's system and leave the Company heavily dependent on older coal-fired units to supply the vast majority of its energy needs at a time of great uncertainty regarding future environmental regulations. For example, by 2020 the average age of coal-fired generating units on APCo's system would be 50 years old.

VI. MARKET PRICE RISK

Q. APCO CLAIMS THAT THE GENERATING ASSETS WOULD BENEFIT CUSTOMERS BY REDUCING THE COMPANY'S EXPOSURE TO FUTURE VOLATILITY IN ENERGY AND CAPACITY MARKETS. DO YOU AGREE?

A. I do agree that APCo would likely purchase less capacity and energy from the PJM market if it acquires the Generating Assets, at least for the foreseeable future. I also agree that excess exposure to market purchases can be a problem, just as over-reliance on coal-fired generation or other energy sources can create price volatility problems.

Q. DOES IT APPEAR THAT APCO COULD HAVE EXCESSIVE EXPOSURE TO MARKET PRICE RISKS IF THE COMPANY DOES NOT ACQUIRE THE GENERATING ASSETS?

A. No. I am not aware of any parties that have suggested that APCo should rely heavily upon market purchases to supply its future energy and capacity requirements. Moreover, APCo's Strategist modeling suggests that the Company would not be over-reliant upon market purchases if the Generating Asset transfers do not occur, except in the Market Portfolio case in which APCo forced the model to select market purchases to supply all new system requirements through the year 2025. For example, as summarized above in my Table 1, under APCo's Optimization Portfolio, which excludes the Generating Asset transfers, the forecasted volume of APCo's future market energy purchases is approximately 50% lower than the actual level of APCo's energy purchases last year. Moreover, under the Optimization Portfolio, market purchases are forecasted to be only approximately 23% of APCo's total system energy requirements by 2020. This represents a reasonable level of market purchases that would not expose APCo and its customers to undue market risk, and coal-fired generation would still be available to supply over 50% of the Company's energy as a hedge against market price risk under the Optimization Portfolio.

Q. COULD ACQUISITION OF THE GENERATING ASSETS INCREASE APCO'S EXPOSURE TO MARKET RISK IN OTHER RESPECTS?

A. Yes. In fact a major portion of the forecasted cost savings from the Generating Asset transfers are related to APCo's increased sales of excess coal-fired energy and capacity into the PJM market. To the extent these sales opportunities do not materialize as forecasted by APCo, or if the market prices for these sales are lower than forecasted, the projected benefits of the Generating Assets would be significantly diminished. In this respect, APCo's proposed acquisition of the Generating Assets could significantly increase the Company's future exposure to market price risk, and that increased market risk would be largely borne by customers.

VII. ECONOMIC ANALYSIS OF GENERATING ASSET TRANSFERS

Q. HOW DID APCO CONDUCT ITS ECONOMIC ANALYSIS OF THE PROPOSED GENERATING ASSET TRANSFERS?

A. APCo used the Strategist production cost model to evaluate the Generating Assets in comparison to market purchase and new construction alternatives over a 30-year study period (2011-2040). (Torpey Direct Testimony, page 9.) The Strategist model is a widely-used and accepted model for conducting resource planning and production cost optimization studies, and it has been used by APCo to prepare past Integrated Resource Plans and to conduct economic studies to support other resource additions, such as the Dresden combined cycle plant which was approved by the Commission in Case No. PUE-2011-00023. The Company used Strategist to evaluate the proposed Generating Asset transfers and other alternatives over base, high, and low range commodity price scenarios that were intended to account for future fuel and market price uncertainty. (Torpey Direct Testimony, pages 14-15.)

Q. WHAT SPECIFIC ALTERNATIVES TO THE PROPOSED GENERATING ASSET TRANSFERS WERE EVALUATED BY APCO?

A. APCo really evaluated only two major alternatives to the proposed Generating Asset transfers: 1) a Market Portfolio that fulfilled all future capacity and energy requirements through the year 2025 by market purchases, with additions after that date supplied from either market purchases or new gas-fired combustion turbine or combined cycle units; and 2) an Optimization Portfolio that fulfilled all capacity and energy requirements through the year 2017 by market purchases, with additions after that date supplied from either market purchases or new gas-fired combustion turbine or combined cycle units. (Torpey Direct Testimony, page 6.) In addition, the Company evaluated scenarios that considered the addition of the Amos 3 and Mitchell 1 & 2 asset transfers individually. The Market Portfolio is not a realistic scenario because it forces the Strategist model to select purchases through 2025 even when there are forecasted to be lower cost alternatives available to serve APCo's needs.

Q. WHAT ARE THE RESULTS OF APCO'S STRATEGIST ANALYSES OF ALTERNATIVES TO THE GENERATING ASSET TRANSFERS?

A. The results of APCo's economic analyses are summarized in Figure 2 on page 15 of Mr. Torpey's direct testimony. These results indicate that under the base case scenario, the proposed Generating Asset transfers are forecasted to provide a present value cost advantage ranging from $1.28 billion to $1.41 billion over the Optimization and Market Portfolios, respectively.

Q. ARE THE UNDERLYING ASSUMPTIONS AND METHOD OF APCO'S STRATEGIST ANALYSES OF THE GENERATING ASSET TRANSFERS REASONABLE?

A. In many respects, the Company's Strategist analyses of the Generating Assets and alternatives to the transfers do appear to have been conducted in a reasonable and appropriate manner. However, there were several apparent deficiencies in APCo's modeling process, including: 1) no true market-based offers were solicited or evaluated by APCo as potential alternatives to the Generating Assets; 2) the operating performance assumptions for the Generating Assets appear to be somewhat optimistic; 3) the forecasted 70 year service lives of the Generating Assets appear to be overly aggressive for a base case analysis; and 4) the Company failed to adjust its off-system sales revenue forecast to reflect the 25% share of margins retained by APCo in Virginia and therefore significantly overstates the cost savings that would be realized by customers. Due to these apparent problems with APCo's Strategist analysis of the Generating Assets, I question the validity of the projected cost savings for the transferred assets as summarized in Figure 2 on page 15 of Mr. Torpey's testimony.

A. FAILURE TO EVALUATE MARKET ALTERNATIVES

Q. WOULD YOU EXPLAIN YOUR CONCERNS REGARDING APCO'S FAILURE TO SOLICIT COMPETITIVE OFFERS AS ALTERNATIVES TO THE GENERATING ASSET TRANSFERS?

A. Yes. My primary concern is that APCo did not solicit offers or attempt to identify possible market alternatives to the proposed Generating Assets. (See Exhibit SN-12, Responses to OAG 2-016 and OAG 2-018.) For this reason, the Company does not really know whether there may have been other suppliers who were willing to sell power from existing or new generation projects at a lower cost than the proposed asset transfers.

Q. WHY DID APCO LIMIT ITS EVALUATION OF NEW RESOURCES TO THE GENERATING ASSET TRANSFERS?

A. Company witness Mr. Torpey indicates on page 18 of his direct testimony that, while the Company chose not to solicit proposals for replacement capacity and energy, that it effectively considered market options because it believes that market offers would reflect the forecasted cost of new-build combined cycle resources that were evaluated in the Strategist analysis of the Optimization Portfolio.

Q. HAS AEP SOLICITED MARKET-BASED ALTERNATIVES IN EVALUATING MAJOR COAL PLANT INVESTMENT DECISIONS IN OTHER JURISDICTIONS?

A. Yes. For example, in a pending AEP case before the OCC,[2] APCo's affiliate PSO indicates that it solicited competitive offers and through this process was able to obtain a long-term purchased power agreement to replace capacity and energy of Northeastern Unit 4, a coal unit that PSO is proposing to retire in 2016 under a settlement with EPA.

Q. DID APCO PROVIDE ANY EVIDENCE AS TO WHETHER THE COMPANY COULD HAVE OBTAINED POWER FROM THIRD PARTIES AT A LOWER COST?

A. No. In the absence of a broad solicitation, APCo cannot know whether there were (or are) lower cost alternatives to the Generating Assets. Without such market information, the Company's analysis relied upon administratively determined market price forecasts which may not reasonably approximate true market prices. For example, APCo's Strategist analysis assumes that the cost to acquire gas-fired combined cycle resources in 2018 is approximately $1,670/kW; however, the capital cost of Dominion's 1,329 MW Warren County combined cycle project was less than $1,000/kW, which is approximately 40% lower than APCo's combined cycle capital cost forecast. Moreover, as recently as September of 2005, AEP acquired the 821 MW Waterford combined cycle plant for approximately $220 million ($267/kW) through a competitive procurement process. (See Exhibit SN-13.) If APCo had been able to acquire combined cycle capacity at a cost 20%

[2] Cause No. PUD 2012000054

lower than the level it has assumed in its Strategist analyses, this would reduce the forecasted cost savings that the Company has attributed to the Generating Asset transfers by approximately $453 million (~35.5%). (See Exhibit SN-14.) APCo's Strategist analysis simply ignores this possibility that lower cost alternatives could have been identified by the Company had it chosen to solicit competitive offers as AEP did in the past with Waterford and as its affiliate PSO has recently done in Oklahoma.

B. OPERATING PERFORMANCE ASSUMPTIONS

Q. WHAT IS YOUR CONCERN REGARDING APCO'S OPERATING PERFORMANCE ASSUMPTIONS FOR THE GENERATING ASSETS?

A. APCo's Strategist analysis of the Generating Asset transfers assumes that the assets will operate at an average capacity factor of more than 77% over the six year period from 2016 through 2021. This level of performance is approximately 20% higher than the average capacity factor (~64%) actually achieved by the Generating Assets over the last 10 years, and more than 45% higher than the average capacity factor of the assets last year (~53%). As a base case forecast, this level of performance improvement for coal units that would be approaching 50 years in service seems suspect.

Q. WHAT IS THE SIGNIFICANCE OF THE RELATIVELY HIGH FORECASTED CAPACITY FACTORS OF THE GENERATING ASSETS DURING THE 2016-2021 PERIOD?

A. The primary driver of forecasted cost savings from the Generating Assets is the sale of surplus coal-fired energy that arises from the asset transfers. For example, approximately $685 million (~54%) of the total forecasted base case savings attributed to the Generating Asset transfers (when compared to the Optimization Portfolio) is accumulated during the same 2016-2021 period in which the apparent high forecasted operating performance of the assets occurs. If the Generating Assets do not perform at the very high levels forecasted by APCo during this period, these forecasted surplus energy sales savings would not occur.

Q. HOW WOULD APCO'S COST SAVINGS FORECAST BE IMPACTED IF THE FORECASTED CAPACITY FACTOR PERFORMANCE OF THE GENERATING ASSETS WAS REDUCED FROM 80% TO THE HISTORICAL AVERAGE LEVEL OF APPROXIMATELY 64% DURING THE 2016-2021 PERIOD?

A. While the impact of this adjustment cannot be precisely determined without re-running the Strategist model, I have estimated that reducing the forecasted capacity factors to the historical average level during the 2016-2021 period would reduce the forecasted base case cost savings by approximately $176 million (~13.8%) (See Exhibit SN-15.) My estimate of the impact of this reduced performance level assumes that 80% of the reduction in energy production by the Generating Assets would result in a like reduction in off-system sales margins based on the difference between the average forecasted price of market sales and the average price of coal-fired energy during this six-year period.

C. GENERATING ASSET SERVICE LIVES

Q. WHAT IS YOUR CONCERN REGARDING APCO'S ASSUMED SERVICE LIVES FOR THE GENERATING ASSETS?

A. APCo's Strategist analysis assumes that the Generating Assets will operate through 2040, at which time the assets will be nearly 70 years old. As stated earlier in my testimony, this assumption conflicts directly with AEP's position in other pending regulatory proceedings in which it has argued that future EPA regulations are likely to force coal units to retire after 50 years of service. The Company's planning retirement dates for most other coal units on its system are in the range of 60 years. (See Exhibit SN-16, Confidential Response to OAG 3-043.) In short, the assumed 70 year service lives of the Generating Assets appears somewhat optimistic for a base case analysis, and assuming this relatively long life serves to inflate forecasted cost savings attributable to the assets by reducing the annual capital recovery for the project and by extending the period over which the assets are forecasted to produce energy cost savings for the APCo system.

Q. HOW WOULD APCO'S FORECAST OF THE COST SAVINGS ARISING FROM THE PROPOSED GENERATING ASSET TRANSFERS BE IMPACTED IF A SHORTER SERVICE LIFE FOR THE UNITS WAS ASSUMED?

A. If the Generating Assets were assumed to retire by 2030 rather than 2040 (i.e., after approximately 60 years of service) the capital cost recovery for the Generating Assets would increase significantly and the forecasted fuel cost savings from the units after 2030 would not occur. Although it would be necessary to re-run Strategist to assess the impact of shortening the assumed service lives of the Generating Assets by approximately 10 years, I have estimated that this change would reduce APCo's forecasted base case cost savings for the proposed asset transfers by approximately $106 million (~8.3%). (See Exhibit SN-17.)

D. <u>TREATMENT OF OFF-SYSTEM SALES MARGINS</u>

Q. WHAT IS THE ISSUE REGARDING THE TREATMENT OF OFF-SYSTEM SALES MARGINS IN APCO'S STRATEGIST ANALYSIS OF THE TRANSFER OF GENERATING ASSETS?

A. APCo's Strategist analysis did not adjust for the fact that the Company retains 25% of off-system sales margins in its Virginia jurisdiction. (See Exhibit SN-18, Response to OAG 8-122.) By including the retained portion of off-system sales margins in the Strategist analysis, APCo has significantly overstated the cost savings to the Company's Virginia customers that would result from acquisition of the Generating Assets, because off-system sales margins are a major component of the cost savings.

Q. WHAT IS THE ESTIMATED IMPACT OF THIS PROBLEM ON APCO'S COST SAVINGS FORECAST FOR THE GENERATING ASSET TRANSFERS?

A. Again, it would be necessary to re-run the Strategist model to precisely quantify the impact of removing the portion of off-system sales margins that APCo retains from the forecasted cost savings for the Generating Assets. However, I have estimated that removing the retained margins from the Strategist analysis would reduce the forecasted cost savings for the Generating Assets by approximately $176 million (~13.8%). (See Confidential Exhibit SN-19.)

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING APCO'S ECONOMIC ANALYSIS OF THE GENERATING ASSETS?

A. APCo has not evaluated true market-based alternatives to the proposed Generating Asset transfers. By failing to solicit offers for capacity and energy as potential alternatives to the Generating Assets, the Company's analysis does not establish that the proposed asset transfers represent the lowest reasonable cost option for serving future capacity and energy requirements of the APCo system. In addition, APCo's Strategist analysis appears to incorporate unreasonably optimistic operating performance and service life assumptions for the Generating Assets, and includes off-system sales margins that are retained by APCo, thereby significantly overstating the forecasted cost savings to customers associated with the proposed asset transfers. Based upon my estimates, it appears that with reasonable adjustments to address these modeling deficiencies, the forecasted base case cost savings attributable to the Generating Asset transfers would be in the range of $365 million on a cumulative present value basis. (See Exhibit SN-4.)

Although this level of savings remains significant, it represents less than 1.3% of the approximately $28.5 billion of total modeled production cost of the APCo system over the Strategist study period. For these reasons, and due to my concerns as detailed above (e.g., risks associated with older coal plants and the Company's proposed system energy supply mix) I have serious concerns regarding whether the proposed asset transfers represent the best choice for serving APCo's future power supply requirements based on the evidence provided by the Company to date in this case.

VIII. MARKET VALUE OF TRANSFERRED ASSETS

Q. WHAT IS THE RELEVANCE OF THE MARKET VALUE OF THE GENERATING ASSETS?

A. It is my understanding that the Commission has historically required that utilities demonstrate that purchases from affiliates occur at "the lower of cost or market value."[3] Moreover, the Commission's Division of Public Utility Accounting has issued standards that a utility should follow when filing an application pursuant to the Affiliates Act. It is my understanding that these standards provide that a utility has the burden of proof to demonstrate that purchases of goods or services from an unregulated affiliate meet the lower of cost or the fair market value standard. These filing standards also provide guidance on the appropriate methods to be used for determining market value for affiliate transactions:

[3] 1997 S.C.C. Ann. Rept. 216, 218, *aff'd sub nom. GTE South Inc. v. AT&T*, 259 Va. 338, 527 S.E.2d 437 (2000).

> The determination of fair market value should be an ongoing process using such methods as competitive bids, appraisals, catalog listings, sales to third parties, and replacement cost of assets. If appraisals are used in determining fair market value, such value should be determined by averaging two or more independent appraisals.

In absence of any market-based valuation of the Generating Assets, it is not possible to determine whether the proposed transfer price (i.e., net book value) meets this affiliate standard.

Q. HAS APCO CONDUCTED ANY ANALYSIS OF THE MARKET VALUE OF THE TRANSFERRED GENERATING ASSETS TO DEMONSTRATE THAT THE PROPOSED TRANSFER PRICE FOR THE ASSETS IS REASONABLE?

A. No. APCo did not conduct competitive bids or appraisals, nor did it provide any analysis of sales to third parties or other evidence to determine the fair market value of the Generating Assets. (See Exhibit SN-20, Responses to OAG 2-013 and OAG 2-015.) The Company asserts that the economic analysis of the transferred assets presented in Exhibit 10 of its application shows that the proposed transfers are the least cost option available to APCo, which the Company believes establishes the reasonableness of the transfer price.

Q. DOES APCO'S ECONOMIC ANALYSIS OF THE TRANSFERRED ASSETS DEMONSTRATE THE REASONABLENESS OF THE TRANSFER PRICE?

A. No. As discussed earlier in my testimony, APCo's economic analysis significantly overstates the potential savings of the Generating Asset transfers. Moreover, the Company's economic analysis of the proposed transferred assets does not fully reflect potential ownership and operating risks that a prospective buyer of the plant would likely consider. For example, the Company's economic analysis assumes that the Mitchell and Amos generating units will operate until they are nearly 70 years old without significant degradation in operating performance and without significant new environmental compliance costs (beyond carbon taxes). While these may be reasonable assumptions for internal planning purposes, it is doubtful that a new owner would ignore these potential risks in determining a proposed purchase price for the assets. It is my understanding that the Commission's affiliate standards require that the price paid by APCo for the proposed transferred Generating Assets be no greater than the market price or that which a non-affiliated party would offer for the assets in an arm's length transaction. The Company's economic analysis of the transfers does not demonstrate that a non-affiliated party would pay net book value for the Generating Assets.

Q. WHAT ADDITIONAL ANALYSIS COULD APCO HAVE UNDERTAKEN TO ESTIMATE THE MARKET VALUE OF THE TRANSFERRED ASSETS?

A. APCo could have solicited purchase offers from third parties to establish the market value of the Generating Assets. The Company also could have evaluated the sale prices for recent sales of other existing coal-fired generating units as a means to estimate the market value of the proposed transferred assets. However, the Company chose not to solicit purchase offers or otherwise attempt to analyze actual market transactions in order to establish the true market value of the Generating Assets. (See Exhibit SN-20.)

Q. ARE YOU AWARE OF ANY EVIDENCE THAT SUGGESTS THAT THE PROPOSED TRANSFER PRICE IS HIGHER THAN THE MARKET VALUE OF THE TRANSFERRED ASSETS?

A. Yes. A recent article published by Electric Power Daily suggests that market values of existing coal plants have been trending downward. (See Exhibit SN-21.) According to information provided by APCo during discovery, other recently reported coal plant sales, although not directly comparable to the Generating Assets at issue in this case, also suggest that the market value of older coal plants is significantly lower than the $700/kW transfer price proposed for the Generating Assets. (See Exhibit SN-21.) While there may be differences between these other plants and the Generating Assets, APCo has not provided any analysis of comparable sales to support the proposed transfer price.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE MARKET VALUE OF THE TRANSFERRED GENERATING ASSETS.

A. APCo has not presented evidence to establish the market value of Generating Assets to demonstrate the reasonableness of the price at which it seeks to acquire such assets from its affiliate Ohio Power. The Company had every opportunity to solicit market offers, which would have eliminated uncertainty that exists regarding the market value of the Generating Assets, but chose not to seek such information. Other recent coal plant sales appear to indicate that market values of existing coal plants may be significantly lower than the $700/kW transfer price proposed by APCo in this case.

IX. WHEELING POWER MERGER

Q. WHAT EVIDENCE HAS APCO PRESENTED TO DEMONSTRATE THE REASONABLENESS OF THE PROPOSED WHEELING POWER MERGER?

A. APCo generally indicates that the proposed Wheeling merger will have a minimal impact on its Virginia jurisdiction cost of service and rates due to the relatively small size of the Wheeling system. (Martin Direct Testimony, page 3.)

Q. DO YOU AGREE WITH APCO THAT THE PROPOSED WHEELING MERGER WOULD HAVE A MINIMAL IMPACT ON ITS VIRGINIA CUSTOMERS?

A. Although I have not examined APCo's Wheeling merger impact calculations in detail, it seems reasonable that the merger would not have a significant impact on APCo's retail rates due to the fact that the Wheeling load represents a relatively small percentage of APCo's total system load. The Wheeling load is located in APCo's West Virginia jurisdiction and therefore should benefit the Company's Virginia jurisdiction customers by increasing the West Virginia jurisdictional allocators, thereby increasing the level of fixed costs that would be assigned to West Virginia (and away from Virginia). Moreover, although approximately one-third of the capacity that APCo proposes to acquire via the Generating Asset transfers would not immediately be necessary to meet APCo system capacity obligations if the Wheeling merger were not implemented, according to the Company's economic analysis, customers are still expected to benefit from the asset transfers even if the Wheeling merger does not occur.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE WHEELING MERGER?

A. The proposed Wheeling merger appears likely to have minimal impact on APCo's retail rates and over time should benefit the Virginia jurisdiction by increasing the assignment of fixed costs to the West Virginia jurisdiction and away from Virginia. For these reasons I do not oppose this merger.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT SN-1

Background and Experience of

Scott Norwood

RESUME OF DON SCOTT NORWOOD

Norwood Energy Consulting, L.L.C.

P. O. Box 30197
Austin, Texas 78755-3197
(512) 343-9077

SUMMARY

Scott Norwood is an energy consultant with over 30 years of experience in electric utility regulatory consulting, resource planning and energy procurement. His clients include government agencies, publicly-owned utilities, public service commissions, municipalities and various electric consumer interests. Mr. Norwood has presented expert testimony on electric restructuring, resource planning and ratemaking issues in regulatory proceedings in Arkansas, Georgia, Iowa, Illinois, Michigan, Missouri, New Jersey, Oklahoma, South Dakota, Texas, Virginia, Washington and Wisconsin.

Prior to founding Norwood Energy Consulting in January of 2004, Mr. Norwood was employed for 18 years by GDS Associates, Inc., a Marietta, Georgia based energy consulting firm. Mr. Norwood was a Principal of GDS and directed the firm's Deregulated Services Department which provided a range of consulting services including merchant plant due diligence studies, deregulated market price forecasts, power supply planning and procurement projects, electric restructuring policy analyses, and studies of power plant dispatch and production costs.

Before joining GDS, Mr. Norwood was employed by the Public Utility Commission of Texas as Manager of Power Plant Engineering from 1984 through 1986. He began his career in 1980 as Staff Electrical Engineer with the City of Austin's Electric Utility Department where he was in charge of electrical maintenance and design projects at three gas-fired power plants.

Mr. Norwood is a graduate of the college of electrical engineering of the University of Texas.

EXPERIENCE

Energy Planning and Procurement Services

Dell Computer Corporation – Negotiated retail power supply agreement for Dell's Round Rock, Texas facilities producing annual savings in excess of $2 million.

Texas Association of School Boards Electric Aggregation Program – Serve as TASB's consultant in the development, marketing and administration of a retail electric aggregation program consisting of 2,500 Texas schools with a total load of over 300 MW. Program produced annual savings of more than $30 million in its first year.

Oklahoma Industrial Energy Consumers - Analyzed and drafted comments addressing integrated resource plan filings by Public Service Company of Oklahoma and Oklahoma Gas and Electric Company.

S.C. Johnson - Analyzed and presented testimony addressing Wisconsin Electric Power Company's $4.1 billion CPCN application to construct three coal-fired generating units in southeast Wisconsin.

Oklahoma Industrial Energy Consumers - Analyzed wind energy project ownership proposals by Oklahoma Gas and Electric Company and presented testimony addressing project economics and operational impacts.

City of Chicago, Illinois Attorney General, Illinois Citizens' Utility Board - Analyzed Commonwealth Edison's proposed divestiture of the Kincaid and State Line power plants to SEI and Dominion Resources.

Georgia Public Service Commission - Analyzed and presented testimony on Georgia Power Company's integrated resource plan in a certification proceeding for an eight unit, 640 MW combustion turbine facility.

South Dakota Public Service Commission - Evaluated integrated resource plan and power plant certification filing of Black Hills Power & Light Company.

Shell Leasing Co. - Evaluated market value of 540 MW western coal-fired power plant.

Community Energy Electric Aggregation Program – Served as Community Energy's consultant in the development, marketing and start-up of a retail electric aggregation program consisting of major charitable organizations and their donors in Texas.

Austin Energy – Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

Austin Energy - Provided technical assistance in the evaluation of the economic viability of the City of Austin's ownership interest in the South Texas Project.

Austin Energy - Assisted with regional production cost modeling analysis to assess production cost savings associated with various public power merger and power pool alternatives.

Sam Rayburn G&T Electric Cooperative - Conducted competitive solicitation for peaking capacity. Developed request for proposal, administered solicitation and evaluated bids.

Rio Grande Electric Cooperative, Inc. - Directed preparation of power supply solicitation and conducted economic and technical analysis of offers.

Electric Restructuring Analyses

Electric Power Research Institute - Evaluated regional resource planning and power market dispatch impacts on rail transportation and coal supply procurement strategies and costs.

Arkansas House of Representatives – Critiqued proposed electric restructuring legislation and identified suggested amendments to provide increased protections for small consumers.

Virginia Legislative Committee on Electric Utility Restructuring – Presented report on status of stranded cost recovery for Virginia's electric utilities.

Georgia Public Service Commission – Developed models and a modeling process for preparing initial estimates of stranded costs for major electric utilities serving the state of Georgia.

City of Houston – Evaluated and recommended adjustments to Reliant Energy's stranded cost proposal before the Public Utility Commission of Texas.

Oklahoma Attorney General – Evaluated and advised the Attorney General on technical, economic and regulatory policy issues arising from various electric restructuring proposals considered by the Oklahoma Electric Restructuring Advisory Committee.

State of Hawaii Department of Business, Economics and Tourism – Evaluated electric restructuring proposals and developed models to assess the potential savings from deregulation of the Oahu power market.

Virginia Attorney General - Served as the Attorney General's consultant and expert witness in the evaluation of electric restructuring legislation, restructuring rulemakings and utility proposals addressing retail pilot programs, stranded costs, rate unbundling, functional separation plans, and competitive metering.

Western Public Power Producers, Inc. - Evaluated operational, cost and regional competitive impacts of the proposed merger of Southwestern Public Service Company and Public Service Company of Colorado.

Iowa Department of Justice, Consumer Advocate Division - Analyzed stranded investment and fuel recover issues resulting from a market-based pricing proposal submitted by MidAmerican Energy Company.

Cullen Weston Pines & Bach/Citizens' Utility Board - Evaluated estimated costs and benefits of the proposed merger of Wisconsin Energy Corporation and Northern States Power Company (Primergy).

City of El Paso - Evaluated merger synergies and plant valuation issues related to the proposed acquisition and merger of El Paso Electric Company and Central & Southwest Company.

Rio Grande Electric Cooperative, Inc. - Analyzed stranded generation investment issues for Central Power & Light Company.

Regulatory Consulting

Oklahoma Industrial Energy Consumers - Assisted client with technical and economic analysis of proposed EPA regulations and compliance plans involving control of air emissions and potential conversion of coal-to-gas conversion options.

New York Public Service Commission - Conducted inter-company statistical benchmarking analysis of Consolidated Edison Company to provide the New York Public Service Commission with guidance in determining areas that should be reviewed in detailed management audit of the company.

Oklahoma Industrial Energy Consumers - Analyzed and presented testimony on affiliate energy trading transactions by AEP in ERCOT.

Georgia Public Service Commission - Presented testimony before the Georgia Public Service Commission in Docket 3840-U, providing recommendations on nuclear O&M levels for Hatch and Vogtle and recommending that a nuclear performance standard be implemented in the State of Georgia.

Oklahoma Industrial Energy Consumers - Analyzed and presented testimony addressing power production and coal plant dispatch issues in fuel prudence cases involving Oklahoma Gas and Electric Company.

Georgia Public Service Commission - Analyzed and provided recommendations regarding the reasonableness of nuclear O&M costs, fossil O&M costs and coal inventory levels reported in GPC's 1990 Surveillance Filing.

New York Public Service Commission - Conducted inter-company statistical benchmarking analysis of Rochester Gas & Electric Company to provide the New York Public Service Commission with guidance in determining areas which should be reviewed in detailed management audit of the company.

Oklahoma Attorney General – Analyzed and presented testimony regarding fuel and purchased power, depreciation and other expense items in Oklahoma Gas & Electric Company's 2001 rate case before the Oklahoma Corporation Commission.

City of Houston - Analyzed and presented testimony regarding fossil plant O&M expense levels in Houston Lighting & Power Company's rate case before the Public Utility Commission of Texas.

City of El Paso - Analyzed and presented testimony regarding regulatory and technical issues related to the Central & Southwest/El Paso Electric Company merger and rate proceedings before the PUCT, including analysis of merger synergy studies, fossil O&M and purchased power margins.

Residential Ratepayer Consortium - Analyzed Fermi 2 replacement power and operating performance issues in 1994 and 1995 fuel reconciliation proceedings for Detroit Edison Company before the Michigan Public Service Commission.

Residential Ratepayer Consortium - Analyzed and prepared testimony addressing coal plant outage rate projections in the Consumer's Power Company fuel proceeding before the Michigan Public Service Commission.

City of El Paso - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1991 rate case before the Public Utility Commission of Texas.

City of Houston - Analyzed and developed testimony regarding the operations and maintenance expenses and performance standards for the South Texas Nuclear Project, and operations and maintenance expenses for the Limestone and Parish coal-fired power plants in HL&P's 1991 rate case before the PUCT.

City of El Paso - Analyzed and developed testimony regarding Palo Verde operations and maintenance expenses in El Paso Electric Company's 1990 rate case before the Public Utility Commission of Texas. Recommendations were adopted.

Power Plant Management

City of Austin Electric Utility Department - Analyzed the 1994 Operating Budget for the South Texas Nuclear Project (STNP) and assisted in the development of long-term performance and expense projections and divestiture strategies for Austin's ownership interest in the STNP.

City of Austin Electric Utility Department - Analyzed and provided recommendations regarding the 1991 capital and O&M budgets for the South Texas Nuclear Project.

Sam Rayburn G&T Electric Cooperative - Developed and conducted operational monitoring program relative to minority owner's interest in Nelson 6 Coal Station operated by Gulf States Utilities.

KAMO Electric Cooperative, City of Brownsville and Oklahoma Municipal Power Agency - Directed an operational audit of the Oklaunion coal-fired power plant.

Sam Rayburn G&T Electric Cooperative - Conducted a management/technical assessment of the Big Cajun II coal-fired power plant in conjunction with ownership feasibility studies for the project.

Kamo Electric Power Cooperative - Developed and conducted operational monitoring program for client's minority interest in GRDA Unit 2 Coal Fired Station.

Northeast Texas Electric Cooperative - Developed and conducted operational monitoring program concerning NTEC's interest in Pirkey Coal Station operated by Southwestern Electric Power Company and Dolet Hills Station operated by Central Louisiana Electric Company.

Corn Belt Electric Cooperative/Central Iowa Power Cooperative - Perform operational monitoring and budget analysis on behalf of co-owners of the Duane Arnold Energy Center.

PRESENTATIONS

Quantifying Impacts of Electric Restructuring: Dynamic Analysis of Power Markets, 1997 NARUC Winter Meetings, Committee on Finance and Technology.

Quantifying Costs and Benefits of Electric Utility Deregulation: Dynamic Analysis of Regional Power Markets, International Association for Energy Economics, 1996 Annual North American Conference.

Railroad Rates and Utility Dispatch Case Studies, 1996 EPRI Fuel Supply Seminar.

Quantifying Potentially Stranded Costs: Modeling and Policy Issues, 1996 NASUCA Annual Meeting.

EXHIBIT SN-2

Estimated Transfer Price of
Generating Assets,
APCo Response to OAG 2-006

Exhibit SN-2

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of
Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Interrogatory OAG 2-006:

Provide details supporting the proposed asset transfer price for the Mitchell and Amos Plants.

Response OAG 2-006:

See OAG 2-006 Attachment 1 for estimates of the 12-31-13 account values, which will be recorded on APCo's books on the transfer date.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

Appalachian Power Company
Determination of Estimated Mitchell Asset Ownership Transfer Cost @ 12/31/2013

Account	Description	Ohio Power Co. Actual 12/31/2011 ($000)	Estimated 2012-2013 Activity (1) ($000)	Estimated 12/31/2013 ($000)
APCo's 50% of Mitchell Plant:				
101-106, 114	Utility Plant	874,397	66,278	940,675
107	Construction Work In Progress	16,372	12,204	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
228	Accumulated Provision for Injuries and Damages	(128)	128	0
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	(3,370)	1,323	(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 -- APCo's 50% of Mitchell Plant	516,168	19,743	535,911

(1) - 2012-2013 Estimated Activity includes actual balances through September 30, 2012 and estimates thereafter.

Appalachian Power Company
Determination of Estimated 66.7% of Amos 3 Asset Ownership Transfer Cost @ 12/31/2013

Account	Description	Ohio Power Co. Actual 12/31/2011 ($000)	Estimated 2012-2013 Activity (1) ($000)	Estimated 12/31/2013 ($000)
66.7% of Amos Unit 3:				
101-106, 114	Utility Plant	1,001,572	23,942	1,025,514
107	Construction Work in Progress	15,344	(228)	15,116
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(194,602)	(53,257)	(247,859)
	Subtotal -- Net Book Value, including CWIP	*822,314*	*(29,543)*	*792,771*
121	Nonutility Property	125	0	125
124	Other Investments	0	0	0
151	Fuel Stock	22,287	9,004	31,291
152	Fuel Stock Undistributed	715	0	715
154	Plant Materials and Operating Supplies	7,354	625	7,979
158.1, 158.2	Allowances	6,141	(1,031)	5,110
186	Miscellaneous Deferred Debits (Property Taxes)	5,026	0	5,026
190	Accumulated Deferred Income Tax	1,931	0	1,931
230	Asset Retirement Obligations	(25,202)	(1,993)	(27,195)
236	Taxes Accrued (Property Taxes)	(5,026)	0	(5,026)
242	Miscellaneous Current and Accrued Liabilities	(660)	0	(660)
282	Accum. Deferred Income Taxes-Other Property	(170,203)	(21,294)	(191,497)
283	Accum. Deferred Income Taxes-Other	(2,149)	0	(2,149)
	TOTAL -- 66.7% of Amos Unit 3	662,654	(44,233)	618,421

(1) - 2012-2013 Estimated Activity includes actual balances through September 30, 2012 and estimates thereafter.

EXHIBIT SN-3

Estimated Revenue Requirement
of Generating Assets

Exhibit SN-3

Estimated Revenue Requirement of Generating Assets
($1000s)

	Generation GWH	Fuel Cost	Total O&M Cost	Ongoing Capital Cost	Transfer Cost	Total Cost	Total Cost $/MWh
2014	9,773	$250,784	$76,330	$85,992	$153,295	$566,400	$58.0
2015	9,240	$241,506	$70,651	$51,023	$153,295	$516,476	$55.9
2016	10,840	$295,299	$66,080	$48,271	$153,295	$562,944	$51.9
2017	10,910	$312,436	$69,465	$108,551	$153,295	$643,746	$59.0
2018	11,254	$329,315	$70,800	$59,141	$153,295	$612,551	$54.4
2019	10,796	$326,406	$72,220	$49,859	$153,295	$601,779	$55.7
2020	11,558	$356,638	$74,458	$45,098	$153,295	$629,490	$54.5
2021	11,008	$347,993	$72,316	$59,214	$153,295	$632,818	$57.5
2022	8,432	$283,390	$76,068	$51,095	$153,295	$563,848	$66.9
2023	8,065	$280,297	$77,344	$47,205	$153,295	$558,142	$69.2
2024	7,865	$280,722	$78,646	$48,872	$153,295	$561,535	$71.4
2025	8,630	$316,475	$79,974	$49,489	$153,295	$599,233	$69.4
2026	8,727	$328,620	$81,328	$50,770	$153,295	$614,014	$70.4
2027	7,942	$306,012	$82,710	$51,559	$153,295	$593,575	$74.7
2028	8,086	$319,663	$84,119	$51,675	$153,295	$608,752	$75.3
2029	8,305	$336,830	$85,556	$52,612	$153,295	$628,293	$75.7
2030	8,327	$346,638	$87,022	$53,401	$153,295	$640,356	$76.9
2031	8,433	$359,431	$88,517	$54,226	$153,295	$655,469	$77.7
2032	8,128	$354,599	$90,042	$54,957	$153,295	$652,893	$80.3
2033	7,833	$350,678	$91,598	$55,677	$153,295	$651,248	$83.1
2034	7,936	$363,940	$93,184	$56,522	$153,295	$666,942	$84.0
2035	8,471	$398,634	$94,803	$57,349	$153,295	$704,080	$83.1
2036	8,226	$394,597	$96,453	$31,920	$153,295	$676,265	$82.2
2037	7,835	$382,208	$98,137	$21,573	$153,295	$655,213	$83.6
2038	8,254	$410,019	$99,854	$11,614	$153,295	$674,783	$81.8
2039	7,944	$402,458	$101,606	$4,503	$0	$508,567	$64.0
2040	8,390	$433,403	$103,393	$0	$0	$536,796	$64.0
						$16,516,206	

Sources are APCo's responses to OAG 3-59 and OAG 3-62.

EXHIBIT SN-4

Adjustments to Cost Benefit Analysis of Generating Assets

Exhibit SN-4

Summary of Adjustments to APCo's Cost/Benefit
Analysis of Generating Assets
($1000s)

		Source
Reduct CCCT Cost by 20%	$453,352	Exh SN-14
Adjust Coal Performance to 64%	$175,982	Exh SN-15
Exclude Retained OSS Margins	$175,640	Exh SN-19
Adjust Coal Lives to 2030 (~60yrs)	$106,287	Exh SN-17
Total Adjustment	$911,262	
Total Forecasted Savings	$1,275,968	APCo Exh 10, Fig 2-1
Total Adjustment,%	71.4%	
Adjusted Savings	$364,707	
CumPV Total Production Savings	28,493,719	APCo Exh 10, Fig 2-1
	1.3%	

EXHIBIT SN-5

Historical and Forecasted Peak Demand of APCo System APCo Response to OAG 2-020

Exhibit SN-5

Historical and Forecasted Peak Demand of the APCo System

	Forecasted Peak Dem, MW	%Change/yr
2002	5,703	
2003	5,657	-0.8%
2004	5,508	-2.6%
2005	5,953	8.1%
2006	6,395	7.4%
2007	6,755	5.6%
2008	6,542	-3.2%
2009	5,786	-11.6%
2010	6,200	7.2%
2011	6,288	1.4%
2012	6,391	1.6%
2013	5,668	-11.3%
2014	6,202	9.4%
2015	6,318	1.9%
2016	6,256	-1.0%
2017	6,229	-0.4%
2018	6,254	0.4%
2019	6,280	0.4%
2020	6,288	0.1%
2021	6,332	0.7%
2022	6,366	0.5%
2023	6,376	0.2%
2024	6,401	0.4%
2025	6,457	0.9%
2026	6,505	0.7%
2027	6,555	0.8%
2028	6,594	0.6%
2029	6,636	0.6%
2030	6,690	0.8%
2031	6,743	0.8%
2032	6,781	0.6%
2033	6,845	0.9%
2034	6,875	0.4%
2035	6,929	0.8%
2036	6,947	0.3%
2037	7,015	1.0%
2038	7,054	0.6%
2039	7,093	0.6%
2040	7,066	-0.4%
2015-2040		0.5%
2003-2012		1.3%

Exhibit SN-5

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of
Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Interrogatory OAG 2-020:

Provide the Company's peak demand and energy sales for each of the last ten calendar years and as forecasted for each year of the economic analysis supporting the proposed asset transfers.

Response OAG 2-020:

The Company's summer peak demand and energy sales for each of the last ten calendar years is below.

Appalachian Power Company
Internal Energy Requirements (MWh)
and Summer Internal Peak Demand (MW)

Year	Energy Requirements	Summer Peak Demand
2002	34,219,515	5,703
2003	33,670,955	5,657
2004	34,417,382	5,508
2005	35,693,094	5,953
2006	38,384,837	6,395
2007	40,345,291	6,755
2008	40,694,984	6,542
2009	36,577,252	5,786
2010	38,636,106	6,200
2011	37,046,109	6,211
2012	35,813,299	6,391

The data used in the analysis is based on the forecasted summer (PJM) peak.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production
of Documents by the OAG of the
State Corporation Commission (Second Set)
To Appalachian Power Company

Response OAG 2-020 (Cont.):

The data used in the analysis is based on the forecasted summer (PJM) peak.

Appalachian Power Company
Internal Energy Requirements (MWh)
and PJM Summer Internal Peak Demand (MW)

Year	Energy Requirements	PJM Summer Peak Demand
2013	35,834,200	5,668
2014	39,261,590	6,202
2015	39,404,730	6,318
2016	39,527,650	6,256
2017	39,582,740	6,229
2018	39,678,620	6,254
2019	39,810,180	6,280
2020	39,955,620	6,288
2021	40,143,940	6,332
2022	40,339,860	6,366
2023	40,549,480	6,376
2024	40,773,850	6,401
2025	40,979,650	6,457
2026	41,239,700	6,505
2027	41,497,730	6,555
2028	41,765,450	6,594
2029	42,013,700	6,636
2030	42,279,400	6,690
2031	42,543,720	6,743
2032	42,808,680	6,781
2033	43,042,460	6,845
2034	43,271,600	6,875
2035	43,495,410	6,929
2036	43,704,270	6,947
2037	43,897,290	7,015
2038	44,061,100	7,054
2039	44,206,400	7,093
2040	44,337,090	7,066

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-6

Forecasted Peak Demand of

Wheeling Power System

APCo Response to OAG 8-125

Exhibit SN-6

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Eighth Set)
To Appalachian Power Company

Interrogatory OAG 8-125:

Refer to the Company's response to OAG 2-031. Provide the peak demand and energy associated of Wheeling Power Company included in each year of each case and scenario provided with this response.

Response OAG 8-125:

The same peak and energy values were used in each case and scenario.

	Wheeling Power Company	
	Peak Demand MW	Energy GWh
2011	0	0
2012	0	0
2013	0	0
2014	475	3,338
2015	478	3,362
2016	479	3,380
2017	481	3,384
2018	482	3,385
2019	482	3,391
2020	481	3,399
2021	484	3,412
2022	485	3,423
2023	487	3,433
2024	488	3,445
2025	491	3,456
2026	492	3,470
2027	493	3,483
2028	494	3,498
2029	498	3,512
2030	500	3,527
2031	501	3,541
2032	500	3,554
2033	503	3,565
2034	506	3,573
2035	506	3,582
2036	505	3,589
2037	507	3,595
2038	507	3,599
2039	507	3,604
2040	508	3,611

The foregoing response is made by John F. Torpey, Director-Integrated Resource Planning, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-7

Forecasted Cost Savings Without Wheeling Merger

APCo Supplemental Response to OAG 8-161

Exhibit SN-7

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the Staff of the State Corporation Commission (Eighth Set) To Appalachian Power Company

Interrogatory Staff 08-161:

Please provide a revised "Comparable Analysis of Resource Portfolios," which is set forth in Schedule 10 of the Application, assuming that the Wheeling transfer does not occur. Such analysis should adjust market purchases and or sales consistent with the removal of the Wheeling load.

Response Staff 08-161:

No such analysis has been performed.

SUPPLEMENTAL RESPONSE 04.09.13

Please see Supplemental Attachment 1 on the enclosed CD for the requested information.

The foregoing response is made by John F. Torpey, Director-Integrated Resource Planning, on behalf of Appalachian Power Company, Inc.

Exhibit SN-7

PUE 2012-00141
Staff 08-161
Supplemental Attachment 1

APCo IRP with No Wheeling Load
BASE Commodity Pricing
Expansion Plan Summary

Case:	Proposed Asset Transfer	Reduced Asset Transfer	Market	Optimization	AM3 Transfer	ML1 Transfer
2011						
2012						
2013						
2014	867- AM3 , 385- ML ,1 -395 ML2,	867 MW AM3, 308 MW ML1 ,			867 MW AM3,	308 MW ML1 ,
2015			736 MW ICAP	736 MW ICAP		445 MW ICAP
2016			818 MW ICAP	818 MW ICAP		530 MW ICAP
2017			782 MW ICAP	782 MW ICAP		492 MW ICAP
2018			815 MW ICAP	12 -85 MW CT's,		8 -85 MW CT's,
2019			810 MW ICAP			
2020			827 MW ICAP			
2021			879 MW ICAP		1- 384 MW CC,	
2022			922 MW ICAP			
2023			927 MW ICAP			
2024			959 MW ICAP			4 -85 MW CT's,
2025		1- 384 MW CC,	20 -85 MW CT's,	8 -85 MW CT's,	1- 384 MW CC,	4 -85 MW CT's,
2026						
2027		1- 384 MW CC,				
2028	4 -85 MW CT's,				1- 384 MW CC,	4 -85 MW CT's,
2029			4 -85 MW CT's,	4 -85 MW CT's,		
2030						
2031						
2032						
2033						
2034		4 -85 MW CT's,				
2035	4 -85 MW CT's,					4 -85 MW CT's,
2036			4 -85 MW CT's,	4 -85 MW CT's,	4 -85 MW CT's,	
2037						
2038						
2039						
2040						
2011- 2040 CPW ($000)						
APCO Production and Capital Cost	26,318,770	26,420,701	26,666,706	27,033,741	26,558,507	26,880,342
Less: Value of ICAP Revenue	486,151	268,739	(336,216)	(20,613)	191,040	43,187
Total APCO Revenue Requirement, Net	25,832,619	26,151,961	27,002,922	27,054,355	26,367,467	26,837,155
Cost/ <Savings> Over Full Asset Transfer	-	101,931	347,936	714,972	239,737	561,572
APCO Production and Capital Cost	-	(217,411)	(822,367)	(506,764)	(295,110)	(442,963)
Less: Value of ICAP Revenue	-	319,342	1,170,303	1,221,736	534,847	1,004,536
Total APCO Revenue Requirement, Net	-					
Cost/ <Savings> Over Asset Transfer						
APCO Production and Capital Cost		-	246,005	613,041	137,806	459,642
Less: Value of ICAP Revenue		-	(604,955)	(289,353)	(77,699)	(225,552)
Total APCO Revenue Requirement, Net		-	850,961	902,394	215,505	685,194

EXHIBIT SN-8

APCo Response to OAG 2-033

Exhibit SN-8

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Interrogatory OAG 2-033:

Provide testimony by AEP in other jurisdictions addressing the potential risk and cost of future EPA regulations on existing AEP coal fired power plants.

Response OAG 2-033:

Engineering studies are not typically performed to assess the physical condition, or the likely useful remaining life, of the generating assets of AEP's operating companies. AEP operating companies, including APCo, do monitor the major components of their generating units, and utilize preventative and predictive maintenance, consistent with good utility practice, to replace or repair equipment as necessary. The Company has on-going experience with the physical condition of Amos 3 and its likely useful remaining life, as it owns 33.33% of the 1300 MW unit and has operated it for many years. Similarly, because the Mitchell units are of the same 800 MW series as Amos Units 1 and 2, and because its Vice President of Generating Assets was previously responsible for the Mitchell Plant, the Company is familiar with the physical condition of Mitchell Units 1 and 2 and their likely useful remaining useful life. Given these circumstances, no engineering studies were performed by or for APCo to assess the physical condition or likely remaining lives of the Mitchell units or Amos 3.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-9

Industry Average Performance Statistics for Coal Plants

2006-2010 Generating Unit Statistical Brochure -- Units Reporting Events

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	ART	SR	NCF	NOF	SF	AF	EAF	FOR	EFOR
FOSSIL	All Sizes	1,437	6,694.75	298.84	97.38	54.74	78.88	62.30	86.56	84.19	6.75	8.83
All Fuel Types	1-99	334	1,456.58	219.86	98.85	32.96	69.25	44.92	87.51	85.40	11.68	13.88
	100-199	371	1,746.50	287.41	97.59	43.38	70.51	60.37	87.69	85.08	5.92	8.04
	200-299	175	823.58	321.57	97.78	52.26	74.82	69.67	85.88	83.17	6.17	8.08
	300-399	124	587.92	274.76	97.75	44.91	70.73	63.85	87.20	85.03	4.49	6.66
	400-599	226	1,083.42	263.73	95.83	53.01	76.71	69.00	84.66	82.23	6.18	8.55
	600-799	143	682.58	525.54	96.55	64.50	85.05	76.49	84.95	82.72	5.95	7.82
	800-999	52	249.17	666.33	96.29	63.46	86.12	73.32	87.83	86.21	3.61	4.91
	1000 Plus	13	65.00	803.30	93.60	72.14	88.89	80.38	82.87	79.90	8.16	9.89
Coal	All Sizes	921	4,313.17	484.09	96.63	69.35	84.10	78.14	86.60	83.61	5.66	7.85
Primary	1-99	173	736.92	257.93	98.72	48.60	72.60	64.19	86.50	83.90	9.40	11.81
	100-199	244	1,160.08	509.50	96.29	58.28	75.68	76.28	88.06	84.56	4.84	7.14
	200-299	121	580.42	602.63	97.35	65.78	80.99	81.03	86.51	83.07	5.21	7.34
	300-399	69	334.33	606.48	96.62	68.94	80.96	84.97	87.46	84.37	4.45	6.76
	400-599	152	721.00	468.33	94.20	69.22	83.79	82.51	84.82	81.86	5.66	8.18
	600-799	116	552.00	710.85	96.11	73.35	86.90	84.57	85.60	83.25	4.97	6.69
	800-999	35	168.42	923.29	96.01	78.34	90.72	86.27	87.41	85.92	3.53	4.53
	1000 Plus	12	60.00	834.96	93.11	75.94	90.67	83.64	84.20	81.21	6.76	8.39
Gas	All Sizes	408	1,760.75	84.96	98.13	12.73	37.41	29.00	87.01	86.12	11.69	12.88
Primary	1-99	123	509.17	95.02	99.08	8.20	47.53	15.25	89.59	88.78	23.48	23.79
	100-199	111	483.92	81.52	98.91	11.62	38.80	29.28	87.03	86.29	11.45	12.52
	200-299	45	196.00	93.61	98.07	17.06	38.98	43.37	85.60	84.71	7.55	8.56
	300-399	43	185.75	79.93	98.31	11.26	33.13	33.98	87.58	86.60	5.52	7.19
	400-599	63	288.17	71.88	97.05	13.23	36.49	37.35	83.58	82.46	10.00	11.73
	600-799	14	55.25	97.32	96.03	9.59	35.76	27.03	81.55	80.54	14.64	17.10
	800-999	9	42.50	225.06	97.34	16.56	40.81	40.37	90.42	89.32	2.90	3.76
Lignite Primary	All Sizes	24	99.00	734.86	97.71	80.87	90.48	89.28	89.61	85.76	3.50	6.46
NUCLEAR	All Sizes	113	505.50	3,631.03	98.19	89.59	99.04	90.26	90.32	88.79	2.34	2.96
All Types	400-799	24	81.50	3,834.69	99.49	85.65	98.08	87.47	87.73	85.66	2.92	3.75
	800-999	38	170.00	3,933.68	97.13	90.47	99.30	91.11	91.11	89.86	2.24	2.77
	1000 Plus	51	254.00	3,406.55	98.31	89.78	99.07	90.56	90.60	89.05	2.23	2.84
PWR	All Sizes	66	316.50	3,678.29	98.62	90.01	99.76	90.23	90.33	89.20	2.52	3.00
	400-799	9	38.50	4,177.19	98.96	89.97	99.59	90.57	91.10	89.79	2.05	2.39
	800-999	23	109.00	4,017.57	97.52	90.20	99.89	90.30	90.30	89.37	2.59	3.02
	1000 Plus	34	169.00	3,389.62	99.57	89.92	99.71	90.11	90.17	88.95	2.59	3.12
BWR	All Sizes	33	164.00	3,565.61	97.01	90.22	97.86	92.35	92.35	90.23	1.49	2.27
	400-799	5	25.00	3,564.13	100.00	91.74	97.22	94.34	94.34	92.02	1.54	2.62
	800-999	11	54.00	3,784.24	95.98	91.17	98.23	92.83	92.83	90.91	1.41	2.09
	1000 Plus	17	85.00	3,425.51	97.10	89.50	97.78	91.45	91.45	89.26	1.53	2.28
GAS TURBINE**	All Sizes	975	4,457.33	5.03	97.57	2.53	70.42	2.50	91.90	89.96	58.57	57.05
	1-19	185	824.08	5.98	94.20	0.84	76.81	1.13	89.60	87.25	83.93	82.80
	20-49	251	1,179.42	3.35	97.37	1.31	60.30	1.48	91.71	89.13	76.11	71.96
	50 Plus	539	2,453.83	5.51	97.99	2.79	71.09	3.45	92.77	91.26	39.79	39.24
COMB. CYCLE (BLOCK REPORTED UNITS ONLY	All Sizes	187	760.67	47.03	98.73	37.40	74.16	43.11	89.50	87.17	5.71	7.46

Source: www.nerc.com.

EXHIBIT SN-10

PSO Testimony on Coal Unit Service Lives/ Future Environmental Risk

Excerpt - Pages 1, 45

BEFORE THE
CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR COMMISSION AUTHORIZATION OF A PLAN AND COST RECOVERY OF ACTIONS OF PSO TO BE IN COMPLIANCE WITH CERTAIN ENVIRONMENTAL RULES PROMULGATED BY THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; SUCH ACTIVITIES TO INCLUDE, BUT NOT BE LIMITED TO, CAPITAL EXPENDITURES FOR EQUIPMENT AND FACILITIES; CONSTRUCTION OR PURCHASE OF AN ELECTRIC GENERATING FACILITY OR ENTER INTO A LONG-TERM PURCHASE POWER CONTRACT (AND POSSIBLE EARNING ON THE CONTRACT); CHANGE IN DEPRECIATION RATES AND/OR ESTABLISHMENT AND RECOVERY OF A REGULATORY ASSET; AND FOR SUCH OTHER RELIEF AS THE COMMISSION DEEMS PSO IS ENTITLED.	) CAUSE No. PUD 201200054

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OF OKLAHOMA

DIRECT TESTIMONY OF

SCOTT C. WEAVER

ON BEHALF OF

PUBLIC SERVICE COMPANY OF OKLAHOMA

SEPTEMBER 26, 2012

By virtue of the fact that the future retirement and replacement of these retrofit options were effectively delayed by ten years, the relative study period CPW of the alternatives' cost differences identified on the bottom section of Exhibit SCW-6, would naturally then more significantly favor a full retrofit solution (Option 1A). Specifically, each of the options analyzed would then be more costly over the study period than that Option 1A under both BASE long-term commodity pricing, as well as under a Lower Band pricing scenario. However, in spite of this (retrofit) recovery period change, the difference between Option 2A and Option 1A (25-year) DFGD sensitivity views themselves continued to be limited to a relative smaller range of $128 million (1.0 percent)—under BASE pricing—to $37 million (0.3 percent)—under Lower Band pricing.

Q. **WHY WAS SUCH A 25-YEAR RECOVERY PERIOD CONSIDERED FOR PURPOSES OF SUCH SENSITIVITY ANALYTICS?**

A. It was deemed reasonable to assume that the expected service life of either Northeastern Unit 3 or 4 could achieve a period approaching or exceeding 60 years; or through the 2040 Strategist® study period. Hence, a 25-year post-retrofit service period was viewed as a very plausible operational and cost recovery timeframe for purposes of performing these sensitivity analytics. However, consideration had also been given by PSO management to the prospect that any further environmental regulation in the future could portend some additional operational risk to coal generation. Therefore, the base disposition options were assumed to reflect a 15-year post-retrofit recovery period that would, instead, approach the unit's 50 year service lives.

EXHIBIT SN-11

Carbon Tax Forecast

APCo Response to OAG 3-057

Exhibit SN-11

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Third Set)
To Appalachian Power Company

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INSURANCE AND UTILITIES

Interrogatory OAG 3-057:

Refer to the response to OAG 2-025. Explain why the same carbon price forecast was used for each asset transfer scenario evaluated.

Response OAG 3-057:

It was the Company's modeling approach to assign a "proxy" tax on each unit of CO_2 produced, and that these values are likely to be the same regardless of a high or low fossil fuel price environment.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-12

APCo Responses to

OAG 2-16 and OAG 2-018

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Exhibit SN-12

Interrogatory OAG 2-016:

Identify potential existing generation acquisition options that were considered by the Company as possible alternatives to the proposed asset transfers.

Response OAG 2-016:

The Company did not identify potential existing generation acquisition alternatives for consideration in its long-term capacity and energy needs analysis. Rather, the Company considered a portfolio that relied on a forecast of the PJM market for energy and capacity through 2025, which provides a proxy for an existing generator alternative. Exhibit 10 shows that such a portfolio is less optimal (i.e. more costly) than the Asset Transfer portfolio.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

Exhibit SN-12

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Interrogatory OAG 2-018:

Identify third parties contacted by the Company to determine potential interest in supplying the capacity and energy requirements that will be provided by the proposed Mitchell and Amos asset transfers.

Response OAG 2-018:

The Company did not contact third parties to determine potential interest in supplying the capacity and energy requirements identified in Exhibit 10 to the Company's Application. Rather, the Company considered a portfolio that relied on a forecast of the PJM market for energy and capacity through 2025, which provides a proxy for such expected third party interest. Exhibit 10 shows that such a portfolio is less optimal (i.e. more costly) than the Asset Transfer portfolio.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-13

AEP Press Release on Waterford Plant Acquisition

AEP completes purchase of Waterford plant from PSEG
Planned acquisition part of broad strategy to keep pace with load growth

COLUMBUS, Ohio, Sept. 28, 2005 – American Electric Power (NYSE: AEP), through its Columbus Southern Power utility subsidiary, has completed the purchase of the Waterford Energy Center from an affiliate of Public Service Enterprise Group (NYSE: PEG) for approximately $220 million. The acquisition will have no material impact on AEP's earnings.

The Waterford Energy Center is a natural gas-fired, combined-cycle power plant, located in southeastern Ohio, with nominal generating capacity of 821 megawatts. The plant began commercial operation in August 2003.

AEP announced the purchase of Waterford May 27 as part of the company's broad strategy to meet the growing electricity needs of customers in its eastern service area. AEP will operate Waterford as part of the company's generating pool that provides power to AEP's utility units serving customers in Ohio, Indiana, Kentucky, Michigan, Tennessee, Virginia and West Virginia. The capacity of the Waterford Plant will help AEP meet annual demand growth of approximately 2 percent in these states and maintain the 15 percent reserve margin required by the PJM Interconnection to ensure reliability.

"Our overall capacity growth plan includes the construction of new plants, like the clean-coal Integrated Gasification Combined Cycle generation projects we are pursuing, and -- if the price is right -- the acquisition of recently completed gas-fired merchant plants in this region," said Michael G. Morris, AEP's chairman, president and chief executive officer. "These natural gas plants seldom operate for long periods of time because of significantly higher natural gas prices and more generation in the market than the owners had forecast, but with a purchase price well below the cost to build a comparable facility, they provide an economical way to ensure that we have the generation we need on days of high electricity demand."

American Electric Power owns more than 36,000 megawatts of generating capacity in the United States and is the nation's largest electricity generator. AEP is also one of the largest electric utilities in the United States, with more than 5 million customers linked to AEP's 11-state electricity transmission and distribution grid. The company is based in Columbus, Ohio.

Source: http://www.aep.com/newsroom/newsreleases

EXHIBIT SN-14

Estimated Reduction in Cost Savings from 20% Reduction in Combined Cycle Capital Cost

Exhibit SN-14

Estimated Reduction in Cost Savings from
20% Reduction in Combined Cycle Capital Cost
($1000s)

	Forecasted CCCT Cost, 1647 MW	20% Reduction
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	0	0
2016	0	0
2017	0	0
2018	$346,837	$69,367
2019	$346,837	$69,367
2020	$346,837	$69,367
2021	$346,837	$69,367
2022	$346,837	$69,367
2023	$346,837	$69,367
2024	$346,837	$69,367
2025	$346,837	$69,367
2026	$346,837	$69,367
2027	$346,837	$69,367
2028	$346,837	$69,367
2029	$346,837	$69,367
2030	$346,837	$69,367
2031	$346,837	$69,367
2032	$346,837	$69,367
2033	$346,837	$69,367
2034	$346,837	$69,367
2035	$346,837	$69,367
2036	$346,837	$69,367
2037	$346,837	$69,367
2038	$346,837	$69,367
2039	$346,837	$69,367
2040	$346,837	$69,367
NOM TOTAL		$1,595,449
CUMPV 8%		$453,352
Total Savings		$1,275,968
Adjustment,%		35.5%

Source for CCCT capital cost is APCo's Response to OAG 2-031.

EXHIBIT SN-15

CONFIDENTIAL

Estimated Reduction in Cost Savings from Adjusting Generating Asset Capacity Factors

Public Redacted Version –
1 page redacted

Confidential
Exhibit SN-15

Estimated Reduction in Cost Savings from Adjusting Generating Asset Capacity Factors
($1000s)

	Mitchell Unit 1	Mitchell Unit 2	Amos 100% Unit 3	GEN ASSETS GWh	GEN ASSETS CapFac	Adjust GWh to 64% CF	80% of Adj GWh	Market Sales GWh	Mkt Sales Revenue$000	Mkt Sales $/MWH	AVG COAL $/MWH	EST OSS MARGIN	ADJUST MARGINS
2011	[redacted]												
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													

2016-2021 Avg CF [redacted]

NOM
CUMPV
Total Savings
Adjustment,% [redacted]

Sources of Generation and Sales data and average coal cost is APCo's Confidential Response to OAG 7-108.

EXHIBIT SN-16

<u>CONFIDENTIAL</u>

AEP Coal Plant Retirement Dates

APCo Response to OAG 3-043

Public Redacted Version –
1 page redacted

Exhibit SN-16

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of
Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Third Set)
To Appalachian Power Company

Interrogatory OAG 3-043:

Provide the net dependable capacity rating, commercial operation date, planned retirement date, and annual average capacity factors in 2011 and 2012 for each coal-fired generating resource currently owned by AEP operating companies.

Response OAG 3-043:

The response contains confidential and/or competitively sensitive information; and is being provided pursuant to the Hearing Examiner's Ruling dated January 29, 2013.

Please see OAG 3-043 CONFIDENTIAL Attachment 1 for the requested information for the AEP East system.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

Exhibit SN-16

PUE-2012-00141
OAG 3-043
CONFIDENTIAL Attachment 1

Generating Resource	Net Dependable Capacity (MW)	Commercial Operation Date	Retirement Date (For Planning Purposes)	Annual Average Net Capacity Factor MWH (%)	
				2011	2012
Amos 1	[redacted]				
Amos 2	[redacted]				
Amos 3	[redacted]				
Beckjord 6	[redacted]				
Big Sandy 1	[redacted]				
Big Sandy 2	[redacted]				
Cardinal 1	[redacted]				
Clinch River 1	[redacted]				
Clinch River 2	[redacted]				
Clinch River 3	[redacted]				
Conesville 3	[redacted]				
Conesville 4	[redacted]				
Conesville 5	[redacted]				
Conesville 6	[redacted]				
Gavin 1	[redacted]				
Gavin 2	[redacted]				
Glen Lyn 5	[redacted]				
Glen Lyn 6	[redacted]				
Kammer 1	[redacted]				
Kammer 2	[redacted]				
Kammer 3	[redacted]				
Kanawha River 1	[redacted]				
Kanawha River 2	[redacted]				
Mitchell 1	[redacted]				
Mitchell 2	[redacted]				
Mountaineer 1	[redacted]				
Muskingum River 1	[redacted]				
Muskingum River 2	[redacted]				
Muskingum River 3	[redacted]				
Muskingum River 4	[redacted]				
Muskingum River 5	[redacted]				
Picway 5	[redacted]				
Rockport 1	[redacted]				
Rockport 2	[redacted]				
Sporn 1	[redacted]				
Sporn 2	[redacted]				
Sporn 3	[redacted]				
Sporn 4	[redacted]				
Sporn 5	[redacted]				
Stuart 1	[redacted]				
Stuart 2	[redacted]				
Stuart 3	[redacted]				
Stuart 4	[redacted]				
Tanners Creek 1	[redacted]				
Tanners Creek 2	[redacted]				
Tanners Creek 3	[redacted]				
Tanners Creek 4	[redacted]				
Zimmer 1	[redacted]				

EXHIBIT SN-17

Estimated Reduction in Cost Savings from Adjusting Generating Asset Lives to 60 Years

Estimated Reduction in Cost Savings from Adjusting Generating Asset Lives to 60 Years
($1000s)

	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts Carrying Charges (E)	Incremental Fixed & Var Costs (F)	Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)
2011	0	0	0	0	0	0	0	0	0	0	0	0	$0
2012	0	0	0	0	0	0	0	0	0	0	0	0	$0
2013	0	0	0	0	0	0	0	0	0	0	0	0	$0
2014	(234,805)	0	(477,485)	242,680	(153,295)	(107,790)	(261,085)	(18,404)	(12,338)	(30,743)	(49,163)	18,420	$14,598
2015	(229,171)	0	(468,328)	239,157	(153,295)	(109,261)	(262,556)	(23,400)	(4,978)	(28,377)	(124,251)	95,874	$84,912
2016	(284,558)	0	(602,492)	317,934	(153,295)	(127,480)	(280,775)	37,159	(2,953)	34,206	(162,148)	196,354	$218,176
2017	(303,049)	0	(603,215)	300,166	(153,295)	(130,797)	(284,092)	16,074	(1,628)	14,446	(135,836)	150,282	$312,564
2018	(150,756)	0	(384,927)	234,171	92,187	(109,438)	(17,251)	216,920	(652)	216,268	(13,786)	230,053	$446,277
2019	(144,220)	0	(365,850)	221,630	92,187	(123,307)	(31,120)	190,510	(642)	189,868	(15,446)	205,314	$556,710
2020	(169,606)	0	(411,055)	241,449	92,187	(134,568)	(42,382)	199,067	0	199,067	(17,431)	216,499	$664,474
2021	(149,143)	0	(382,279)	233,136	137,287	(126,466)	10,821	243,957	0	243,957	14,355	229,602	$770,235
2022	(74,650)	0	(315,345)	240,695	137,287	(122,665)	14,622	255,317	(85,982)	169,335	15,592	153,743	$835,771
2023	(86,274)	0	(338,645)	252,370	137,287	(129,723)	7,564	259,934	(89,467)	170,467	16,698	153,769	$896,429
2024	(85,016)	0	(339,735)	254,719	137,287	(135,815)	1,472	256,191	(89,159)	167,033	17,665	149,368	$950,956
2025	(238,551)	0	(626,712)	388,160	(5,165)	(165,714)	(170,879)	217,281	(118,149)	99,132	(34,996)	134,128	$996,268
2026	(251,088)	0	(648,244)	397,156	(5,165)	(173,789)	(178,954)	218,202	(120,949)	97,254	(36,257)	133,511	$1,038,007
2027	(221,268)	0	(589,276)	368,008	47,139	(170,343)	(123,204)	244,804	(110,792)	134,012	8,819	125,194	$1,074,226
2028	(228,773)	0	(610,404)	381,631	47,139	(178,263)	(131,124)	250,507	(113,920)	136,587	8,970	127,617	$1,108,393
2029	(247,298)	0	(643,798)	396,500	47,139	(187,391)	(140,252)	256,248	(118,718)	137,530	9,036	128,495	$1,140,229
2030	(250,155)	0	(656,735)	406,580	47,139	(195,326)	(148,187)	258,394	(120,924)	137,470	9,016	128,454	$\boxed{\$1,169,681}$
2031	(260,623)	0	(677,852)	417,229	47,139	(203,767)	(156,628)	260,601	(123,913)	136,688	9,082	127,606	$1,196,756
2032	(276,695)	0	(676,288)	399,592	(12,037)	(217,495)	(229,532)	170,060	(120,883)	49,178	(38,614)	87,792	$1,213,994
2033	(251,356)	0	(644,412)	393,057	48,619	(216,212)	(167,593)	225,464	(116,560)	108,904	9,213	99,691	$1,232,109
2034	(252,663)	0	(650,867)	398,204	48,619	(224,022)	(175,403)	222,800	(118,068)	104,732	9,279	95,453	$1,248,160
2035	(278,490)	0	(707,104)	428,614	48,619	(236,361)	(187,742)	240,872	(128,366)	112,506	9,344	103,161	$1,264,213
2036	(270,223)	0	(695,234)	425,011	48,619	(241,452)	(192,833)	232,178	(125,483)	106,695	9,413	97,282	$1,278,222
2037	(244,136)	0	(651,666)	407,530	48,619	(241,604)	(192,985)	214,545	(119,348)	95,197	9,482	85,715	$1,289,644
2038	(255,526)	0	(691,753)	436,227	48,619	(248,368)	(199,749)	236,477	(126,359)	110,118	9,548	100,570	$1,302,047
2039	(290,390)	0	(730,616)	440,226	131,570	(255,113)	(123,543)	316,683	(127,253)	189,430	(40,597)	230,027	$1,328,299
2040	(309,712)	0	(776,768)	467,056	131,570	(999,108)	(867,538)	(400,482)	(135,904)	(536,386)	(40,888)	(495,497)	$\boxed{\$1,175,968}$
													$106,287
													8.3%

Source is APCo's Response to OAG 2-031. Amounts represent difference between Asset Transfer and Optimization Portfolios for base case scenario.

EXHIBIT SN-18

OSS Margins

APCo Response to OAG 8-122

Exhibit SN-18

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Eighth Set)
To Appalachian Power Company

Interrogatory OAG 8-122:

Refer to the Company's response to OAG 2-031. Provide the forecasted off-system sales margins for each year of the analysis of the Asset Transfer case and each of the other four cases evaluated under the base commodity price scenario and indicate whether the forecasted total costs of each case were adjusted to account for the off-system sales margins retained by APCO in Virginia and other jurisdictions. If not, explain why not and provide the portion of off-system sales that would be retained by APCO in each jurisdiction under current approved margin sharing provisions for each year of the analysis.

Response OAG 8-122:

The Strategist model does not calculate off-system sales margins; however, sales net of purchases are shown on the various portfolio tabs in the "Market Revenue/(Cost) column. The Company retains 25% of off-system sales margins in Virginia, and no off-system sales margins in West Virginia.

The foregoing response is made by John F. Torpey, Director-Integrated Resource Planning, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-19

CONFIDENTIAL

Estimated Reduction in Cost Savings

Due to Exclusion of Retained Margins

Public Redacted Version –
1 page redacted

Confidential
Exhibit SN-19

Estimated Reduction in Cost Savings due to Exclusion of Retained Margins
($1000s)

	Energy Sales GWh	Energy Sales Revenue	Energy Sales $/MWH	AVG COAL $/MWH	Energy Sales Margin, $/MWh	GWH Chg in Mkt Sales	Forecasted Margins	APCO Retained Margins, 25%
2011	[redacted]							
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								
2022								
2023								
2024								
2025								
2026								
2027								
2028								
2029								
2030								
2031								
2032								
2033								
2034								
2035								
2036								
2037								
2038								
2039								
2040								
							Adjustment	
							Total Savings	
							Adjustment,%	

Sources of Generation and Sales data and average coal cost is APCo's Confidential Response to OAG 7-108.

EXHIBIT SN-20

APCO Responses to OAG 2-013 and OAG 2-015

Exhibit SN-20

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Interrogatory OAG 2-013:

Provide any analysis of the market value of the Mitchell and Amos generating assets, which has been conducted to support the reasonableness of the asset transfer price.

Response OAG 2-013:

The Company has not performed any market value analysis of Mitchell and Amos to support the reasonableness of the transfer of those generating assets to APCo at net book value. However, please refer to Exhibit 10 of APCo's Application, which shows that the proposed transfer is the least cost option available to APCo and its customers as part of a long-term integrated resource plan.

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

Exhibit SN-20

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Second Set)
To Appalachian Power Company

Interrogatory OAG 2-015:

Provide documentation of any third party offers to purchase the transferred Mitchell and Amos generating assets solicited by the Company in order to establish the reasonableness of the proposed transfer price.

Response OAG 2-015:

No such third party offers for the Mitchell and the Amos unit 3 plants have been solicited by the Company.

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The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc.

EXHIBIT SN-21

Information on Coal Plant Sales: APCo Response to OAG 3-046 and Electric Power Daily Article

Exhibit SN-21

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF APPALACHIAN POWER
SCC CASE NO. PUE-2012-00141
Interrogatories and Requests for the Production of Documents by the DIVISION OF CONSUMER COUNSEL
Office of the Attorney General (Third Set)
To Appalachian Power Company

Interrogatory OAG 3-046:

Identify any other sales of coal-fired generating assets which have occurred during the last five calendar years, along with the reported sale price, MW rating and age of such generating assets.

Response OAG 3-046:

Please see the following table for available information:

Name of Asset	Sale Year	Seller	Price ($MM)	Capacity (MW)	First unit in service year
Danskammer	2012	Dynegy Inc	$3.5	501	1959
Herbert A Wagner	2012	Exelon Corp	$400.0	977	1956
C P Crane	2012	Exelon Corp		399	1961
Brandon Shores	2012	Exelon Corp		1,273	1984
Four Corners	2012	Southern California Edison Co	$294.0	720	1963
Westwood generating	2012	Integrys Energy Group	$6.2	36	1987
Escanaba	2012	Escanaba Municipal Electric Utility	$1.0	46	1958
AES Somerset LLC	2012	AES Corp	$240.0	685	1951
AES Cayuga	2012	AES Corp		313	1955
Salem Harbor	2012	Dominion Resources Inc	NA	587	1952
AES Thames	2011	AES Corp	$2.0	181	1989
Walter Scott Jr Energy Center	2011	Pella Municipal Light & Power	$24.6	11	1954
Roxboro	2011	Capital Pwr Income L.P.	$123.0	56	1987
Southport	2011	Capital Pwr Income L.P.		107	1987
Wygen III	2010	Black Hills Power Inc	$66.0	25	2010
Wygen I	2009	Black Hills Power Inc	$51.0	21	2003
Edgewater (WI)	2009	Wisconsin Elec Pwr Co	$38.0	95	1951
Wygen III	2008	Black Hills Power Inc	$64.0	25	2010
Wabash River	2008	Duke Energy Indiana	$123.0	290	1953

The foregoing response is made by William A. Bosta, Director Regulatory Services, on behalf of Appalachian Power Company, Inc..

Exhibit SN-21

platts

www.platts.com

Electric Power Daily

Friday, March 15, 2013

Dynegy to acquire Ameren merchant coal plants at fire-sale price

Dynegy will assume ownership of Ameren's merchant coal assets and energy marketing businesses late this year and Ameren will immediately start seeking a buyer for its three merchant natural gas units under a largely cash-free deal unveiled Thursday. But one analyst thinks the agreement may be undone by market power concerns.

Executives at Houston-based Dynegy said in a conference call that the agreement to acquire Ameren Energy Resources' 4,119 MW of coal-fired capacity in Illinois — plus AER's wholesale and retail energy marketing businesses — through the assumption of $825 million in debt offers Dynegy the opportunity to benefit handsomely from increases in natural gas prices and from power-supply tightening in the Midwest Independent Transmission System Operator and the PJM Interconnection.

And, by "ring-fencing" or cordoning off the assets Dynegy is acquiring from Ameren in a newly formed, non-recourse subsidiary called Illinois Power Holdings,

(continued on page 7)

Iowa bill aims to boost small wind farms with feed-in tariff

Legislation introduced in Iowa could result in 60 MW a year of wind energy built on farmland and sold to utilities through a feed-in tariff. However, the state's utilities oppose the mesaure.

State Senator Joe Seng, Democratic chairman of the Agriculture Committee, last week introduced S.F. 372, which would allow wind projects up to 20 MW to be built on farmland and mandate that it be purchased by utilities. "It would open the door for small producers to be a part of meeting the energy needs of the state," Seng said Wednesday.

Utilities would be obligated to purchase an amount of energy from the small projects that equals 50% of the increase in the utility's retail sales growth during the previous year. That requirement means utilities would have to meet growing demand with power from the smaller-generation projects before they consider building large fossil or nuclear plants, Seng said.

Developers would be required to sell the power from the small wind projects

(continued on page 9)

LG&E/KU respond to PSC staff report on IRP; will weigh CO2

Kentucky's largest electric utilities, Louisville Gas & Electric and Kentucky Utilities, will tell the Public Service Commission how their heavily coal-fired generation fleets will comply with government environmental rules, including potential carbon dioxide regulations, as well as provide an updated analysis of their planning reserve margin in their next integrated resource plan, a company spokeswoman said Thursday.

"We will strive to follow the commission's suggestions and will follow the staff's suggested guidelines in the next IRP," Liz Pratt, spokeswoman for the PPL subsidiaries, said. "As part of the IRP's routine development process, we'll revisit the target reserve margin analysis."

Pratt was responding to a PSC staff report released Wednesday that sided in part with the Sierra Club and other environmental intervenors who chided the utilities for assuming in their latest IRP there will be "zero future costs related to CO2,

Deals set new price floor for coal-fired assets: analysis

Two deals announced this week — one involving the sale by Dominion Resources of interests in various power plants and the other involving Ameren's plan to divest merchant plants to Dynegy — establish a new price floor for coal-fired assets.

Dominion Resources on Monday agreed to sell interests in three power plants totaling 3,398 MW to Energy Capital Partners. The sale price was not announced, but a source close to the deal said the purchase price is about $200 million below the $650 million, including tax benefits, that Dominion expects to receive from the sale, which is expected to close in the second quarter.

At that price, the valuation for the Dominion plants is $132/kW.

The second deal is harder to value.

Ameren announced Thursday it has agreed to divest Ameren Energy Resources to Dynegy. AER owns five coal-fired plants in Illinois totaling 4,100 MW, 80% of a 1,186-MW coal- and gas-fired plant in Joppa, Illinois, on

(continued on page 9)

Big 2012 jump in solar aided by costs, subsidies

The US boasts 7,700 MW of solar-powered generation thanks to record installations in 2012, the Solar Energy Industries Association said in report Thursday.

The big buildout, SEIA said, was aided by lower photovoltaic panel prices, but federal cash subsidies totaling $2.7 billion since late 2011 played a key role.

The SEIA and the research firm that supports it, GTM Research, said a record 3,313 MW of PV power was installed last year, while 30 MW of concentrating solar power was added, pushing up total installed generation by 40% in one year. It was a 76% improvement over 2011, which was itself a record year with 1,887 MW of PV installation.

The US market significantly outpaced the growth of the global market in 2012, and, SEIA and GTM said, "the US market share of global installations rose above 10% for the first time in recent history."

SEIA said it is projecting more than

(continued on page 10)

The McGraw-Hill Companies

Exhibit SN-21

wind generators in the lost more than $2 million in power sales in 2011.

Iberdrola asked FERC expedited consideration of its proposal because BPA transmission customers must elect self-supply or "third-party ancillary and control area services" for the 2014-15 fiscal year by April 1, the company said.

Iberdrola's expansion of the CSGI program would be part of a new BPA rate structure that BPA expects to be complete in July. Following that, BPA must provide FERC with a detailed plan for how it will compensate curtailed generators that are curtailed in the future when hydro levels are especially high.

The tariff would allow Iberdrola to curtail participating generation as needed to ensure proper balancing.

Ultimately, the program would "lessen the curtailment exposure faced by generators within Bonneville's" balancing authority area and allow it to buy fewer reserves, Iberdrola said. Less curtailment and more cost-effective imbalance services as envisioned by Iberdrola "can improve reliability and reduce the overall balancing reserve capacity burden on Bonneville," the company said.

At least two third-party resources have expressed interest in participating in the CSGI program through Iberdrola, according to the company.

Another early adopter of wind balancing was a Constellation Energy subsidiary. In 2009, Constellation Energy Control and Dispatch agreed to maintain a wind farm's reliability to the grid through constantly balancing generation and/or load resources, with personnel supervising it 24 hours a day.

CECD agreed to manage the 106.5-MW Glacier wind farm in in Cut Bank, Montana, and at the same time hone some skills beneficial to integrate wind resources into the fuel mix.

Glacier's transmission provider — NorthWestern Energy — did not have the resources or ability to manage the volatility the wind farm introduced.

To help shape the wind energy, CECD contracted with Grant County for 10 MW of automatic generation control, or AGC, energy. In addition to the AGC energy, there also is a 20-MW dynamic schedule that allows for balancing energy.

Grant operates the Priest Rapids Project that generates almost 2,000 MW of hydroelectric power.

These new services "are definitely an evolutionary concept" that have "not caught on in a big way yet." said Gary Ackerman, executive director of the Western Power Trading Forum. "There are competing tools to achieve similar results, such as energy imbalance markets" like the one proposed by the PacifiCorp and the California Independent System Operator.

An EIM allows changes in supply and demand in one grid operating area to be netted out with opposite changes in other grid operating areas at frequent intervals.

While an EIM is preferred by Iberdrola, the efforts of it and Constellation are a step in the right direction according Robert Kahn, executive director of the Northwest & Intermountain Power Producers Coalition. NIPPC strongly supports the creation of an EIM in the West, he noted.

But "you can't always wait around for the limousine," Kahn said. "Sometimes you have to hop into the next Volkswagen that comes along."

— Martin Coyne

Crisson to resign as APPA chief

American Public Power Association President and CEO Mark Crisson said Thursday he will leave his post at the association effective April 1, 2014. Crisson announced his retirement in a news release that did not cite a reason.

Crisson, who previously was CEO/director of Tacoma Public Utilities in Tacoma, Washington, became president and CEO in 2008, succeeding Alan Richardson, who served in the position for 12 years. Crisson has served in the past as chairman of the APPA board and is a past chairman of the Large Public Power Council. He has earned numerous awards for leadership among municipal utilities and for his involvement in the Tacoma community.

"I have been associated with public power for 35 years. It has been an honor and a privilege to conclude my career as the head of its national organization." Crisson said in a letter to the APPA board of directors. "We have accomplished much in the past five years. I am confident that the APPA team will continue to strengthen the organization and improve the quality of service to our members."

Phyllis Currie, chairwoman of the APPA board of directors and general manager of Pasadena Water & Power, in a written statement said: "We are grateful for the strong leadership Mark has provided during his term as CEO and thank him for his willingness to serve one more year to facilitate a smooth transition and provide us the time we need to search for and secure a new CEO for the association." Currie accepted the letter of resignation at APPA's most recent board meeting, according to a news release.

— Jason Fordney

Dynegy to acquire Ameren plants ... *from page 1*

or IPH, they said, Dynegy gains that potential upside without putting at risk the finances of its remaining businesses.

"In structuring the transition, we established and followed these principles: IPH must stand on its own and be a viable self-sustaining business; Dynegy cannot and will not put its balance sheet at risk; and there is no intent, no plan and no reason to engage in any type of financial restructuring of [AER's] public debt," said Robert Flexon, Dynegy's president and CEO.

He added, "This transaction, requiring minimal to no capital from Dynegy, dramatically magnifies our upside leverage for the same fundamental value drivers to which our investors want exposure, tightening reserve margins resulting from [older coal-unit] retirements, higher power prices, increasing capacity payments, and a strengthening national gas curve."

Executives at St. Louis-based Ameren, in turn, said during a conference call of their own that Ameren will benefit from the deal by exiting the merchant business and its vagaries; eliminating $825 million in debt on its books; and focusing on its regulated electric, natural gas, and transmission businesses in Missouri and Illinois that promise stable and significant returns on equity.

Parts of deal subject to FERC, other approvals

Under the agreement, parts of which are subject to Federal Energy Regulatory Commission and other approvals, Dynegy's new IPH subsidiary by year's end will acquire AER and its subsidiaries Ameren Energy Generating Co., Ameren Energy Resources Generating Co. and Ameren Energy Marketing Co.

With that, Dynegy will add AER's Duck Creek, Coffeen, E.D. Edwards, Newton and Joppa coal units in Illinois — a total of 4,119 MW already compliant with the Environmental Protection Agency's Mercury and Air Toxics Standards rule — and give Dynegy a total of more than 8,000 MW of mostly coal-fired capacity in Illinois and nearly 14,000 MW nationally.

Flexon and other Dynegy executives said that while the new IPH subsidiary, as a special purpose entity, will maintain "corporate separateness" from the rest of Dynegy, IPH offers the company as a whole the opportunity to more directly leverage any increases in natural gas — and wholesale electricity prices — into big gains.

For example, they said that while a $1/MMBtu increase in natural gas prices would increase earnings before interest, taxes, depreciation and amortization by Dynegy's existing fleet by $150 million, or $1.50/share, the planned addition of AER's coal-fired assets would provide an additional $182 million, or $1.82/share in EBITDA from that same $1 increase.

"Creating this asymmetric risk/return profile while protecting our balance sheet and maintaining our capital allocation flexibility is what makes this opportunity so compelling," Flexon said.

He noted that there is about 800 MW of transmission capacity from MISO to PJM available to AER "with no upgrade cost. This newly available capacity, along with the existing 150-MW of transmission capacity from [AER's] Edwards [coal] facility into PJM, results in Ameren's ability to deliver over 900 MW into the PJM energy markets and the ability to participate in [PJM's] upcoming 2016, 2017 base residual auction."

Flexon said the MISO generating capacity offered into PJM "would further tighten reserve margins within MISO," providing further benefits to the Dynegy/IPH fleet in MISO.

Ameren executives said that under their part of the deal the company agreed to pay Dynegy either $133 million or an updated appraised value of Ameren's three merchant gas units in Illinois — whichever is higher — prior to the close of the deal later this year.

Ameren to seek buyer for gas units

In the meantime, Ameren will seek a buyer for the three Illinois gas units — the 478-MW Grant Tower combined-cycle unit, the 460-MW Elgin peaking unit, and the 220-MW Gibson City peaking unit — with the expectation of closing on their sale by the end of this year. If the sales price exceeds the $133 million or appraised value that had been established for the units, IPH will receive that incremental money. The same would hold true even if the gas units' sale occurs within two years after the Ameren/Dynegy deal closes.

Asked by an energy analyst whether FERC is likely to raise market-power concerns, Catherine Callaway, Dynegy's chief compliance office, executive vice president and general counsel, said, "We've looked at it preliminarily and done as much analysis we can ... We expect the transaction to meet FERC's Section 203 market power test and that we can maintain market-based rate authority."

Finally, asked if any other major acquisitions in the Midwest are possible, Flexon said, "I actually don't know the answer to that question. I presume it depends on the specific market as to what level of market power would exist there, so that would have be an analysis to an asset-by-asset basis, and we haven't looked at that ... I have to say that right now, particularly after spending the last thee months working on this, I can't even think about another one at this point in time."

Paul Patterson, an analyst at Glenrock Associates in New York, said in an interview that the Ameren/Dynegy deal appears to provide significant benefits for both parties. Ameren, he said, now can focus on its expanding — and stable and profitable — regulated operations. "That's where their core competency lies." Dynegy, meanwhile, is increasing its exposure to coal — and the benefits that could come from that if natural gas prices rise — but without adding real financial risk, he said.

UBS said in a note to investors that it believes the coal-fired assets Dynegy/IPH will be acquiring "are not 'out of the hole' yet, as they remain encumbered by $825 million of debt ... which we believe will still need to be restructured."

UBS also said, "We believe market power issues could prove a real issue given the stumbling issues even seen as recently as last week with the Mach Gen transaction being denied despite a proposed mitigation plan." That was a reference to FERC's March 7 finding that the sale of Mach Gen's 1,092-MW combined-cycle gas plant in Tonopah, Arizona, to an energy fund would harm competition in western power markets.

"It remains unclear if there will be any mandated mitigation plan" for Dynegy in Illinois, "or forced divestitures from the combination to satiate market power considerations," UBS said. "Also, we believe the transaction firmly removes any chance for Ameren to join PJM, as Dynegy has lost a key potential sponsor for this move."

UBS concluded by saying the deal is a positive for Dynegy in the near term, assuming they can get the deal done ... Simplifying Ameren's story [by divesting its merchant assets] is a clear positive."

Moody's Investors Service downgraded Ameren Energy Generating Co. $825 million of debt to B3 from B2. "The downgrade ... considers the company's weak cash-flow generating prospects, declining liquidity, and the continued depressed power market conditions in the Midwest region," as well as the announcement of the Dynegy deal, Moody's said in a statement.

"The terms and conditions of the acquisition by Dynegy will leave Ameren Genco with limited financial flexibility and finite liquidity resources to weather an anticipated prolonged period of low power prices", said Toby Shea, a Moody's vice president and senior analyst. Moody's noted that while it views Ameren's planned divestiture of its merchant assets as "credit positive ... it it will not change Ameren's current Baa3 senior unsecured rating or stable rating outlook."

— Housley Carr

Iowa bill aims to boost small wind ... *from page 1*

to the utility for 10 years before using the power themselves. "Utilities won't lose a customer. We tried to make the bill palatable for utilities," Seng said, likening the fight to get the bill passed to the match between David and Goliath.

The power would be sold to utilities under contracts at a price that is based on the utility's cost to develop wind generation and including the return on equity the utility would receive from such a project.

Ed Woolsey, legislative director of Iowa Renewably Energy Association, said he developed the 60 MW estimate of what could be built each year based on historical data obtained from the Energy Information Administration. The legislation would limit the amount of power developed to no more than 50% of a utility's retail sales growth during the previous year.

The amount of growth varied over the period that Woolsey reviewed with some years showing no growth but other had high growth in demand. In 2009 there was a 666 MW increase in usage, he said.

"The legislation certainly has stirred up a lot of interest, and that is what it will take to overcome the opposition," Woolsey said Wednesday in an interview.

The Agriculture Committee last week passed the bill unanimously, showing that it has bipartisan support, Woolsey said. Only bills with deep bipartisan support are making it through the deeply divided Legislature, he said.

"We believe we can get it to the Senate floor for debate," Woolsey said.

The vote by the Agriculture Committee shows the bill has bipartisan support, but there is still some question whether it will clear the full Senate, Nathaniel Baer, energy program director for the Iowa Law Center, said in an interview.

The bill is on the Senate calendar; it has not been scheduled for debate, Baer said.

Support for the bill is sharply divided with utilities, co-ops and municipal utilities opposed and environmentalists in favor. The Iowa Farmers Union is one of the main proponents of the bill.

Others are undecided, including Clean Line Energy, the Iowa Renewable Fuels Association, the Iowa Utilities Board and NextEra Energy.

The opposition has blocked similar legislation, but proponents hope changes in the bill have made it less offensive to utilities and co-ops and simple enough to get public support behind it.

"Iowans have a long history of supporting economic development on their own. They are capable of building things on their own," Paul Gipe, a California-based wind energy advocate, said. He noted that without such legislation, wind generation in the state has been built only by large out-of-state corporations.

"This kind of bill opens the market to more players," Gipe said.

— Mary Powers

Deals set new price floor ... *from page 1*

the Kentucky border, an energy marketing business and a retail energy business.'

There is no cash value for the Dynegy-AER deal, so a standard analysis would yield a per-kW value of zero, but there are other considerations.

Dynegy has agreed to provide Ameren a $25 million, 24-month guarantee for coal and rail contracts. Ameren is also shedding $825 million in non-recourse debt associated with the coal plants. That debt will not go to Dynegy, but to Illinois Power Holdings, the subsidiary Dynegy is forming to house the AER coal assets.

Ameren is also holding back three gas-fired peakers totaling 1,166 MW from the deal. Ameren will pay AER $133 million for those plants and then have them appraised and put them up for sale. If the sale price is above $133 million or above the appraised price, the overage would go to Dynegy.

"The trend is not a coal seller's friend; the value of coal assets is deteriorating," analyst Paul Patterson with Glenrock Associates said.

But Patterson cautioned that it is difficult to make comparisons with coal plants. More so than with gas-fired plants, they tend to be unique assets.

In fact that plants that ECP is buying are not all coal fired. Three of the units at the 1,528-MW Brayton Point plant in Somerset, Massachusetts, are coal-fired; one can be fired by either oil or natural gas. The 1,158-MW Kincaid plant in Kincaid, Illinois, is coal fired. And the 1,424-MW Elwood station outside Chicago, which is only 50% owned by Dominion, is a gas-fired peaker.

Taking the unique characteristics of that portfolio into could yield different valuations.

The person close to the deal said that the value of Brayton Point is negligible. Despite the fact that Dominion recently invested about $1 billion in upgrades to Brayton, the plant is "distressed" with a capacity factor of 18%, reflecting a low dispatch rate, according to analysts at Tudor Pickering Holt. The highest value of the plant is its option value if the operating environment for coal plants improves. Brayton represents 50% of New England's coal capacity.

Similarly the Elwood peaker does not run frequently, but it has a tolling contract with a financial institution that runs until 2018, and it receives capacity payments.

The star asset in the package is the Kincaid plant. It is

Exhibit SN-21

scrubbed, burns relatively low-cost Powder River Basin coal, and has an attractive rail transport contract. It also dispatches well, north of 50% even at current gas prices, the source said.

If the Brayton Point plant is excluded, ECP is paying $240/kW for the two plants in Illinois. If the purchase price is applied to the Kincaid plant alone, the valuation would be $388/kW.

Prior to the two recently announced deals, the most recent valuation for a coal plant was Exelon's sale of 2,648 MW of plants in Maryland to private equity firm Raven Holdings for $400 million, which was announced in August and closed in December.

The sale valued the assets at $151/kW, even though initial expectations for the sale price had been as high as $800 million to $1 billion.

Some bidders who participated in the sale, but eventually dropped out, said that the only valuable asset was the 1,273-MW Brandon Shores plant. The other two plants, the 399-MW C.P. Crane and the 976-MW H.A. Wagner, would require as much as $500 million of capital expenditures to bring them into environmental compliance.

Valuations aside, it remains to be seen if the new owners will be able to make money running plants that, for the most part, were losing money for the former owners.

In part, the answer to that question is financial. The sales reprice the assets to levels more in line with current market conditions in which electricity demand and power prices are low. That could help the new owners because their hurdle rate or internal rate of return targets are easier to meet. But the acquisitions could have strategic benefits for Dynegy and ECP.

For Dynegy, the Ameren assets would double the size of Dynegy's Illinois coal fleet and contribute to operational synergies. Dynegy has already spent about $1 billion to bring its existing Illinois coal fleet into environmental compliance. Some of the coal plants in the Ameren fleet are scrubbed and some are not, but Dynegy says the fleet is compliant with the Environmental Protection Agency's upcoming Mercury and Air Toxics Standards rule on a portfolio basis.

The acquisition also would fulfill Dynegy's goal of adding retail business to its portfolio and give it a built-in hedge for some of its generation assets.

For ECP, the Dominion purchase would bulk up its portfolio to about 9,000 MW, a level that some analysts say puts ECP across the threshold size required to float an initial public offering. That could supply ECP with the exit that all private equity firms eventually need to cash out and pay back their investors.

— Peter Maloney

Big 2012 jump in solar ... *from page 1*

5,200 MW of solar generation will come online in 2013. It said that of that total it expects 4,300 MW to be PV, with 907 MW of concentrating solar power due to come on line at four utility-scale facilities.

The report points to this year's expected completion of the 392-MW Ivanpah power tower facility in California owned by NRG, BrightSource and Google; the 125-MW Phase 1 of NextEra Energy Resource's parabolic trough Genesis facility near Blythe, California; SolarReserve's 110-MW power tower Crescent Dunes facility in Tonopah, Nevada; and Abengoa Solar's 280-MW parabolic trough Solana facility in Arizona.

In 2012, SEIA and GTM said there were close to 16 million PV solar panels installed. They said there were more than 90,000 PV installations in 2012, including 83,000 in the residential market.

The industry lobbyist group and its researcher said the heightened activity was due largely to a 60% decline in the price of solar panels since the beginning of 2011.

GTM put the "blended average sales price" for PV modules in the fourth quarter 2012 at 68 cents/watt, 41% below the fourth quarter 2011 price of $1.15/watt.

Not mentioned was that 7,402 applicants who have done multiple installations around the country have received a total of $4.2 billion in direct cash subsidies over the 40-month span of the Treasury Department's 1603 cash grant in lieu of tax credits program.

That program reimburses 30% of the cost of construction of a solar project to the developer once the project is providing electricity.

The cash subsidies have been paid out to a wide variety of types of solar installers over a period stretching from September 2009 to mid-February 2013.

Since December 2011, $2.7 billion of that total has been paid out by the Treasury. In just the seven months between July 20 and mid-February, subsidy payments totaled $1.4 billion.

Among the many who received the subsidy in recent weeks is a New York-based company installing in California; 245 Park Avenue received $6.6 million from Treasury on February 12.

AZ Solar I received in January a $10.6 million reimbursement and Eiger Lease $5.2 million, both for projects in Arizona. Eiger Lease received a $517,782 reimbursement February 4 for a project in Massachusetts.

Solar Energy Solutions received a $16,217 reimbursement January 24 for a project in Wisconsin. On the same day, PPL Renewable received a $2.4 million reimbursement for a solar electricity project in New Jersey, according to Treasury data.

On February 8, Southern Maryland Electric Cooperative received $5.9 million for projects in Maryland.

On February 2 SunPower Residential I received $1.96 million for a project in Colorado. And 11 days later, on February 13, Treasury data shows that SunPower Residential I was reimbursed an additional $3 million.

— Jeffrey Ryser

AG REHEARING EXHIBIT B

MOTION FOR LEAVE TO INTERVENE OF
THE KENTUCKY ATTORNEY GENERAL

FERC DOCKET NO. ER14-86

October 30, 2013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power	)	Docket No. ER 14-86
Service Corporation	)	

MOTION FOR LEAVE TO INTERVENE
OF THE KENTUCKY ATTORNEY GENERAL

Pursuant to Rules 211, 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"), 18 C.F.R. §§385.211, 385.212 and 385.214, Attorney General Jack Conway of the Commonwealth of Kentucky hereby seeks Leave to Intervene in the above-captioned proceedings. In support of this Motion, the Attorney General states as follows:

1. The Attorney General is the chief law enforcement officer for the Commonwealth of Kentucky. Ky. Rev. Statutes § 15.020. Pursuant to Ky. Rev. Statutes § 367.150(8), the Attorney General is granted the right and obligation to appear before federal regulatory bodies to represent the interests of Kentucky consumers in ratemaking and other utility matters.

2. The name, address, telephone, facsimile and e-mail address of the Attorney General's designated representatives for receipt of service in these proceedings are:

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3. The specific interests of Kentucky residential consumers are not adequately represented by other parties to this matter, and the Attorney General's intervention is necessary in order to protect these interests and ensure that the waivers sought by the Applicants, American Electric Power ("AEP") and its affiliates, will not result in harm to Kentucky ratepayers.[1]

4. The Attorney General for the Commonwealth of Kentucky intends to participate in these proceedings, which directly affect the rates paid by and service provided to Kentucky customers within the regulated territory of Kentucky Power Company ("KPCo"), a wholly-owned subsidiary of AEP.

5. The AEP Applicants' are seeking waivers of the Commission's affiliate restrictions, 18 C.F.R. 35.39 *et seq.*, with respect to the Mitchell Power Generation Facility ("Mitchell Plant"), which the Applicants propose to have co-owned by KPCo, a regulated public utility under Kentucky law, Ky. Rev. Stat. § 278.010(3) and AEP Generation Resources, a market-regulated power sales affiliate. The resulting Mitchell Plant Operating Agreement ("Mitchell Operating Agreement") tendered for approval will directly impact Kentucky ratepayers.

6. The Applicants' petition for these affiliate waivers is based in part on the recent decision by the Kentucky Public Service Commission authorizing KPCo's acquisition of an undivided 50 percent interest in the Mitchell Plant by order dated October 7, 2013.[2] The Order of

[1] *See* 18 C.F.R 35.39; *see also, Virginia Elec. & Power Co. Dominion Energy Mktg., Inc. Dominion Nuclear Connecticut, Inc. Dominion Energy Kewaunee, Inc. Dominion Energy Brayton Point, LLC Dominion Energy Manchester St., Inc. Dominion Energy New England, Inc. Dominion Energy Salem Harbor, LLC Dominion Retail, Inc. Elwood Energy, LLC Fairless Energy, LLC Kincaid Generation, L.L.C. Nedpower Mt. Storm, LLC State Line Energy, L.L.C. Fowler Ridge Wind Farm LLC*, 142 FERC ¶ 61103 (Feb. 8, 2013) ["the Commission codified certain affiliate restrictions in its regulations to protect captive customers from the potential for a franchised public utility to interact with a market-regulated power sales affiliate in ways that transfer benefits to the affiliate and its stockholders to the detriment of the captive customers. Captive customers are defined as 'any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation.'" *Id.* at 5 ¶ 16 (internal citations omitted.)]

[2] *In the Matter of: 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 Associate Assets and related approvals and relief*, Ky. P.S.C. Case No. 2012-00578, Order (October 7, 2013).

the Kentucky Public Service Commission is subject to petition for rehearing and appeal under Ky. Rev. Stat. §§ 278.400 and 278.410, respectively.

7. On the date of this filing, the Attorney General has filed a petition seeking rehearing of the Kentucky Public Service Commission's October 7, 2013 Order. In relevant part, the Attorney General seeks a rehearing of the following issues:

(a) Whether the Commission's erroneous reliance on KPCo's "stacking analysis"[3] of the conforming responses to the Big Sandy Unit 1 request of proposals ("RFP") to support its finding that the acquisition of a 50% interest in the Mitchell Plant was the best and least-cost option for KPCo's ratepayers was unreasonable and contrary to Kentucky law regarding affiliate transactions (KRS 278.2207 *et seq.*), and that rehearing is required to afford the Attorney General and the ratepayers procedural due process.

(b) Whether the Commission's failure to consider whether the new Mitchell Plant Operating Agreement,[4] violates Kentucky state law or federal law regarding affiliate transactions or otherwise creates the potential for a Kentucky regulated utility, such as KPCo, to be joined with a market-regulated power sales affiliate, AEP Generation Resources, in a manner that will transfer benefits to the affiliate and its stockholders to the detriment of KPCo's captive, retail ratepayers constituted clear error; and that rehearing is required to afford the Attorney General and the ratepayers procedural due process.

8. Pending a decision by the Kentucky Public Service Commission regarding a rehearing of the foregoing issues, the October 7, 2013 Order is not final, and AEP's transfer of a 50 percent

[3] Order of the Kentucky Public Service Commission (October 7, 2013) at 21-22.

[4] The American Electric Power ("AEP"), KPCo and related affiliates filed the Mitchell Plant Operating Agreement and related tariff filings with the Federal Energy Regulatory Commission ("FERC") on October 15, 2013, (FERC Docket Nos. ER13-238, ER13-239 and ER14-86) and by letter with this Commission on October 22, 2013 (Case No. 2013-00578).

interest in the Mitchell Plant from its unregulated state affiliate in Ohio to its regulated state affiliate in Kentucky, KPCo, is neither assured nor complete.

WHEREFORE, the Attorney General for the Commonwealth of Kentucky respectfully requests that it be permitted to intervene and participate fully in these proceedings with leave to file protest or seek all other relief that may be afforded the Commonwealth under federal law.

Respectfully submitted,

JACK CONWAY
ATTORNEY GENERAL

/s/ Signed electronically

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 30th day of October, a copy of the forgoing Motion For Leave To Intervene of the Attorney General for the Commonwealth of Kentucky was served on each person designated on the official service list compiled by the Secretary in these proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. 385.2010).

/s/ Signed electronically

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