AEP OHIO EX. NO._________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider	))))))	Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority	)))	Case No. 14-1694-EL-AAM

DIRECT TESTIMONY OF
KELLY D. PEARCE
IN SUPPORT OF AEP OHIO'S
AMENDED APPLICATION

Filed: May 15, 2015

INDEX TO DIRECT TESTIMONY OF
KELLY D. PEARCE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
KELLY D. PEARCE
ON BEHALF OF
OHIO POWER COMPANY

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelly D. Pearce. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Director - Contracts and Analysis for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Ohio Power Company (AEP Ohio or the Company).

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My group is responsible for performing financial and other analyses concerning AEP's generation resources and load obligations, settlement support for AEP's operating companies, including that associated with certain affiliate agreements and the PJM regional transmission organization, and regulatory support in areas that relate to commercial operations. In addition, my group is responsible for AEP's wholesale formula rate agreements.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University in 1984. I received Master of Science and Doctor of Philosophy degrees in Nuclear Engineering from the University of Michigan in 1986 and 1991 respectively. I received a Master of Science in Industrial Administration degree from Carnegie Mellon University in 1994.

From 1986 to 1988 I worked for a subsidiary of Olin Corporation. From 1991 to 1996 I worked for the United States Department of Energy within the Office of Fossil Energy. My responsibilities included serving as a Contracting Officer's Representative in the oversight and administration of government-funded research of advanced generation and environmental remediation technologies and projects. I also supported strategic studies for deployment and commercialization of these technologies as well as administration and support of Government research and development solicitations. I was promoted twice during this time.

In 1996 I joined AEPSC as a Rate Consultant I in Regulatory Services. In 2001, I was promoted to Senior Regulatory Consultant. My responsibilities included preparation of class cost of service studies and rate design for AEP operating companies and the preparation of special contracts and regulated pricing for retail customers. In 2003 I transferred to Commercial Operations as Manager of Cost Recovery Analysis. In 2007 I was promoted to Director of Commercial Analysis. During this period, I was responsible for analyzing the financial impacts of Commercial Operations-related activities. I also supported settlement of AEP's generation pooling agreements among the operating companies. In 2010 I transferred to Regulatory Services in my current position.

I am a registered Professional Engineer in Ohio and West Virginia.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony and testified before the Public Utilities Commission of Ohio ("Commission") in Case Numbers 11-346-EL-SSO, et al, and 10-2929-EL-UNC on behalf of AEP Ohio.

I submitted testimony to the Virginia State Corporation Commission (VSCC) in Case Numbers PUE-2001-00011 and PUE-2011-00034 and submitted testimony and testified before the VSCC in Case No. PUE-2001-00306. I also testified before the Indiana Utility Regulatory Commission in Cause No. 43992 and before the Kentucky Public Service Commission in Case No. 2014-00225. I have also submitted testimony to the Federal Energy Regulatory Commission in Docket No. ER13-539-000. My testimony in all of these proceedings was on behalf of operating companies that are affiliates of AEP Ohio.

<u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony includes four topics.

- First, I will describe the major terms of the proposed Power Purchase and Sale Agreement ("Affiliate PPA") between AEP Generation Resources (AEPGR) and AEP Ohio. For clarity, when I refer to the Affiliate PPA or related items, this discussion includes only certain generation units owned, in whole or in part, by AEPGR and does not include generation units owned by the Ohio Valley Electric Corporation (OVEC).

- Second, I will describe how the AEP Ohio entitlement to the OVEC units would also be included in the Purchase Power Agreement (PPA) Rider. As such, the PPA Rider would include revenues and costs from both the Agreement units and the OVEC units under the Company's proposal.
- Next, I will present a forecast of the revenues and costs under the PPA Rider using the supporting information provided by Company witnesses Bletzacker and Hawkins.
- Finally, I will briefly discuss the long-term cost stability benefits of the PPA Rider to AEP Ohio retail customers in the context of the PJM markets.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following exhibits:

Exhibit KDP-1	Summary of Affiliate PPA Major Terms
Exhibit KDP-2	Forecasted PPA Rider Revenues and Costs

<u>SUMMARY OF TESTIMONY</u>

Q. WOULD YOU SUMMARIZE YOUR FINDINGS?

A. Yes. First and foremost I expect that the PPA Rider will be a benefit to AEP Ohio and its customers. The largest benefit will be in its ability to hedge against periods of high market prices due to load and price volatility over the life of the PPA Rider generation units. I arrived at this result by comparing forecasts of the revenues and costs of the proposed PPA Rider which are summarized below in Table I:

TABLE I

PPA Rider Forecast using average of high load and low load cases Total October 2015 - December 2024 ($Millions)

PJM Revenues (excl. PJM Capacity Performance)	$11,845
PPA Rider Costs*	$11,271
Net PPA Rider Credit	**$574**
Potential maximum additional near-term PJM Capacity Performance (CP) Revenues**	$196
PPA Rider Credit with Maximum PJM CP Revenues	**$770**

Net PPA Rider Credit Range
Based on Average High/Low Load Case
$574 to $770 Million

*PPA Rider Costs include $768 million dollars of carbon tax expense.
**Near-term revenues based on PJM 16/17 and 17/18 Planning Years.

Q. DO THESE PPA RIDER BENEFITS COMPORT WITH THE COMMISSION'S ORDER IN CASE NO. 13-2385-EL-SS0, ET.AL ("ESP III ORDER")?

A. Yes they do. Company witness Vegas describes several factors the Commission stated on page 25 of the ESP III Order that they would balance in deciding cost recovery of the PPA Rider. I will address Factor 1, "…financial need of the generating plant…" and Factor 2, "…necessity of the generating facility, in light of future reliability concerns, including supply diversity…". Regarding, Factor 1, I demonstrate how the PPA Rider units face financial uncertainty, particularly in the near-to-intermediate term, which requires a long-term financial commitment to resolve. Regarding Factor 2, I submit that the PPA Rider will provide such diversity by providing customers a balance of long-term generation at cost-based prices via the PPA Rider and generation at market prices, which competitive suppliers and auction participants are likely to provide over the near-to-intermediate term.

AFFILIATE PPA TERMS

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE AFFILIATE PPA.

A. The Affiliate PPA provides for the sale of the electrical output from nine generation resources to AEP Ohio. The Affiliate PPA excludes OVEC since AEP Ohio already has a contract in place for receipt of the output from the OVEC facilities.

Q. ARE THE AFFILIATE PPA TERMS SIMILAR TO THE TERMS IN ANY OTHER POWER AGREEMENTS?

A. Yes. The proposed Affiliate PPA terms are similar to those in another unit power agreement (UPA) that AEPGR has in place with AEP Generating Company, which is a subsidiary of AEP not to be confused with AEPGR. This UPA is for the Lawrenceburg generation facility located in Indiana under which AEP Generating Company receives reimbursement for the costs of owning and operating the generation facility and AEPGR in turn receives all of the capacity, energy and ancillary service benefits from that facility. The Lawrenceburg UPA is very familiar to AEP Ohio since, prior to corporate separation; it was AEP Ohio that received the output from this generation facility.

Q. PLEASE PROVIDE A SUMMARY OF THE TERMS UNDER THE PROPOSED AFFILIATE PPA?

A. The major terms of the Affiliate PPA are summarized in Exhibit KDP-1. As I will discuss, under the terms of the Affiliate PPA, AEP Ohio will receive all of the capacity, energy and ancillary service revenues from AEPGR's ownership interest in all of the units listed in Attachment A of Exhibit KDP-1. These units are the following:

- Cardinal unit 1
- Conesville units 4, 5 and 6
- Stuart units 1, 2, 3 and 4
- Zimmer unit 1

Q. WHAT ARE THE MAJOR TERMS OF THE AFFILIATE PPA?

A. As summarized in Exhibit KDP-1, AEPGR or its subsidiary will retain ownership of the units listed in Attachment A of Exhibit KDP-1. As shown in that attachment, AEPGR wholly owns Cardinal unit 1 and Conesville units 5 and 6. AEPGR jointly owns Conesville unit 4, Stuart units 1 through 4, and Zimmer unit 1 with Dayton Power and Light (DP&L) and Dynegy. AEPGR operates the Conesville plant, while DP&L operates the Stuart plant and Dynegy operates Zimmer. Under the Affiliate PPA, AEP Ohio will receive all of the capacity, energy and ancillary services revenues produced by AEPGR's ownership interest in those units in exchange for payment to AEPGR of all of the costs of the units as described in the Affiliate PPA.

Q. HOW WILL THE COSTS OF THESE UNITS BE SEPARATELY IDENTIFIED RELATIVE TO AEPGR'S OTHER UNITS?

A. Much of the separate accounting has already been established for these units. In the case of the jointly-owned units, Conesville unit 4, Stuart units 1 through 4 and Zimmer unit 1, procedures are already in place to allocate costs between AEPGR and the other plant owners. The same is true for Cardinal unit 1 since the Cardinal plant is operated under the Cardinal Station Agreement (CSA) and Cardinal units 2 and 3 are owned by Buckeye Power, Inc. ("Buckeye"). Conesville units 5 and 6 costs can be identified collectively since both of these Conesville units are part of the Affiliate PPA. Furthermore, AEPGR plans to establish a new subsidiary and transfer these assets into that separate legal entity. As a result of this structure, the Company can be assured that it will pay only costs properly attributable to the units listed in Attachment A of Exhibit KDP-1.

Q. HOW WILL THE SEPARATION OF PJM REVENUES AND COSTS BE ACHIEVED?

A. A separate PJM subaccount will be established for the generation units subject to the Affiliate PPA which will separately account for all of these units' PJM revenues and costs. These revenues and costs will be accounted for and passed directly through to AEP Ohio.

Q. HOW WILL THE UNITS BE DISPATCHED?

A. The regulated commercial operations group of AEPSC, acting as agent for AEP Ohio, will provide guidance to AEPGR in order to make the daily offers of the units into PJM. The regulated commercial operations organization is the same group that AEP's vertically integrated, regulated AEP operating companies, including Appalachian Power Company (APCo), Kentucky Power Company, Indiana Michigan Power Company (I&M), Public Service of Oklahoma, Southwestern Electric Power Company and Wheeling Power Company, use for this function. The regulated organization within AEPSC is separate and distinct from the commercial operations organization of AEPGR. As such, AEP Ohio, through its agent, will have oversight of the units' day-to-day dispatch subject to the PJM daily offer and award process and any other operating limitations such as unit outages in a manner similar to when it previously owned these units.

Q. DO THE TERMS INCLUDE A PROVISION UNDER WHICH AEP OHIO WILL ALSO RECEIVE THE NET COSTS OR BENEFITS UNDER THE CARDINAL STATION AGREEMENT?

A. Yes.

Q. WHAT IS THE CARDINAL STATION AGREEMENT?

A. The CSA is an agreement among AEPGR, Buckeye and the Cardinal Operating Company to operate Cardinal units 1, 2 and 3. Buckeye is a generation and transmission cooperative that is jointly owned by 25 electric distribution cooperatives that serve customers in the state of Ohio. Twenty-four of these cooperatives are based in Ohio and obtain their electricity from Buckeye. The service territories of these cooperatives span many parts of the state of Ohio. Buckeye owns Cardinal units 2 and 3. The Cardinal Operating Company is the company that operates the Cardinal plant on behalf of the owners and bills the owners monthly for the costs of their respective units. The CSA is the same agreement that has been in place for many years including when AEP Ohio previously owned Cardinal Unit 1.

Q. WHY IS THIS PROVISION INCLUDED IN THE PROPOSED AFFILIATE PPA?

A. Since Cardinal unit 1 is a part of the Affiliate PPA, it is consistent to have AEP Ohio "stand in the shoes" of AEPGR with respect to the Cardinal Station Agreement with Buckeye. As a result, AEP Ohio will also receive additional power from Cardinal units 2 and 3 to sell into the market to the extent that this generation exceeds the Buckeye obligation. This revenue, net of the production costs, will be provided to AEP Ohio. In return, when Buckeye requires back-up when Cardinal units 2 and/or 3 are out of service, this power will be acquired from PJM and the net cost will be borne by AEP Ohio.

Q. WHAT IS THE AMOUNT OF THE CARDINAL BACKUP?

A. Per the terms of the Cardinal Station Agreement, Buckeye is entitled to take up to approximately 87% of the output of Cardinal units 2 and 3, which is a nominal 1,052 Megawatts (MW). AEP Ohio would then be able to sell the remaining output of Cardinal units 2 and 3 when both units are operating, which is a nominal 158 MW. When one or both units are down and Buckeye receives backup power up to their entitlement, it will be provided from a PJM purchase. Cardinal units 2 and 3 will be included in the same PJM subaccount as the Affiliate PPA units so these surplus and back-up sales and purchases will automatically flow through the PJM settlement process.

<u>AEP OHIO OVEC ENTITLEMENT</u>

Q. PLEASE DESCRIBE THE COMPANY'S OVEC ENTITLEMENT.

A. The AEP Ohio share of the OVEC units are not part of the Affiliate PPA since AEP Ohio already has a direct contractual relationship with OVEC for this output through the Amended and Restated Inter-Company Power Agreement ("ICPA" or "OVEC PPA"). Through this OVEC PPA, AEP Ohio receives 19.93% of the power output from the 11 units at the Kyger Creek and Clifty Creek facilities, which equates to approximately 423 MW.

Q. HOW WILL THE COSTS OF AEP OHIO'S ENTITLEMENT TO THE OVEC UNITS BE SEPARATELY IDENTIFIED?

A. Each entity with an OVEC entitlement receives a bill from OVEC for its monthly portion of the OVEC costs. These costs are allocated per the terms of the OVEC PPA. Consequently, the AEP Ohio OVEC entitlement is already separately accounted for.

Q, HOW WILL THE COMPANY'S OVEC ENTITLEMENT BE DISPATCHED?

A. The AEP Ohio OVEC entitlement already resides in its own PJM subaccount. The regulated commercial operations group of AEPSC, acting as agent for AEP Ohio, will provide dispatch instruction for the AEP Ohio OVEC entitlement in the same manner as they currently do for the APCO and I&M OVEC entitlements.

FORECASTED PPA RIDER REVENUES AND COSTS

Q. HAVE THE REVENUES AND COSTS UNDER THE PPA RIDER BEEN FORECASTED?

A. Yes. Using various information including the supporting information provided by Company witnesses Bletzacker and Hawkins, forecasts of the revenues and costs under the PPA Rider have been developed for the first 9 years and 3 months of the PPA Rider, from October 1, 2015 through December 31, 2024.

These forecasts were performed to capture the impact that load volatility can have on the resulting PPA Rider revenues and costs. Each case includes scalars which are factors used to provide the hourly and daily weather volatility based on historic multiple year averages. These loads and prices are then modeled to forecast unit dispatch under the various scenarios.

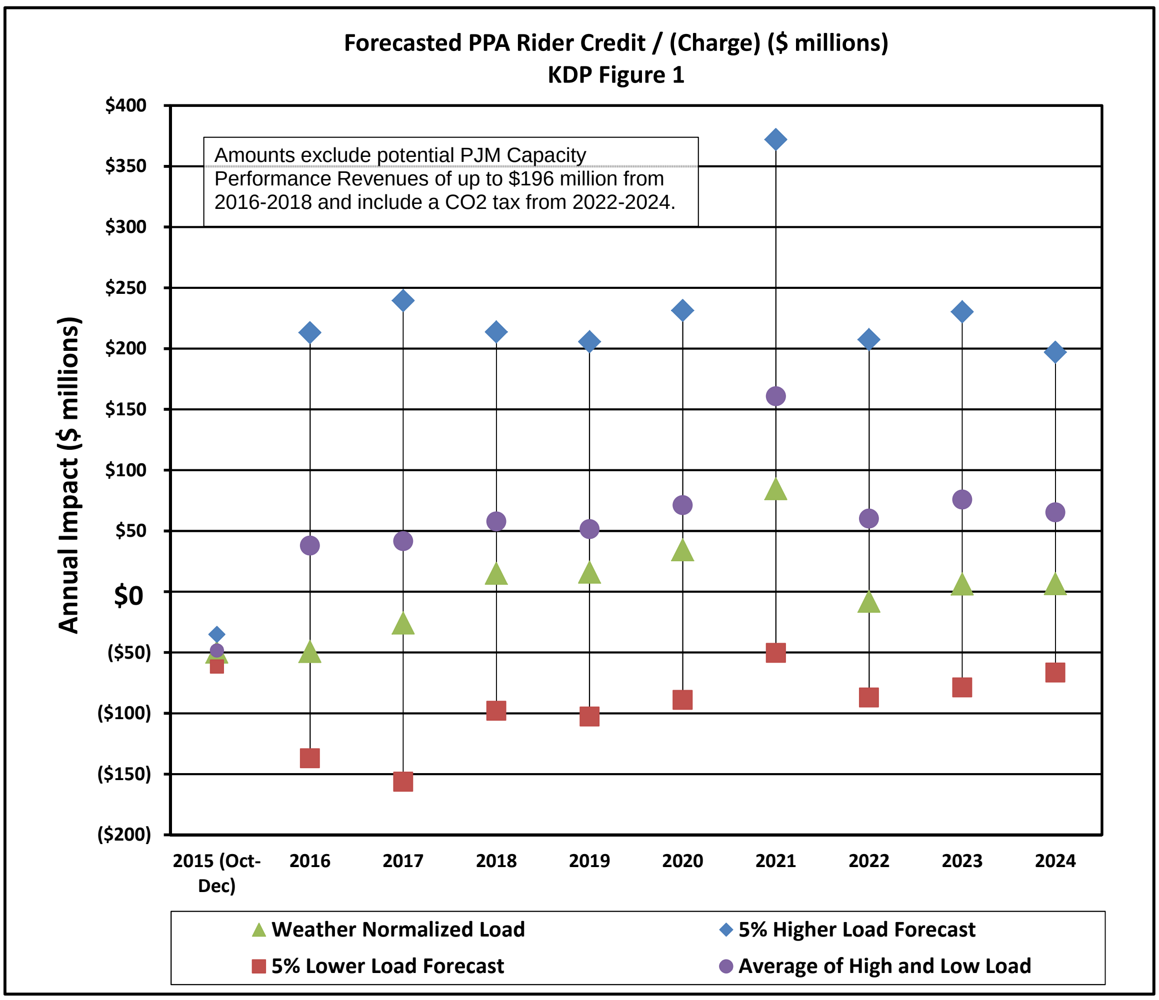
Q. HOW WAS THE ENERGY REVENUE AND COST DETERMINED?

A. The market revenue and variable cost of production was based on a generation forecast for each unit prepared utilizing the simulation model PLEXOS®. PLEXOS® is an hourly, chronological, production cost model that AEP uses to forecast the dispatch of units in the PJM power market. PLEXOS® utilizes assumptions for each unit's cost of energy (e.g., fuel, fuel handling, variable operations & maintenance, consumable costs and emission allowance costs, if any), scheduled maintenance outages, and forced outages along with forecasted market prices of energy (provided by Company witness Bletzacker) to determine forecasted generation output, costs, and energy revenues for each unit.

Q. WHAT ARE THE RESULTS OF THESE FORECASTS?

A. The results are shown in Figure 1 and in Exhibit KDP-2. These cases include, from top to bottom, (1) a case with a five percent increase in load, (2) an average of five percent increase and five percent decrease in load for each year, (3) a weather normalized load case and (4) a case with a five percent decrease in load.

<u>FIGURE 1</u>



Q. PLEASE DESCRIBE THESE FORECAST RESULTS.

A. These cases provide a range of the value of the PPA Rider in each year under the load scenarios I just described. The average of high and low load cases, represented by the midpoint for each year in Figure 1, sum to the $574 million total credit to customers that I provided earlier in Table I and are also shown in Exhibit KDP-2. This midpoint would result in a net credit in every year from 2016 to 2024. This benefit to customers is also net of a carbon tax which I will describe later in my testimony.

Q. PLEASE DESCRIBE THE DIFFERENCES IN THE CASES RESULTING FROM VARYING LOAD ASSUMPTIONS.

A. The ranges show what can happen when loads differ from normal, such as during severe winter or summer seasons or due to other factors such as changes to the economy. In that sense, each of the years shown can be considered as its own one-year forecast for a range of results. These weather and other load variability factors can have an asymmetric impact on electric prices. During mild periods, energy has a "floor" cost for units to run and recoup their variable costs -- even the most efficient, lowest heat rate units. On the other hand, times of high load, caused by abnormal weather or other factors, and potentially exacerbated by other issues such as fuel supply congestion, can result in extremely high prices above this floor. The nominal energy price cap in PJM is currently $1,000 per Megawatt-hour (MWh). However, during shortage events, when real-time reserve margins are below the PJM target levels, energy prices can go as high as $2,700/MWh beginning with the PJM 2015/16 delivery year that begins June 1. What is clear from these forecasts is that such volatility and variation from the norm drives an asymmetry in prices. By that, I mean that compared to a given weather-normalized case, load shifts up tend to increase prices more so than the price decreases that may result when load shifts down.

Q. HAVE ANY OF THESE FORECASTS CHANGED SINCE OCTOBER 2014 WHEN THIS DOCKET WAS INITIATED?

A. Yes. First and foremost, the Company has modified the forecast results to include the OVEC units. Secondly, the Company determined that a different fuel forecast assumption was utilized for the Conesville plant within the weather normalized case than that used for the high, low and resulting high/low average forecast cases. Therefore, for consistency, all of the cases have been updated to utilize the same forecast for Conesville fuel costs. In addition, my analysis has been adjusted to include only the last 3 months of 2015 to reflect an effective date of October 1, 2015.

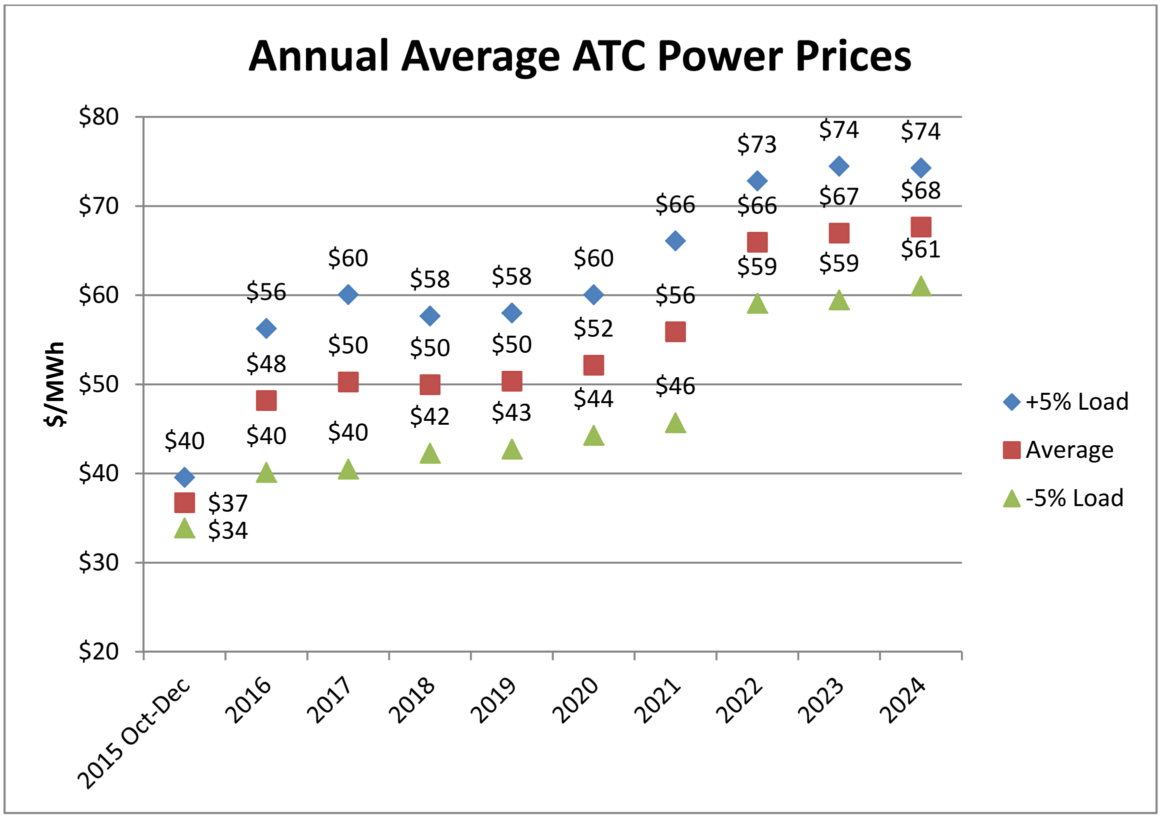
Q. DID THE COMPANY UPDATE ITS RETURN ON EQUITY OR DEBT RATE ASSUMPTIONS USED FOR THE AFFILIATE PPA?

A. Yes, the Company updated both its debt rate and return on equity ("ROE") forecast that are included in the PPA Rider impacts shown in Figure 1 and Exhibit KDP-2. The reason for this is that the previous analysis utilized the most recent Moody's Baa corporate bond monthly average index available at the time the forecast was performed, 4.73%. The December 2014 bond index rate is now known and therefore was utilized throughout the entire forecast period. Per the Affiliate PPA, the updated rate of 4.74% would be the actual debt rate and, with adder, the ROE for the first 3 months of the Affiliate PPA assuming an October 1, 2015 start date. This update was minor given the change of only one basis point in the rate.

Q. WHAT CAN BE GATHERED FROM THESE RESULTS?

A. The PPA Rider net revenues or costs must be considered in the context of their impact to AEP Ohio customers in conjunction with wholesale market prices. Provided in Figure 2 are the Around The Clock (ATC) prices provided by Company witness Bletzacker under the plus and minus five percent load cases along with their average for each year.

FIGURE 2 – Around the Clock (ATC) Market Prices



The PPA Rider revenues will provide a reverse or negative correlation with these market prices, and thereby provide the hedge sought against volatility and high market prices.

This is evident by comparing the impact that various forecasted wholesale market prices have on AEP Ohio customers over the long term with and without the PPA Rider. As shown in Table II, the PPA Rider average case is expected to provide a net benefit to customers over the period forecasted. The average price without the PPA Rider over the period is $54.4/MWh while the average price with the PPA Rider is reduced more than a dollar per Megawatt-hour to $53.2/MWh.

Table II – Potential PPA Rider Volatility Reduction Benefit ($/MWh)

	Item	2015 (Oct-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	Avg.
	Without PPA Rider											
1	+5% Load ATC Price	$39.6	$56.3	$60.1	$57.7	$58.0	$60.0	$66.1	$72.8	$74.5	$74.3	$61.9
2	-5% Load ATC Price	$33.9	$40.1	$40.5	$42.3	$42.7	$44.3	$45.7	$59.1	$59.5	$61.0	$46.9
3	Average	$36.7	$48.2	$50.3	$50.0	$50.4	$52.2	$55.9	$66.0	$67.0	$67.7	**$54.4**
4	Spread	$5.7	$16.1	$19.6	$15.4	$15.3	$15.8	$20.4	$13.7	$15.0	$13.2	**$15.0**
	With PPA Rider											
5	+5% Load ATC Price	$40.9	$51.4	$54.6	$52.8	$53.3	$54.8	$57.7	$68.2	$69.3	$69.9	$57.3
6	-5% Load ATC Price	$36.3	$43.3	$44.1	$44.5	$45.1	$46.3	$46.8	$61.1	$61.2	$62.5	$49.1
7	Average	$38.6	$47.3	$49.3	$48.7	$49.2	$50.5	$52.3	$64.6	$65.3	$66.2	**$53.2**
8	Spread	$4.6	$8.1	$10.5	$8.3	$8.3	$8.5	$10.8	$7.1	$8.1	$7.4	**$8.2**
9	PPA Impact on Spread	($1.0)	($8.0)	($9.0)	($7.1)	($7.0)	($7.3)	($9.5)	($6.6)	($6.9)	($5.9)	**($6.8)**

In addition to this benefit is the arguably even bigger benefit that the PPA Rider would have on retail price volatility in the long term. As can be seen in line 4 of Table II, the load cases resulted in anywhere from approximately a $6 to $20/MWh range of impact on wholesale market prices for a given year, with an average of $15/MWh over the period. These types of swings could create "rate shock" for customers. Fortunately, with the proposed PPA Rider, as shown on line 8 of Table II, the PPA Rider very clearly and significantly reduces this volatility as can be seen in the reduction in the spread between high and low priced periods. The spread is reduced down to approximately $5/MWh to $11/MWh depending on the year, and has an average spread of only $8/MWh. This volatility reduction will lead to more stable retail rates.

Q. HOW DO THESE RESULTS SUPPORT THE INSTRUCTION PROVIDED BY THE COMMISSION IN THE ESP III ORDER REGARDING A PROPOSED PPA RIDER?

A. The Commission stated on page 25 of the ESP III Order that one factor it would consider is the necessity of the generating facility, in light of future reliability concerns, including supply diversity ("Factor 2" as described by Company witness Vegas). Diversity is normally intended to reduce some form of volatility. The results in Table II show specifically how the market price volatility will be reduced due to the diversity gained with the approval of the PPA Rider.

Q. SO WILL THE PPA RIDER PRODUCE A HEDGE AGAINST HIGH MARKET PRICES?

A. Yes. The approximate 3,100 MWs of generation under the proposed PPA Rider is more than a third the size of the AEP Ohio connected retail load. As such it will serve as a significant hedge against the year-over-year market price volatility that can occur.

This provides the benefit of a portfolio approach for consumers. AEP Ohio retail customers served by rates that trend with wholesale market prices, which may include many served from competitive retail suppliers and those served by the Standard Service Offer (SSO) auctions, would incur a net charge under the PPA Rider when the wholesale market prices are low, but would get the benefit of those same low wholesale prices.

More importantly, the PPA Rider will serve to mitigate, on an annual basis, retail customer rate increases due to wholesale market prices in either or both the energy and capacity markets that are higher than the costs of the PPA Rider units. As these wholesale prices are expected to rise and are reflected in retail rates, the PPA Rider is expected to provide retail customers a net credit on their bills for the difference between the cost of the PPA Rider and the revenues received from the PJM markets. These results indicate that the PPA Rider will be beneficial to AEP Ohio customers over the long term.

In addition, continued operation of these plants will avoid the transmission costs described by Company witnesses Bradish and Allen.

Q. DOES YOUR ANALYSIS SHOW THAT AEP OHIO CUSTOMERS WOULD HAVE RECEIVED SUBSTANTIAL BENEFIT IF THE PPA RIDER HAD BEEN IN EFFECT DURING THE 2014 POLAR VORTEX?

A. Yes. As was clearly the case during 2014, weather is variable and unpredictable over anything beyond a very near term. As an example, in January 2014, the average around-the-clock energy price in PJM on the wholesale market was over $113/MWh and in August 2014 it was just over $33/MWh. No one knows what the weather will hold over the next ten years in Ohio and across PJM. However, what is certain is that weather is variable and this PPA Rider can have a clear benefit during those variable periods. As evidence of this, in addition to the forecasts, the revenues and cost of the PPA Rider were analyzed as though it had been in effect for the first quarter of 2014 when the Polar Vortex occurred. The result is that the PPA Rider would have provided approximately a $54 million dollar net benefit to AEP Ohio customers even if the capacity of the PPA Rider units had been sold at the very low PJM price of $27.73/MW-day applicable during that period. To put this in context, if the capacity had been sold at the average clearing price of the 11-year PJM base residual auctions that have already occurred for the PJM Planning Years 2007/08 through 2017/18, a price of $93.15/MW-day, customers would have benefited by $70 million. This is a clear indicator of the benefit that the PPA Rider can provide as a hedge to AEP Ohio customers during volatile weather in the form of a credit on subsequent bills.

Q. CAN YOU SUMMARIZE THE IMPACTS OF THE ANALYSIS ON CUSTOMERS?

A. Yes. This analysis shows that the PPA Rider has more "upside" for customers than "downside". If loads increase due to weather volatility and/or a strengthening economy, AEP Ohio customers, both shopping and default service customers alike, will be exposed to the resulting higher wholesale prices, which the PPA Rider will offset. Ohio experienced this in the last decade for AEP Ohio customers when wholesale markets were very strong and very little shopping occurred because AEP Ohio had generation resources serving its customers at substantially lower cost than the prevailing wholesale market. At present, AEP Ohio customers have no such cost-based hedge.

Even if a scenario occurs where load growth and market prices remain depressed and even drop further, the net cost paid under the PPA Rider is tied to the actual cost of the units, as is the standard cost of service formula used in surrounding, regulated states. In addition, under the low market price scenario Ohio customers would also get the offsetting benefit of lower wholesale prices through the retail auctions and new Competitive Retail Electric Supplier (CRES) Provider offerings.

Overall, the proposed PPA Rider captures the financial benefit of a diversified portfolio for AEP Ohio customers that includes a cost-based generation hedge against market prices sourced from 20 generation units. It provides a more balanced approach than relying solely on market.

Q. DO YOU HAVE ANY COMMENTS ON THE SENSITIVITY OF THE FORECASTS TO CARBON DIOXIDE LEGISLATION ASSUMPTIONS?

A. Yes I do. While Company witness Bletzacker can speak to the Company's carbon dioxide ("CO_2") emission cost assumptions, it is my understanding that the actual future terms and timing of carbon regulation are uncertain. This is supported by Company witness McManus. The forecasted PPA Rider costs in my testimony include $768 million of CO_2 emission cost in the 3-year period from 2022 through 2024 in the average high load and low load case. This is the result of an assumed $15 per metric tonne of CO_2 emissions tax adder as discussed by Company witnesses Bletzacker and McManus. This adder resulted in a higher cost profile and thus less dispatch of these coal units. As a consequence, the results are reasonably conservative in that they include a "double whammy" of both the carbon expense and the resulting reduced dispatch due to the higher cost basis.

ELECTRICITY MARKET VOLATILITY

Q. CAN YOU IDENTIFY AND DESCRIBE ANY DIFFERENCES BETWEEN THE ELECTRICITY MARKET AND OTHER COMMODITIES WHICH ARE BROADLY TRADED?

A. Yes. Electricity has several unique features that cause it to be unlike any other commodity traded. From a manufacturing standpoint, electricity is the ultimate "just in time" product since it requires the electric grid remain balanced at all times between generation from producers and consumption by end users. This lack of storage capability makes it unique among commodities and can drive large price volatility in the energy market, particularly during periods where load increases beyond expected levels due to weather and/or generation resources fail to perform as expected. This volatility is not confined to isolated “cold spell or heat wave of the decade” events. It can even happen in shoulder months when maintenance outages combine with temperature aberrations.

Q. DO THE PJM CAPACITY MARKETS ALSO EXHIBIT A HIGH DEGREE OF VOLATILITY?

A. Yes, they do. PJM has conducted capacity auctions for eleven planning years with clearing prices for the area including AEP’s service territory ranging from $16/MW-day to $174/MW-day.

<u>PJM GENERATION ADEQUACY AND RETAIL RATE STABILITY</u>

Q. DO YOU HAVE ANY COMMENTS ON CAPACITY ADEQUACY IN THE PJM CAPACITY MARKET?

A. Yes. There are three primary sources of revenue available in the PJM markets through which a generation facility can recover its fixed and variable costs and earn a fair rate of return on its major capital investments: (1) energy revenues, (2) ancillary service revenues, and (3) capacity revenues. The ability of these three revenue streams to incent investment in new generation and/or provide the necessary economic signals for incremental investment in existing generation, will be tested in the coming years under conditions that are unprecedented in the history of PJM. Since the inception of the RPM capacity market in 2007, the PJM RTO has been net long on capacity in the sense that the cleared reserve margin has always exceeded the target reserve margin, with some years near or exceeding a 20 percent reserve margin. However, the region is in the middle stages of a very large wave of plant retirements. According to the PJM Independent Market Monitor’s (IMM) market data, 26,680 MWs of fossil-fuel capacity in PJM has retired or is planning to retire between 2011 and 2019[1]. The AEP Zone accounts for 6,024MW or 22.6% of all MW planned for retirement from 2015 through 2019.[2]

According to net revenue evaluations performed by the Market Monitor another 22 units with 6,946 MW of additional capacity is at risk of retirement[3]. This represents approximately 3.4% of PJM installed generation capacity in 2014.[4] According to the IMM these are primarily coal units which are not covering their avoidable costs and/or did not clear the May 2014 Base Residual Auction (BRA) for 2017/18. Further, at this time the Market Monitor has not analyzed whether nuclear units are at risk in PJM.[5] Substantial generation in PJM[6], including significant amounts of nuclear generation, were offered above the market clearing price and failed to clear[7]. These uncleared MWs were offered on a cost basis because generation owners of existing units in PJM are required to cap their offers at a maximum of going forward costs. Still more pressing, the events of the winter of 2014 demonstrate a need for substantial amounts of

[1] 2014 State of the Market Report, Volume 1 Introduction, page 50. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume1.pdf

[2] id.

[3] id, page 37.

[4] id, page 50. Market Monitor states that average installed capacity for PJM was 201,689 MW as of December 31, 2014.

[5] 2014 State of the Market Report, Volume 2, Section 7 Net Revenues, page 266 (or 22 of 22 in section 7). http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec7.pdf

[6] 2017/18 Base Residual Auction Report, Page 21, Table 6. 166,205MWs of generation (UCAP) were offered; 154,690MWs of generation cleared in the 2017/18 auction. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

[7] Exelon reported that Quad Cities and Byron in Illinois and Oyster Creek in New Jersey did not clear the PJM capacity auction. Article from Nuclear Energy Institute is one of the sources of this information. http://www.nei.org/News-Media/News/News-Archives/Exelon-on-the-2014-PJM-Capacity-Market-Auction

generation with on-site fuel or firm delivery capability, capabilities that are overwhelmingly provided in PJM by the coal, nuclear and old dual-fuel resources that are most at risk of retirement.

Q. WILL NEW CONSTRUCTION REPLACE THESE EXISTING UNITS THAT ARE RETIRING?

A. No. New construction is unlikely to replace the premature retirements in time to avoid an adverse impact on reliability. While 15.4 GW of new gas-fired and renewable generation cleared RPM for delivery years 2013/14 through 2016/17[8], only 9.2 GW is expected to be on-line by June 2015[9]. This is not just a temporary observation. Past experience indicates that only a fraction of those resources in the planning queue actually come to fruition. For example, the IMM estimates that about 19% of the generation in the interconnection queue that completes a feasibility study eventually enters commercial operation.[10] It is also noteworthy that, of those resources that have undergone a system impact study, the IMM estimates that only 53% reach commercial operation.[11]

PJM discloses that even though it cleared 5,350MW of new generation in May 2012 for the 2015/16 delivery year, only 3,800MW of this generation will be in service

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8 2016/2017 RPM Base Residual Auction Results, at 22 (Table 8); http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx

9 Affidavit filed by Michael Rutkowski (Navigant Consulting) in PJM Utilities Coalition (including American Electric Power) comments to the PJM Capacity Performance docket #ER15-623-000, Paragraph 39.

10 Q1 2014 State of the Market Report for PJM, page 371, Table 12-14. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014q1-som-pjm.pdf

11 id.

on June 1, 2015 at the start of the delivery year.[12] Company witness Wittine provides more detail on the lack of new generation being placed in service in PJM.

Q. ARE THERE CONCERNS WITH RELYING ON GAS UNITS FOR ALL NEW CONSTRUCTION?

A. Yes. The current PJM capacity market provides incentives primarily for the construction of new gas units. As we saw in the winter of 2014, over-reliance on gas for future capacity additions, especially after the several thousand MWs of MATS-related coal-fired retirements, could create more gas/electric coordination issues and significant price spikes in the energy market. From a reliability standpoint, in a severe winter situation, if gas pipeline distributors have to decide whether to deliver gas to heat homes or deliver gas to run generators, there is no real choice at all – pipeline distributors must give priority to gas heating customers and gas generation can be given instruction to curtail. These gas curtailments drive up wholesale electricity market prices and costs for retail electric customers.

Q. ARE THERE ANY CONCERNS WITH GENERATION AVAILABILITY?

A. Yes, there are questions about the true availability of some generation resources during extreme weather periods like those experienced in January and February of 2014. PJM reported that on January 7, 2014, "approximately 22 percent of total installed generation capacity in PJM was unavailable because of forced outages associated with routine equipment breakdowns, problems related to operating in extreme cold temperatures and, fuel-supply issues."[13] This was a total of 40,200MWs. Of that total, 9,700MWs

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[12] PJM Interconnection, L.L.C., Filing, Docket No. ER15-738-000, at 7 (filed Dec. 24, 2014).

[13] Mike Kormos testimony on Polar Vortex to FERC, April 1, 2014; page 3.

resulted from outages at gas-fired generation plants and another 9,300MWs were due to natural gas supply interruptions[14].

Q. DID PJM SURVIVE THIS PAST WINTER WITHOUT INTERRUPTION?

A. Yes, the PJM system did withstand periods of high demand in the winter of 2015, and while the region's resources should be commended for performance during this weather, the reality of the unit retirements in the future is still imminent. Unfortunately, as is often stated regarding financial markets, past performance is no guarantee of future performance. Approximately 12,000MWs of coal-fired generation is scheduled to retire in 2015 and 2016[15]. Many of these retiring units helped keep the lights on both this winter and last winter, but will be unavailable in the near future. Further, even this past winter highlighted potential concerns with gas deliverability issues in an extended winter peaking period. Specifically, on February 19 and 20 of this year, 34.7% and 29.9% of total forced outages were due to gas availability issues. This was equivalent to over 6,900MWs on February 19 and over 7,400MWs on February 20.[16]

Q. HAS PJM TAKEN ANY ACTIONS TO ADDRESS THIS CONCERN?

A. PJM has had various stakeholder groups working on modifications to the PJM capacity market design. Concerns continue among the generation owners that PJM market clearing prices such as the $59 per MW-day price that cleared for the twelve-month

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[14] Kormos testimony, Figure 2, page 4.

[15] February 2014 PJM General Session Meeting presentation by Andy Ott. http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/general-session/20140212/20140212-comments-of-andy-ott.ashx

[16] PJM Winter Update at 4.20.15 Members Committee Information Webinar. http://www.pjm.com/~/media/committees-groups/committees/mc/20150420-webinar/20150420-item-03-winter-update.ashx

period beginning June 1, 2016 or even the $120 per MW-day that cleared beginning June 1, 2017, are not capacity prices that will tend to encourage new generation or perhaps sustain a large amount of existing generation. This raises concerns about how much of this future generation that has cleared in the PJM auctions will actually come on line prior to the delivery year.

Consequently, in December 2014, PJM filed with FERC for approval of a new type of capacity product, the Capacity Performance Resource. The intent of the filing is to raise the level of capacity performance and reliability during emergency events by: (a) assessing higher charges for non-performance during these events, (b) allowing higher price offers into the auction and (c) requiring generating units to provide fuel and operational assurances that they can perform reliably during emergency events.

PJM's purpose in making this filing was twofold. First, PJM recognized that the historical price volatility from the existing RPM construct was not conducive to making future long term investments in the capacity market. Second, PJM had a genuine concern about the unit performance in the winter of 2014, when forced outages reached nearly 40% and gas units had challenges obtaining gas supplies on a regular basis.

The PJM December filing was the latest in a series of efforts to address these concerns related to the capacity and energy markets. In 2014 alone, PJM filed to (1) limit imported capacity to reliable sources including firm transmission[17], (2) limit summer-only demand response products[18], (3) require more robust operational performance for

[17] ER14-503, filed November 29, 2013. http://www.pjm.com/~/media/documents/ferc/2013-filings/20131129-er14-503-000.ashx

[18] ER14-504, filed November 29, 2013. http://www.pjm.com/~/media/documents/ferc/2013-filings/20131129-er14-504-000.ashx

demand response products[19], and (4) flatten the capacity market demand curve.[20] These recommendations will tend to push capacity clearing prices higher in the future.

PJM made a fifth filing in 2014 asking FERC to approve a series of actions to eliminate speculative bidding activity in the capacity market[21]. This type of bidding behavior has been significant in many of the auctions to date, so much so that the IMM has issued two reports on the amount of buyback activity that has occurred through the 2013/14 delivery year. For example, in the Incremental Auctions for the 2013-14 Delivery Year, 21.4% of capacity imports and 71% of Demand Response that was sold in the BRA was subsequently withdrawn when it was bought back by purchases in the Incremental Auction[22]. This type of activity is not conducive to procuring real, physical, and deliverable capacity products which is important not only for the reliability that only comes from having sufficient real sources of generation, but is also important for transmission planning. The impact on the capacity market clearing price of such speculative bidding behavior is to suppress the base residual auction price in the short term. However, in the longer term, as inappropriate pricing signals are sent to market participants, such behavior creates a real and valid concern that new capacity will not be

[19] ER14-822, filed December 24, 2013. http://www.pjm.com/~/media/documents/ferc/2013-filings/20131224-er14-822-000.ashx

[20] ER14-2940, filed September 25, 2014. http://www.pjm.com/~/media/documents/ferc/2014-filings/20140925-er14-2940-000.ashx

[21] ER14-1461, filed March 10, 2014. http://www.pjm.com/~/media/documents/ferc/2014-filings/20140310-er14-1461-000.ashx

[22] Market Monitor's "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013" Table 9, page 10. http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf

built, even though existing units are retiring. Under this scenario, capacity shortages could occur, in which case capacity prices are likely to increase significantly.

With regard to the above-referenced filing on the incremental auctions, FERC decided to suspend ruling on it until they actually issue an order on the Capacity Performance filing. However, FERC may eventually issue an order in that docket, because the Capacity Performance filing did not substantially address the speculative bidding concept in the incremental auctions. However, even PJM, in their Capacity Performance docket initial filing, recognized that the current RPM construct fails to produce sufficient revenues to support its proposed Capacity Performance resource.[23] For this reason, PJM felt the need to submit a dramatic change to the existing capacity market rules.

Q. WOULD YOU PLEASE DESCRIBE THE PJM DECEMBER 2014 FERC FILING REGARDING THE NEW CAPACITY PERFORMANCE RESOURCE?

A. Yes. To qualify for this new Capacity Performance category, a generator will likely need to have a combination of fuel inventory or firm supply, flexible operation, and high availability.

PJM indicates they need approximately 81% of their capacity requirements in the form of this new Capacity Performance category by delivery year 2018/19, increasing to 100% by delivery year 2020/21. And, in order to provide incentives for this type of category, PJM's proposal includes certain bidding rule changes that are expected to significantly increase the clearing price. Specifically, PJM's filing contained the following recommendations:

[23] Capacity Performance Proposal at 54.

- **Non-performance Charges.** Charges for non-performance during emergency hours (expected to be approximately 30 hours a year) will be assessed at approximately \$3,500/MWH.
- **Maximum Charge.** The maximum charge for non-performance will be 150% of Net Cost of New Entry ("CONE"). Net CONE is approximately \$300/MW-day for 2018/19.
- **Offer Caps.** Generation owners will be able to offer up to Net CONE without being subject to cost-based mitigation as in the past.
- **Qualification Criteria.** PJM provided general criteria for qualifying as a capacity performance unit. The key criterion is having the fuel availability to perform in even the most severe conditions. This may require gas units to incorporate dual fuel capabilities into their offer.

This new Capacity Performance category creates yet another source of uncertainty to the market. On April 24, 2015, FERC granted PJM's request to delay the May 2015 auction for the PJM 2018/19 Planning Year. PJM requested that the auction would be held 30-75 days after the Commission issues an order on the merits of the Capacity Performance proposal, but no later than the week of August 10-14, 2015. FERC did not provide any certainty as to when they would actually issue an order. Therefore, at the time of this filing the magnitude of these changes is uncertain. However, if such changes are implemented, it is likely to put even further upward pressure on PJM capacity prices.

Q. WHAT ARE THE IMPLICATIONS OF THIS PJM ACTIVITY FOR THE PPA RIDER?

A. This activity underscores the benefits of the PPA Rider for AEP Ohio and its customers. I previously discussed the energy hedge benefits of the PPA Rider. Regarding capacity, if the PJM capacity market begins rising to more sustainable clearing prices due to all of this market reform activity, AEP Ohio customers will be partially shielded from these higher PJM market capacity prices. The long term expectation of the PJM capacity market is for capacity prices that clear at or near Net CONE. For 2018/19 this is approximately $300/MW-day. Although the precise impact of this activity is uncertain, what is clear is that PJM's proposals to raise the non-performance charges and impose higher performance standards on units is intended to foster higher levels of performance and reliability from generating units that seek capacity revenues in the PJM market -- which in turn will likely drive capacity prices higher than in the past.

The PPA Rider will help mitigate these higher expected capacity costs. This will occur since the PPA Rider capacity costs are not tied to the PJM capacity market, yet customers will receive the credits from increasing capacity market revenues via the PPA rider.

Q. IS THE IMPACT OF PJM'S DECEMBER 2014 PROPOSAL INCLUDED IN YOUR FORECASTS OF THE NET BENEFITS OF THE PPA RIDER?

A. Given that FERC has not yet issued an order in the proceeding, it is difficult and somewhat premature to attempt to provide a precise forecast of the expected additional value that the proposal will provide under the PPA Rider. With that said, the PPA Rider units are well positioned to qualify as capacity performance resources. Consequently, what I have done in Table I is provide an entire range of outcomes in terms of the potential additional revenues that the PPA units could in theory receive in total for the

2016/17 and 2017/18 planning years. As shown, the Capacity Performance revenue uplift could result in additional PJM revenues of up to $196 million over these two planning years, which would then flow through to customers through the PPA Rider.

<u>FINANCIAL NEEDS OF THE GENERATING PLANTS</u>

Q. DO THESE PLANTS HAVE A FINANCIAL NEED AS DESCRIBED IN THE ESP III ORDER AND COMPANY WITNESS VEGAS AS "FACTOR 1"?

A. Our forecasts indicate that they potentially do at least in the near term. Table III shows the energy margins the units are required to make in the near term to cover their fixed costs.

<u>Table III – PPA Energy Margin Revenue Requirement to Recover Fixed Capacity Costs</u>

	Period			
	2015 (Oct-Dec)	**2016**	**2017**	**Total**
1) Fixed Capacity Costs ($/MW-Day UCAP)	$505.41	$497.67	$507.46	
2) PJM Capacity Revenues ($/MW-Day UCAP) *	($136.00)	($91.30)	($94.74)	
3) Capacity Revenue Deficiency ($/MW-Day UCAP)	$369.41	$406.37	$412.72	
4) **Resulting Energy Margin Requirement ($ Millions)**	**$96**	**$398**	**$408**	**$902**

*Represents pro-rated calendar year PJM RPM capacity auction prices, which are $136.00 for 2015/16, $59.37 for 2016/17 and $120.00 for the 2017/18 PJM planning years.

As seen in this table, in the near term PJM capacity market revenues are far below the fixed costs of the plants. While the Company's forecasts indicate that this hurdle can be overcome, particularly if any additional capacity revenues can be obtained from the PJM Capacity Performance auctions, this large "gap" is a clear indication of the uncertainty that drives the financial need of these plants in the near term given what we know as of the date of this filing.

Q. WHAT THEN IS THE BENEFIT TO CUSTOMERS?

A. What the PPA Rider offers to customers is a hedge against high market prices and therefore some level of rate stability. In turn, what the PPA Rider provides for the generation resources is a long-term commitment under which their operation can be optimized and their value to customers maximized. Much of this is due to the ability to make long-term capital investment decisions for these units as discussed by Company witnesses Vegas and Thomas.

While our forecasts indicate that with either above average load growth or year-over-year load volatility, the plants are economically viable, and particularly so in the intermediate to long term, such conditions are not guaranteed. If load is depressed, as indicated in one of the forecasts provided, without the PPA Rider the units would potentially have less-than-optimal operation.

Q. CAN YOU PROVIDE AN EXAMPLE OF THIS?

A. Yes. Under the PJM proposals for the new capacity performance product, the non-performance charges are fairly severe. Although PJM is attempting to make its capacity market higher risk and higher reward than the current PJM capacity construct in order to enhance reliability, it is still a one-year-at-a-time market. This means that long-term plant decisions are still hindered. As a result, the PPA Rider will provide the ability to use long-term planning horizons for capital investment and maintenance expenditure decisions to provide customers the benefits of additional revenues within this new construct with less risk of resulting reliability charges for non-performance.

Q. HOW DO YOU RECONCILE THE FINANCIAL NEEDS OF THE PLANTS WITH THE PPA RIDER BEING A GOOD DEAL FOR CUSTOMERS?

A. While the plants do have the financial need driven by market uncertainty and volatility in the near- to intermediate-term, these same factors are undesirable to customers as well and these are precisely what the plants will provide a hedge against. Whether you consider the PPA Rider a financial hedge or a type of insurance -- the latter being a valuable commodity without which many of us could not sleep at night -- the PPA Rider units will provide the most value to customers following spikes or large increases in wholesale market prices which undoubtedly are going to occur, at least from time-to-time. This hedge benefit of the PPA Rider is on top of the economic development benefits and the avoided transmission investment benefit as discussed by Company witnesses Allen and Bradish.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

Summary of Major Terms
Power Purchase and Sale Agreement ("Agreement")

Buyer:	Ohio Power Company ("OPCo" or "Buyer")
Seller:	AEP Generation Resources Inc. or a subsidiary thereof ("AEPGR" or "Seller")
Agreement Start Date:	October 1, 2015
Generation Facilities:	OPCo will receive entitlement to all of the power output (capacity, energy and ancillary services) associated with Seller's ownership interest in the generation facilities listed in Attachment A (collectively, the "PPA Units" or individually a "Unit").
Term:	Agreement term is through the entire commercial operational life of all of the PPA Units, including any post-retirement period necessary to fulfill all asset retirement obligations and complete any other removal projects. The currently planned retirement dates are set forth in Attachment A. Alternative Agreement end dates will be by mutual agreement between the Buyer and Seller.
Operating Committee:	The Agreement will provide for establishment of an Operating Committee and representatives of OPCo, Seller and American Electric Power Service Corporation ("AEPSC") shall each name one representative to act for it in matters pertaining to the Agreement and to develop, as necessary, arrangements for the generation, delivery and receipt of energy hereunder, including the items designated below and such other mutually agreed upon contract administration procedures. With respect to the Agreement, the Operating Committee, or its designees, shall review and approve: (a) capital budgets and any major Operations and Maintenance ("O&M") expenditures for the PPA Units, (b) operating parameters or capability of a Unit or changes thereto (c) Fuel and consumable procurement practices, including fuel specifications, and any new substantive supply contracts, and (d) Unit retirement decisions. The representative for AEPSC shall not vote except in the case of a tie between OPCo and Seller. The Operating Committee shall meet at least annually. For co-owned PPA Units, the Operating Committee determinations will be utilized in voting actions in co-owner meetings.
Delivery Points:	The PJM nodes located at each of the PPA Units.

Fuel: Seller will arrange, provide, procure, supply, transport, manage, transact and deliver Fuel to Units, and at jointly owned Facilities, Buyer will have the right to monitor the fuel transaction and logistics process and provide input on this activity to Seller at Operating Committee meetings. Seller agrees to conduct Fuel purchases using competitive methods, and Buyer will have the right to monitor and approve the results of such competitive methods, but Fuel agreements in place as of the Start Date will continue to be utilized for the Units. Any other fuel transaction that is not obtained through competitive methods must be approved by Buyer, including extensions or renewals of Fuel agreements in place as of the Start Date.

Offers and Scheduling: Buyer or its agent will dispatch the generation associated with the Facilities by reviewing and determining the parameters associated with PJM generation offers, including how such generation will be offered to PJM, for the Energy and Ancillary Services associated with Buyer's Contractual Capacity and Seller will, subject to the requirements of PJM and the operating parameters of the Facilities, as determined by the Facility operator, operate and control the Facilities and schedule with PJM pursuant to Buyer's dispatch criteria and PJM's requirements and instructions.

Capacity Entitlement: OPCo will receive all of the net capacity revenues of the PPA Units.

Energy Entitlement: OPCo will receive all of the net energy revenues of the PPA Units.

Ancillary Services Entitlement: OPCo will receive all of the net ancillary services revenues from the PPA Units.

Buyer Payments: In exchange for the above entitlements, OPCo will reimburse Seller for all costs associated with the PPA units. OPCo will make monthly payments to Seller equal to the sum of the following: (a) Fuel Payment, (b) O&M Payment, (c) Depreciation Payment, (d) Capital Payment, (e) Tax Reimbursement Payment, and (f) Other Miscellaneous Payment.

<u>Fuel and O&M</u>: OPCo will reimburse Seller monthly for the total actual monthly fuel and O&M costs incurred by Seller at the PPA Units. Fuel costs include, without limitation, fuel, fuel handling, fuel storage, transportation, transloading, fuel hedging, sales, consumables/chemicals and emission costs. O&M costs include, without limitation, O&M costs plus Administrative and General costs, accretion expense and overheads.

Depreciation: OPCo will make a monthly depreciation payment equal to actual depreciation and amortization expense on the PPA Units. The deprecation rates expected to be in effect at the Agreement Start Date are presented in Attachment B. These rates will remain the same for the first 15 months of the Agreement and will be updated thereafter no less frequently than every five years.

Any remaining net book value that exceeds zero at the end of life of a given unit will be depreciated at an adjusted rate of other units at the same plant. If the final Unit or Units of a plant is/are retired, any remaining net book value of that plant will be payable by OPCo at that time unless other payment arrangements are made between OPCo and Seller.

Capital: OPCo will make a monthly Capital payment consisting of the net book value of the PPA Units times a cost of capital. Net book value will include plant in service, construction work-in-progress, accumulated depreciation, fuel and materials and supplies inventory, other working capital, asset retirement obligations, and accumulated deferred income taxes. For purposes of computing the cost of capital, the capital structure will be based on a fixed “50/50” capital structure that includes 50% equity and 50% debt. The cost of debt will be the actual debt cost of the Seller beginning with 2017. Until then, debt cost will be based on Moody’s Baa corporate bond index average for the month of December of the previous year. The cost of equity shall be equal to the Moody’s Long-term Baa corporate bond index interest rate (averaged for each day in December and adjusted annually) plus a fixed 650 basis point adder. The cost of equity will not be less than 8.9% or greater than 15.9%.

Tax Reimbursement: For each calendar month, OPCo shall pay Seller an amount equal to all taxes for that month applicable to the PPA Units and the Agreement. Any tax based upon income, gross receipts, commercial activity or any similar tax for which the inclusion of such tax in the monthly payment increases Seller’s tax liability shall be grossed-up at the applicable statutory rate. All other taxes (e.g., property tax) will be billed as incurred.

Other Miscellaneous: Other miscellaneous payment shall include any other costs and credits as described within the Agreement not already included in the other payment components or any other costs or credits reasonably associated with the Facilities which may be billed monthly or if incurred less frequently, on either a quarterly or as incurred basis. Beginning five (5) years prior to the Planned Retirement Year of each Unit as shown in Attachment A, Other Miscellaneous payments will also include a component for recovery of forecasted retirement-related costs associated with the Unit.

Cost Computation: The FERC Uniform System of Accounts will be utilized by Seller and costs to be paid by OPCo will be formulaically computed based on the actual costs as recorded in Seller's books and records.

Billing and Payment: The calendar month shall be the standard period for all payments under the Agreement. As soon as practicable after the end of each month, Seller will render to Buyer an invoice for the payment obligations incurred during the preceding month. Each component of the invoice will be described in reasonable detail. All invoices under the Agreement shall be due and payable on or before the twentieth (20^{th}) day of each month. Buyer will make payments by electronic funds transfer to the account designated by Seller, or by other mutually agreeable method(s).

Books, Records and Audit Rights: Seller shall keep, or shall cause to be kept, all necessary books of record, books of account, and memoranda of all transactions involving the PPA units, in conformance, where required, with the FERC's Uniform System of Accounts. Seller shall make, or shall cause to be made, all computations relating to the PPA Units and all allocations of the costs and expenses of these Units. Buyer has the right to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to the Agreement (including any statements evidencing the energy quantities delivered to Buyer at the Delivery Points) within twelve (12) months of receipt of the statement, charge or computation. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly, along with interest, provided, however, that any claim by a Party for overpayment or underpayment with respect to an invoice is waived unless the other Party is notified of the claim within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made.

Unit Contingent:	Failure to deliver power, including capacity, energy and/or ancillary services is excused to the extent any of the PPA Units are unavailable as a result of (a) an outage, (b) force majeure or (c) Buyer's failure to perform.
Early Termination	Buyer can terminate the Agreement upon notice to the Seller if retail cost recovery for Buyer's Agreement costs is discontinued or substantially diminished, including through a one-time significant disallowance for retail rate recovery of costs, provided Buyer must pay Seller an amount equal to the sum of the net book value and retirement-related costs associated with the PPA Units at that time.
Unit Dispositions:	Decisions regarding retirement or pre-retirement divesture of any of the PPA Units shall be by mutual agreement of the Buyer and Seller.
Buckeye:	Seller shall extend, and Buyer shall accept extension of, the entitlements and obligations under the Cardinal Station Agreement related to unit dispatch, capacity, energy and ancillary service entitlements and back-up obligations related to Buckeye Power Inc.'s Cardinal Units 2 and 3.
Other Agreement Terms & Conditions:	The foregoing provides a summary of the Major Terms of the Agreement. The Agreement contains such other terms and conditions as are customarily set forth in such agreements, including, but not limited to events of default, assignment, limitation of liabilities and a Mobile Sierra provision. The summary is provided for convenience and any conflicts between the summary and the Agreement will be governed by the terms of the Agreement.

Additional Items

Attachments	Attachment A:	PPA Units
	Attachment B:	Initial Depreciation Rates

Attachment A

PPA Units

Plant	**Unit**	**Average Annual Capacity (MW)**	**AEPGR Ownership (%)**	**AEPGR Ownership (MW)**	**Currently Planned Retirement Year**
Cardinal	1	592	100.0%	592	2033
Conesville	4	779	43.5%	339	2033
Conesville	5	405	100.0%	405	2036
Conesville	6	405	100.0%	405	2038
Stuart	1	577	26.0%	150	2033
Stuart	2	577	26.0%	150	2033
Stuart	3	577	26.0%	150	2033
Stuart	4	577	26.0%	150	2033
Zimmer	1	1,300	25.4%	330	2051
Total		5,789		**2,671**	

Attachment B

INITIAL PLANT DEPRECIATION RATES

Plant	Annual Depreciation Rate (%)
Cardinal	3.55%
Conesville	3.01%
Stuart	3.27%
Zimmer	1.42%

FORECASTED OHIO PPA RIDER IMPACTS
COMBINED CARDINAL, CONESVILLE, STUART, ZIMMER and OVEC
October 31, 2015 through December 31, 2024
Dollars in Millions (Nominal)

Year	2015 (Oct-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	TOTALS
5% Higher Load Forecast											
PJM Revenues, excluding PJM Capacity Performance	$198	$1,271	$1,328	$1,385	$1,426	$1,480	$1,659	$1,756	$1,734	$1,785	$14,020
Agreement Costs, including CO_2 tax	$233	$1,058	$1,088	$1,171	$1,220	$1,248	$1,287	$1,549	$1,503	$1,588	$11,946
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	($35)	$213	$239	$214	$206	$231	$372	$207	$230	$197	$2,074
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($35)	$275	$336	$251	$206	$231	$372	$493	$502	$482	$3,113
Average of High Load and Low Load Forecast											
PJM Revenues, excluding PJM Capacity Performance	$180	$1,057	$1,070	$1,168	$1,189	$1,249	$1,359	$1,538	$1,495	$1,539	$11,845
Agreement Costs, including CO_2 tax	$228	$1,019	$1,029	$1,110	$1,138	$1,178	$1,198	$1,477	$1,419	$1,474	$11,271
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	**($48)**	**$38**	**$42**	**$58**	**$51**	**$71**	**$161**	**$60**	**$76**	**$65**	**$574**
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($48)	$100	$138	$95	$51	$71	$161	$326	$324	$319	$1,537
Weather Normalized Case											
PJM Revenues, excluding PJM Capacity Performance	$180	$993	$1,038	$1,151	$1,202	$1,246	$1,325	$1,482	$1,484	$1,542	$11,644
Agreement Costs, including CO_2 tax	$230	$1,042	$1,064	$1,136	$1,186	$1,211	$1,240	$1,490	$1,478	$1,536	$11,613
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	($50)	($49)	($26)	$15	$16	$34	$85	($8)	$6	$7	$31
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($50)	$13	$71	$53	$16	$34	$85	$261	$270	$277	$1,031
5% Lower Load Forecast											
PJM Revenues, excluding PJM Capacity Performance	$162	$842	$813	$952	$953	$1,018	$1,060	$1,319	$1,256	$1,294	$9,669
Agreement Costs, including CO_2 tax	$223	$980	$969	$1,050	$1,056	$1,107	$1,110	$1,406	$1,335	$1,360	$10,597
Net PPA Rider Credit / (Charge) excl. PJM CP, including CO_2 tax	($62)	($137)	($156)	($98)	($103)	($89)	($50)	($87)	($79)	($67)	($927)
Net with Maximum PJM Capacity Performance, excluding CO_2 tax	($62)	($75)	($60)	($60)	($103)	($89)	($50)	$159	$146	$156	($39)

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of Ohio Power Company's *Pre-Filed Direct Testimony of Kelly D. Pearce* have been served upon the below-named counsel and Attorney Examiners by electronic mail to all Parties this 15th day of May, 2015.

/s/ Steven T. Nourse
Steven T. Nourse

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