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
APPLICATION

Filed: October 3, 2014

INDEX TO DIRECT TESTIMONY OF
KELLY D. PEARCE

Page No.

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), referred to as 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. 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.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony includes three topics. First, I will describe the major terms of the proposed Power Purchase and Sale Agreement ("Agreement") between AEP Generation Resources (AEPGR) and AEP Ohio. Next, I will present a forecast of the revenues and costs under the Agreement using the supporting information provided by Company witnesses Bletzacker and Hawkins. Finally, I will briefly discuss the long-term cost stability benefits of the Agreement 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 Major Terms

Exhibit KDP-2 Forecasted Agreement Costs and Revenues

SUMMARY OF TESTIMONY

Q. WOULD YOU SUMMARIZE YOUR FINDINGS?

A. Yes. First and foremost I expect that the Agreement 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 term of the Agreement. I arrived at this result by comparing forecasts of the costs and revenues of the Agreement.

AGREEMENT TERMS

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

A. Yes. The proposed Agreement 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. CAN YOU PROVIDE A SUMMARY OF THE TERMS UNDER THE PROPOSED AGREEMENT?

A. Yes. The major terms of the Agreement are summarized in Exhibit KDP-1. As I will discuss, under the terms of the Agreement, 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 AGREEMENT?

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 Duke Energy Ohio ("Duke"). AEPGR operates the Conesville plant, while DP&L operates the Stuart plant and Duke operates Zimmer. Under the Agreement, 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 Agreement.

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 unit owners. The same is true for Cardinal unit 1 since the Cardinal plant is operated under the Cardinal station agreement and Cardinal units 2 and 3 are owned by Buckeye Power, Inc. ("Buckeye"). Conesville costs can be identified at the plant level since all Conesville units are part of the Agreement. Furthermore, AEPGR plans to establish a new subsidiary and transfer these assets into that separate legal. 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 BE ACHIEVED AT PJM?

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

Q. HOW WILL THE GENERATION REVENUES BE RECEIVED BY AEP OHIO?

A. Since these generation resources will be within their own PJM subaccount, the revenue payments received will be provided directly to AEP Ohio from PJM through the main regulated account as opposed to any type of receipt and "pass through" from AEPGR.

Q. HOW WILL THE UNITS BE DISPATCHED?

A. The regulated commercial operations group of AEPSC, acting as agent for AEP Ohio, will make the daily offers of the units into PJM through the same regulated commercial operations organization that AEP's vertically integrated, regulated AEP operating companies, including Appalachian Power Company, Kentucky Power Company, Indiana Michigan Power Company, Public Service of Oklahoma and Southwestern Electric 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, not AEPGR, will have control 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.

Q. ARE THESE OPERATIONAL AND SETTLEMENT TERMS BENEFICIAL TO AEP OHIO?

A. Yes they are. While I do not believe AEP Ohio would be disadvantaged in any way if AEPGR offered the units for dispatch within PJM and subsequently collected and passed through the revenues, the proposed arrangement provides an even higher level of control and transparency for AEP Ohio.

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 Cardinal Station Agreement 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.

Q. WHY IS THIS PROVISION INCLUDED IN THE PROPOSED AGREEMENT?

A. Since Cardinal unit 1 is a part of the Agreement, 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 1052 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 subaccount as the Agreement units so these surplus and back-up sales and purchases will automatically flow through the PJM settlement process.

<u>FORECASTED AGREEMENT COSTS AND REVENUES</u>

Q. HAVE THE COSTS AND REVENUES UNDER THE AGREEMENT BEEN FORECASTED?

A. Yes. Using various information including the supporting information provided by Company witnesses Bletzacker and Hawkins, certain forecasts of the costs under the Agreement have been developed for the first 9 years and 7 months of the Agreement, from June 1, 2015 through December 31, 2024. The resulting revenues and costs for each of these forecasts are shown in Exhibit KDP-2.

These forecasts were performed to capture the impact that load volatility can have on the resulting Agreement 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.

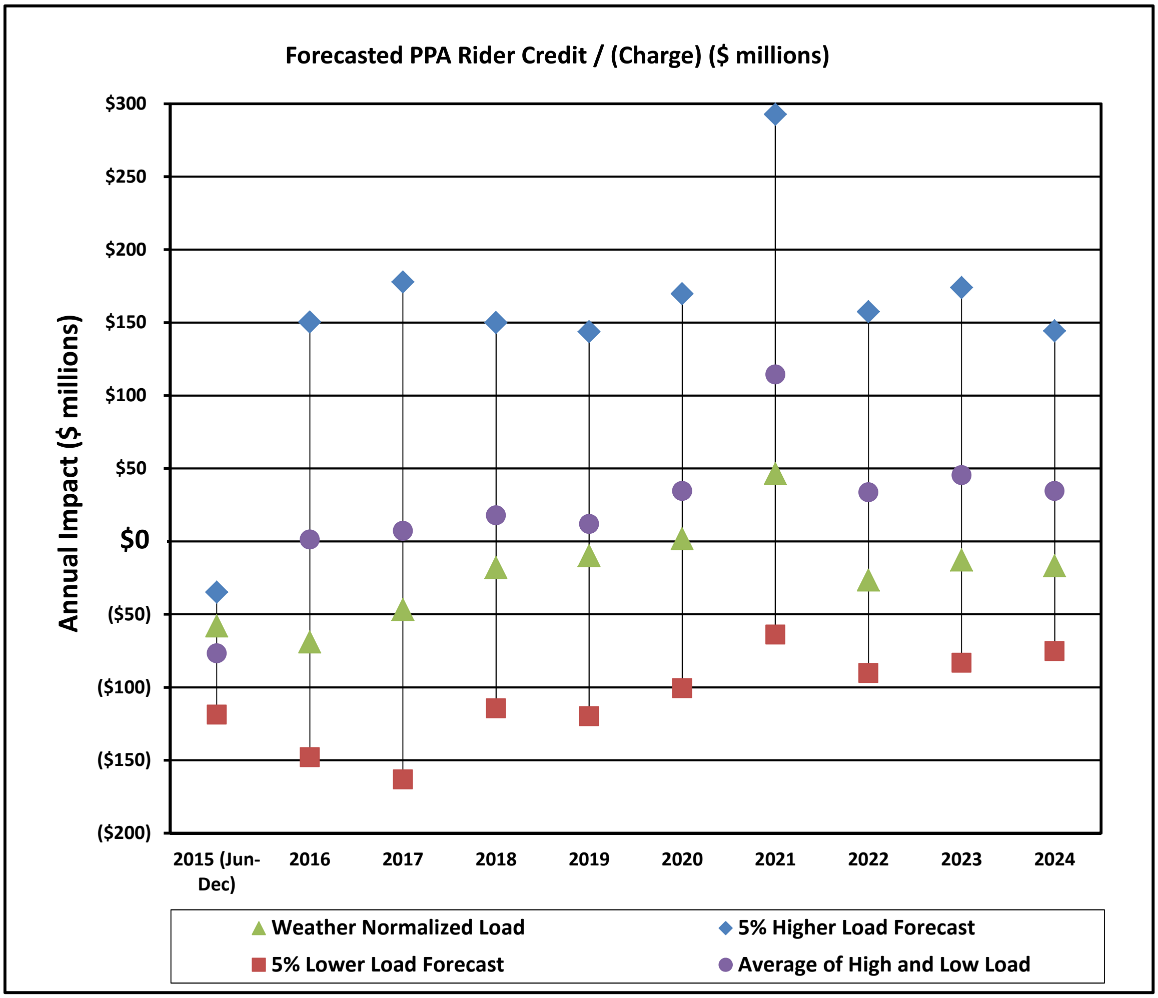
Q. HOW WAS THE ENERGY REVENUE AND COST DETERMINED?

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 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 five percent decrease in load.

FIGURE 1



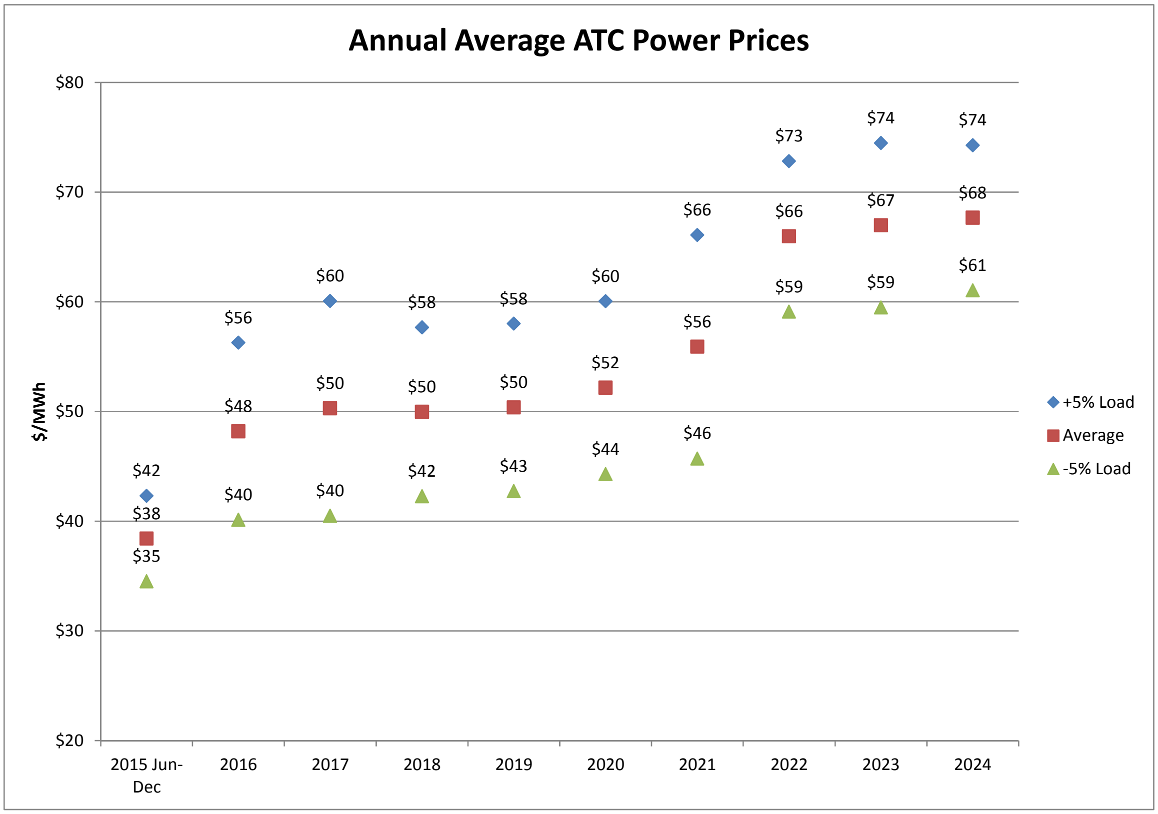
Q. PLEASE DESCRIBE THESE FORECAST RESULTS.

A. These cases provide a range of the value of the Agreement in each year. 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 in 2015/16. 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. WHAT CAN BE GATHERED FROM THESE RESULTS?

A. These Agreement 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 under the plus and minus five percent cases along with their average for each year.

FIGURE 2 – AROUND THE CLOCK (ATC) MARKET PRICES



The Agreement revenues will provide a reverse or negative correlation with these market prices, and thereby provide the hedge sought against volatility and high market prices. As shown in Table I, the Agreement average case is expected to provide a net benefit to customers over the period forecasted. In addition to this is the arguably even bigger benefit that the Agreement would have on retail price volatility. As see in Table I, the load cases resulted in anywhere from an $8 to $20/MWh range of impact on wholesale market prices for a given year, with an average of $15/MWh over the period. It is these types of swings that may create “rate shock” for customers. Fortunately with the proposed Agreement, 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 with the Agreement. The spread is reduced from $3 to $8/MWh depending on the year, and has an average spread of only $9/MWh.

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

Item	2015 (Jun-Dec)	2016	2017	2018	2019	2020	2021	2022	2023	2024	Avg.
Without PPA Rider											
1 +5% Load ATC Price	$42	$56	$60	$58	$58	$60	$66	$73	$74	$74	$62
2 -5% Load ATC Price	$35	$40	$40	$42	$43	$44	$46	$59	$59	$61	$47
3 Average	$38	$48	$50	$50	$50	$52	$56	$66	$67	$68	**$55**
4 Spread	$8	$16	$20	$15	$15	$16	$20	$14	$15	$13	**$15**
With PPA Rider											
5 +5% Load ATC Price	$44	$53	$56	$54	$55	$56	$59	$69	$71	$71	$59
6 -5% Load ATC Price	$39	$44	$44	$45	$45	$47	$47	$61	$61	$63	$50
7 Average	$41	$48	$50	$50	$50	$51	$53	$65	$66	$67	**$54**
8 Spread	$5	$9	$12	$9	$9	$10	$12	$8	$9	$8	**$9**
9 PPA Impact on Spread	($3)	($7)	($8)	($6)	($6)	($6)	($8)	($6)	($6)	($5)	**($6)**

These results indicate that the Agreement will be beneficial to AEP Ohio customers. 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 HAD BEEN IN EFFECT DURING THE RECENT POLAR VORTEX?

A. Yes. As was clearly the case during the Polar Vortex this past winter and a fairly mild summer in Ohio, it is clear that weather is variable and unpredictable over anything beyond a very near term. As an example, in January 2014, the average around-the-clock energy prince in PJM on the wholesale market was over $113/MWh and in August 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 Agreement can have a clear benefit during those variable periods. As evidence of this, in addition to the forecasts, the revenues and cost of the Agreement 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 Agreement would have provided approximately a $90 million dollar net benefit to AEP Ohio customers in that quarter alone. This is a clear indicator of the benefit that the Agreement can provide as a hedge to AEP Ohio customers during volatile weather in the form of a credit on subsequent bills.

In simple terms, this analysis shows that the Agreement 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. 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 other than the pending proposal to utilize the OVEC generation, which represents a small percentage of AEP Ohio load.

Even if a scenario occurs where load and prices remain depressed and even drop further, the net cost paid under the Agreement is tied to the actual cost of the units, as is the standard cost of service formula used in surrounding, regulated states. Therefore, these costs are capped when wholesale prices cycle upward again. In addition, under the low market price scenario Ohio customers would also get the offsetting benefit of lower wholesale prices through the auctions and new Competitive Retail Electric Supplier (CRES) Provider offerings. The proposed PPA captures the financial benefit of a diversified portfolio for AEP Ohio customers that includes a generation hedge against market prices for 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. For example, the forecasted Agreement costs include, depending on the scenario, \$563 to \$697 million of CO_2 emission cost in just the 3-year period from 2022 through 2024. This is the result of an assumed \$15 per ton 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 somewhat conservative in that they include a "double whammy" of both the carbon expense and the resulting reduced dispatch due to the higher cost basis.

Under the recently proposed EPA rules, as explained by Company witness McManus, coal generation dispatch may be reduced in favor of forcing increased levels of gas generation, but not through a carbon tax mechanism. If this is the case, the lower dispatch would still occur, but the carbon tax expense we have included as an assumption would not. Under these circumstances, the tax payment of \$563 to \$697 million included in the forecast may never come into being even with carbon limitations in effect. Such an outcome could easily make the economics and risk mitigation even more attractive for AEP Ohio and its customers.

<u>ELECTRICITY MARKET VOLATILITY</u>

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.

Q. EVEN IF IT IS VOLATILE, HAVE MARKET PARTICIPANTS DONE WELL PREDICTING FUTURE PRICE SWINGS?

A. There are some clear examples where that has not been the case for the capacity market. For the 2016/17 planning year a survey conducted by Morgan Stanley indicated that 70% of investors had expected a clearing price between $120/MW-day and $140/MW-day, yet it actually cleared at $59/MW-day. Similarly, for the 2017/18 planning year, most analysts expected prices to rebound to anywhere from $70 to $100/MW-day. The actual clearing price turned out to be $120/MW-day. While price volatility may be useful in some instances in the trading community, it is not desirable to the investment community that would fund power plant developers who might seek to build new generation. Such investors need assurances of cost recovery and not over just a single year at a time in a three-year forward market like PJM. This is the type of "roll the dice" world that AEP Ohio's customers are exposed to for capacity and energy in the PJM market.

PJM GENERATION ADEQUACY AND RETAIL RATE STABILITY

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 the major capital investment of these facilities: (1) energy revenues, (2) ancillary service revenues, and (3) capacity market 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. As discussed in a recent FERC technical conference on the functioning of the RTO/ISO capacity markets, since the inception of the RPM capacity market in 2007, the PJM RTO has been net long on capacity. However, the region is entering the beginning stages of the greatest wave of plant retirements ever experienced. According to the PJM Independent Market Monitor's

(IMM) market data, 24,933 MW of fossil-fuel capacity in PJM is planning to retire in the next few years or has already recently retired. Another 14,597 MW of fossil-fuel generation is at risk of retirement due to net revenue inadequacy in the PJM markets. This represents approximately 8% of PJM installed generation capacity in 2014. According to the PJM Independent Market Monitor (IMM) these are primarily coal units which have not covered their avoidable costs since 2009. Of additional concern is that the 14,597 MW of identified uneconomic generation does not include any nuclear generation despite the IMM finding that none of it has been covering its going forward costs in recent years. Moreover, the IMM analysis of uneconomic existing generation predates the most recent Base Residual Auction (BRA) in which substantial generation in western PJM, including significant amounts of nuclear generation, were offered above the market clearing price and failed to clear. 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. Much of the generation that is scheduled to be retired or at risk of retirement is the type of generation that has historically provided much of the spinning reserve and regulation service -- ancillary services for which the need is increasing as a result of the expansion of energy-limited renewable resources. Still more pressing, the events of this past winter in PJM and elsewhere in the Northeast demonstrate a need for substantial amounts of 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. 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 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 brings into question whether how much of this future generation that has cleared in the PJM auctions will actually come on line prior to the delivery year.

Efforts are underway to address these concerns related to the capacity and energy markets. In the past year alone, PJM has filed to (1) limit imported capacity to reliable sources including firm transmission, (2) limit summer-only demand response products, and (3) require more robust operational performance for demand response products. These recommendations will tend to push capacity clearing prices higher in the future.

PJM made a fourth filing in 2014 asking FERC to approve a series of actions to eliminate speculative bidding activity in the capacity market. 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. 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, it is a real and valid concern that new capacity will not be built, even though existing units are retiring. Under this scenario, capacity shortages could occur, in which case capacity prices are likely to increase significantly.

While PJM has taken some positive actions, there is still much that is uncertain and, from my perspective, PJM has appeared to address these concerns in a somewhat reactionary way which can create further uncertainty about the future.

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

A. Yes. The PJM capacity market provides incentives primarily for the construction of new gas units. As we saw this last winter, over-reliance on gas for future capacity additions, especially after the several thousand MWs of MATS 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 distributors have to decide whether to deliver gas to heat homes or deliver gas to run generators, there is no real choice at all – distributors must give priority to gas heating customers and gas generation can be given instruction to curtail. These gas curtailments drive up electricity market prices and costs for 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. As a result, PJM has recently introduced a new Capacity Performance proposal. 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 85% of their capacity requirements in the form of this new Capacity Performance category, 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.

Details of the proposal need to be developed with PJM stakeholders, but PJM has indicated they plan on filing for this new Capacity Performance product at FERC in November. This new Capacity Performance category creates yet another source of uncertainty to the market.

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 PPPA RIDER?

A. This activity underscores the benefits of the Agreement for AEP Ohio and its customers. I previously discussed the energy hedge benefits of the Agreement. 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. This will occur since the Agreement 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. WILL THIS PRODUCE A HEDGE AGAINST HIGH MARKET PRICES?

A. Yes. The approximate 2,700 MWs of Generation listed in Exhibit KDP-1 is more than a fourth the size of the AEP Ohio connected load. As such it will serve as a hedge for a significant portion of 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 retail suppliers and those served by the auctions, will still get the benefits when these wholesale market prices are low and are passed through to customers by customers' suppliers. During such periods, customers would incur a net charge between the cost of this Agreement and the revenues received in the PJM markets through the PPA rider.

More importantly, this Agreement will also serve to mitigate, on an annual basis, retail customer rate increases due to high wholesale market prices in either or both the energy and capacity markets. As these wholesale prices rise and are flowed through to customers, the customers will receive what is expected to be a net credit on their bills for the difference between the cost of the Agreement and the revenues received from the PJM markets.

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: June 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:	AEPSC, on behalf of OPCo, shall make offers of the generation and otherwise schedule the PPA Units into the PJM market, subject to (a) PJM scheduling and dispatch requirements and (b) obligations of the units not wholly owned and operated by Seller, and (c) the operating parameters of the PPA Units as determined or communicated by the plant operator.
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. <u>Depreciation</u>: 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 17 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.

<u>Capital</u>: 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%.

<u>Tax Reimbursement:</u> 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.

<u>Other Miscellaneous:</u> 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 (20th) 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%

Exhibit KDP-2

FORECASTED OHIO PPA RIDER IMPACTS
COMBINED CARDINAL, CONESVILLE, STUART AND ZIMMER
$ in Millions (Nominal)
50% Equity, 50% Debt, ROE: 11.23%, Cost of Debt 4.73%

5% Higher Load Forecast											
Year	**2015** (Jun-Dec)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**TOTALS**
PJM Revenues	$474	$1,083	$1,135	$1,172	$1,216	$1,251	$1,408	$1,482	$1,449	$1,486	$12,156
Agreement Costs	$509	$933	$957	$1,022	$1,072	$1,081	$1,116	$1,325	$1,275	$1,341	$10,631
Net PPA Rider Credit / (Charge)	($35)	$150	$178	$150	$144	$170	$293	$157	$174	$144	$1,526

Average of High and Low Forecast											
Year	**2015** (Jun-Dec)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**TOTALS**
PJM Revenues	$420	$908	$920	$995	$1,015	$1,040	$1,143	$1,287	$1,242	$1,276	$10,245
Agreement Costs	$497	$906	$912	$977	$1,003	$1,006	$1,028	$1,253	$1,196	$1,241	$10,020
Net PPA Rider Credit / (Charge)	($77)	$1	$7	$18	$12	$35	$114	$34	$45	$35	**$224**

Weather Normalized Case											
Year	**2015** (Jun-Dec)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**TOTALS**
PJM Revenues	$434	$861	$901	$979	$1,052	$1,034	$1,107	$1,234	$1,232	$1,284	$10,118
Agreement Costs	$492	$930	$947	$997	$1,062	$1,033	$1,061	$1,260	$1,245	$1,301	$10,327
Net PPA Rider Credit / (Charge)	($58)	($69)	($47)	($18)	($10)	$2	$46	($27)	($13)	($17)	($209)

5% Lower Load Forecast											
Year	**2015** (Jun-Dec)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**TOTALS**
PJM Revenues	$366	$732	$704	$817	$815	$829	$877	$1,091	$1,035	$1,066	$8,333
Agreement Costs	$485	$880	$867	$931	$935	$930	$941	$1,181	$1,118	$1,141	$9,410
Net PPA Rider Credit / (Charge)	($119)	($148)	($163)	($114)	($120)	($101)	($64)	($90)	($83)	($75)	($1,077)