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FILE

August 31, 2011

Chairman Todd A. Snitchler
Public Utilities Commission of Ohio
Ohio Power Siting Board
180 East Broad Street
Columbus, Ohio 43215-3793

Matthew J. Satterwhite
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RE:

In the Matter of the Commission Review	)	
of the Capacity Charges of	)	Case No. 10-2929-EL-UNC
Columbus Southern Power Company	)	
and Ohio Power Company	)	

Dear Chairman Snitchler:

Attached please find the testimony of Columbus Southern Power Company and Ohio Power Company (AEP Ohio) witnesses in the above listed docket required to be filed today in the procedural schedule issued in the August 11, 2011 Entry. Those witnesses providing pre-filed direct testimony are:

Richard E. Munczinski
William A. Klun
Frank C. Graves
✓Dana E. Horton
Kelly D. Pearce

Please contact me if there are any questions.

Cordially,

Matthew J. Satterwhite
Senior Counsel

Testimony attached

CERTIFICATE OF SERVICE

I hereby certify that this letter and the testimony accompanying it was served by electronically pursuant to the August 11, 2011 Entry in this case, upon counsel for the entities below on this August 31, 2011.

Matthew J. Satterwhite

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EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	))))	Case No. 10-2929-EL-UNC

DIRECT TESTIMONY OF
DANA E. HORTON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: August 31, 2011

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
DIRECT TESTIMONY OF
DANA E. HORTON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

PERSONAL BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dana Earl Horton. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed as Director – RTO Policy in the Regulatory Services Department of American Electric Power Service Corporation (AEP). American Electric Power Service Corporation is agent for AEP Ohio, which is comprised of Columbus Southern Power Company and Ohio Power Company, hereby referred to as AEP or the Company.

Q. PLEASE PROVIDE YOUR EDUCATION AND WORKING CAREER BACKGROUND.

A. I graduated from Muskingum College in New Concord, Ohio, in 1979 with a Bachelor of Arts in Accounting. I also received a Masters of Business Administration from Miami (Ohio) University in 1980. I worked for Ernst & Whinney as a CPA from 1980-83 before I joined AEP in January 1984. During my tenure at AEP, I have held positions in the Controllers Department, Trading & Marketing, Commercial Operations, and most recently in Regulatory Services. My main responsibility since AEP joined PJM in 2004 has been as an advocate for AEP in the PJM stakeholder process. In this role I work extensively with the stakeholder process under which PJM transmission and market rules are established. As relevant to this testimony, I was part of the AEP team that participated in the PJM stakeholder process leading up to the adoption of the rules implementing the Reliability Pricing Model ("RPM") and the Fixed Resource Requirement ("FRR") that initially was developed in 2006. As one of the key members of the AEP negotiating team, I was present at the Federal Energy Regulatory Commission ("FERC") offices during each of the RPM/FRR settlement discussions. For the reasons I discuss below, AEP was at the center of the discussions around the FRR and was one of the most active participants in the stakeholder process that led up to the FRR rules at issue in this proceeding, including several key provisions in the PJM Tariff and PJM's Reliability Assurance Agreement ("RAA").[1]

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. The primary purpose of my testimony is to describe the RPM and FRR options to supply capacity, the development of the FRR and why AEP chose this option. In addition, I will provide background and explanations for certain provisions in the FRR procedures including the requirements for alternative retail suppliers (called CRES providers in Ohio) with respect to their capacity obligations.

Q. **PLEASE EXPLAIN THE METHODS FOR SUPPLY AND PROCUREMENT OF CAPACITY IN PJM.**

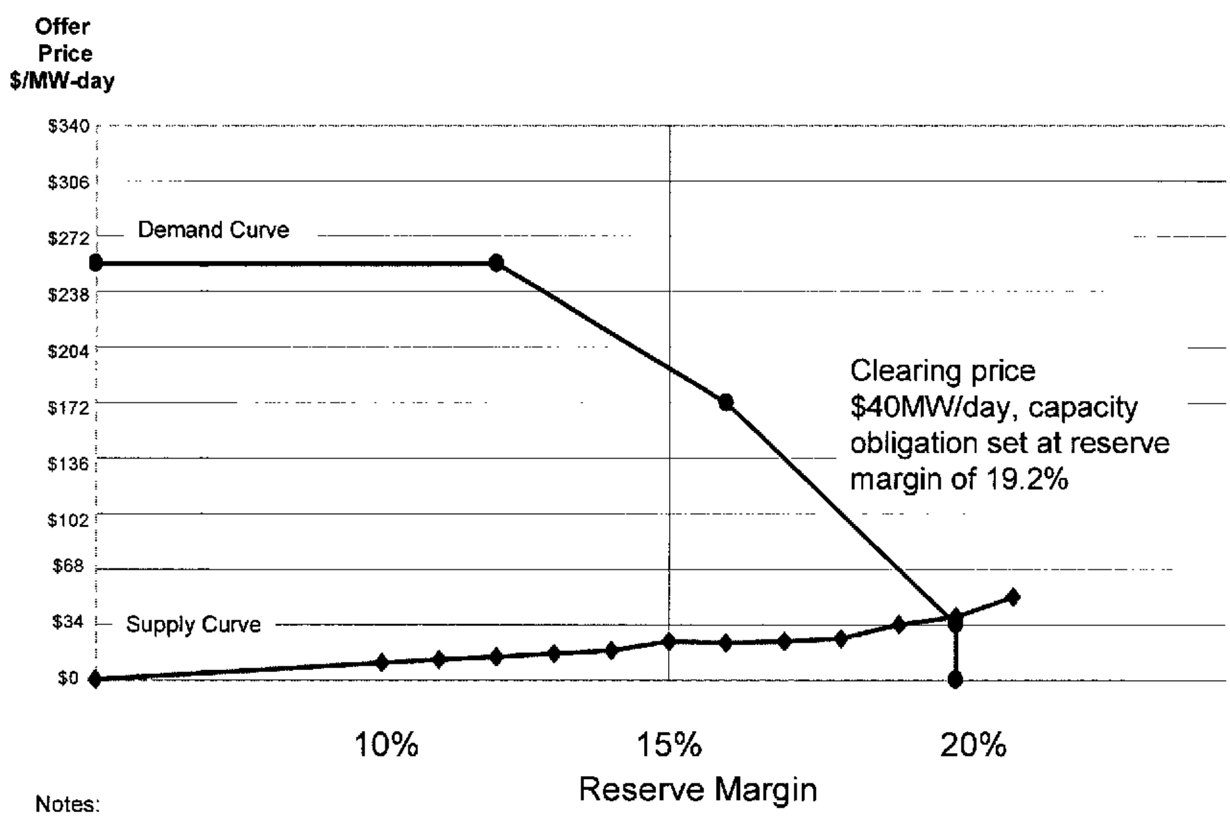
A. There are two methods in PJM for the supply and procurement of capacity – RPM and FRR.

Q. PLEASE BRIEFLY EXPLAIN THE RPM CAPACITY OPTION.

[1] PJM's Reliability Assurance Agreement defines protocols necessary for maintaining reliability on the PJM system.

A. The RPM is an administratively determined market approach. Under the RPM, PJM clears the supply offers from generators against an administrative demand curve to arrive at both a price and a quantity paid by Load Serving Entities (LSEs) for their capacity and reserve obligations. Figure 1 below graphically represents the supply and demand curves for a Base Residual Auction. The Base Residual Auction is what PJM calls the initial auction used to set the RPM clearing prices three years in advance of the delivery year.

Figure 1: Example of Supply/Demand Curve – Entire PJM Region



Notes:
- Demand curve is administratively set by PJM. Maximum clearing price = 1.5 x Net CONE = $255/MW-day in graph.
- Supply curve is based on offers by generators in RPM capacity market.
- Net CONE is equivalent to $172/MW-day. Net CONE is defined as the cost of new entry for a gas peaking unit. PJM uses this value as the basis for determining the RPM demand curve.

In the graph above, the top line is the administrative demand curve. It is generally a downward sloping curve. This means that the more MWs which are purchased, the lower the price paid per MW of capacity. PJM calls this the Variable Resource Requirement curve.

The upward sloping curve is the supply curve. This curve is developed through actual offers submitted by generators into the RPM auction.

In this graph, the two curves cross where the price equals approximately $40/MW-day and the quantity of capacity procured is approximately at a 19.2% reserve margin. The graph shows that all the loads in this zone will need to purchase capacity equal to a 19.2% reserve margin at $40/MW-day. So, as a simplistic example, an LSE with a 100MW peak load obligation in the 2007/08 delivery year, which is participating in the RPM auction process, will pay $1.7M (100MWs x 1.192 x $40/MW-day x 365 days = $1.7M) to PJM for its capacity obligations in this particular example, which is representative of the 2007/08 delivery year auction.

Q. PLEASE EXPLAIN THE FRR OPTION.

A. The FRR was developed to allow a utility the ability to provide its own capacity resources for its load obligations and not be subject to the RPM capacity market fluctuations (i.e. volatile clearing prices and reserve margins). Under the FRR option, the LSE supplies its own capacity obligations through its own generating fleet, or through bi-lateral arrangements with another supplier. If an LSE has a 100MW capacity obligation and chose FRR, the LSE could supply this capacity from its own generation fleet without making any payments to PJM.

Q. WHY WAS THE FRR OPTION DEVELOPED AS ANOTHER METHOD FOR SUPPLYING CAPACITY?

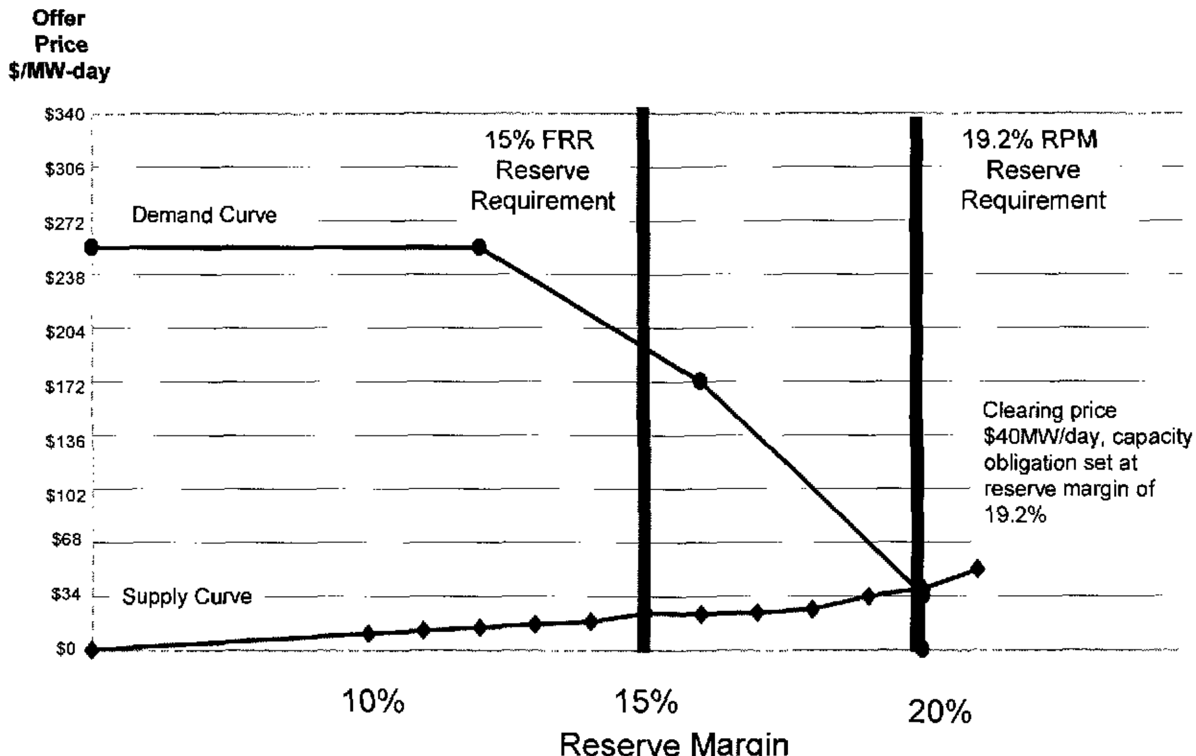
A. It was important to have an appropriate mechanism for LSEs that owned or controlled sufficient generation to meet their own load and reserve margin obligations. AEP advocated strongly at FERC and during the stakeholder negotiations for the FRR option. This option was important to AEP, because:

- FRR was consistent with the Company's regulatory framework. AEP utilities in PJM were among the few remaining vertically integrated utilities that retained their generation to meet the load obligations of their customers. For AEP, the FRR mechanism allowed it to continue to recover its embedded generation costs associated with the customers it serves through existing Commission approved rate structures. Conversely, many of the other PJM utilities have segregated their load from their generation, either by divesting their generation to third parties or transferring it to affiliated generation companies.
- It did not make sense for AEP to offer its own generation into a capacity auction and then essentially be required to buy it back to satisfy its load obligation, since the Company had sufficient generation to meet its own load obligation.
- AEP was at risk for being required to purchase more capacity than necessary because of the potential for the RPM auction to clear at a higher reserve margin level than the Company carried on its system.

Q. WHAT WAS THE OUTCOME OF THIS INITIAL DECISION?

A. At the time AEP initially made the decision to choose FRR, the FRR reserve requirement as set by PJM was 15%. In 2007/08, the auction actually cleared at a 19.2% reserve margin. If we had chosen RPM in 2007/08, AEP would have purchased an additional 4.2% of capacity to meet the RPM reserve margin that was not necessary to meet the Company's internal load obligations. See Figure 2 for a graphic representation of this difference.

Figure 2: Comparison of Reserve Requirements FRR vs RPM



Notes:
- Demand curve is administratively set by PJM. Maximum clearing price = 1.5 x Net CONE = $255/MW-day in graph.
- Supply curve is based on offers by generators in RPM capacity market.
- Net CONE is equivalent to $172/MW-day. Net CONE is defined as the cost of new entry for a gas peaking unit. PJM uses this value as the basis for determining the RPM demand curve.

Q. WHY WAS THE RPM RESERVE MARGIN HIGHER THAN THE FRR RESERVE MARGIN?

A. The key difference is in how the reserve margins are determined for FRR and RPM. For FRR, the reserve margin used is the reserve margin PJM calculates for the entire PJM RTO for planning purposes. However, the reserve margin for RPM is set by supply offers and an administratively set demand curve. Figure 2 above shows this relationship graphically.

Q. WHAT WOULD THIS ADDITIONAL 4.2% IN CAPACITY RESERVES HAVE COST AEP AND ITS CUSTOMERS?

A. In the 2007/08 period, this additional capacity obligation would have cost AEP and its customers an additional $15.7M.

Q. HOW DID YOU DERIVE THIS NUMBER?

A. AEP's total company peak load in PJM is approximately 22,000MWs. If the Company had been required to carry an additional 4.2% in capacity reserves, AEP would have been obligated to supply 925MWs of additional capacity for 2007/08 (4.2% of 22,000MWs). With the billed RPM capacity rate of $46.73/MW-day (which is the $40/MW-day clearing price grossed up for reserve margin and losses), the total cost would have been 925MWs x $46.73/MW-day x 365 days = $15.7M.

Q. PLEASE COMPARE THE RESERVE MARGIN FOR FRR TO THE RESERVE MARGIN FOR RPM FOR ALL THE YEARS THE AUCTION HAS CLEARED TO DATE.

A. There have been eight RPM auctions held since the initiation of the capacity auctions for the 2007/08 delivery year. The average target reserve margin set annually by PJM has been approximately 15.5% from 2007/08 through 2014/15. The average reserve margin cleared in the RPM auction in these eight years has been approximately 19% in the AEP zone. The difference is 3.5%. With the average RPM clearing price for all auctions being approximately $90/MW-day, AEP has saved its customers $25M annually (22,000MWs x 3.5% x $90/MW-day x 365 days = $25M) by choosing FRR.

Q. BACK TO THE INITIAL DEVELOPMENT OF THE FRR OPTION, HOW DID FERC RULE ON FRR IN ITS INITIAL OPINION?

A. FERC agreed that it was not necessary or appropriate to force utilities such as AEP to participate in the RPM auction. In their April 20, 2006 Initial Order, FERC states in paragraph 110 that "We agree with AEP that LSEs and states should have the option of choosing an alternative to the forward procurement auction if they identify sufficient capacity to meet their loads…."

At that point, as part of the settlement process at FERC, PJM and the PJM stakeholders entered into negotiations to develop the FRR process. These deliberations focused on the preparation of rules that enabled utilities such as AEP to meet their capacity obligations through use of their own generation (including bi-lateral arrangements) and to maintain reserve margins established by the PJM planning process rather than through the auction process. This provided benefits to native load customers by giving the LSEs choices for meeting capacity requirements.

Q. WERE YOU PART OF THE FERC SETTLEMENT NEGOTIATIONS RELATING TO THE FRR RULES?

A. Yes. The development of the FRR was largely driven by AEP. The AEP team (including myself) was at the core of and very active in the PJM stakeholder deliberations relating to these issues. These discussions took place under FERC Docket ER05-1410.

Q. PLEASE EXPLAIN HOW A CRES PROVIDER SERVING LOAD IN THE SERVICE TERRITORY OF AN FRR ENTITY MAY SUPPLY ITS CAPACITY REQUIREMENT.

A. The CRES provider has two options for supplying its capacity requirement. These include: 1) supplying its own capacity (with its own generation or through a bi-lateral contract) or 2) paying the FRR entity to supply capacity for the CRES provider.

Q. DURING THE FERC SETTLEMENT PROCESS, DID THE STAKEHOLDERS DISCUSS THE LEVEL OF COMPENSATION FOR CAPACITY TO BE PAID BY CRES PROVIDERS TO FRR ENTITIES?

A. Yes. The stakeholders held several discussions throughout the FERC settlement process regarding the compensation level for capacity that CRES retail LSEs would pay to the FRR entities in the event that the CRES provider did not have sufficient generation resources to enable them to meet their capacity requirements.

Q. WHY WAS IT NECESSARY TO DISCUSS THE CAPACITY COMPENSATION TO BE PAID BY CRES PROVIDERS?

A. Under the FRR rules, AEP is ultimately responsible for ensuring adequate capacity resources to meet the load obligation in its service territory, except for capacity that is self-supplied by a CRES provider. This includes not only the load served by AEP, but also any load that has switched to a CRES provider. To fulfill the total capacity requirement for the AEP service territory, the Company supplies capacity resources to meet the Company's load obligation while the CRES provider has the option of either 1) paying AEP to supply its capacity obligation or 2) providing its own resources to meet its capacity obligation. Therefore, this compensation discussion was necessary to ensure that the FRR entity was adequately compensated for supplying capacity resources used by a CRES provider.

Q. WERE THERE MULTIPLE OPTIONS DISCUSSED FOR CHARGING CRES PROVIDERS FOR THE CAPACITY COVERED UNDER AN FRR PLAN?

A. Yes. The PJM stakeholders ultimately agreed upon three options for determining an adequate capacity reimbursement price for CRES providers. The first approach, which would initially serve as a default mechanism, would be for the charges to track the market clearing price set in the RPM auctions. However, the major drawback was that there was no guarantee the auction prices would reimburse an FRR entity for its embedded cost of capacity. So, the stakeholders agreed upon another method under which the level of capacity compensation would be based on the FRR's embedded capacity costs.

Further, during the PJM stakeholder process, there also was a discussion about the possibility that any state utility commission might seek to implement a retail choice program with rules that require shopping customers to pay capacity-related charges directly to the incumbent utility. Although AEP was not aware of any such retail mechanism in any of the states in which AEP utilities operated, the Company did not oppose the inclusion of a provision that would accommodate the possibility that Ohio or another retail-choice state might one day decide to implement such a capacity charge directly to a retail customer (as opposed to a wholesale charge to a CRES provider). AEP fully expected that any such provision within our regulated jurisdictions would allow the Company to recover the costs for the capacity it is obligated to supply.

Q. HAS THE PUBLIC UTILITY COMMISSION OF OHIO (COMMISSION) VOICED SUPPORT FOR THE FRR PLAN SINCE ITS INCEPTION?

A. Yes. The Commission staff referred to FRR in public comments filed at FERC provided in advance of a FERC Staff Technical Conference on June 7, 2006. In the first sentence of their comments, the Commission staff said they "would like to compliment the FERC for accepting the traditional resource requirement approach (the Fixed Resource Requirement option) as a legitimate alternative to RPM. The Ohio Staff would like to request that, in developing the rules for the two alternatives, the FERC needs to ensure that a resource supplier is treated equitably in terms of the [Installed Reserve Margin (IRM)] requirement, the penalties for violating an IRM requirement, and the appropriate length of a resource commitment, regardless of what alternative the supplier chooses."

Q. DID THE COMMISSION PARTICIPATE IN THE RPM AND FRR NEGOTIATIONS?

A. The Commission staff was present at many of the sessions in Washington D.C. Because of the nature of the settlement negotiations, I am not permitted to disclose any details of positions voiced or taken during the discussions.

Q. YOU HAVE DISCUSSED THE RESERVE MARGIN BENEFITS OF CHOOSING FRR. WERE THERE OTHER BENEFITS THAT RESULTED FROM CHOOSING FRR?

A. Yes. In addition to the reserve margin benefits noted above, the FRR plan allows AEP the flexibility to substitute generating units within its fleet for meeting the Company's FRR capacity obligations in case of significant unit outages. In other words, AEP can utilize generating units that **are not** committed as capacity resources to replace generating units that **are** committed capacity resources in the event of unforeseen operational issues. This flexibility allows AEP the ability to minimize, or possibly eliminate, financial penalties assessed by PJM associated with non-performance of a committed capacity resource.

Q. HAS AEP BENEFITED FROM THIS FLEXIBILILTY?

A. Yes. In 2009, AEP experienced an extended, but unexpected outage with a committed capacity resource that lasted for over a year. Fortunately, under the FRR, AEP was able to substitute other uncommitted capacity resources within the AEP fleet for this unit in order to avoid most of the penalties that PJM would have assessed had AEP been in RPM. The RPM rules do not allow LSEs to hold some units in reserve to cover unexpected forced outages.

Q. IS THERE A FINANCIAL BENEFIT TO THIS FLEXIBILITY?

A. Yes. To illustrate the financial implications of being able to manage the risk of forced outages, if AEP would find itself 1000 MW short of capacity due to an unexpected forced outage, the penalty provisions for the 2009/10 delivery year would be 120% of the RPM clearing price. This would equate to $44M of penalties for a 1000 MW shortage (1000MWs x 365 days x 120% x $102/MW-day RPM clearing price).

Q. WOULD AEP HAVE REALIZED THE SAME BENEFITS IN RPM?

A. No. Under RPM AEP would have to offer 100% of its capacity into the auction and not hold any capacity in reserves to address forced outage situations.

Q. ARE THE CRES PROVIDERS EXPOSED TO THESE PENALTY PROVISIONS IF THEY DO NOT BRING THEIR OWN CAPACITY TO SERVE THEIR RETAIL OBLIGATIONS?

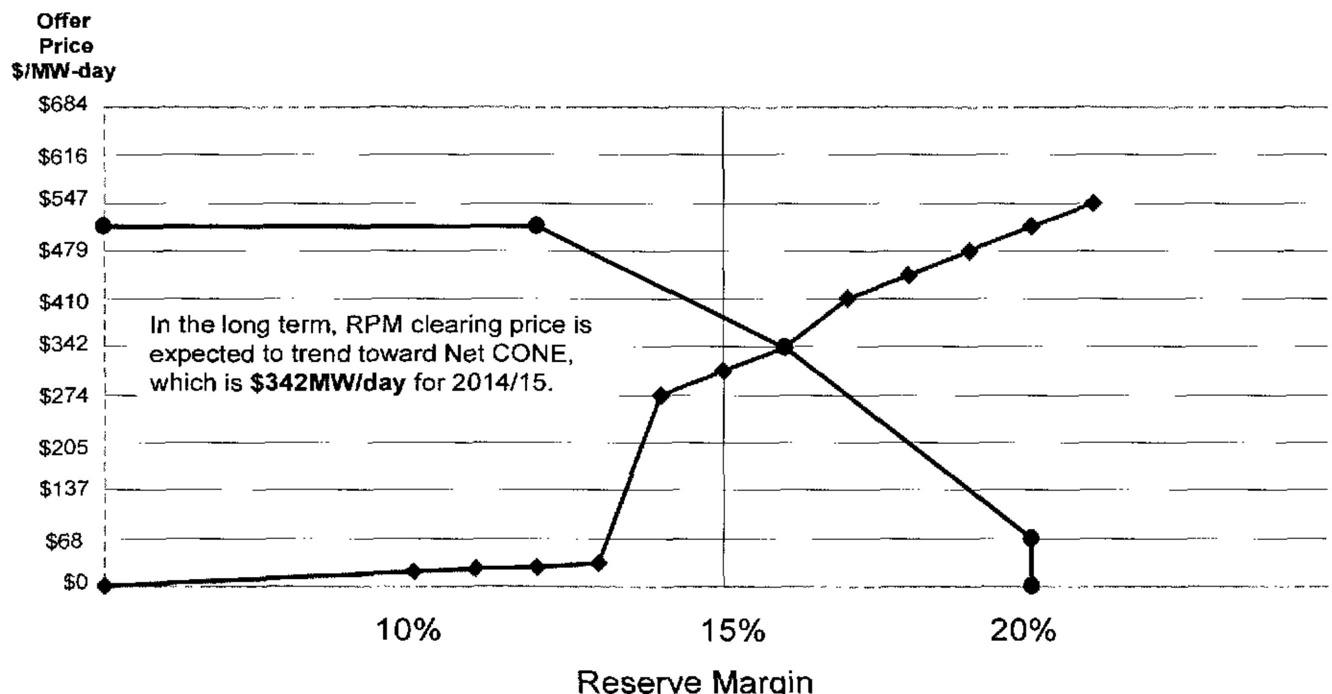
A. No. If a CRES provider relies on AEP for its capacity requirement, AEP is responsible for 100% of the penalties associated with non-performance under the FRR, and does not pass on to the CRES providers any of the penalties incurred.

Q. PLEASE ILLUSTRATE THE IMPACT OF USING THE RPM AUCTION CLEARING PRICE ON THE CAPACITY CHARGE PAID BY CRES PROVIDERS AND THE FRR ENTITY.

A. For 2012/13, the RPM auction clearing price in the AEP zone was approximately \$20/MW-day. This is equivalent to a \$0.83/MWH adder to the energy cost (\$20/MW-day/24 hours). The average PJM wholesale energy costs in 2010 were \$48.34/MWH. The \$0.83/MWH for capacity is only 1.7% of the energy price using these illustrative numbers.

However, if the RPM capacity auction clearing price continues to rise to Net CONE, the clearing price will be closer to \$342/MW-day (the Net CONE used for the 2014/15 auction, as represented in Figure 3 below). This would equate to a \$14.25/MWH (\$342/MW-day / 24 hours) cost for capacity. This \$14.25/MWH for capacity is over 29% of the 2010 energy cost of \$48.34/MWH.

Figure 3: Long Run RPM Auction Clearing Price at Net CONE



Notes:
- Demand curve is administratively set by PJM. Maximum clearing price = 1.5 x Net CONE = $513/MW-day in graph.
- Maximum reserve margin cleared = 20%, or target reserve margin (15% in example) + 5%.
- Supply curve is based on offers by generators in RPM capacity market.
- Net CONE is equivalent to $342/MW-day. Net CONE is defined as the cost of new entry for a gas peaking unit. PJM uses this value as the basis for determining the RPM demand curve.

Q. WHAT HAS PJM STATED FOR THE FUTURE OF CAPACITY SUPPLIES AND RPM AUCTION CLEARING PRICES?

A. PJM believes that in the long run, capacity prices will likely average close to the Net CONE prices ($342/MW-day for the 2014/15 RPM auction), even if there is continued volatility in the short run. PJM is supported in this opinion by independent consultant Professor Benjamin Hobbs[2], who provided opinions and analytical work as part of the RPM development process. Professor Hobbs supported the premise that in the long run Net CONE would be the value that would

[2] See PJM Interconnection, L.L.C., June 30, 2008 informational filing at FERC in Docket Nos. ER05-1410-000 and EL05-148-000.

attract the necessary reserve levels of primarily gas units in the RPM capacity market.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.