BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

OHIO POWER COMPANY'S INITIAL POST-HEARING BRIEF

Steven T. Nourse
Matthew J. Satterwhite
Yazen Alami
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
(614) 716-1608
Fax: (614) 716-2950
Email: stnourse@aep.com
mjsatterwhite@aep.com
yalami@aep.com

Daniel R. Conway
Christen M. Moore
Porter, Wright, Morris & Arthur, LLP
41 South High Street
Columbus, Ohio 43215
(614) 227-2270
Fax: (614) 227-2100
Email: dconway@porterwright.com
cmoore@porterwright.com

Counsel for Ohio Power Company

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I. INTRODUCTION

Despite the rhetoric and hyperbole this case has generated, the crux of this case is a straightforward ratemaking matter that should be processed and decided in the same manner as other more routine ratemaking cases that come before this Commission. Consistent with other cases, the Public Utilities Commission of Ohio's (Commission) task here is to establish just and reasonable rates that reflect cost, avoid rate shock and preserve the financial integrity of the affected utility. Ohio Power Company (dba AEP Ohio) merely asks for a rate that reflects its costs of providing the service being conveyed.

The Commission may also decide it needs to consider how its decision in this case will affect retail competition in the state, an issue around which there has been extensive and often misleading rhetoric from intervening parties who would stand to benefit unfairly from prices that do not reflect AEP Ohio's costs. While AEP Ohio supports the state's policies to promote retail choice, it is important that the Commission not confuse fostering genuine competition with simply bestowing an unwarranted wealth transfer to aspiring retail competitors, via forcing AEP Ohio to resell its capacity at a substantial loss.

Under the FRR provisions in the PJM Interconnection, L.L.C. (PJM) Reliability Assurance Agreement (RAA), AEP Ohio has always opted out of the Reliability Pricing Model (RPM) market and opted to enter into a binding contract as a Fixed Resource Requirement (FRR) entity, with strong encouragement from the Commission, to provide sufficient capacity for all connected load. As such, AEP Ohio is obligated to provide capacity resources sufficient to support all shopping load in its service territory. Using RPM pricing for the June 2012 through May 2015 period does not permit AEP Ohio to recover anything close to its costs of providing capacity to support shopping, which costs are reflected in the rates AEP Ohio charges its non-shopping customers. Thus, RPM pricing would propagate an unreasonable and unlawful subsidy of competition for generation services in AEP Ohio's service territory. Indeed, the RPM capacity prices are scheduled to decline from the already very low and non-compensatory levels that are currently in effect to a near-zero level beginning June 1, 2012. Because of that problem and in light of increasing shopping activity in its service territory, AEP Ohio proposed in November 2010 to implement an existing clause within the RAA to change the basis of compensation for use of its capacity by competitive retail electric service (CRES) providers to an AEP Ohio cost-based method.

Nonetheless, as a major step and sign of good faith that AEP Ohio is committed to a fully competitive standard service offer (SSO) process, AEP Ohio recently declared that it will not continue its FRR status and, instead, decided to fully participate in the RPM market for capacity starting on June 1, 2015, which is the soonest possible date to achieve the transition from FRR to RPM. This significant development reduces the scope of this proceeding to establishing a three-year transitional (rather than permanent) capacity charge. AEP Ohio's recent RPM election is a huge step that intervenors in the recent ESP proceeding universally advocated for (and bargained for in the now-rejected ESP Stipulation). Now that AEP Ohio has proceeded to take that important step (even without the benefits contained in the Stipulation package), intervenors greedily clamor for immediate RPM pricing (having already achieved their primary goal of getting AEP Ohio to elect to become an RPM entity).

In response to recent policy directives of the Commission, AEP Ohio is further pursuing a comprehensive and accelerated transition to fully market-based SSO rates, during which it must: (1) achieve full corporate separation, (2) unwind the 60-year old AEP Interconnection Agreement (Pool) that presently links the AEP East operating companies' generation fleet together, and (3) transition to an auction-based SSO in three years rather than the 6-10 year period required under a market rate offer. Because of the necessary actions described above and in light of the undisputed fact that AEP Ohio will remain an FRR Entity until June 1, 2015, however, it is not appropriate to require AEP Ohio to accept auction prices based on the RPM for its capacity resources until June 1, 2015.

As the Commission is aware, there are multiple cases pending before the Federal Energy Regulatory Commission (FERC) relating to the ongoing dispute about the proper capacity charges to be collected by AEP Ohio when it provides capacity resources supporting shopping load in its service territory. In addition to being the just and reasonable thing to do, the Commission's establishment of the proposed cost-based rate in this proceeding or acceptance of the package of modified ESP terms as filed that includes discounted capacity rates discussed below will also diffuse the Federal-State jurisdictional conflict that is staged regarding jurisdiction over the wholesale capacity charges if the Commission either establishes the proposed cost-based rate in this proceeding or accepts the package of modified ESP terms as filed in Case Nos. 11-346-EL-SSO *et al.* (that includes discounted capacity rates). By contrast, if the Commission rejects the notion of establishing a reasonable cost-based rate in this proceeding, the Federal-State jurisdictional conflict will need to be fully litigated and resolved. Moreover, rejecting a reasonable cost-based capacity charge in this proceeding will also, at best, severely undermine the course of the modified ESP proceeding.

The additional arguments below demonstrate, in detail, why the Company's proposed cost-based capacity charge of $355.72/MW-day is reasonable and supported by the manifest weight of the record. Those detailed arguments about a cost-based charge will not be repeated here but there are a few points that should be understood up front. AEP Ohio has advanced a cost-based capacity charge of $355.72/MW-Day on a merged Company basis. The formula rate approach that Dr. Pearce used to calculate an appropriate cost-based capacity price is based upon the average cost of serving AEP Ohio's Load Serving Entity (LSE) obligation load (both the load served directly by AEP Ohio or by a CRES provider) on a dollar-per-MW-day basis. Because the Company is self-supplying its own generation resources to satisfy these load obligations, the cost to provide this capacity is the *actual embedded capacity cost* of CSP's and OPCO's generation. The formula rate template that Dr. Pearce utilized here is tested and proven. As Dr. Pearce testified, "[f]ormula rates are currently utilized in many states by AEP for other wholesale sales." (AEP Ohio Ex. 102 at 8.) Notably, FERC itself has previously approved the template utilized by Dr. Pearce.

AEP Ohio has not proposed to offset, in the first instance, the cost-based capacity rate ($355.72/MW-Day on a merged Company basis) with an energy credit. Dr. Pearce explained that an energy credit offset is not warranted in light of PJM's complete separation of the markets for capacity and energy. As an initial matter, an energy credit operating to reduce the price of capacity being provided to CRES providers should not reflect an offset for off-system sales (OSS) margins that are not associated with the capacity being paid for to support shopping load – especially since non-shopping retail customers do not receive such an offset. At a minimum, if the energy credit is to capture the OSS margins attributed to "freed up" energy associated with the capacity being used by a CRES provider, it should not also confiscate AEP Ohio's pre-existing traditional OSS margins that are unaffected by the sale of capacity to CRES providers. If an energy credit is to be applied without regard to the actual test period energy credit that is based on actual 2010 results, a projected energy credit must be estimated with due care and precision. Unfortunately, the energy credit proffered by Staff through its outside witnesses does not fulfill that description.

One complicating factor is the transition toward eliminating the 60-year old Pool. AEP has proposed to terminate the Pool effective January 1, 2014 – but the outcome of the involved process before FERC is uncertain and, in any case, will not be completed until the latter part of the transition period described above. The Company's proposed cost-based capacity charge is based on a 2010 test period and fully reflects the current operation of the Pool. The Staff's capacity charge was developed through testimony from external witnesses from Energy Ventures Analysis (EVA) and Larkin & Associates (Larkin). The method used by Larkin to establish a demand charge reflects the benefits of the Pool to AEP Ohio (through recognition of the substantial $125/MW-day credit associated with the Pool's capacity equalization payments to AEP Ohio), while the energy credit developed by EVA partially ignores the costs of the Pool (through an energy credit that does not fully recognize operation of the Pool with respect to OSS margins that would be retained by AEP Ohio). EVA's best-of-both-worlds approach is unacceptable and violates the FERC-approved Pool. EVA's energy credit is riddled with errors and faulty assumptions, which substantially overstate the likely margins to be retained by AEP Ohio. One particularly egregious error was that EVA imputed a fictional market-based margin attributable to 100% of the non-shopping load and incorporated that into the energy credit to offset the charge for shopping load, which not only creates an unreasonable and unlawful subsidy but also confiscates margin that is authorized for AEP Ohio to retain under SSO rates. Due to all of these errors, EVA's projected margins result in an unrealistically high energy credit.[1] Indeed, as revealed by EVA's witnesses, their forecasting exercise was utterly divorced from reality and simply failed to take into account both the actual costs associated with the real-world operation of AEP Ohio's generating plants and the forward energy market prices that exist for the time period at issue.

To the extent the Commission believes that its relatively straightforward ratemaking task in this case is complicated by the potential impact on shopping, there are two important things to be remembered. First, the evidence shows that there will still be competition if the proposed cost-based capacity charge is adopted. Many of the comments of interveners have focused on the capacity component as if by itself it determined the opportunity for CRES providers to succeed in the AEP territories. However, this is simply not the case. Energy costs are a much bigger component of generation supply, and those have fallen more substantially at wholesale than capacity prices, creating significant opportunities for entry. Second, the shopping being advocated by intervenors in this case would not reflect any improvement or advantage the CRES providers can bring to the supply process. Rather, it would be simply uneconomic bypass because the CRES provider is not bringing its own resources to the table or competing based on its own lower costs or a fair market advantage. Rather, the CRES provider who currently wins a retail customer in AEP Ohio's service territory is merely a middle man who creates shopping based upon obtaining below-cost access to AEP Ohio's generation resources. That CRES provider relies on being able to obtain below-cost capacity from AEP Ohio, even though the rates that AEP Ohio charges its non-shopping customers reflects AEP Ohio's costs. The result of that kind of uneconomic shopping represents nothing more than a transfer of wealth from AEP

[1] Staff witness Harter (employed by EVA) testified that he had reviewed a published report about his testimony by Jeffries Equity Research that was entitled *AEP Energy Margins Gone Wild*. (Tr. IX at 2035.) While the report was not discussed in detail or moved for admission into the record, AEP Ohio submits nonetheless that the title of the report is apropos.

shareholders to CRES providers, without a significant benefit to customers and at great financial harm to AEP Ohio. If the Commission nonetheless desires a higher level of shopping without being constrained to shopping that is economic or that provides significant benefits to customers, the Commission should bear in mind the Company's compromise proposal of discounted capacity charges being offered in AEP Ohio's recent Modified ESP filing as an integral part of a package of terms and conditions that includes the Retail Stability Rider to mitigate financial harm. The Commission's stated goals of compensating AEP Ohio while protecting retail shopping are best achieved through one of those two options: the cost-based capacity rate advocated by AEP Ohio in this proceeding or the compromise, discounted capacity rate offered by AEP Ohio as part of a package proposal made in its recent Modified ESP filing.

CRES interveners in this case have also argued that there AEP is seeking an unfair opportunity to recover sunk costs which their affiliated supply companies do not enjoy. However, this over-simplifies the history of the market restructuring in Ohio, fails to consider how the FRR obligation AEP has borne was supported and encouraged by the Commission and other parties. It also glosses over the fact that being a capacity provider in PJM's RPM markets, or having capacity obligations as a CRES provider, is not the same kind of burden as being an FRR supplier. One key distinction is that under FRR, AEP cannot opportunistically move in and out of providing the capacity needs of its territory as/when economically favorable conditions arise. Instead, it must hold capacity for the potential maximum needs of its region, and cannot easily or quickly place unneeded capacity into the wholesale markets. This is a costly constraint regardless of whether retail shopping increases or decreases in its service territory. None of the interveners seeking FRR capacity at RPM prices faces a similar burden.

II. BACKGROUND AND PROCEDURAL HISTORY

Under the FRR provisions in the PJM RAA, AEP Ohio is obligated to provide capacity resources sufficient to support all shopping load in its service territory. The initial default charge collected by AEP Ohio for providing this essential service is based on PJM's RPM capacity auction prices. RPM pricing established for the 2012-2015 period would not permit AEP Ohio to recover anything close to the full amount of its costs of providing capacity to support shopping. Indeed, the RPM capacity prices are scheduled to decline from the already very low and non-compensatory levels that are currently in effect to a near-zero level beginning June 1, 2012. Accordingly, in November 2010, consistent with the provisions in the RAA and its rights established by the Federal Power Act (FPA), AEP Ohio proposed to implement an existing clause within the RAA to change the basis of compensation for use of its capacity by CRES providers to an AEP Ohio cost-based method.[2]

Prior to 2007, and during the PJM RPM auction development phase, AEP, as well as other parties, expressed concern over the long-term negative impacts of the RPM capacity market on vertically integrated utilities, such as AEP Ohio, and their customers. Thus, as discussed in the testimony of Company witness Horton, Section D.8 of Schedule 8.1 of the PJM RAA, or the FRR provision, was drafted to ensure that FRR entities could request a cost-based method of recovering their capacity costs. (AEP Ohio Ex. 103 at 10.)

With the decrease in RPM auction prices and the onset of retail shopping in AEP Ohio's service territory in 2010, the adverse financial impact on AEP Ohio of supplying CRES providers with below-cost capacity became material. Accordingly, AEP Ohio made the decision

[2] On November 2, 2010, AEP Ohio filed an application with the FERC in FERC Docket No. ER11-1995-000. On November 24, 2010, at the direction of FERC, AEP Ohio refiled its application in FERC Docket No. ER11-2183-000 (the "§ 205 proceeding").

to pursue its right under the RAA to collect a cost-based rate from CRES providers for its capacity. In its November 2010 FERC application, AEP Ohio proposed cost-based formula tariffs that were based on Columbus Southern Power Company's and Ohio Power Company's 2009 FERC Form 1 filings, and showed the rates would be in effect if the formula was populated with 2009 FERC Form 1 data.[3] This application was intended to remedy the situation where CRES providers were receiving a subsidy from AEP Ohio for their use of the Company's capacity due to the use of RPM auction prices. Company witness Pearce has provided an update to these rates based on 2010 information and provided the evidence of the proper level of compensation to be recovered from CRES providers who utilize AEP Ohio's capacity. (AEP Ohio Ex. 102.) Since AEP Ohio's November 2010 FERC application, CRES providers in AEP Ohio's service territory have had multiple opportunities to choose to self-supply capacity, but none have done so. Each CRES provider that chooses not to self-supply its own capacity merely acts as a middle-man on capacity flowing from AEP Ohio for ultimate use by retail customers. (*See* AEP Ohio Ex. 101 at 5.)

In response to AEP Ohio's November 2010 application to the FERC, the Commission represented to FERC that as of December 8, 2010, it was "adopt[ing] as the state compensation mechanism for the Companies the current capacity charges established by the three-year capacity auction conducted by PJM," which is the PJM RPM auction price.[4] *See* Case No. 10-2929-EL-UNC, Entry at 2 (Dec. 8, 2010). AEP Ohio applied for rehearing of the Commission's

[3] At the time of the FERC filing, the merger of Ohio Power Company's predecessor companies, Columbus Southern Power Company and Ohio Power Company, had not been finalized. Hence, for 2009 and 2010, formula calculations were done for each company in recognition of their status as separate legal entities. The merger was effective as of December 31, 2011.

[4] At the time of the Commission's December 8, 2010 Entry, CRES providers were paying AEP Ohio $220/MW-day as the then-current RPM price.

December 8, 2010 Entry on January 7, 2011. In its application for rehearing, AEP Ohio argued, *inter alia*, that:

- The Commission's Entry establishing an interim wholesale capacity rate was unreasonable and unlawful because the Commission is a creature of statute and lacks jurisdiction under both Federal and Ohio law to issue an order affecting wholesale rates regulated by the Federal Energy Regulatory Commission.

- The Entry was issued in a manner that denied AEP Ohio due process and violated statutes within Title 49 of the Revised Code, including Sections 4903.09, 4905.26, and 4909.16, Revised Code.

- The Entry directly conflicts with, and is preempted by, federal law and therefore should be reversed and vacated.

(*See* Jan. 7, 2011 App. for Rehearing.) On February 2, 2011, the Commission granted AEP Ohio's application for rehearing of the December 8, 2010 Entry, finding that "sufficient reason has been set forth by AEP Ohio to warrant further consideration of the matters specified in the application for rehearing." Case No. 10-2929-EL-UNC, Entry on Rehearing at 2 (Feb. 2, 2011). That rehearing request remains pending.[5]

On January 20, 2011, FERC issued an Order rejecting AEP Ohio rate proposal, not on its merits, but due to the Commission's December 8, 2010 Entry stating that the Commission was adopting an interim state compensation mechanism. *See* FERC Docket No. ER11-2183-000, Order at 4-5 (Jan. 20, 2011). AEP Ohio's application for rehearing of FERC's January 20, 2011 Order also remains pending before FERC.[6] As a related matter, AEP Ohio filed a complaint

[5] By participating in this Commission-initiated docket, AEP Ohio is not waiving its stated objections (as previously advanced in this docket and in the FERC proceedings) concerning the Commission's jurisdiction and the adjudicative procedure used in this case, and the Company reserves the right to pursue any available legal remedies or avenues of relief before any state or federal administrative agency or court.

[6] FERC granted AEP Ohio's request for rehearing on March 24, 2011, s*ee* FERC Docket No. ER11-2183-001, Order Granting Rehearing for Further Consideration (Mar. 24, 2011), but has not yet issued a decision on rehearing.

case, FERC Docket No. EL11-32-000 (the "§ 206 proceeding"), to seek modifications to Section D.8 of Schedule 8.1 of the RAA designed to clarify the original intent of that section as AEP Ohio understood it. The purposes of that filing were: (1) to confirm that any state compensation mechanism must compensate FRR entities for capacity costs through charges included in retail rates; and (2) to preserve the FRR entities' right to submit filings under Section 205 of the Federal Power Act to establish just and reasonable FRR charges. Both FERC proceedings remain pending and could be decided at any time.[7]

In its August 11, 2011 Entry in this proceeding, the Commission established an initial procedural schedule for the hearing necessary to establish an evidentiary record on a state compensation mechanism. The Commission confirmed, at Finding 6, that the goal was to establish cost-based pricing for the capacity that AEP Ohio furnishes to CRES providers:

> Interested parties should develop an evidentiary record on the appropriate capacity <u>cost</u>/pricing recovery mechanism including, if necessary, the appropriate components of any proposed capacity <u>cost</u> recovery mechanism.

(Emphasis added). Subsequently, in its March 7, 2012 Entry in this proceeding, the Commission reiterated that its goal for the hearing in this proceeding was to establish "an evidentiary record on the appropriate capacity <u>cost</u> pricing/recovery mechanism . . . ." (Emphasis added). In their March 14, 2012, Entry, at Finding 8, the Commission's Attorney Examiners again reiterated that

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[7] After AEP Ohio entered into the September 7, 2011 ESP Stipulation, which proposed to resolve this case as well as a number of other cases pending before the Commission, AEP Ohio and American Electric Power Service Corporation (AEPSC) filed requests with the FERC in September and December 2011 that asked the FERC to defer ruling in FERC Dockets ER11-2183-000 and EL11-32-000 because the Stipulation, if approved, would have resolved the outstanding issues in both FERC dockets. *See* FERC Docket Nos. ER11-2183-000, EL11-32-000, Status Report (Sept. 16, 2011); FERC Docket Nos. ER11-2183-000, EL11-32-000, Status Report (Dec. 22, 2011). After the Commission issued its February 23, 2012 Entry on Rehearing rejecting the Stipulation, AEP Ohio and AEPSC filed a Motion for Expedited Rulings in both FERC dockets. The FERC has not yet ruled on that motion.

the objective of the evidentiary hearing scheduled to begin April 17, 2012, was to "develop an evidentiary record on the appropriate capacity <u>cost</u> pricing/recovery mechanism . . . ." (Emphasis added).

Also of note, on March 15, 2012, PJM Interconnection, L.L.C. filed a Response to AEP's February 29, 2012 Motion for Expedited Rulings in FERC Dockets ER11-2183-001 and EL11-32-000. (AEP Ohio Ex. 103C.) In its pleading, at page 2, PJM questioned whether the action taken by this Commission to date in fact meets the requirement of Section D.8 of Schedule 8.1 of the RAA as a state compensation mechanism, but expressed its expectation that this Commission "ultimately will adopt a final state compensation mechanism that, consistent with the intent of Section D.8, will compensate AEP for the <u>cost</u> to satisfy its FRR capacity obligations associated with load * * * served by CRES Providers." (*Id.* at 2 (emphasis added).)

Even though the Commission's inquiry and statements before FERC have indicated that the purpose of this proceeding is to explore AEP Ohio's true capacity costs, intervenors continue to lobby all-or-nothing for RPM pricing and their testimony largely fails to meaningfully engage in an examination of AEP Ohio's capacity costs. This phenomenon is captured in an exchange between Commissioner Porter and Retail Energy Supply Association (RESA) witness Ringenbach. During her cross examination by AEP Ohio counsel, Ms. Ringenbach acknowledged that her testimony does not address the issue of a proper cost-based charge, even though she stated that it is her understanding that an FRR Entity has the option to establish a cost-based capacity charge. (Tr. IV at 801-802.) Commissioner Porter followed up her testimony with a clarifying question:

> By Commissioner Porter:
>
> Q. Ms. Ringenbach, quickly I want to understand an exchange that you had with Mr. Nourse. You agree that the purpose of this

> proceeding is to assist the Commissioners in understanding the true cost of capacity for AEP Ohio?
> A. Yes.
> Q. And you testified on behalf of RESA or Direct Energy, I'm sorry?
> A. Both.
> Q. Both, okay. Has either of RESA or Direct Energy taken a position with regard to the true costs of capacity what the rate should be?
> A. No. We -- it's the focus is on making sure it's balanced between shoppers and non-shoppers.

(*Id.* at 831-832.) Thus, RESA has failed to address the main issue in this case. Other intervenors also admitted they did not evaluate AEP Ohio's costs. (*See, e.g.,* Tr. IV at 774: 11-14; Tr. VI at 1247:3-10.) For its part, Staff has submitted testimony that addressed a cost-based charge but ended up recommending a rate that is non-compensatory, as further discussed below.[8]

III. AEP OHIO IS ENTITLED TO CHARGE A COST-BASED PRICE FOR THE CAPACITY IT SUPPLIES TO CRES PROVIDERS.

A. Section D.8 Of Schedule 8.1 Of The RAA Permits AEP Ohio The Right To Establish A Rate For Capacity That Is Cost-Based.

The plain language of Schedule 8.1, Section D.8 of the RAA establishes AEP Ohio's right to elect to charge a cost-based rate to CRES providers for the capacity that it is obligated to provide to them. Section D.8 of Schedule 8.1 of the RAA states:

> In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail

[8] Though Staff's testimony did not advocate RPM pricing and only addressed the method for establishing a cost-based capacity rate, it is not clear that Staff will advocate on brief that AEP Ohio's capacity charge should be cost-based.

> LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, **provided that the FRR Entity may, *at any time*, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's costs** or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

(Emphasis added). Under the FRR Alternative, pursuant to Section D.8 of Schedule 8.1, there are three alternatives for pricing capacity provided to CRES providers: (1) a properly designed retail state compensation mechanism and in the absence of such a mechanism, (2) rates based on the PJM RPM capacity auction price, and (3) a method based on the FRR Entity's costs (a formula cost-based method) or such other cost basis shown to be just and reasonable. Notably, Section D.8 provides that the FRR Entity may, at any time, change the basis for compensation to a method based on the FRR Entity's cost. Thus, by its plain language, the RAA allows an FRR Entity like AEP Ohio to change the basis for capacity pricing to a cost-based method at any time.

As AEP Ohio witness Horton explained in his direct testimony, AEP Ohio was an active participant in drafting Section D.8 of Schedule 8.1 of the RAA, and AEP Ohio expected at the time the RAA was drafted that Section D.8 would allow AEP Ohio to recover the embedded costs of the capacity that it is required to supply to CRES providers. (*See* AEP Ohio Ex. 103 at 9-10.) This compensation provision was important to AEP Ohio to ensure that it would be adequately compensated for supplying to CRES providers in its service territory the capacity resources that CRES providers provide to switching customers. (*Id.* at 10.)

During the drafting of Section D.8, the stakeholders also discussed the possibility that a state utility commission might seek to implement a retail choice program with rules that would require shopping customers to pay capacity-related charges directly to the incumbent utility.

(*Id.*) Although AEP Ohio 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 adopt a state compensation mechanism that would implement such a capacity charge directly to a retail customer (as opposed to a wholesale charge to a CRES provider). (*Id.*) AEP Ohio fully expected, however, that any such provision would still allow AEP Ohio to recover its costs for the capacity it is obligated to supply. (*Id.*)

Further, because the FERC has jurisdiction over wholesale electric rates and State commissions like the PUCO have jurisdiction over retail rate matters, it should be manifestly evident that Section D.8's reference to a state compensation mechanism contemplates a retail – not a wholesale – capacity charge.[9] (*See* Tr. III at 621:11-622:2; AEP Ohio Ex. 101 at 5, 7. *See also* Jan. 7, 2011 App. for Rehearing at 19 (stating AEP Ohio's position that "the provision of generation capacity to CRES providers is a wholesale transaction that falls within the exclusive ratemaking jurisdiction of the FERC").)[10] Accordingly, for each of these reasons, the plain language of the RAA requires that AEP Ohio be permitted to establish a cost-based rate for the capacity that AEP Ohio provides to CRES providers.

[9] Witnesses universally agreed that the capacity charges at issue in this case are wholesale charges. (*See, e.g.,* Tr. IV at 795; Tr. V at 1097:12-17, 1125:4-8; Tr. VI at 1246:15-21, 1309:1-5, 1314:12-15.)

[10] As described in Section II, *supra*, AEP Ohio's § 206 proceeding, in which AEP Ohio has asked the FERC to confirm that any state compensation mechanism, as that term is used in Schedule 8.1, Section D.8 of the RAA, must compensate FRR entities for capacity costs through charges included in retail rates and to confirm that FRR entities have the right to submit filings under Section 205 of the FPA to establish just and reasonable FRR charges, remains pending before the FERC. (*See* AEP Ohio Ex. 101 at 7.)

B. AEP Ohio's Proposed Cost-Based Capacity Rate Advances Commission And State Policy Objectives.

It is a policy of the state to "[e]nsure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service." R.C. 4928.02(A). The Commission has repeatedly voiced its commitment to this policy objective both in this proceeding and in proceedings before the FERC, as well as in its mission statement. *See* Public Utilities Commission of Ohio, Mission and Commitments, PUCO Mission, http://www.puco.ohio.gov/puco/index.cfm/about-the-commission/mission-and-commitments/ (accessed May 18, 2012) (stating that the Commission's mission is accomplished by "[e]nsuring financial integrity and service reliability in the Ohio utility industry"). In a March 2012 filing in the § 205 and § 206 proceedings, the Commission reiterated its commitment to that policy objective and stated, with regard to this proceeding, that it is "endeavoring to arrive at a CRES capacity rate that will promote alternative competitive supply and retail competition while simultaneously ensuring an incumbent electric utility provider's ability to attract capital investment to meet its FRR obligations." (*See* OEG Ex. 101 at 4 (emphasis added).)

1. AEP Ohio's proposed cost-based capacity rate achieves the Commission's first objective of promoting alternative competitive supply and retail competition.

The Company's proposed cost-based $355.72/MW-Day capacity rate satisfies the Commission's first stated objective. As witness Allen demonstrated, there will be an opportunity for customers in all classes to shop, and for CRES providers to earn margins, at the Company's proposed $355.72/MW-Day full-cost capacity rate. (Tr. XI at 2330:20-2331:14.) He explained that a capacity charge greater than RPM will not discourage or lead to a decrease in shopping; rather, a CRES provider's ability to compete will depend on whether the CRES provider can offer rates that are below Ohio Power's SSO rates. (*Id.* at 2504:14-16.) A CRES provider's ability to compete depends on a number of price inputs and other factors, including the price the CRES provider pays for wholesale energy.

The price of energy, a major input, has been and continues to be in decline. (AEP Ohio Ex. 104 at 6.) Thus, when all other price inputs are held constant, a decrease in the price of energy would lead to an increase in a CRES providers' margin or headroom. If the price of capacity increased above the RPM rate while the energy price decreased, Mr. Allen explained that he would expect that CRES providers could and would still make competitive offers to retail customers. Moreover, he reasoned that customers who decide to shop will do so regardless of the relative size of the ultimate discount they receive. (Tr. XI at 2405:16-20; 2406:9-14.) The opportunity for a greater level of savings might be present with a lower capacity charge but that might also simply increase the CRES providers' margin.

Mr. Allen's expectation is supported by the fact that shopping presently is occurring at capacity prices that are well above current and future RPM prices. (*Id.* at 2332:24-2333:2; AEP Ohio Ex. 104 at 6.) Specifically, he noted that CRES providers made offers to customers when the capacity charge was $255/MW-Day and the price of energy was $10/MW-hour higher than it is now. (Tr. XI at 2406:4-7.) Moreover, he explained that a CRES provider's gross margin at the $355.72/MW-Day price is 13.7% on an average class basis. (Tr. III at 635:2-4.) That level of margin is significant. (*Id.* at 632:5.) That the amount of shopping may not increase as significantly as it would if AEP Ohio were required to provide capacity at RPM rates does not mean that a rate higher than RPM does not promote competition. As Mr. Allen noted, the Commission's focus should be on fair and balanced competition, not on shopping for shopping's sake. (Tr. XI at 2332.) Mr. Allen's testimony was confirmed by other witnesses as well. RESA confirmed that its members' offers continue to be made generally at $255/MW-day, while some customers would receive offers at $355.72/MW-day. (Tr. IV at 820-21.) Of course, capacity prices from AEP Ohio are only one factor that drive whether CRES providers can make offers to retail customers. (*Id.* at 821; Tr. VIII at 1562-1563, 1693.) Indeed, Exelon witness Fein testified that "there are many factors that go into" whether a customer views an offer as a good offer. (Tr. VIII at 1562-1563.) Similarly, FES witness Banks agreed that "there are various component costs that go into a price that FES might offer a customer." (*Id.* at 1693.)

RPM-based capacity pricing, by contrast, would induce an uneconomic bypass opportunity for CRES providers – at the expense of AEP Ohio's customers and shareholders – and would not foster efficient or durable competition. (AEP Ohio Ex. 105 at 7.) As AEP Ohio witness Graves explained, even more CRES providers would be encouraged to enter AEP Ohio's service territory if AEP Ohio charged nothing at all for the capacity it supplies them, but that would serve only to create a market of free riders, not one of capable suppliers with truly lower costs or superior service. (*Id.* at 13.) This could ultimately necessitate significant increases in non-shopping SSO rates and/or or non-generation retail rates, since a capacity rate of $20/MW-day is not sustainable.

In any case, contracts between CRES providers and retail customers accommodate an increase in the capacity charge. For RESA members' competitive retail offerings, small commercial customers were offered fixed prices under the Stipulation based on both the RPM and $255/MW-day capacity prices; medium and larger commercial and industrial customers negotiated a capacity charge tracking provision, which is a passthrough of increases or decreases. (Tr. IV at 796-97.) RESA members' retail contracts involve capacity charge passthrough provisions as well as "regulatory out" clauses and *force majeure* clauses that may permit termination of the contract based on capacity charge increases; customers also have the right to terminate which for residential customers involved a nominal fee (such as FES's $10 exit fee, IGS's zero fee, and others' $25 fee). (*Id.* at 829-30.) Of course, as RESA witness Ringenbach admitted, CRES providers also have the option of absorbing capacity charge increases. (*Id.* at 831.) Exelon witness Fein similarly testified that "CRES providers can decide what they want to offer." (Tr. VIII at 1573.) And, FES witness Banks agreed that even if FES were required to pay a cost-based capacity charge, "FES would always honor its contracts." (*Id.* at 1688; *see also id.* at 1704-1705.)

In sum, the Commission's focus should be on fairness and genuine competition, not on the manufacture of artificial competition through subsidization for its own sake. Accordingly, because shopping will still occur and CRES providers will still realize a significant margin if capacity costs for CRES providers of $355.72/MW-Day, AEP Ohio's proposed rate satisfies the Commission's objective of promoting competition. Moreover, as further discussed below, the Commission should promote "effective competition" under R.C. 4928.02(H) and should not promote artificial or subsidized competition, especially given the financial harm that such artificial, subsidized "competition" would cause to AEP Ohio.

2. AEP Ohio's proposed cost-based capacity rate achieves the Commission's second objective of ensuring that AEP Ohio is able to continue to attract capital and comports with the state policy articulated in R.C. 4928.02(A).

The Company's proposed cost-based $355.72/MW-Day capacity rate also satisfies the Commission's second stated objective and furthers the state policy set forth in R.C. 4928.02(A). Section 4928.02 of the Revised Code sets forth Ohio's state policy with regard to competitive electric retail service. Among others, it is a policy of the State to "[e]nsure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service." R.C. 4928.02(A). Approving AEP Ohio's proposal to charge CRES providers a cost-based rate for capacity will enable AEP Ohio to continue to attract capital, which in turn will allow AEP Ohio to satisfy its FRR obligation without harm to AEP Ohio and will allow AEP Ohio to provide customers with reliable and reasonably priced retail electric service as contemplated in R.C. 4928.02.

A cost-based capacity rate advances the state policy set forth in R.C. 4928.02(A) and represents a long-term view of affordable and reliable capacity for Ohio customers for two reasons. First, such a pricing mechanism will encourage investment in generation in Ohio and thereby increase retail reliability and affordability. As AEP Ohio witness Munczinski explained, power plants are built as long-term assets, with an understanding between the state and the company building them (in this case, AEP Ohio) that the company will be compensated over the long term for its investment. (Tr. I at 43:8-18.) Allowing AEP Ohio to recover its capacity costs would allow AEP Ohio to recover some of the costs of its long-term generation investments and would provide incentives for additional future investment in in-state generation. As Mr. Munczinski explained, capacity pricing based on short-term RPM auction prices would not provide such an incentive. Instead, it would amount to an "abdication of the [Commission's] authority to ensure long-term generation adequacy and reliability within the state." (*See* AEP Ohio Ex. 101 at 13.)

Second, cost-based capacity pricing adequately compensates AEP Ohio for its obligations as an FRR Entity. As Company witness Munczinski testified, because AEP Ohio is an FRR Entity, its capacity is dedicated to its Ohio service territory, including those customers who choose to shop and who are served by CRES providers that opt to utilize capacity that AEP Ohio supplies to them. (AEP Ohio Ex. 101 at 10.) The Commission Staff supported AEP Ohio's FRR election and the increased reliability that it secured for Ohio's retail electric customers. (*See*

AEP Ohio Ex. 103 at 11; AEP Ohio Ex. 103A.) By agreeing to dedicate this capacity to its Ohio customers, AEP Ohio has forgone the opportunity to sell its capacity in the market or to buyers outside Ohio. (AEP Ohio Ex. 101 at 10.) This point is of particular significance, given that market prices for electricity have been substantially higher than AEP Ohio's SSO rates over most of the past decade. That long-term capacity dedication and agreement not to sell capacity elsewhere, where it might recover more than its costs, warrants permitting AEP Ohio to charge a price for capacity to CRES providers that is based on AEP Ohio's costs of creating that capacity, not on the comparatively short-term RPM auction prices. (*Id.*) Thus, for both of the reasons discussed above, AEP Ohio's recovery of a cost-based price for capacity furthers and reflects the state policy supporting the provision of adequate and reliable electric service that is set forth in R.C. 4928.02(A).

An RPM-based capacity rate, by contrast, would not reflect or advance this state policy. RPM would significantly undercompensate AEP Ohio for the capacity that it provides to CRES providers, as further discussed below. As Company witness Allen explained, if it were allowed to charge CRES providers only the RPM-based price for capacity, AEP Ohio would earn a return on equity of only 2.4% in 2013. (*See* AEP Ohio Ex. 104 at 3, Ex. WAA-1; Tr. III at 579:6-21.) Such a return would significantly undercompensate AEP Ohio for its capacity. (Tr. III at 579:16; AEP Ohio Ex. 101 at 8.) As Company witness Allen explained, "a reasonable return on equity in today's environment is in the 10 to 12 percent range" for a utility. (Tr. III at 581:1-3.) A return of 2.4% – <u>four to five</u> times <u>lower</u> than the range of reasonable returns – would be confiscatory and would not fairly compensate AEP Ohio for its generation asset investments. More importantly, the fact that RPM prices are so much lower than AEP Ohio's demonstrated costs for providing capacity to support shopping load means that there is a negative return for that part of the business; whether the wires business lines (*e.g.*, transmission and distribution) make up for such losses is beside the point. CRES providers are relying on AEP Ohio's capacity resources and should pay a cost-based rate, even if AEP Ohio's other revenue streams could support a reasonable overall ROE, especially since such a cross subsidy of a competitive service is unreasonable and unlawful.

Moreover, If AEP Ohio were compensated at RPM-based rates, AEP Ohio's ability to provide customers with adequate and reliable service could be undermined because the yearly price fluctuations attendant to the RPM auction (which in past years have been dramatic) make investment in Ohio generation assets undesirable. (*See id.*; AEP Ohio Ex. 102 at Ex. KDP-7 (presenting historical auction clearing prices).) As Mr. Munczinski explained, this unclear and unstable cost recovery environment would make investment in long-term capital imprudent and irresponsible. (AEP Ohio Ex. 101 at 14.) This instability in cost recovery, coupled with increasing state and federal environmental mandates, would put Ohio customers at risk for long-term in-state generation capacity deficiencies. (*Id.*) Regardless of the fact that AEP Ohio is not planning to build significant new generation prior to 2015, capital maintenance of existing generation is necessary on a continual basis. The following table demonstrates the dramatic yearly fluctuations that have or will occur in the RPM market since the beginning of this proceeding.

		$/MW-Day	
PJM Planning Year		PJM Base Residual Auction (BRA) Rate	CRES Capacity Charges*
2010/2011		$ 174.29	$ 220.96
2011/2012		$ 110.00	$ 145.79
2012/2013		$ 16.46	$ 20.01
2013/2014		$ 27.73	$ 33.71
2014/2015		$ 125.99	$ 153.89
*BRA adjusted for Final Zonal Capacity price, Scaling Factor, Forecast Pool Requirement, and Losses			

And, as AEP Ohio witness Munczinski explained, aligning the retail state compensation mechanism to the RPM wholesale price would result in Ohio capacity being solely influenced by the administrative RPM auction process administered by PJM. (*Id.* at 9.) Accordingly, for each of the reasons discussed above, AEP Ohio's proposed cost-based capacity rate – not the RPM auction-based price – enables AEP Ohio to continue to attract capital and comports with the state policy articulated in R.C. 4928.02(A).

C. During The Period In Which AEP Ohio Remains An FRR Entity, RPM Is Not An Appropriate Basis Upon Which To Price AEP Ohio's Capacity.

1. AEP's current status as an FRR Entity makes the use of RPM-based pricing inappropriate.

AEP Ohio's unique position in PJM as an FRR Entity make it inappropriate to use an RPM-based capacity charge for the capacity that AEP Ohio supplies to CRES providers. As an FRR Entity, AEP Ohio does not procure capacity for its load obligations in PJM's RPM auctions or capacity procurement, except to the extent that it has capacity that it does not need for its native load. Even then, its auction participation is limited to 1,300 MW. (AEP Ohio Ex. 105 at 8; *see also* Tr. III at 661-662 (where Mr. Allen notes that AEP Ohio did not participate in the most recent RPM auction and that the RPM auction is not AEP Ohio's market).) As Mr.

Munczinski testified on cross-examination, given AEP Ohio's status as an FRR Entity, if the capacity charge that CRES providers pay is based on RPM pricing, then AEP Ohio is not recovering its capacity costs, and the difference is not made up from SSO customers. (Tr. I at 64.) Additionally, Mr. Munczinski explained that a move to RPM pricing would "reprice the capacity at an auction price that [the Company] did not even participate in." (*Id.* at 183.) Such a requirement would not be compensatory for AEP Ohio, as discussed elsewhere in this brief.

Intervenor witnesses recognize the significance of AEP Ohio's FRR status, by agreeing that AEP Ohio has opted out of the RPM market. (*See* Tr. IV at 800; Tr. VIII at 1518.) Indeed, FES witness Stoddard explained that while a CRES provider's sole obligations are to "serve their load and pay a price" (Tr. VIII at 1606:22-23), an FRR Entity like AEP has detailed obligations that are set forth in sections 7 through 12 of Attachment DD to the PJM tariff with which it must comply. (*Id.* at 1606:24-1607:2.)

Intervenors also fail to point to any legal obligation that AEP Ohio has to continue providing RPM-priced capacity. Rather, they merely argue as a policy matter that RPM would be favorable to their interests. (*See, e.g.,* Tr. IV at 765, 802.) The Company remains obligated to PJM, however, to provide long-term capacity (with a 5-year minimum initial commitment) for all of the load in its distribution franchise territory, including the load that is served by CRES providers. (AEP Ohio Ex. 105 at 8; Tr. III at 662:2-3.) CRES providers, by contrast, enjoy advantages and flexibilities in power supply and pricing that AEP Ohio's generation does not. Specifically, CRES providers do not have any obligation to serve load beyond the extent to which they voluntarily enter into forward sales contracts, and they may choose to stop serving customers if providing retail electric service becomes disadvantageous to them. (AEP Ohio Ex. 105 at 17.) None of the CRES providers operating in AEP Ohio's service territory, though, have elected to self-supply. (*See, e.g.,* Tr. IV at 803-04.) Thus, as AEP Ohio witness Graves explained, they have the advantage of moving in and out of the market that AEP Ohio as an FRR Entity presently does not enjoy. (*Id.* at 18.)

Moreover, as AEP Ohio witness Graves explained, while the Base Residual Auction (BRA) has attracted sufficient incremental capacity resources to maintain reliability over the next few years, those resources are not the same kinds of resources that would be preferred for an FRR Entity like AEP Ohio. (*Id.* at 7.) AEP Ohio's resources were chosen because they are preferable for long-term resource planning that is focused on minimizing lifecycle costs of power, minimizing risks, and maintaining long-term reliability and, thus, they are very different, both in their character and in their carrying costs, from resources typically bid into the BRA. (*Id.*)

RESA opposes any regulatory structure for pricing and universally advocates market-based pricing, though Ms. Ringenbach agreed that SB 221's ESP option is a regulated pricing option for the SSO and stated that RESA prefers an MRO structure. (Tr. IV at 794, 798-99.) Intervenor preferences do not alleviate AEP Ohio's existing FRR obligations. And Ohio CRES providers have been well aware of AEP Ohio's position for years now. RESA witness Ringenbach agreed that all or virtually all of the existing retail contracts in existence today have been entered into after November of 2010, when AEP Ohio filed its FERC case to establish a cost-based capacity charge. (Tr. IV at 831.) CRES providers cannot claim reliance upon, or a continuing expectation of, RPM pricing.

Thus, because its obligation as an FRR Entity is a longer and more binding reliability obligation than a CRES provider's obligations as a Load Serving Entity (LSE), allowing AEP

Ohio to recover only an RPM-based price for its capacity would not be compensatory. For these reasons, RPM-based capacity pricing should be rejected.

2. RPM-based capacity pricing would give CRES providers an unfair preference over the members of AEP Ohio's pooling agreement.

AEP Ohio's pooling agreement with other members of the AEP East Pool also makes it inappropriate to require AEP Ohio to supply CRES providers with RPM-priced capacity. It is planned that AEP Ohio will remain a member of its present pooling agreement until January 2014. (Tr. I at 31:21-25.) Under the terms of the pooling agreement, the members of the pooling agreement are required to have sufficient capacity to meet their load. (*Id.* at 57:9-11; 58:16-24.) If one member of the pool has insufficient capacity to meet its load obligations, and another member is long on capacity, then the member with insufficient capacity is required to purchase additional capacity from the member that is long on capacity. When these inter-pool sales or transfers occur, capacity is sold at its embedded cost. (*Id.* at 59:21-24.) Thus, for example, if Appalachian Power has less capacity than it needs to cover its load, it purchases additional capacity from Ohio Power Company at Ohio Power's embedded cost. (*Id.* at 59:25-60:2.)

As AEP Ohio witness Munczinski explained, due to the nature of the AEP Pool Agreement and the requirement that transfers of capacity be made at embedded-cost rates, it would be unfair and inequitable for CRES providers in Ohio to receive capacity at RPM prices. (*Id.* at 60:2-5.) Indeed, charging a rate lower than AEP Ohio's embedded costs to CRES providers would discriminate against both the other members of the Pool, as well as AEP Ohio's non-shopping customers. (*See id.* at 85.) Allowing CRES providers to receive preferential pricing would disadvantage members of the pooling agreement and their customers, as well as AEP Ohio's SSO customers. (*See id.*) On cross-examination, AEP Ohio witness Nelson explained this issue as follows:

> And one of the big inequities when we're talking about what CRES providers pay for capacity is that other pool members pay a high rate for capacity, they pay our costs, cost-based capacity. And they're entitled to the other provisions of the pool. And to subsidize CRES providers while we're paying what other affiliates are paying a higher capacity rate would be very inappropriate and also for CRES providers to pay less than what our SSO customers pay for capacity would be inappropriate.

(Tr. XI at 2500-2501.) Thus, because such an arrangement is inequitable, the Commission should decline to order AEP Ohio to supply CRES providers with capacity at an RPM-based price.

3. RPM pricing will cause financial harm to AEP.

Intervenors recognize that there is a cost for AEP Ohio to discharge its FRR obligation by providing capacity resources to support shopping load. (*See* Tr. IV at 772, 779.) RESA witness Ringenbach agrees that rates should not be confiscatory, which she views as AEP Ohio incurring costs that are not being reimbursed. (Tr. IV at 802.) And that is why RESA recommends a retail charge to ensure that CRES provider customers are not subsidizing non-CRES customers and vice-versa. (*Id.* at 803.) Indeed, RESA agrees that a transition to RPM pricing is appropriate, and that is another reason why it recommends the nonbypassable RSR to facilitate that transition. (*Id.* at 827-28.) Absent such cost recovery (cost-based capacity charge) or corollary compensation (such as the Rate Stabilization Rider being proposed in the ESP proceeding in order to provide financial stability for all of the components of the ESP, including reduced capacity charges), AEP Ohio will incur substantial financial harm if RPM pricing is retained in full or in part.

Specifically, AEP will suffer financial harm if it is required to charge CRES providers RPM pricing for capacity through May 31, 2015, because RPM pricing is not compensatory. During the development phase of the RPM model, the Commission had concerns with protecting a state's generation resource adequacy, and the Commission (represented by its Staff) recognized that a electric utility's recovery of reasonable investment costs and timely repayment of debt are "bedrock principles required for financing an industry as capital intensive as the electricity industry." (*See* AEP Ohio Ex. 101 at 13.) In those comments, the Commission also stated that "[g]enerator owners cannot long survive on recovery of the short run marginal costs of energy alone, but must consistently recover some of their long run marginal costs as well." (*Id.*) A decision to set the price for the capacity that AEP Ohio supplies to CRES providers at the RPM price would disregard these bedrock principles.

AEP Ohio witness Allen demonstrated that a decision which forced the Company to provide RPM-priced capacity to CRES providers would cause AEP Ohio to suffer significant financial harm. (Tr. III at 677:11-16; AEP Ohio Ex. 104 at 3-5, Ex.WAA-1; AEP Ohio Ex. 142 at 21-22, Ex. WAA-R8.) Indeed, financial harm to the Company is implicit in any requirement that it provide the use of its assets at a rate below its costs. (*See* Tr. III at 697:16-18; *id.* at 698:1-3.) Specifically, if the Company is required to provide CRES providers with capacity at RPM, Mr. Allen calculated that the Company would earn a return on equity of 7.6% in 2012 and a return on equity of only 2.4% in 2013. (AEP Ohio Ex. 104 at 3-5, Ex. WAA-1.) Moreover, the Company's earnings would suffer a $240 million dollar decrease between 2012 and 2013. (Tr. III at 701:14-17.) As discussed above, such a result would significantly harm AEP Ohio, particularly in light of the fact that a reasonable return on equity for a public utility in the present economic environment is <u>four to five times</u> greater than that which AEP Ohio would realize in 2013. The Commission should approve a capacity charge that reasonably and fairly compensates AEP Ohio for its generation investments and production costs and should not approve an RPM-based charge that will significantly undermine the Company's ability to earn an adequate return on its investments in Ohio.

4. RPM pricing would provide CRES providers with an illegal subsidy.

An RPM-based charge for the capacity that AEP Ohio supplies to CRES providers also is inappropriate because such a charge would constitute an illegal subsidy to CRES providers in violation of R.C. 4928.02(H). R.C. 4928.02(H) states that it is the State's policy to "[e]nsure *effective competition* in the provision of retail electric service *by avoiding anticompetitive subsidies* flowing from a noncompetitive retail electric service to a competitive retail electric service * * *." (Emphasis added). As the language of R.C. 4928.02(H) recognizes, and as AEP Ohio witness Munczinski testified, it is important that neither shareholders nor AEP Ohio's non-shopping customers subsidize CRES providers for the CRES providers' use of AEP Ohio's capacity because such a subsidy is inequitable. (AEP Ohio Ex. 101 at 9.)

Mr. Munczinski further explained that because the RPM is so low in the next two years, allowing CRES providers to purchase AEP Ohio's capacity at the RPM auction price, rather than at a price equal to AEP Ohio's embedded costs, would constitute an illegal subsidy to CRES providers. (Tr. I at 199:8-10; *see also* AEP Ohio Ex. 102 at 8.) This is because, from a financial standpoint, if an RPM-based capacity charge were ordered, AEP Ohio's nonshopping load would effectively be subsidizing CRES providers and shopping load. Thus, while AEP Ohio would recover its true costs of capacity from the non-shopping load SSO rate (*see* Tr. II at 247:7-13), it would recover less than its true costs from CRES providers or shopping load. (*See* Tr. I at 98:16-25.) For instance, if AEP Ohio's cost to provide capacity was $2, and through its SSO rates it recovered that $2 of cost, but CRES providers only paid $1 of the $2 cost for the shopping load they served, then AEP Ohio would not recover the full amount of its capacity costs and the CRES providers would receive a $1 subsidy, the cost of which will be borne by AEP Ohio. Requiring AEP Ohio to collect RPM-based capacity pricing from CRES providers forces AEP

Ohio to absorb the cost of an unreasonable and ultimately unsustainable subsidy. (*See* AEP Ohio Ex. 101 at 11.) This is a windfall to CRES providers that the Commission should not condone.

IEU witness Murray asserts that allowing AEP Ohio to collect a cost-based charge from CRES providers would be "contrary to the state's policies" and would "provide an unwarranted subsidy to AEP Ohio, to the detriment of its competitors and shopping and non-shopping customers * * *." (IEU Ex. 102-A at 14, 20, 25.) This position, however, is fundamentally flawed. Allowing AEP Ohio to recover its costs does not in any way subsidize the Company. Rather, as explained above, requiring the Company to supply CRES providers with capacity at below-cost rates will provide an inappropriate subsidy to the CRES providers that should be avoided. Upon termination of AEP Ohio's FRR plan on June 1, 2015, all providers of generation service in AEP Ohio's service territory will obtain capacity to support their retail load from the RPM auction (the auction for the 2015/16 planning year was recently completed).

Further, there is no likelihood that CRES providers would pass on more than a token amount of any of the savings they would enjoy under an RPM-based capacity pricing scheme to their customers. And, as AEP Ohio witness Graves explained, even if they did, AEP Ohio subsidizing CRES providers at its own expense is not economically desirable. (*See* AEP Ohio Ex. 105 at 10.) Allowing CRES providers to pay only an RPM-based price for the capacity they receive from AEP Ohio will not only cause AEP Ohio to take a loss on the resale of that capacity, but will also deter CRES providers from taking responsibility for their own future capacity procurement and development. CRES providers also need a transition to be weaned from relying on AEP Ohio for capacity. (*Id.*) As Mr. Graves explained, the subsidy that CRES providers would receive would serve to encourage them to avoid capacity procurement and development commitments and would give them the incentive and opportunity to become active sellers in years when RPM prices turn out to be below AEP Ohio's embedded costs, then return customers to AEP Ohio's SSO load when the reverse occurs. (*Id.*) This is not a desirable economic outcome and it is not in customers' best interests in the long run. Accordingly, RPM-based capacity pricing should be rejected.

5. Other arguments by intervenor witnesses that RPM is an appropriate price for AEP Ohio's capacity are misplaced.

A number of intervenor witnesses have offered various opinions and rationales upon which they argue that RPM is an appropriate price for AEP Ohio's capacity. Most of them are simply policy arguments that favor their business model. Their arguments, however, are without merit and should be disregarded.

Exelon witness Fein makes a number of arguments in support of Exelon's position that the state compensation mechanism should be set at a rate equal to RPM. Specifically, he argues (1) that Ohio law does not require that a state compensation mechanism be cost based; (2) that RPM pricing is consistent with Ohio state policy directives set forth in R.C. 4928.02; (3) that AEP Ohio should not be permitted to choose cost-based pricing now, when market prices are low, because it has previously made capacity available to CRES providers at RPM; (4) that PJM's rules have created a situation in which CRES providers are "captive" to AEP Ohio because CRES providers would have had to purchase and commit capacity to serve retail customers more than three years in advance or delivery, at a time when they had few or no committed retail customers; (5) that AEP Ohio's proposed capacity pricing, if adopted, would be discriminatory because other capacity is sold at RPM in other service territories in the state; and (6) that RPM should be adopted because the RPM auctions are a competitive market for capacity and reflect "true, transparent market and competitive conditions."

Each of Mr. Fein's arguments is without merit and should be disregarded. With respect to his first argument, Ohio law also does not require that a state compensation mechanism be based on RPM prices. Mr. Fein agreed with this fact at hearing. (*See* Tr. VIII at 1539:7-9.) IEU witness Murray similarly argues that the Commission lacks authority to approve a capacity charge that is not based on RPM (*see* IEU Ex. 102-A at 16, 28); however, Mr. Murray offers no substantive basis for his lay opinion of Ohio law other than his conclusion that, because the Commission "no longer has the authority to *subject* generation service to cost-based regulation," the Commission apparently lacks authority to *approve* a cost-based charge. (Emphasis added). Mr. Murray is not an attorney and thus, his legal opinions should be disregarded. Accordingly, because the arguments by Messers Fein and Murray regarding Ohio law are without merit, they should be disregarded.

Mr. Fein's second argument, that a non-RPM price would violate state policy, is inaccurate. As discussed in Section III.B above, RPM pricing is wholly inconsistent with the State's and Commission's policies and would cause significant financial harm to AEP Ohio if adopted.[11]

Mr. Fein's third point is without merit because, as discussed in Section III.A above, AEP Ohio has a contractual right under the RAA to elect to pursue cost-based compensation. Moreover, the contention that AEP Ohio seeks the "better of cost or market" mischaracterizes the events leading up to today. As AEP Ohio witness Munczinski explained, AEP Ohio attempted to exercise its right to elect cost-based capacity pricing in 2010, shortly after shopping began in earnest in the AEP Ohio service territory. (*See* AEP Ohio Ex. 101 at 6; Tr. I at 83-84.) As described in Section II, *supra*, AEP Ohio had no reason to pursue its cost-based election

[11] FES witness Lesser's state policy argument (*see* FES Ex. 103 at 10) is similarly without merit for the reasons discussed above.

under the RAA prior to 2010 because the amount of shopping at that time was insignificant and, therefore, providing capacity at an RPM-based price did not have the significant adverse financial impact on AEP Ohio that it now does. The bottom line, however, is that AEP Ohio has a contractual right to charge a cost-based rate for the capacity it supplies to CRES providers. When AEP Ohio chose to exercise that right is immaterial.

Mr. Fein is also incorrect in his assertion that CRES providers are "captive" to AEP Ohio for capacity.[12] As discussed in Section II above, CRES providers have been on notice for nearly two years that AEP Ohio seeks cost-based compensation for its capacity. Since that time, there have been two auctions in which a CRES provider could have purchased capacity to meet its needs. (*See* Tr. VIII at 1559:10-15.) Notably, however, <u>none</u> has chosen to do so, as Mr. Fein himself conceded at hearing. (*See* Tr. VIII at 1522:5-9; 1522:21-1523:4.) AEP Ohio should not now be penalized for CRES providers' failure to manage the price of their capacity input.

Mr. Fein's fifth contention that AEP Ohio's proposed capacity pricing, if adopted, would be discriminatory because capacity is sold at RPM-based prices in other service territories in the state ignores two salient facts. There is no requirement that capacity be supplied at RPM. Moreover, it ignores the fact that those EDUs that agreed to provide capacity to CRES providers at RPM did so in a stipulation in exchange for numerous other benefits and advantages. That other EDUs have agreed to supply capacity at RPM as one component of a larger stipulation (*see* Exelon Ex. 101 at 8; Tr. VIII at 1552:21-1553:6 (discussing Duke Energy Ohio's stipulation agreement to provide capacity at RPM-based prices)), does not mean that AEP Ohio should be

[12] FES witness Lesser also makes this argument. (*See* FES Ex. 103 at 8, 16-17.) The argument, for the same reasons as Mr. Fein's argument, is incorrect.

required to do so, nor that RPM pricing is an appropriate state compensation mechanism.[13] The contention that AEP Ohio's proposal to move to a cost-based capacity charge is discriminatory because AEP Ohio would not be providing the same discount for capacity that other EDUs have voluntarily bargained for in exchange for other incentives and benefits is simply nonsensical.

Mr. Fein's sixth contention (as also made by other intervenor witnesses) that the RPM auction is a competitive market for capacity also is incorrect. (*See, e.g.,* Exelon Ex. 101; IEU Ex. 103A at 15, 25-26. 37; IGS Ex. 101 at 5.) Indeed, the market monitor has set an offer cap on pricing for existing generation that bids into the auction for <u>every</u> BRA to date. (*See* Tr. VIII at 1599:13-1600:6.) The reason the market monitor does this is because he has consistently determined that the market is not competitive. (*See id.* at 1599:24-1600:2.) RPM is an administratively controlled auction, not an open, competitive market. FES witness Stoddard conceded this fact at hearing. (*Id.* at 1591:13-16; 1592:7-25 (noting that PJM is a "well regulated" market, in which the market monitor determines offer caps and floors on offer pricing); 1596:8-12.) Mr. Stoddard specifically noted that "the whole demand-structure capacity is, itself, intrinsically a regulatory construct" that includes "many regulatory checks and balances." (*Id.* at 1601:4-5, 1603:9-10.) Further, the RPM price is a short-term price and does not categorically or exclusively represent *the* market price for capacity. Other intervenor witnesses also acknowledged that bilateral contracts exist, including long-term agreements based on cost, that also reflect market prices for capacity. (*See* Tr. IV at 769, 805; Tr. VI at 1248.)

[13] FES witness Lesser makes a related argument that allowing AEP Ohio to charge CRES providers a cost-based rate for capacity is discriminatory because in doing so, the Commission would be allowing AEP Ohio to charge SSO customers a different amount for capacity than charged to non-SSO customers. (*See* FES Ex. 103 at 18-22.) This argument, however, is incorrect because, as discussed above, AEP Ohio's embedded cost of capacity is built into the SSO rate charged to retail customers. (*See* Tr. II at 347:7-13.)

Finally, OEG witness Kollen recommends that the Commission establish an RPM-based price for capacity (*see* OEG Ex. 102 at 9); however, as described in greater detail in Section V, *infra*, Mr. Kollen's direct testimony does not contain an analysis of the appropriateness of RPM; rather, it explains in detail Mr. Kollen's "alternative proposal," which he calls the Earnings Stabilization Mechanism (ESM). (*See* OEG Ex. 102 at 15-22.)

IV. THE APPROPRIATE COST-BASED CAPACITY PRICE TO BE CHARGED TO CRES PROVIDERS FOR CAPACITY SUPPORTING SHOPPING LOAD IS $355.72/MW-DAY.

AEP Ohio has advanced a cost-based capacity charge of $355.72/MW-Day on a merged Company basis. Although the Company does not recommend, in the first instance, that there be an energy credit offset to the cost-based capacity price, Company witness Pearce does make a recommendation for how such an energy credit could be devised. The issue that engendered the broadest and perhaps most intense debate at hearing is the appropriate level for an energy credit, if one is to be used to reduce the "demand charge" for capacity. In addition, there was significant disagreement regarding how a cost-based capacity charge should be determined, against which any energy credit would be offset. Notably, in the end, the evidence made clear and there was little serious disagreement that the Company's SSO base generation rates, in the aggregate, recover capacity costs from non-shopping customers in an amount comparable to the proposed cost-based capacity charge before any energy credit offset. As RESA witness Ringenbach agreed, assuming that AEP Ohio is collecting $355.72/MW-day for capacity from SSO customers (as was demonstrated in Mr. Allen's testimony), it is appropriate to charge CRES providers $355.72/MW-day, in order to match rates and ensure there is no subsidy. (Tr. IV at 815.) The discussion below shows that the Company's proposed cost-based capacity charge is just and reasonable and should be adopted.

A. The Appropriate Cost-Based Capacity Charge Is $355.72/MW-Day And Is Based Upon AEP Ohio's Costs Before Consideration Of Any Offsetting Energy Credit.

AEP Ohio presented testimony from Dr. Kelly Pearce regarding the appropriate cost-based price to be charged to CRES providers for capacity supporting shopping load, before consideration of any offsetting energy credit. Dr. Pearce is the Director of Contracts and Analysis at American Electric Power Service Corporation. (AEP Ohio Ex. 102 at 2.) In his direct testimony in this proceeding, Dr. Pearce introduced, described, and supported the formula rate that is proposed by AEP Ohio to compensate the company for capacity that is used by CRES providers to serve former AEP Ohio generation customers where the CRES providers choose not to provide their own capacity. (*Id*. at 3.)

1. Dr. Pearce's formula rate template is fair, appropriate, and FERC-approved.

The formula rate approach that Dr. Pearce used to calculate an appropriate cost-based capacity price is based upon the average cost of serving AEP Ohio's LSE obligation load (both the load served directly by AEP Ohio or by a CRES provider) on a dollar-per-MW-day basis. (*Id.* at 7.) Because the Company is self-supplying its own generation resources to satisfy these load obligations, the cost to provide this capacity is the *actual embedded capacity cost* of CSP's and OPCO's generation. As AEP Ohio witness Frank Graves explained, "AEP Ohio's cost reflects the average capital and fixed costs of its fleet of generation, which includes approximately 13,000 MW of plants of a variety of ages and technologies, but is largely comprised of baseload coal plants." (AEP Ohio Ex. 105 at 6.) As Dr. Pearce explained further in his testimony, the formula rate "provides fair and appropriate compensation for use of the Company's capacity" because "[b]y CRES providers paying a rate that is based upon average costs, they are neither subsidizing nor being subsidized by AEP Ohio." (AEP Ohio Ex. 102 at 7.)

Under Dr. Pearce's formula rate approach, the Company's annual production costs are reduced by the amount of revenues that are collected from other wholesale entities related to capacity transactions (including capacity transactions with affiliates and non-affiliates alike). (*Id.* at 10.) This allows CRES providers to obtain the benefit of these transactions, and prevents them from paying for capacity costs associated with transactions to other wholesale entities, including affiliates and PJM RPM market participants. (*Id.*) Dr. Pearce's formula rate approach also results in a capacity rate that is roughly approximate to the capacity rate charged to standard service offer customers – a comparison that Dr. Pearce used as a "sanity check" for the template that he proposed here. (Tr. II at 304:1-22, 350:6-15.)

The formula rate template that Dr. Pearce utilized here is nothing new or untested. As Dr. Pearce testified, "[f]ormula rates are currently utilized in many states by AEP for other wholesale sales." (*Id*. at 8.) Notably, FERC itself has previously approved the template utilized by Dr. Pearce:

> The formula rate template selected for this rate development is *modeled after the template recently approved by FERC* to derive the capacity charges applied to wholesale sales made by Southwestern Electric Power Company (SWEPCo), an AEP-Ohio affiliated operating company, to the Cities of Minden, Louisiana and Prescott, Arkansas. These cities are full requirements customers taking both capacity and energy from SWEPCo under long term agreements. *This formula rate was the subject of a lengthy negotiation between the seller and purchasers and FERC Staff. In addition, it adopts various modifications originating from FERC Staff.* As such, this template represents a fair and reasonable formula for calculation of capacity costs. The capacity portion of this formula rate template was used to develop the proposed AEP Ohio capacity rate.

(*Id*. at 9 (emphasis added).) In cross-examining Dr. Pearce, counsel for FES noted that the settlement agreement approved by FERC in the Minden/Prescott transaction stated that it was not to be regarded as establishing precedent for the appropriate rate formulas in any other proceeding. (Tr. II at 250:20-25.) Dr. Pearce agreed, but also noted that this language is common in such settlements, and that the formula rate template utilized in the Minden/Prescott transaction was a "just and reasonable wholesale deal" that had undergone "heavy regulatory review from FERC staff" and could be appropriate and helpful in other contexts, such as this one. (*Id.* at 251:1-20.) Dr. Pearce also noted that the formula rate template "is not unlike over 30 *** similar agreements that we have *** with [municipalities] and co-ops in several of our operating states." (*Id.* at 253:18-21.) During cross-examination, when Staff's counsel asked Dr. Pearce if Louisiana and Arkansas were the only states in which formula rates were being utilized, Dr. Pearce disagreed, noting their use in Michigan, Indiana, Kentucky, West Virginia, Virginia, Arkansas, Louisiana, and Texas. (*Id.* at 338:20-339:1.)

2. Dr. Pearce's formula rate approach is transparent and, if adopted, would be updated to reflect the most current input data.

In addition to being a FERC-approved template for the calculation of capacity costs, Dr. Pearce's formula rate approach has added advantages of transparency and currency. The bulk of the inputs to the formula rate template are derived directly from FERC Form 1 annual reports of the Company, audited financial statements which are publicly available on FERC's website, and from the various supporting workpapers, which are readily available to affected parties upon request for verification. (AEP Ohio Ex. 102 at 8.) If the Commission approves the formula rate approach, then after approval, the rate that results from the template is simply updated using the most current accounting information. (*Id.*) "As a result, updating the rate becomes a straightforward, fairly mechanical process and the updates are readily available for regulatory review. Under the company's proposal, rates will be known prior to the beginning of a given PJM PY." (*Id.*) For example, once the Company's 2012 FERC Form 1 becomes available in the Spring of 2013, AEP Ohio will update the capacity rate derived from Dr. Pearce's formula rate and have it available no later than May 31, 2013, and this would be the capacity rate in effect for the PJM PY 2013/2014 that runs from June 1, 2013 through May 31, 2013. (*Id.*) The same process would be used for each subsequent year as long as such rates are in effect (currently anticipated to end after the PJM PY 2014/2015). (*Id.*) Dr. Pearce emphasized the transparency of his approach on cross-examination, stating:

> Well, let's be clear. All of the data in this ties in total to the FERC Form 1. In certain instances we are pulling additional detail out of the company's books and records, very transparent through the workpapers, through other supporting documentation that we can provide upon request for any audit purposes to make any adjustments to it and check it all the way back to the totals that are shown in the FERC Form 1. So to me it is still a fairly simple process that does tie in total to the FERC Form 1.

(Tr. II at 290:19-291:4.)

3. The three modifications that AEP Ohio proposes to the FERC-approved templates for Minden and Prescott are justified.

Dr. Pearce did not simply utilize the FERC-approved Minden/Prescott template here without first adjusting it appropriately to the circumstances. As described in his testimony, Dr. Pearce's formula rate template includes three key modifications. (AEP Ohio Ex. 102 at 11.) First, in order to be consistent with the peak demands that are used to charge CRES providers today through the PJM settlement process, the denominator of the fraction corresponding to $/MW in Dr. Pearce's formula rate template is based on the average CSP and OPCo peak demands that are coincident with the PJM five highest daily summer peak demands. (*Id.*) Next, although the ROE in the FERC-approved Minden/Prescott template was 11.10%, the ROE in Dr.

Pearce's template was modified to a fixed 11.15% in order to be consistent with the ROE proposed by AEP Ohio witness Avera in CSP's and OPCo's distribution rate cases, PUCO Case Nos. 11-0351-EL-AIR and 11-0352-EL-AIR. (*Id.*) As Dr. Pearce testified, this ROE is in line with ROEs that the Company is recovering in several wholesale transactions across several states. (Tr. II at 305:4-24.) Finally, because it would be impractical and administratively burdensome to perform a "true up" with CRES providers (by making an after-the-fact determination of the difference between the rates charged and revenues collected during a given period, as well as the actual costs incurred by the seller during the same period), Dr. Pearce modified the Minden/Prescott template to eliminate the post-period reconciliation. (AEP Ohio Ex. 102 at 12.) As Dr. Pearce explained, this third modification actually benefits CRES providers by reducing uncertainty about their capacity rate over the period. (*Id.*)

4. The appropriate cost-based rate is $355.72/MW-Day before consideration of any offsetting energy credit.

The first two exhibits to Dr. Pearce's Direct Testimony depict the "blank" formula rate templates, without the input data filled in. (AEP Ohio Ex. 102 at 20, Ex. KDP-1, Ex. KDP-2.) The third and fourth exhibits to Dr. Pearce's Direct Testimony depict these templates populated with information obtained from the 2010 CSP and OPCo FERC Form 1s. (*Id.*at 20, Ex. KDP-3, Ex. KDP-4.) As seen on page 1 of Exhibits KDP-3 and KDP-4, the capacity compensation rates would have been $327.59/MW-day for CSP and $379.23/MW-day for OPCo, for the PJM PY 2011/2012. (*Id.* at 20, Ex. KDP-3, Ex. KDP-4.) And as shown in Exhibit KDP-6, the current merged capacity rate would be **$355.72/MW-day** for the PJM PY 2011/2012. (*Id.* at 21, Ex. KDP-6.)[14]

[14] As Dr. Pearce testified, AEP Ohio is not proposing that an energy credit be offset against this capacity rate. (AEP Ohio Ex. 102 at 13; Tr. II at 341:23-25.) However, AEP Ohio did propose a

Beginning in 2011, due to the merger, AEP Ohio filed a single FERC Form 1, which (if the Commission adopts Dr. Pearce's formula rate template) would be the basis for computing the updated FRR capacity compensation rate beginning with the PJM PY 2012/2013. (*Id*. at 21.) This 2011 FERC Form 1 became available shortly before Dr. Pearce was cross-examined at hearing in this proceeding, and Dr. Pearce testified that, as is the case for the 2011-2012 planning year, AEP Ohio cannot recover anything close to its full embedded costs in the upcoming 2012-2013 planning year if it receives revenue solely from PJM pricing for capacity. (Tr. II at 243:10-18.)

5. Dr. Pearce's formula rate template promotes stability and will result in reasonable projected earnings for AEP Ohio.

Given that the formula rate template proposed by Dr. Pearce is updated annually, Dr. Pearce was asked at hearing about whether he expected substantial variations from year-to-year in the capacity rate that results from the template. Dr. Pearce emphasized that he did *not* expect such substantial variations, saying:

> No, I do not. And nothing on the order of what we've seen like in the volatility of the RPM rate. The original 2010 FERC filing we made which was based because of the time period on the 2009 data, the rate of $359 approximately per megawatt day when we updated it for this case. The rate now is $355.72.
>
> Our FERC Form 1 2011 just came out last week. It's available on the website to whoever wants it. In fact, we have the templates. People can start populating it. We worked over the weekend and, subject to check, we are coming up with a rate that's approximately $358, so it's been incredibly stable over those three years.

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straightforward methodology to be used should the Commission choose to adopt such a credit, which Dr. Pearce described as "the difference between market-based revenues and the Companies' energy cost." (AEP Ohio Ex. 102 at 14.) For a more detailed discussion of AEP Ohio's methodology for calculating any energy credit, and its criticisms of the intervenor and Staff approaches the energy credit, see Part IV.B below.

(Tr. II at 12-25.) Thus, in addition to receiving FERC's imprimatur in the Minden/Prescott transaction, and in addition to being based on publicly-available FERC Form 1 data, Dr. Pearce's formula rate template has demonstrated remarkable stability and predictability in terms of reflecting the Company's embedded costs of capacity.

Commissioner Porter asked at hearing about the projected earnings of AEP Ohio if the Company collected a capacity charge rate of $355.72/MW-day from CRES providers. (Allen RT at 21.) AEP Ohio witness Allen updated the analysis that he presented in his Direct Testimony to reflect recovery of Dr. Pearce's proposed $355.72/MW-day capacity charge from CRES providers. (*Id.*) Mr. Allen held all other assumptions constant and simply removed the capacity revenues that would have been recovered under an RPM-based pricing mechanism, and replaced those revenues with the revenues that would be recovered based upon the Company's proposed cost-based mechanism. (*Id.*) "This estimate *** demonstrates that the Company's return on equity *** would be a reasonable 12.2% in 2013." (*Id*. at 21-22.)

For all of the foregoing reasons, therefore, Dr. Pearce's calculations demonstrate that the fairest, most transparent, and most appropriate cost-based price is $355.72/MW-day, before consideration of any offsetting energy credit.

B. If An Energy Credit Is Used To Partially Offset The Demand Charge, It Should Reflect Actual 2010 Energy Margins Or At Least A Realistic And Accurate Projection Of Anticipated Energy Margins To Be Realized During The 2012-2015 Period.

1. The energy credit should be calculated based on upon actual 2010 data, as explained by AEP Ohio witness Dr. Pearce, in order to be grounded in reality and best match the corresponding cost basis for calculating the demand charge.

AEP Ohio has not proposed to offset, in the first instance, the cost-based capacity rate ($355.72/MW-Day on a merged Company basis) with an energy credit. Dr. Pearce explained that an energy credit offset is not warranted in light of PJM's complete separation of the markets for capacity and energy. As a result, Dr. Pearce observed, obtaining capacity through PJM's RPM market or through an FRR plan does not provide any rights or a call option on energy at any price. Consequently, he concluded, the capacity rates proposed by AEP Ohio are appropriate for charging CRES providers. (AEP Ohio Ex. 102 at 13.)

Nevertheless, in the event that the Commission chooses to use an energy credit, Dr. Pearce included a template (or formula) for the calculation of energy costs that could be adopted for the purpose of determining the amount of such a credit. It is part of the same template accepted for use by the FERC and, therefore, is consistent with the capacity cost portion of the formula rate and has also undergone the same regulatory scrutiny. (*Id.* at 14.)

Such a credit would be calculated as the difference between the revenues that the CSP and OPCo historic load shapes, including all shopping and non-shopping load, would be valued at using Locational Marginal Prices (LMP) that settle in the PJM Day-Ahead (DA) market, less the cost basis of this energy. The result of this calculation, using the 2010 energy cost basis rates, are provided in Exhibits KDP-1 through KDP-4 of Dr. Pearce's Direct Testimony. (*See* AEP Ohio Ex. 102 at Ex. KDP-1 – KDP-4.) The final energy credit is provided in Exhibit DKP-5 to his Direct Testimony.

Dr. Pearce explained that the calculation relies upon a fair and reasonable proxy for the energy revenue that could have been obtained by CSP and OPCo (and, thus, the merged entity) by selling equivalent generation into the market. (*Id.* at 15.) He noted that the cost basis for the energy is computed using the same formula rates described for the capacity rate calculation, which provides for a consistent and straight forward solution. (*Id.* at 16.)

The only modifications to the original FERC-approved templates is that the impacts of cost deferrals and off-system sales (OSS) are eliminated. With regard to elimination of cost deferrals, Dr. Pearce explained that cost deferrals should not be considered because that would not reflect the actual commercial operation of AEP Ohio's generation units in the PJM energy market. (*Id*. at 16-17.) With respect to OSS, he explained that it would not be reasonable to increase the margins from energy sales related to capacity supplied to CRES providers by adding to them margins from OSS that are not related to that capacity. (*Id*. at 17.)

Once the value of the gross margins from energy sales related to capacity sales to the CRES providers is calculated, Dr. Pearce explained that only the Member Load Ratio share of such gross margins would be retained by AEP Ohio. He also noted that the appropriate share of margins must also be allocated to the firm, full requirements, wholesale contract with Wheeling Power Company. (*Id.* at 17-18.)

Dr. Pearce recommended that the OSS energy margins properly attributed to the CRES capacity sales that are retained by AEP Ohio should be shared on a 50%/50% basis between AEP Ohio and CRES providers. (*Id.* at 18.) This reflects the lag that can occur between the historic period utilized and the term during which the credit would be in effect. In addition, Dr. Pearce explained that CRES providers who purchase capacity on a year-to-year basis should not receive the full offset received by long-term full requirement wholesale customers. (*Id.* at 18.)

Finally, Dr. Pearce recommended that any energy credit should be capped at 40% of the capacity charge that would be applicable with no energy credit. Dr. Pearce testified that such a cap is appropriate so that in high price wholesale periods, the energy credit could get so high as to greatly, and unduly, reduce any capacity payment whatsoever from CRES providers. Such a result, according to Dr. Pearce, would be a clear and inappropriate subsidy to CRES providers.

One of the principle benefits of the energy credit approach that Dr. Pearce recommends, if one is to be used, is that it relies upon the same cost data that underlies the capacity cost rate. In addition, because it is updated annually to reflect the most current FERC Form 1 data, the cost data will be very closely aligned with the period during which the capacity rate and energy credit are applied to establish the applicable price for capacity.

2. The Staff's methodology for calculating an energy credit is flawed in numerous ways and produces unrealistic and greatly overstated results.

Staff presented an energy credit sponsored by witnesses Harter and Medine. Mr. Harter and Ms. Medine are employed by Energy Ventures Analysis (EVA). Mr. Harter's and Ms. Medine's analysis (also referred to as the EVA analysis) is based upon their use of the AURORAxmp (Aurora) model. Initially, Mr. Harter sponsored and attempted to defend and support the methodology he used, relying upon the Aurora model, to develop an energy credit that might be used as an offset to the cost-based capacity charge that Staff witness Smith developed.[15] (Staff Exs. 101 and 102.) After Mr. Harter's cross-examination, however, it became clear that there were a number of errors in the implementation of, and the results produced by, EVA's energy credit methodology. Consequently, Staff asked for, and received, permission to present supplemental testimony by Ms. Medine in an effort to correct some of the errors, and to bolster, the methodology and the energy credit that Mr. Harter developed. (Staff Ex. 105.)

Unfortunately, Ms. Medine only partially, and superficially, corrected the errors in the calculations that Mr. Harter initially sponsored. The result of both EVA's initial (Harter) and subsequent (Medine) efforts is an energy credit calculation that suffers from a number of

[15] Mr. Smith's cost-based capacity charge is discussed in Section IV.C, *infra*.

fundamental flaws. These fundamental errors uniformly produce significant overstatements of the energy margins that AEP Ohio could actually realize and, ultimately, the energy credit that EVA recommends.

Notably, the problem is not that Aurora is a fundamentally flawed model. The problem is that Aurora is not well-suited for the task to which EVA has applied it. Moreover, the manner in which EVA has implemented the model is flawed. In particular, the choices that EVA made to implement the model, and the inputs that EVA selected, are in every observable respect biased towards inflating the gross margins that EVA uses the model to calculate. Company witness Meehan explained various respects in which EVA misapplied the Aurora model and, to the extent they were discernible, he described EVA's inappropriate assumptions and inaccurate inputs. (AEP Ohio Ex. 144 at 8-23.) Company witness Allen further supported the conclusion that the EVA witnesses had used inaccurate and biased input data that inflated the gross energy margins. (AEP Ohio Ex. 142 at 2-14.)

In order to provide a comprehensive measure of the extent to which EVA's methodology overstates the gross energy margins that AEP Ohio could realistically achieve, Mr. Meehan also presented an alternative quantification of gross margins. In contrast to EVA's methodology, Mr. Meehan's alternative approach provides a reliable, accurate, and transparent quantification of gross margins. It cuts through the opaque web of errors and partial disclosures that makes EVA's model impossible to comprehensively evaluate in any direct and explicit manner. It confirms, and quantifies, what the observable errors in EVA's methodology make clear. The EVA approach overstates achievable gross energy margins during the June 2012 through May 2015 period by close to <u>200 percent</u>.

AEP Ohio witnesses Nelson and Allen both describe another major flaw in EVA's approach, which occurs when EVA converts the gross energy margins to the amount retained by AEP Ohio. EVA failed to reflect how the AEP East Interconnection Agreement (Pool Agreement) limits the extent to which gross margins are retained by AEP Ohio and, thus, are available to support an energy credit. (AEP Ohio Ex. 143 at 6-14; AEP Ohio Ex. 142 at 4.) EVA's failure to properly recognize the impact of the Pool Agreement manifests itself in EVA's assumption that energy margins that it imputes to non-shopping SSO load would be retained 100% by AEP Ohio and should be used in their entirety to offset costs of capacity used to serve CRES providers. In effect, Mr. Nelson explained that, through this imputation of SSO energy margins and the assumption that the imputed margins are retained 100% by AEP Ohio, EVA improperly converted the Member Load Ratio (MLR) for AEP Ohio from 40% (real world under the FERC-approved Pool) to 92% (fictional world that only exists in EVA's testimony). (AEP Ohio Ex. 143. at 10.) In substance, this flawed method confiscates revenues from AEP Ohio's retail SSO sales and uses them to subsidize CRES providers through a lower wholesale rate they pay to AEP Ohio for capacity. (AEP Ohio Ex. 143 at 6,11.) Of course, this fictional imputation and retention of energy margins further, and substantially, inflates retained energy margins and, ultimately, EVA's proposed energy credit.

The errors that affect EVA's approach to calculating an energy credit are numerous. Indeed, they are so wide-ranging that it is a challenge to "fix" all of them. However, Mr. Allen describes each of the adjustments that must be made, at a minimum, at pages 4-13, and provides a summary of those adjustments, at the top of page 14, of his Rebuttal Testimony (AEP Ohio Ex. 142):

	($/MW-day)
Medine's Energy Credit	**152.41**
Understated Fuel Cost for Coal Units	(70.10)
Understated Heat Rate for Gas Units	(1.87)
Overstated Market Prices	(50.42)
Failure to Recognize Wheeling Power Contract	(5.00)
Cross Impact of Fuel and Market	22.44
Energy Credit after Adjustments	**47.46**

Each of Mr. Allen's proposed corrective adjustments is conservative. In addition, Mr. Allen's EVA Energy Credit after Adjustments of $47.46 is made further conservative because it has not been adjusted to correct for an additional flaw in how EVA converted gross energy margins to retained margins. Below is a more detailed explanation of the various errors that affect EVA's methodology and its conclusions regarding the proposed energy credit.

a. There are a host of errors in EVA's energy credit calculation

i. EVA's methodology does not withstand basic scrutiny and is largely a "black box."

When Mr. Harter testified, he stated that he considers himself an expert in modeling capacities but relies on EVA partners for the inputs. (Tr. IX at 1838.) When Ms. Medine testified in order to correct errors of Mr. Harter, she readily acknowledged that she did not run the Aurora model and, instead, relied on Mr. Harter to do so. (Tr. X at 2132-33.) Yet, Ms. Medine maintained that she was defending the Aurora modeling as part of her testimony. (*Id.* at 2142.)

Regarding operation of the Aurora model, however, Ms. Medine admitted that she does "not know the innerworkings of the model" and repeatedly stated in response to questions that "it's a very complex model." (*Id.* at 2206, 2208.) She also could not recall specifically what reserve margin was used in the modeling. (*Id.* at 2207-08.) As further discussed below, there were several impactful matters regarding the operation of the Aurora model that could not be answered or addressed by either Mr. Harter or Ms. Medine.

Both Mr. Harter and Ms. Medine professed accuracy and realism in performing the modeling. Mr. Harter intended that his modeling captured actual margins that would be experienced by AEP Ohio during the period and not a hypothetical textbook price. (Tr. IX at 1855-56.) Further, Mr. Harter agreed that modeling is only as good as the inputs; bad data into the model means inaccurate results come out of the model. (*Id.* at 1861.) Ms. Medine unequivocally stated regarding the accuracy of input data that "[o]bviously if any input was inaccurate, you have to rerun the model." (Tr. X at 2244.) Unfortunately, their modeling actions did not match their principled statements in this regard.

EVA's modeling approach cannot be meaningfully evaluated or tested by others, due to the "black box" nature of EVA's methodology. Mr. Harter testified that all the data used in the model was either off-the-shelf from the software developer's default database or developed by others at EVA besides Mr. Harter, so that he could not answer questions about it. (Tr. IX at 1865.) Mr. Harter doesn't know what reserve margin was used in the Aurora modeling. (*Id.* at 1872.) Also, Mr. Harter is not clear on what data is used in the coal forecast because it is handled by a separate team within EVA. (*Id.* at 1844.) Mr. Harter did not even know the vintage of the data used in the modeling. (*Id.* at 1873-74.)

With regard to high level information about how the model was run, Mr. Harter testified that EVA customized the emission rates, emission allowance costs, heat rates, and fuel costs but relied on off-the-shelf data from Aurora for resource groups, zonal aggregation, hourly wind and hydro shapes, etc. (*Id.* at 1863.) Though Mr. Harter testified that heat rates were customized by EVA, Ms. Medine stated that his statement was false because heat rates were not customized as part of the Aurora modeling. (Tr. X at 2151, 2158-59.) There were multiple problems with EVA's workpapers that were supposed to be provided to parties to assist their understanding of EVA's testimony. During cross examination at the hearing, EVA witness Harter acknowledged that he did not provide a complete set of workpapers. After being ordered to submit the workpapers by Monday April 30, EVA ended up discovering additional errors in Mr. Harter's testimony and Staff requested leave to file Ms. Medine's testimony. It was not until several days after Mr. Harter's testimony on the stand when EVA was preparing after-the-fact workpapers for the testimony (which should have been completed by the time the testimony was originally filed) that EVA discovered these errors, which were also already indicated during cross examination. In short, neither Mr. Harter nor Ms. Medine effectively explained or defended their use of the Aurora model.

Mr. Meehan and Mr. Allen further demonstrated the unsuitability of EVA's approach as a basis for establishing an energy credit. First, its documentation is incomplete and inadequate (AEP Ohio Ex. 144 at 13-14.) Second, the EVA model and the data it used cannot be reasonably verified (*Id.* at 15-16.) Third, EVA's quality control measures are deficient. (*Id.* at 17-18.) Fourth, even if the EVA methodology were acceptable, the execution of the analysis contains significant errors and has not been performed with requisite care. The approach cannot be adequately tested or validated. (*Id.* at 18.)

ii. EVA failed to calibrate the model or otherwise account for the impact of zonal rather than nodal prices.

The most basic step in any large-scale production costs model analysis is to calibrate the results of the model that will be used to a known measure. (AEP Ohio Ex. 144 at 10.) That does not appear to have been done by EVA. For example, one would compare the forecast of market prices that the model and data set are producing on and off peak to available forward market data at the AEP/Dayton hub (recognizing that prices at the AEP Dayton hub have been roughly 3% above prices at the AEP generation hub). AEP Ohio witness Meehan, a veteran energy market analyst from NERA, explained that, if one could determine that the model and data were consistently overstating prices by say 5%, the model results could be reduced by that amount. If one could determine that the model and data were consistently understating prices by say 5%, the model results could be increased by that amount. Mr. Meehan allowed that this would be a rough adjustment, but at least would represent an effort to assess any model and/or data bias and make an adjustment. Alternatively, he observed, one could do a backcast[16] with the model and see how well the model reproduces prices at the AEP generation hub.

Staff witness Harter testified that even though the modeling produced an energy credit of $231/MW-day for Ohio Power (based on the pre-merger view of Ohio Power as presented in Mr. Harter's original testimony), he did not have a reason to doubt the result or go back and double-check it, because he stated: "I'm fairly careful with my analysis. I was confident with my number." (Tr. IX at 1845.) Of course, the numerous errors (admitted to and otherwise) in Mr. Harter's analysis belies his false confidence in the flawed results. Further, even though it only takes a few hours each time, Mr. Harter only did one run of the Aurora model to support his

[16] A "backcast" is a method used to calibrate and verify a forecasting model, by applying the projection method to historical data to determine the method's accuracy. A forecast is forward-looking, whereas a backcast is backward-looking

testimony. (Tr. IX at 1846.) Ms. Medine also admitted that the Aurora model had not been calibrated in connection with the work on this case to produce the AEP Ohio runs of the model. (Tr. X at 2210.)

Briefly during cross examination, Ms. Medine maintained that EVA relied on a federal government project involving a complicated set of regulatory rate impact issues to suggest that EVA has calibrated the Aurora model and keep it "hot" and ready to run. (Tr. X at 2163.) When asked to discuss any supporting details or corroborate her statement, Ms. Medine declined saying that she is not allowed to talk about the secret government project she worked on. (Tr. X at 2210.) Ms. Medine's testimony that the model was pre-calibrated does not meet best industry practices. And as a basic matter of due process, the Commission must ignore Ms. Medine's incredulous claim that EVA's work on a secret government project purportedly honed the model for purposes of using it for AEP Ohio in this case, given that EVA refused to discuss or support its claim on the record. Indeed, Ms. Medine could not agree that it is a best industry practice to test the validity or sensitivity of a forecast by "backcasting" to compare the forecasted data to historical data, stating that she prefers to start with actual data and adjust it based on her subjective views. (Tr. X at 2165.) Mr. Meehan explained that the failure to perform and describe the results of any type of calibration exercise reinforces the unsuitability of the methodology used by EVA. (AEP Ohio Ex. 144 at 10-12.) The reality is that EVA's one full-time modeler (Mr. Harter) simply did not have time to properly calibrate the model (due to EVA's late date of engagement by Staff for this case) and consequently took unacceptable short-cuts in performing his work.

Another flaw related to use of a complex set of generic data without properly calibrating the results is EVA's use of the zonal mode of the Aurora model. Consistent with Mr. Harter's testimony, Ms. Medine stated that EVA did not own the nodal version of the Aurora license but agreed that it more accurately modeled LMP prices as compared to the zonal version used by EVA. The nodal version is more expensive, takes more time to calibrate and longer to run the model. Further, the zonal version does not capture intra-zonal congestion costs. (Tr. X at 2280-82.) Mr. Harter used the zonal mode of Aurora, which is quicker and simulates only one price for the entire zone. He agreed that the nodal mode would produce more accurate results that are closer to the LMP price in a constrained market. (Tr. IX at 1865-66.) Ms. Medine could not confirm whether more than 10 RTOs are modeled; whether more than 10,000 generation units are modeled; whether more than 100 market zones are modeled; or how many transmission interconnection paths are modeled. (Tr. X at 2207-08.)

In sum, without calibration or benchmarking, and through use of the zonal mode versus the nodal mode of Aurora, EVA's modeling lacks validation and accuracy. As AEP Ohio witness Meehan testified, generating units receive revenue at the nodal level and most often at a several percent discount to the zonal LMP. Consequently, use of the zonal analysis, without performing any calibration, results in yet another overstatement of EVA's modeled forecast market prices. (AEP Ohio Ex. 144. at 16.)

iii. EVA erred in forecasting LMP prices instead of using available forward energy prices.

EVA used modeled forecasted prices instead of the more accurate current forward prices for June 2012 through May 2015. As demonstrated below, EVA's modeled forecast prices exceeded the current forward prices for that three-year period by about $4/MWH. This led to an overstatement of market prices by EVA and, thus, another overstatement of gross margins.

Interestingly, it was the same EVA witness, Ms. Medine, who stated, in another case where she opposed the use of a forecast, that "people who use crystal balls end up being crushed by glass." On cross examination in the case at bar, she explained that she gave that warning because "obviously forecasting is a dangerous business." (Tr. X at 2170.) She also readily conceded on cross that her analysis predicting the energy credit in this case is merely a "good analytical tool" and is "almost assuredly" not going to be exactly right. (Tr. X at 2176.)

Regardless of which method one concludes is appropriate, there is also an issue of the disconnect or inconsistency between the method used by Staff witness Smith in developing the demand charge and the work done by Staff witnesses Medine and Harter in developing the energy credit. The demand charge and energy credit are tightly related and are supposed to work together to produce a net capacity charge. In that regard, Mr. Harter testified that his assumptions and modeling was consistent with Mr. Smith's analysis. (Tr. IX at 1856-57.)

Yet, there are multiple inconsistencies between the two components of Staff's presentation. The most glaring and material inconsistency is the fact that Staff's energy credit does not properly apply the Pool, while Mr. Smith's demand charge fully reflects a $125/MW-day credit based on capacity equalization payments made to AEP Ohio under the Pool, a matter which is separately discussed below. But Staff's demand charge and energy credit are also inconsistent as a matter of methodology. This is because Staff's demand charge was developed using 2010 actual cost data while Staff's energy credit is based on projected energy margins. In this regard, Mr. Harter agreed that the methodologies between Mr. Smith's demand charge and his energy credit should be consistent. (Tr. IX at 1902.) By contrast, Ms. Medine voluntarily characterized AEP Ohio witness Pearce's calculation of an energy credit based on actual 2010 data as "apples to oranges" compared with her forecast (Tr. X at 2172); she also described the work she did to forecast the energy credit and the work Staff witness Smith did to calculate the demand charge based on actual cost as "two different things" (Tr. X at 2173.) Ms. Medine acknowledged that even though her forecasted energy credit was used as an offset to Mr. Smith's demand charge, the two components were different analyses that don't use the same method. (Tr. X at 2171.) Not to be deterred, Ms. Medine steadfastly maintained her view that it is better in this case to rely on her subjective judgment than rely on actual forward contract data reflecting negotiated market prices. (Tr. X at 2168.)

AEP Ohio witness Meehan testified that forward energy prices are the market's collective view of the most likely price outcome, as they represent real money committed to actual market transactions by actual buyers and sellers. While any one entity may have a different view, the forward energy price reflects the consensus that the market has reached. Forward prices also represent at any given time the price at which any commitment can be hedged. Mr. Meehan explained that parties look to the current market price as established in forward markets to make pricing decisions and do not look to models when forward prices are available. The forward market price is the most realistic and current forecast of the market prices that will prevail in the future. He noted that the forward price is not subject to the whim of potential errors or inconsistencies in thousands of input data items or limitations, as is the case with models.

Instead, using a forward price eliminates the need to construct a forecast from thousands of unverifiable inputs and to calibrate for things that a model cannot measure. These items are all embedded in the forward market price. (AEP Ohio Ex. 144 at 14-15.) As Mr. Meehan aptly asserted in describing why using forward market prices is preferable to using modeled prices:

> To claim otherwise is the height of arrogance. If EVA had forecasting skills that were reliably superior to the market, it would be irrational for the firm to provide client services as they do. The rational thing to do would be to take proprietary market positions and trade using their superior insight.

(AEP Ohio Ex. 144 at 26-27. *See also* Tr. XII at 2757 (if someone has a forecast that is better than actual market data, they should be trading, not testifying).) In reality, Ms. Medine herself admitted that the gas prices she used in developing the energy credit were already outdated and that EVA has, in fact, revised its projected gas price since the time it only recently performed the Aurora modeling; while Ms. Medine could not recall the particulars, EVA's updated gas price projection is consistent with the EIA updated forecast referenced AEP Ohio Ex. 141. (Tr. X at 2277.)

On rebuttal, AEP Ohio witness Allen made a quantitative comparison of the modeled market prices used in Staff witnesses Harter's and Medine's analysis to publicly available forward market prices for the AEP Zone. His comparison shows that EVA's modeled market prices are overstated by over $4/MWh over the three-year forecast period. Overstated market prices will have the effect of overstating the margins produced by the generating resources of AEP Ohio and, as a result, will overstate the energy credit calculated by Staff. (AEP Ohio Ex. 142 at 8-9.)

Mr. Allen estimated that the use of current forward market prices for the AEP Zone would have reduced EVA's energy credit by $50.42/MW-day. (*Id*. at Ex. WAA- R4.) To estimate the impact of using current forward market prices to determine the margins from the coal fired and hydro generation resources of AEP Ohio Mr. Allen calculated the difference in annual market prices (on a dollar per megawatt hour basis) and then multiplied this difference by the projected generation for each of these plants/units to determine the annual dollar impact on

Staff witness Harter's margins. Mr. Allen then subtracted this difference in margins from Staff's projected margins to determine the impact on their energy credit. (*Id.* at 9.)[17]

iv. Inaccurate and understated fuel costs.

Errors in estimates of future fuel costs led EVA to materially understate AEP Ohio's fuel costs for the June 2012 through May 2015 ESP period. That resulted in EVA substantially overstating the amount of gross energy margins that AEP Ohio realistically could earn during the three-year period. AEP Ohio witnesses Allen and Meehan confirmed through separate analyses that EVA relies upon very significantly understated fuel costs. Even Ms. Medine agreed that her fuel cost assumptions "were certainly aggressive." (Tr. X at 2288-2289.) She also acknowledged that, if the fuel cost projection is too low, then the margin EVA calculated would be too high. (Tr. X at 2290.) In other words, the problem for AEP Ohio is that an aggressive assumption about low fuel costs means that real capacity costs incurred by AEP Ohio (and verified under Mr. Smith's testimony) are offset by unrealistic hypothetical energy margins that will never materialize.

In his review of EVA's analysis, Mr. Allen observed that the fuel cost data that EVA used appeared to be very low for AEP Ohio's coal-fired generation resources, in comparison to 2011 actual fuel costs. What really stood out, in Mr. Allen's view, was that the fuel cost that Staff witnesses Harter and Medine included for Gavin units 1 and 2 was between $13/MWh and $15/MWh which was well below the level that he expected. On cross examination, Staff witness Medine admitted that the projected costs for the Gavin units used in EVA's analysis were "certainly aggressive." (Tr. X at 2289.) Gavin units 1 and 2, with a capacity of approximately

[17] Mr. Allen explained that he did not calculate the impact on Staff's energy credit related to margins from the gas-fired resources of AEP Ohio since the difference in market prices is correlated to the gas costs included in Staff's analysis. He confirmed that this is a conservative approach to making corrections to Staff's energy credit calculation. (Id. at 10.)

1,300 MW each, are the largest generation resources of AEP Ohio. Mr. Allen conducted a review of EVA's fuel cost data used for the Gavin units, which showed that the values used by Staff witnesses Harter and Medine were understated by over $5/MWh, compared to 2011 actual fuel costs. This is a gross understatement of fuel costs. Based upon the Staff witnesses' projected generation for the Gavin units this resulted in an understatement of fuel cost in excess of $390 million for the Gavin units alone. (AEP Ohio Ex. 142 at 5.)

In addition to reviewing the fuel cost data that Staff witnesses Harter and Medine used for the Gavin units, Mr. Allen also reviewed the fuel cost data that was used for the other generation resources that were included in EVA's analysis. He confirmed that the analysis included similar understatements of fuel costs for the other coal units listed in the final work papers of Staff witness Medine. (*Id.*) Mr. Allen calculated that, using 2011 actual fuel costs as the point of reference, EVA had underestimated fuel costs for the Company's coal-fired generation resources by over $750 million for the three-year ESP period. (*Id.* at Ex. WAA-R1.) Mr. Allen explained that using 2011 actual fuel costs as the point of reference for evaluating the amount by which EVA's fuel cost assumptions are understated for the June 2012 through May 2015 period is very conservative because, in fact, the fuel costs for those coal units is escalating during the time period in accordance with the terms of the coal contracts that will provide the bulk of the fuel for the plants during the period. (Tr. XI at 2460-61.)

Mr. Allen has conservatively estimated that the use of more reasonable fuel costs, based on 2011 costs, would have reduced Staff's energy credit by $70/MW-day. This analysis is included in Exhibit WAA-R1 to his Rebuttal Testimony, AEP Ohio Ex. 142. In preparing this analysis Mr. Allen calculated the difference in total fuel costs that results from replacing Staff witness Harter and Medine's fuel costs (on a dollar per megawatt hour basis) with the actual fuel costs from 2011 for each coal unit included in the final work papers of Staff witness Medine (on a dollar per megawatt hour basis) and multiplying that difference by the projected generation for each of these units. He then subtracted the difference in fuel costs from Staff's projected margins to determine the impact on EVA's energy credit. (*Id.* at 6, Exhibit WAA-R1.)

Mr. Meehan confirmed that the fuel costs which EVA used are significantly understated compared to the actual AEP data received and their estimated gross margins are similarly overstated. He estimates that, using as the point of reference the forecast of coal costs for Gavin (which would include increased coal costs during the three-year period, above the costs experience in 2011, that will occur due to coal contracts already in place), EVA's error for Gavin alone leads to a $600 million understatement of fuel costs and a corresponding overstatement of gross margins in the same amount. (AEP Ohio Ex. 144 at 16, 34.)

Mr. Allen also explained that the EVA witnesses had used significantly understated heat rate values in their modeling, which understates the amount of and, thus, the cost of fuel used to generate electricity. Mr. Allen provided a comparison of the heat rates used by Staff witnesses Harter and Medine to the actual heat rates for 2011. (AEP Ohio Ex. 142 at Ex. WAA-R2.) Mr. Allen noted that actual heat rate data for the Company's plants is publicly and readily available. (*Id.* at 7.)

Mr. Allen estimated that the use of correct actual heat rates for the gas fired generation resources would have reduced Staff's energy credit by $1.87/MW-day. (*Id.* at Ex. WAA-R3.) The impact of EVA's heat rate errors on the coal units is included in Mr. Allen's fuel cost analysis, discussed above, so he appropriately did not include them again as part of his heat rate analysis. The understated heat rates that Staff witnesses Harter and Medine used for the gas fired generation resources of AEP Ohio result in overstated margins. To estimate the impact of correcting the heat rates for the gas fired generation resources of AEP Ohio on Staff witness Harter's margins, Mr. Allen calculated the difference in fuel cost for each plant (on a dollar per megawatt hour basis) that results from applying the actual heat rates for 2011 to the delivered gas cost (on a dollar per BTU basis) used in his analysis. He then multiplied this difference by the projected generation for each of these plants/units to determine the dollar impact on fuel costs of these errors. Mr. Allen then subtracted the difference from Staff's projected margins to determine the impact on the energy credit. (*Id.* at 8.)

v. EVA failed to use correct heat rates to capture minimum and start time operating constraints and associated cost impacts.

Another material flaw in EVA's approach was the failure to incorporate into its model the constraints under which AEP Ohio's generating units operate. In particular, EVA assumed that each of the Company's generating units either operates at its full load heat rate (*i.e.*, its optimal heat rate) or is offline. (Staff Ex. 105 at 10-11.) Even Ms. Medine agreed that it is critical to get the heat rates right for gas units, since they often set the LMP price and have tight margins to begin with. (Tr. X at 2267:12-2668:12.) And Ms. Medine testified that EVA did consider whether to customize heat rates and there was an internal debate within EVA about whether to do so. (Tr. X at 2151:5-24.) Unfortunately, EVA again ended up simply taking the expedient route on this critical modeling assumption and blindly relied upon the generic/default data that comes with the Aurora software on this critical component. This is a significant error in EVA's proposed energy credit that, once again, falsely inflates the energy credit. Mr. Harter's response to this problem was that we could assume that all of the heat rate data for the more than 10,000 units modeled is similarly erroneous and that the magnitude of the errors would be the same – then the errors "may not have a large effect on the energy credit." (Tr. IX at 1888.) Of course, that kind of massive speculation is inappropriate – even Mr. Harter agreed that would "a big assumption" to make. (Id.)

Ms. Medine agreed that heat rates for units typically involve three different levels based on the three major categories of operational status: full output, less than full output, and temporary startup mode after a shutdown. The average heat rate reflects a combination of all three heat rates. EVA's modeling used the most efficient or "optimal" heat rate, which only reflects the full output mode and represents the default setting in the Aurora model. (Tr. X at 2236:9-2238:1.) More specifically, Ms. Medine agreed there is a heat rate curve for various operational levels, which reflects different economic decisions and different operational hourly states: (1) running at a profit, which adds to margins, (2) out of the money but unavoidably running, which reduces margins, (3) offline during a profitable hour, losing a potential margin, and (4) offline and out of the money, which avoids a loss but does not add to margins. (Tr. X at 2261:15-2265:20.) Ultimately, Ms. Medine agreed that using optimal heat rates does not capture the minimum run operation or start times and she acknowledged that EVA had not done the modeling for AEP Ohio using anything close to an average heat rate. (Tr. X at 2246:3-23.)

When asked whether the Aurora model allows one to review individual plants to see how many times they started and stopped, she first stated she was not familiar with the feature, then said she assumed that was a feature of Aurora. (Tr. X at 2251:6-17.) When asked whether she used the default numbers to startups, she stated EVA used the default numbers for startups, then she relented saying "I'm going to stop. I'm just speculating." (Tr. X at 2251:13-2252:1.) This kind of discourse around EVA's modeling does not instill confidence in the analysis or the result.

In her written testimony, Ms. Medine attempts to marginalize the impact of the optimal heat rate assumption, stating that the average (real life) heat rate and the optimal (only attained during certain hours of operation) converge for the units operating at high capacity factors. (Staff Ex. 105 at 11.) Of course, converging is not the same as being equal; in addition to the fact that not all units are high capacity factor units, there is still a significant cost difference even for the large units that usually run. With regard to her statement in testimony that large plants with high capacity factors correlate better with optimal heat rates, she acknowledged that the table on page 12 of her testimony shows that even the largest plant, Gavin station, does not run 20% of the time and, therefore, it cannot experience the optimal heat rate. Similarly, the Cardinal plant does not run about 20% of the time and the heat rate she used for Cardinal was 5% less than the average heat rate recently experienced at the plant. (Tr. X at 2243:20-2246:23, 2250:11-2251:5.)

Ms. Medine acknowledged the significant difference in capacity factors among the several major plants listed in AEP Ohio Ex. 137, Cardinal, Conesville, Darby, Gavin, Lawrenceburg, Stuart, Waterford and Zimmer. (Tr. X at 2248:17-2249:3.) She also agreed that startup costs are not immaterial for low capacity units, where there are more frequent stops and starts, and admitted they were not reflected in EVA's modeling. (Tr. X at 2252:9-12.) Thus, Ms. Medine's point about converging data for high capacity factor units is misguided and improperly attempts to sidestep the fact that real and significant costs are ignored under EVA's modeling.

In short, EVA's use of the optimal heat rates resulted across-the-board in understating the costs of AEP Ohio units, thus producing an erroneous dispatch of the units and an overstated LMP projection. Ms. Medine acknowledged that the historical heat rates, as reflected by the EIA and FERC Form 1 data in the table on page 12 of her testimony, were similar to each other but universally higher (*i.e.*, less efficient and more expensive) than the optimal heat rates she assumed in her modeling. (Tr. X at 2240:11-20.) Ultimately, Ms. Medine agreed that both the costs and the projected market prices are overstated through the use of optimal heat rates, because start costs and minimum run costs are not reflected. (Tr. X at 2255:25-2256:4.)

AEP Ohio witness Meehan (from NERA) explained that EVA's claim that it is appropriate to use full load heat rates and have units be at full capacity or off is simply wrong because large coal-fired steam units simply cannot run that way. (AEP Ohio Ex. 144 at 22.) Many of AEP Ohio's large steam units are supercritical units, such as Gavin and Amos 3, that have minimum up and down times of 72 hours. (*Id.*) If the unit is economic over this cycle it will run and it will be profitable during the day, but to achieve these profits it will have to run at minimum load over the night period and sustain losses that will offset its daytime profits. (*Id.*) Mr. Meehan explained that the failure to model with correct minimum up and down times, to model a heat rate at minimum load, and to only reflect the full load heat rate and turn AEP Ohio's coal units on and off with no regard for minimum up and down times, is a fatal flaw in EVA's modeling of unit profits. (*Id.*) While it may well be a simpler way to model, Mr. Meehan confirmed that it is inadequate for estimating unit margins because it does not recognize the losses that will be incurred to run the generating units at minimum load overnight. (*Id.* at 23.) EVA's approach unrealistically assumes that the units can be turned off and on at the flip of a switch. (*Id.*) Mr. Meehan confirmed that EVA's description of the heat rates it used shows that EVA has misused the Aurora model for this application. Specifically, EVA did not provide any data on unit minimum up and down times, unit start-up costs or unit commitment parameters nor any data on heat rate curves. (*Id.*) Consequently, Mr. Meehan stated, EVA's approach simply does not reflect the real-world operating constraints under which the Company's generating units must operate. (*Id.* at 22-23.) EVA's failure to correctly model operational constraints is a very significant flaw. Mr. Meehan estimated that EVA's failure to properly model operational constraints for the coal-fired generating units, results in an *overstatement of gross margins by $256 million*, all else equal. (*Id*. at 30.)

vi. EVA's static assumption of 26% shopping throughout the 2012-2015 period is flawed.

EVA assumed 26% shopping throughout the entire 2012-2015 period at issue in this case, for purposes of calculating the energy credit. (Staff Ex. 105 at 19.) According to Ms. Medine, the 26% static shopping assumption was "the most conservative approach" that could be used and Ms. Medine has no knowledge or expertise about projected shopping levels. (Tr. X at 2193:21-2194:4.) When probing the validity of this assumption during cross examination, Ms. Medine was asked whether she believes that shopping levels would stay at 26% for the three-year period – and her complete answer was "I can guarantee you they won't." (Tr. X at 2189:19-23.) This unrealistic assumption under EVA's approach is inaccurate, irrational and produces perverse results.

EVA's static assumption undermines the validity of the energy credit, for two reasons. First, the 26% shopping level is already outdated; as confirmed by AEP Ohio witness Allen on rebuttal, April 30, 2012 shopping levels were already at 30%. (AEP Ohio Ex. 142 at 21) Thus, the 26% static assumption for 2012-2015 has already been proven inaccurate in the short time that has passed since Staff filed its testimony.

Second, even if the energy credit were adjusted to reflect actual shopping levels, the inverse relationship between shopping and the capacity charge confirms that EVA's method is flawed. Under EVA's energy credit, if shopping goes up above 26%, CRES providers would pay a higher net capacity charge (because EVA's energy credit would decrease). (Staff Ex. 105 at 19.) If increased shopping were to be reflected, the model output data would have to be reaggregated and cannot be presently determined. (Tr. X at 2190:16-2191:22.) The inverse relationship of shopping to the net capacity charge is counterintuitive because additional shopping should produce additional OSS margins, a portion of which would be allocated to AEP Ohio under the AEP generation Pool and would be attributed to the energy credit. The counterintuitive inverse relationship between shopping and the net capacity charge under EVA's approach is caused by the fact that EVA retained 100% of the imputed non-shopping margin reflected on AEP Exhibit 132. (Tr. X at 2198:1-3.) So, the additional shared margins actually bring the MLR share closer to reality, since the non-shopping load is less and would have been retained 100% under EVA's approach. The imputation of a LMP-based margin and 100% allocation to the benefit of CRES providers is inappropriate, as is further discussed below.

vii. EVA failed to exclude from the analysis AEP Ohio's full requirements obligation to serve Wheeling Power Company.

Staff witness Harter's calculation of OSS margins produced by the generation resources of AEP Ohio first compares the non-shopping retail sales of AEP Ohio to the generation of AEP Ohio. He then calculates a margin for the generation in excess of the non-shopping retail sales. Mr. Allen explained that Mr. Harter failed to account for the full requirements contract between AEP Ohio and Wheeling Power Company. Mr. Harter erroneously thought the Wheeling Power contract contained market-based pricing, when it is a cost-based formula contract that has been in effect for decades. (Tr. IX at 1918.) Thus, in reality, the sales to Wheeling Power Company reduce the quantity of generation available for OSS. Mr. Allen estimated that recognizing the full requirements contract between Ohio Power Company and Wheeling Power Company would have reduced Staff witnesses Harter and Medine's energy credit by $5.00/MW-day. This analysis is included in Exhibit WAA- R5 to Mr. Allen's Rebuttal Testimony. (*See* AEP Ohio Ex. 142.)

viii. AEP Ohio witness Meehan's alternative calculation of forecast gross margins shows that EVA's estimate of gross margins that AEP Ohio will earn in the June 2012 through May 2015 period are overstated by nearly 200%.

Mr. Meehan developed and presented an alternative to EVA's approach that illustrates and quantifies the flaws of the EVA approach. (AEP Ohio Ex. 144 at 23, *et. seq.*) In contrast to the EVA model, Mr. Meehan's analysis is a well-documented, transparent, and verifiable assessment of the gross margins that AEP Ohio realistically could earn during the three-year period.

Mr. Meehan's approach can be summarized as follows. First, he developed a forward-looking price profile (for hourly nodal prices) for the period June 1, 2012 to May 31, 2015 that is completely calibrated to actual market outcomes. (*Id.* at 23-24.) This is the base against which unit gross margins can be calculated on a nodal basis. (*Id.* at 24.) Once Mr. Meehan developed these calibrated hourly nodal prices, he undertook what he described in his testimony as a "very detailed" modeling exercise consisting of the following three steps using input data provided by AEP Ohio witness Nelson: (1) assembling detailed cost data for each generation unit, including fuel costs, variable O&M costs, and emission allowance costs; (2) assembling detailed unit output curves; and (3) assembling detailed unit operating characteristics, including minimum up and down times, unit start-up costs, unit forced outage rates, maintenance and retirement dates, and units that are "must run" for area security. (*Id.* at 27-28.)

At this point, Mr. Meehan had assembled all the data required to examine the commitment and dispatch of AEP Ohio units against the calibrated nodal prices. (*Id.* at 28.) His next step was to analyze that commitment and dispatch pursuant to a six-step process, including: (1) calculating for each generating unit the point at which the incremental cost of operation equals the market price for the hour; (2) determining the margin in each hour resulting from operating at the point where the unit's incremental cost equals the market price; (3) looking ahead over the unit minimum run time (usually 36 or 72 hours for coal plants) to determine anticipated market margins over the cycle; (4) starting up and shutting down units as appropriate based on the minimum run period and profit margins; (5) calculating *revenues* at the nodal prices and dispatch level, as well as the *costs* at the nodal prices and dispatch level, and the resulting gross margin; and (6) summing the gross margin over all hours, adding in start-up costs, and adjusting margins to account for forced outage rates. (*Id*. at 28-29.)

As Mr. Meehan testified, the end result of this process is "an estimate of gross margins based on calibrated nodal market prices that fully account[s] for unit operating characteristics." (*Id*. at 30.) This kind of detailed analysis is critical, Mr. Meehan explained, because "there are many hours in which AEP Ohio units are either operated at minimum load or at a point between minimum and maximum." (*Id*.) EVA's failure to recognize these operational constraints alone overstated gross margins by $256 million – in addition to the $600 million overstatement error resulting from Gavin fuel costs. (*Id*.)

When asked how he could be sure that his own analysis of gross margins does not "grossly understate" the margin, as EVA's analysis grossly overstated it, Mr. Meehan contrasted his approach with EVA's "black box" approach as follows:

> There is simply no room for material misstatement in the type of analysis I have conducted. The forward prices are what they are. Different analysts may use slightly different methods to shape annual forwards to months, but the impact of the results will not be significant compared to the difference with EVA. Adjustments from the AD hub which is the traded product to the AEP

> generation hub and then to each generation node could also be done slightly differently by different analysts *** but again the impact will not be material relative to the difference with EVA. Similarly I have developed a logical set of commitment rules and different analysts may use somewhat different rules, but again the impact will not be material relative to the aggregate difference with EVA's analysis. I have supplied in my work papers every assumption and calculation that validates the results. In contrast, the EVA analysis is a black box with known errors. There is no question that in comparing the two analyses it is the EVA results which are overstated.

(*Id.* at 33-34.) As such, Mr. Meehan's analysis is a documented, transparent, and verifiable approach to assessing the gross margins earnable by AEP Ohio in the three-year period. The transparency of Mr. Meehan's approach was demonstrated under cross examination when counsel for IEU asked Mr. Meehan to explain each column of the hourly calculations performed for each generating unit. (*See* Tr. XI at 2725-2731.)

Mr. Meehan's alternative calculation of forecast gross margins shows that EVA's estimate of gross margins that AEP Ohio will earn in the June 2012 through May 2015 period are overstated by nearly 200%. This is demonstrated by comparing Exhibit ETM-R2, Mr. Meehan's estimate of gross margins during the three-year period for "All AEP Ohio Resources Included in EVA Final Analysis" of $583,564,000 to Exhibit ESM-1 Gross Margin (2012$) (Merged view), EVA's estimate of gross margins for the period of $1,648,708,378.[18] $1,648,708,378 is 2.825 times, or 182.5% (nearly 200%) higher than Mr. Meehan's more objective and accurate estimate of realizable margins, $583,564,000. (*Id.* at 23-35, Ex. ETM-R2, ETM-R3.)

[18] From the Gross Margin column of Exhibit ESM-1 to Ms. Medine's Supplemental Testimony, the sum of $308,109,685 + $547,222,855 + $552,237,359 + $241,138,479 = $1,648,708,378.

b. EVA's energy credit wrongly incorporates traditional OSS margins and otherwise fails to properly reflect the impact of the Pool.

Under EVA's approach, the gross margins made possible by sales of capacity to CRES providers (the "freed up" energy sales) are calculated based on EVA's 26% shopping assumption, in order to determine an appropriate energy credit to the CRES capacity charge. In addition, EVA's approach incorporates OSS margins not associated with shopping as well as imputing a market-based margin for non-shopping customers as part of its calculation of an energy credit. Mr. Harter intended his model to reflect real world application of the Pool. (Tr. IX at 1926:20-23.) Ms. Medine agreed with Mr. Harter that the modeling is intended to simulate actual operation of the Pool. (Tr. X at 2179:2-6.) While EVA professes to develop the energy credit based on OSS margins actually retained by AEP Ohio under the Pool, its implementation of the model grossly violates that goal and, thus, violates the FERC-approved contract. There are several additional problems with EVA's approach relating to implementation of the Pool and sharing of projected OSS margins.

i. If an energy credit is used, it should reflect only the OSS margins created by "freed up" energy associated with the capacity being paid for by CRES providers.

Under the EVA/Staff approach, Staff assumes that AEP Ohio's Member Load Ratio (MLR) share (currently 40%) of <u>all</u> OSS margins are retained and available to offset costs of capacity furnished to CRES providers. (AEP Ohio Ex. 143 at 8-9.) Thus, at the outset, Staff's approach does not offset CRES capacity costs with just AEP Ohio's retained energy margins from "freed up" OSS sales. Rather, Staff's approach not only captures the OSS margins from "freed up" energy associated with the capacity being used by CRES providers but also commandeers retained margins from unrelated OSS sales (*i.e.*, traditional OSS margins).

It should not be presumed that an energy credit operating to reduce the price of capacity being provided to CRES providers should reflect an offset for OSS margins that is not associated with the capacity being paid for to support shopping load – especially since non-shopping retail customers do not receive such an offset. Further, the RAA does not say that an FRR Entity can establish a cost-based rate net of any revenues that are directly or indirectly associated with freed up energy. Instead, the RAA says that an FRR Entity may establish a rate based on cost. In the same manner, AEP Ohio's retail rates approved by the Commission do not reflect a credit for OSS margins (except for any residual and insignificant portion of OSS margins remaining in generation rates that relate back to the base rate cases in the mid-1990s). At a minimum, if the energy credit is to capture the OSS margins attributed to "freed up" energy associated with the capacity being used by a CRES provider, it should not also confiscate AEP Ohio's traditional OSS margins that are unaffected by the sale of capacity to CRES providers.

Staff witness Harter's recommendation is based on the false notion that 100% of OSS margins are required to be redistributed to "captive customers." (Staff Ex. 101 at 9; Tr. IX at 2034.) Of course, SSO customers in Ohio are not captive customers at all. Customers in AEP East operating companies' other jurisdictions pay rates reflecting 100% embedded costs for the underlying generation assets; unlike Ohio where a customer can come and go (as can the CRES provider's service of that customer), the rates in those traditionally regulated jurisdictions are established under a regulatory compact that guarantees recovery over the life of the asset. Based on that relationship, there is generally sharing of OSS margins – not confiscation of 100% of those margins. (*See* RESA Ex. 103 (most AEP jurisdictions using "traditional" regulation have approved sharing of OSS margins, except for West Virginia, which utilizes an expanded fuel clause).)

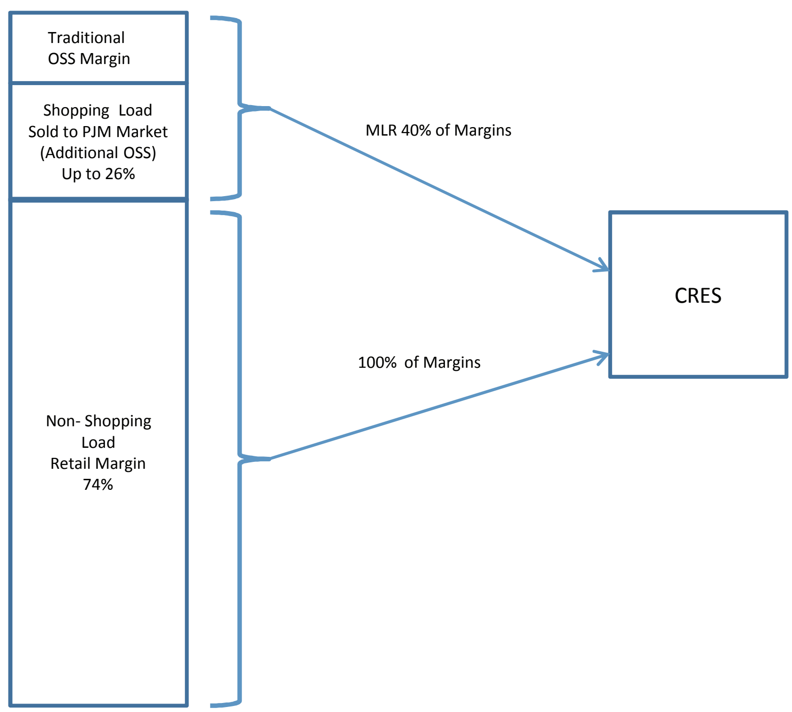
Moreover, it cannot be disputed that AEP Ohio's current SSO rates do not reflect an adjustment for OSS margins; the Commission affirmatively rejected OCC's proposal to establish such an adjustment to offset fuel costs. (*ESP I*, March 18, 2009 Opinion and Order at 17.) Likewise, the Commission has affirmatively rejected the notion that OSS margins be subjected to the SEET and is presently defending that decision before the Supreme Court of Ohio. (*See* Sup.Ct. Case No. 2011-751, PUCO September 26, 2011 Merit Brief at 13-19.) Due to the unique regulatory regime associated with SB 221, the Commission has seen fit to decline making any retail rate adjustments to credit OSS margins to retail customers. And rightly so, since AEP Ohio is at risk for losing those customers to CRES providers for generation service. Of course, only a portion of OSS margins even relate to physical assets; a substantial portion is tied to hedging, trading and non-physical transactions. If the Commission does entertain applying a credit based on OSS margins, it should certainly not appropriate the margins retained by AEP Ohio that are independent of the capacity supplied to CRES providers. CRES providers and their customers should not have an OSS margin credit when retail customers do not. Instead, the energy credit should only capture OSS margins that are created by freed up energy associated with the capacity being used by CRES providers.

ii. Even setting aside whether only the OSS margins related to "freed up" energy sales should be reflected in the energy credit, EVA fails to reflect operation of the FERC-approved Pool in its inflated energy credit.

EVA/Staff imputes market-based energy margins associated with retail sales to non-shopping SSO customers, which are then used to defray the costs of capacity furnished to CRES providers. Specifically, Staff assumes that <u>100%</u> of those imputed retail energy margins are available, and uses them to offset the cost of capacity furnished to CRES providers. Staff does not explain why any, let alone why all of such imputed retail SSO margins should be co-opted for the benefit of CRES providers. In order to determine the amount of these imputed retail margins that are available, and should be used, to offset CRES capacity costs, Staff assumes that it is 74% of AEP Ohio's entire retail load, *i.e.*, the total load minus an assumed 26% level of shopping.

Below is a diagram, prepared by AEP Ohio witness Nelson and included in his Rebuttal Testimony (AEP Ohio Ex. 143 at 9), which illustrates the Staff's formula for converting gross energy margins into the amount that Staff believes are retained by AEP Ohio, and should be used to offset CRES capacity costs.

Diagram of Staff's Energy Margin Credit



Under the EVA methodology, as the shopping level increases from 26% to 100% (and the SSO sales decline from 74% to 0%), the Staff/EVA energy credit declines from $152/MW-Day to $67/MW-Day, and the Staff's net capacity charge (after the energy credit is taken into account) increases the price to CRES providers from $146/MW-Day to $231/MW-Day. (*Id.* at

12.) Thus, under the Staff's methodology, the level of shopping assumed is a critically important driver for the size of the energy credit. (*Id.* at 9-10.) This indicates, as further discussed below, that there is a fundamental flaw in the Staff's methodology because there is no rational basis for the capacity charge to decrease (or increase) in this fashion depending on increases (or decreases) in the level of shopping.

Mr. Nelson also explained that EVA imputation of 100% non-shopping SSO margins as an offset to CRES providers' capacity costs is wholly inappropriate. (*Id.* at 9-10.) In addition to the perverse impact that the Staff methodology imbeds in the energy credit by making the amount of the credit inversely proportional to the level of shopping assumed, Mr. Nelson offered two additional perspectives that further illustrate the inappropriateness of the methodology. First, Mr. Nelson observed that by imputing non-shopping SSO energy margins as "Retail Margins" and then providing 100% of that margin to CRES providers, the result effectively increases the MLR from an actual 40% (the level required to be retained by AEP Ohio under the FERC-approved Pool) to about 92% (a level not permitted by the Pool). (*Id.* at 10.) This approach greatly overstates the amount of margin that AEP Ohio can retain under the FERC-approved AEP Pool Agreement and provides a windfall to CRES providers, particularly at the low level of shopping that Staff has assumed. (*Id.* at 10-11.)

This result is driven by the mathematical relationship created by EVA's approach, as follows. The more shopping there is, the less of the 100% imputed non-shopping margin is available to water down the effect of the MLR share of OSS margins; conversely, if less shopping is assumed, then there is more of the 100% imputed non-shopping margin to dilute the MLR sharing of OSS margins. In other words, EVA's false and improper imputation of 100% non-shopping margins mathematically dilutes the impact of the Pool, based on an arbitrary and capricious inclusion of *non-shopping margin* in the energy credit calculation relating to the price of capacity *for shopping load*. Because AEP Ohio's SSO pricing has been, and is being, established through separate proceedings involving the distinct ESP regulatory regime, SSO pricing and SSO margins have no place in the energy credit calculations related to shopping load. The purpose of this proceeding is to establish a wholesale capacity charge and retail rates cannot change as a result of this case. Thus, it is inappropriate to confiscate, in whole or in part, non-shopping SSO revenues by commingling them with OSS margins used to develop the wholesale capacity charge for CRES providers. (*Id.* at 11.) In addition to violating the FERC-approved Pool and the Federal Power Act, funding a capacity charge discount through the use of SSO revenues also amounts to a subsidy of a competitive service and, therefore, is inconsistent with Ohio's energy policy and basic economic principles advanced by §4928.02, Ohio Rev. Code. (*Id.*)

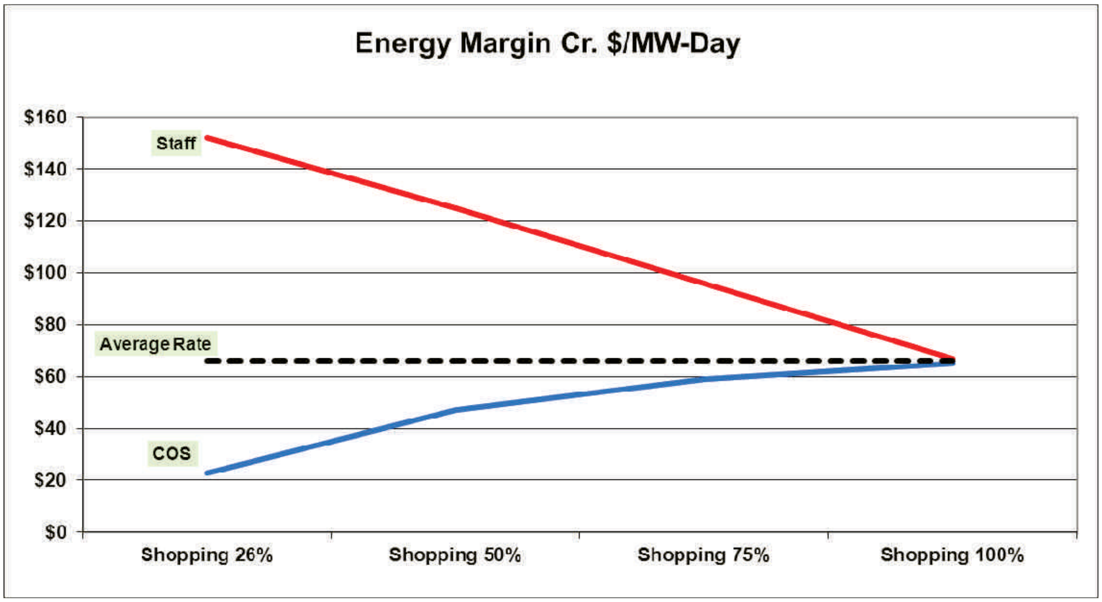
Mr. Nelson did provide suggestions regarding how the Staff's methodology could be adjusted to eliminate the anomalous impact of the assumed shopping level on the result. Another problem with EVA's tie in with shopping load is that its calculations do not adjust the load determinants to reflect the shopped load being incorporated into the calculation. In other words, the energy credit related to shopping load should be calculated using the peak load contribution of the shopped load. This was illustrated by Mr. Nelson as follows:

Shopping Level	Total Gross Margin	Gross Margin Attrib. to Cust. Shopping	MLR	Retained Margin Attrib. to Cust. Shopping	Total PLC MW	PLC of Shopped Load - MW	Total Days in Period	($/MW-day) Energy Cr. Margin Allocated Across Shopped Load
(1)	(2)	(3)=(1)x(2)	(4)	(5)=(3)x(4)	(5)	(6)=(1)x(5)	(7)	(8)=(5)/[(6)x(7)]
1%	$1,648,708,378	$16,487,084	40%	$6,594,834	9,061	91	1,095	**$66.47**
26%	$1,648,708,378	$428,664,178	40%	$171,465,671	9,061	2,356	1,095	**$66.47**
50%	$1,648,708,378	$824,354,189	40%	$329,741,676	9,061	4,531	1,095	**$66.47**
75%	$1,648,708,378	$1,236,531,284	40%	$494,612,513	9,061	6,796	1,095	**$66.47**
100%	$1,648,708,378	$1,648,708,378	40%	$659,483,351	9,061	9,061	1,095	**$66.47**

Source
(2) Exhibit ESM-1 Energy Credit Merged Table, "Gross Margin" Column, Total June 2012 - May 2015
(4) Exhibit ESM-1 Merged Table "MLR" Column
(5) Exhibit ESM-1 Merged CP-5 (MW)
(7) Equals days in three-year period 6/1/12 - 5/31/15 (3 x 365)

(*Id.* at 14.) Thus, if the load is simply adjusted along with the shopping assumptions, a stable energy charge results that is $66.47/MW-day, a more appropriate energy credit for use in this case. Consequently, Mr. Nelson recommends considering an “Average Rate Method” that would produce a result that does not vary in accordance with the shopping level. (*Id.* at 13.) It also has the virtue of avoiding the erroneous confiscation of AEP Ohio’s non-shopping SSO revenues for the benefit of CRES providers and does not conflict with the AEP Pool Agreement. (*Id.* at 13-14.)

As Mr. Nelson’s testimony details, if various approaches are used to develop an energy credit that assume 100% shopping (*i.e.*, in order to avoid incorporating specific shopping levels and look at an average energy credit for the total cost of capacity), then the results converge around $66/MW-day:



(AEP Ohio Ex. 143 at 8.) This analysis again shows that EVA got it wrong and the Company's cost-based method holds up well under multiple sensitivity tests.

c. Summary of adjustments to correct EVA's energy credit

Mr. Nelson's recommendation does not address the additional errors in the Staff's approach that Mr. Allen and Mr. Meehan describe. (*Id.* at 15.) Mr. Allen summarized his adjustments to EVA's energy credit (each of which were discussed above) as follows:

	($/MW-day)
Medine's Energy Credit	**152.41**
Understated Fuel Cost for Coal Units	(70.10)
Understated Heat Rate for Gas Units	(1.87)
Overstated Market Prices	(50.42)
Failure to Recognize Wheeling Power Contract	(5.00)
Cross Impact of Fuel and Market	22.44
Energy Credit after Adjustments	**47.46**

(AEP Ohio Ex. 142 at 14.) Accordingly, if it is to be relied upon at all, then EVA's energy credit should be corrected to be $47.46/MW-day.

C. Staff and Intevenors' Proposals For a Cost-Based Demand Charge Are Significantly Understated.

1. Staff witness Smith eliminated some costs included in Dr. Pearce's calculations, and made unwarranted downward adjustments to other costs, despite Dr. Pearce's use of a formula rate template approved by FERC.

Staff retained consultant Ralph Smith of Larkin & Associates, PLLC, to compute a capacity rate for AEP Ohio. (Staff Ex. 103 at 6.) In his direct testimony, Mr. Smith responded to AEP Ohio witness Kelly Pearce's testimony concerning the capacity rates developed in Dr. Pearce's Exhibits. (*Id*. at 7-8.) Mr. Smith combined his adjustments to Dr. Pearce's formula with information that was provided from Staff witness Ryan Harter (concerning energy credits) to proffer a proposed calculation of the appropriate capacity rate for AEP Ohio. (*Id*.) As depicted on his Exhibit RCS-3, Mr. Smith concluded that "a capacity rate for merged CSP and OPCo based on adjusted 2010 information is $305.48 per MW day" before any deductions for energy margins and ancillary service receipts. (*Id.* at 9.)

As AEP Ohio's counsel stated on the record during Mr. Smith's cross-examination, AEP Ohio does not doubt that Mr. Smith's work as a Staff consultant was done in a competent and professional manner. (Tr. IX at 1986:6-7.) But the significant eliminations and near-uniformly downward adjustments that Mr. Smith made to Dr. Pearce's capacity cost calculations share a key, fundamental flaw, in that the formula rate approach for determining capacity costs that Dr. Pearce developed is <u>based on an approach previously approved by FERC</u> – the agency charged with regulating wholesale capacity transactions such as those at issue here between AEP Ohio and CRES providers. (AEP Ohio Ex. 102 at 10) ("The formula rate template selected for this rate development is modeled after the template recently approved by FERC to derive the capacity charges applied to wholesale sales made by [SWEPCo], an AEP Ohio-affiliated operating company, to the Cities of Minden, Louisiana and Prescott, Arkansas.") As Dr. Pearce testified, "[t]his formula rate was the subject of a lengthy negotiation between the seller and purchasers and FERC Staff. In addition, it adopts various modifications originating from FERC Staff. As such, *this template represents a fair and reasonable formula for calculation of capacity costs*." (*Id.* (emphasis added).) Mr. Smith conceded on cross-examination that FERC has indeed approved rates resulting from Dr. Pearce's formula rate approach. (Tr. IX at1976:2-8.) Mr. Smith also agreed that for the recent Arkansas wholesale capacity transactions described by Dr. Pearce, the company utilized Dr. Pearce's formula-based rate and those wholesale contracts were approved by FERC.[19] (*Id.* at 1976:22-1977:2.) And Mr. Smith testified that he verified Dr. Pearce's cost data for AEP Ohio against the data appearing in the company's FERC Form 1s. (*Id.* at 1951:12.)

So, Mr. Smith had no quarrel with the FERC Form 1 data underlying Dr. Pearce's calculated capacity rates. And he agreed that FERC itself previously approved Dr. Pearce's formula-based rate. Yet in this proceeding, for reasons that Mr. Smith never fully explained at hearing, he believed that a different approach to calculating AEP Ohio's capacity costs than the FERC-approved approach was warranted. Mr. Smith testified that applying the FERC-approved formula in this proceeding would be akin to fitting "a shoe size E to a totally different size shoe." (*Id.* at 1977:10-11.) He testified that "it just seems to me" that the FERC-approved formula is "not the right model," and that applying that formula in this proceeding "just seems to be a bad idea." (*Id.* at 1977:11-16.) Although purporting not to criticize FERC's regulatory practices or that agency's expertise in the context of wholesale capacity transactions, Mr. Smith testified that

[19] The Company notes that Mr. Smith's references to "Arkansas wholesale contracts" (*see* Tr. IX at 1976:7, 16, 1976:25-1977:1, !977:15, 1982:7, 1987:25-1981:1) were presumably intended to be a reference to the Arkansas *and Louisiana* capacity transactions that Dr. Pearce described.

utilizing a FERC-approved formula here "seems like you're trying to impose that on a situation in Ohio that is probably quite a bit different and has a different standard." (*Id.* at 1982:17-19.) The closest Mr. Smith came at hearing to describing this "different standard," or explaining any overriding justification for his several eliminations and downward adjustments to the FERC-approved formula rate template utilized by Dr. Pearce, was when he testified that "We're not at the FERC. We are at the PUCO and a lot of stuff does appear to be very inconsistent with standard regulatory practices here." (*Id.* at 1978:16-18.)

Thus, instead of adopting Dr. Pearce's FERC-approved formula rate template to calculate AEP Ohio's capacity costs, Mr. Smith affirmatively chose a path "inconsistent with standard regulatory practices." He chose to adjust and deviate from the FERC-approved formula rate template, based on *his* perception of Ohio ratemaking practices and what *he* described as *his* "best judgment." (*Id.* at 1979:1-5.) In doing so, Mr. Smith proposed either downward adjustments to (or the complete elimination of) significant costs attributable to various items included in Dr. Pearce's formula rate template, including: return on equity ("ROE"); O&M expenses attributable to severance programs; prepaid pension assets; cash working capital; construction-work-in-progress ("CWIP"); and plant held for future use ("PHFU"). (Staff Ex. 103 at 10-12.) Counsel for AEP Ohio asked Mr. Smith whether the adjustments he proposed to the FERC-approved formula were based on *his* independent judgment about Ohio ratemaking principles that *he* believed should apply to Dr. Pearce's proposal, and Mr. Smith agreed that this was a "pretty good, high-level characterization" of *his* approach as a consultant for Staff. (Tr. IX at 1982:24-1983:6.) Thus instead of reflecting the methodology and rate template approved by the federal agency charged with regulating wholesale capacity transactions, as Dr. Pearce's cost values do, Mr. Smith's many adjustments to the FERC-approved approach utilized by Dr. Pearce reflect the independent judgment of an individual consultant retained by Staff.

Notably, Mr. Smith agreed at hearing that, with but one exception, every single adjustment that he proposed to Dr. Pearce's FERC-approved formula rate approach resulted in a *decrease* to the cost-based rate proposed by Dr. Pearce. (*Id.* at 1983:7-1984:2.) The only minor exception to these consistently downward adjustments was an adjustment that Mr. Smith proposed regarding accumulated deferred income taxes ("ADIT"), which he conceded was "near a wash on the merged results" (i*d.* at 1983:7-22) and thus effectively meaningless as a practical matter in terms of affecting the capacity rate that the Commission plans to establish here. Although Mr. Smith testified at one point that "[w]e weren't looking for adjustments one way or another," (*id.* at 1984:13-14), he also testified that Dr. Pearce's "rate was too high and these adjustments need to be made." (*Id.* at 1984:2-3.)

Given this record, and Mr. Smith's conscious decisions to deviate and adjust from Dr. Pearce's FERC-approved formula rate template in a consistently downward direction, it is difficult to view Mr. Smith's adjustments as anything but calculations that were made to deliberately *decrease* the cost-based rate proposed by Dr. Pearce. As the following discussion will show, Mr. Smith's most significant error (on a dollar-per-megawatt-day basis) was his failure to account for nearly $66.5 million in certain energy costs that were also ignored by Staff witness Harter in his energy-credit calculation, and which thus became "trapped costs" that should have been applied to increase Mr. Smith's proffered capacity charge. These "trapped costs" are discussed below. Moreover, other specific downward adjustments proposed by Mr. Smith and addressed below inappropriately understate AEP Ohio's costs and are in direct tension not only with FERC-approved practice in the context of wholesale capacity transactions, but also, in some cases, with this Commission's prior orders and practices.

2. Staff witness Smith and Harter's approaches result in nearly $66.5 million in "trapped costs," which costs were ignored by Mr. Harter (and thus not netted against the energy margins he calculated), yet also excluded from Mr. Smith's capacity calculations.

As noted above, Mr. Smith proffered a proposed calculation of the appropriate capacity rate for AEP Ohio after taking into account Staff witness Harter's information concerning energy credits. (Staff Ex. 103 at 7-8.) Neither witness, however, considered the effect of nearly $66.5 million in certain energy costs incurred by AEP Ohio. AEP Ohio witness Philip Nelson, Managing Director of Regulatory Pricing and Analysis in the Regulatory Services Department of AEP Service Corp., testified in rebuttal about how these significant energy costs became "trapped" under the Smith and Harter approaches, and both Mr. Nelson and AEP Ohio witness Allen testified about the significant net effect of these trapped costs on the capacity charge proffered by Mr. Smith. (AEP Ohio Ex. 143 at 3, 5-6; Tr. XI at 2311:18-22.)

As Mr. Nelson explained, Mr. Smith accepted in his capacity rate calculations the demand and energy classification that was used by Dr. Pearce. (AEP Ohio Ex. 143 at 5.) Mr. Harter, however, in calculating the energy credit that Mr. Smith later utilized to reduce Staff's proposed capacity rate, conceded that he did not pick up all of the energy components, and thus did not use them to reduce his energy margins. (*Id.*; *see also* Tr. IX at 1891:2-1892-17; AEP Ohio Ex. 125.) Mr. Nelson included a table in his rebuttal testimony that depicts the values of the costs excluded by Staff from *both* the capacity *and* energy sides of Staff's calculations. (*Id.* at 6, *citing* AEP Ohio Ex. 102 at 5, 10, 16, 18, Ex. KDP-3, Ex. KDP-4.) These costs included Production-Related Administrative & General Expenses, Return on Production-Related Investments, Production-Related Depreciation Expenses, and Production-Related Income Taxes.

(*Id.*) All together, these costs excluded by Staff from *both* capacity and energy totaled $66,497,475. (*Id.*) Because these items were both ignored by Mr. Harter (and thus not used to reduce his energy margins), and also excluded from Mr. Smith's capacity calculation (and thus not used to increase the capacity rate he proposed), "these costs fall through the cracks and become 'trapped costs' for the Company." (AEP Ohio Ex. 143 at 5.) Mr. Smith should have added these costs to his fixed charge adjustments because Mr. Harter failed to include them in his energy calculations. (*Id.* at 6.) Mr. Smith's failure to do so resulted in the capacity charge that he proffered being *understated* by $20.11/MW-day on a merged AEP Ohio basis. (*Id.*) AEP Ohio witness Allen, in his rebuttal testimony, incorporated this $20.11/MW-day trapped cost value into his calculation of what Staff's capacity rate would be, as adjusted by his recommended energy credit and cost-of-service issues. (AEP Ohio Ex. 142 at 18.) As Mr. Allen testified:

> If you start with a capacity cost of $325.59/MW-day and subtract an energy credit of $47.16/MW-day and ancillary service revenues of $6.66/MW-day, the resultant capacity rate would be $271.47/MW-day. *Adding in the trapped cost of $20.11/MW-day described by Company witness Nelson, the capacity rate would be $291.58/MW-day.*

(Tr. XI at 2311:18-22 (emphasis added).) To avoid improperly "trapping" nearly $66.5 million in energy costs, the Commission should adjust the capacity rate that Mr. Smith proffered on behalf of Staff as Mr. Allen and Mr. Nelson described in their rebuttal testimony.

3. Other specific adjustments that Staff witness Smith made to Dr. Pearce's cost calculations inappropriately understate AEP Ohio's costs and contradict the Commission's prior orders and practices, as well as those of FERC.

a. Mr. Smith's downward adjustments to ROE from 11.15% to 10.0% (CSP) and 10.3% (OPCo) were simply plucked from a negotiated stipulation in a distribution rate case, and Mr. Smith agreed that the generation business faces risks that the distribution business does not face.

With respect to ROE, Dr. Pearce testified that "[t]he ROE approved in the original template was 11.10%. The ROE has been modified to a fixed 11.15% to be consistent with the ROE proposed in CSP's and OPCO's distribution proceedings, Case Numbers 11-0351-EL-AIR and 11-0352-EL-AIR supported by AEP Ohio witness Avera." (AEP Ohio Ex. 102 at 12-13.) In his direct testimony, however, Mr. Smith noted that he adjusted the 11.15% ROE used by AEP Ohio on page 11 of Dr. Pearce's exhibits KDP-3 and KDP-4 down to 10.0% for CSP and 10.3% for OPCo. (Staff Ex. 103 at 10.) He obtained these lower ROE values from a *stipulation* in the most recent CSP and OPCo electric distribution rate cases. (*Id.* at 12-13.) He described these ROE values as "reasonable inputs" and testified that they "appear to represent a consensus position," while conceding that he made these downward adjustments "[i]n lieu of preparing a specific cost of capital analysis directed to AEP Ohio's capacity costs." (*Id.* at 13.)

At the hearing however, Mr. Smith admitted that if ROE had been litigated to a conclusion in the recent distribution rate cases, the authorized ROEs could very well have been higher than those included in the stipulation from which he obtained his ROE values. (Tr. IX at 1990:21-1991:7.) Mr. Smith also admitted that "generation operating in an unregulated market or an open market, in competitive generation, is probably more risky than distribution." (*Id.* at 1991:21-24.) And, in another admission further undercutting his downward adjustment to ROE, Mr. Smith conceded that the generation business faces substantially greater risks from the imposition of costly environmental regulations than the distribution business is ever likely to confront. (*Id.* at 1993:22-25.)

As AEP Ohio witness William A. Allen further testified in rebuttal, it was inappropriate for Mr. Smith to simply use the ROEs that were stipulated to in the company's most recent distribution rate case. (AEP Ohio Ex. 142 at 17.) As Mr. Allen succinctly testified, consistent with Mr. Smith's above-described admissions on cross-examination, "[t]he risk profiles of the generation and distribution functions are not the same." (*Id*. at 17.) Moreover, as Mr. Allen noted, "[t]he Commission has most recently recognized an ROE of 10.5% for certain generating assets of AEP Ohio. * * * Every 0.1% change in ROE changes the capacity charge rate an additional $1.08/MW-day." (*Id.* at 17-18.) On cross-examination, Mr. Allen noted that "[t]ypically the ROEs that the company has requested in the other jurisdictions has been in the 11 plus percent" range. (Tr. XI at 2392:23-25.) When questioned about ROEs in other jurisdictions, Mr. Allen also noted that in Virginia, "the generation business unit would have had an ROE of probably north of 11 percent." (*Id.* at 2393:23-24.)

Based on Mr. Smith's admissions during cross-examination, as well as the rebuttal testimony from Mr. Allen, it was inappropriate for Mr. Smith to adjust Dr. Pearce's 11.15% ROE value substantially downward for the riskier *generation* side of the company's business, based on "consensus" values that he obtained from a negotiated stipulation in *distribution* rate cases. After Mr. Smith's improper exclusion of the $66.5 million in "trapped costs" described in Part B above, his improper adjustment of ROE was the next most significant downward adjustment that Mr. Smith made to Dr. Pearce's formula rate template. As Mr. Allen explained in rebuttal, "[i]ncluding an 11.15% ROE versus the ROEs used by Staff witness Smith would increase the capacity charge rate by $10.09/MW-day." (AEP Ohio Ex. 142 at 17.) "Including a 10.5% ROE versus the ROEs used by Staff witness Smith would increase the capacity charge rate by $2.95/MW-day." (*Id.* at 18.) The Commission should reject Mr. Smith's aggressive downward adjustment to ROE and retain the 11.15% ROE value utilized by Dr. Pearce. At the very least, the Commission should adopt the 10.5% ROE that it has recognized recently for certain generating assets of AEP Ohio.

b. Mr. Smith's elimination of certain severance costs is contrary to treatment of the same costs by the Commission.

In terms of net reduction on a dollar-per-MW-day basis, Mr. Smith's elimination of certain severance costs, combined with his downward adjustments to payroll taxes for severed employees, resulted in the next most significant categories of adjustments that he made to Dr. Pearce's capacity cost values. These adjustments, too, improperly understate AEP Ohio's costs and are inconsistent with the Commission's prior treatment of the same cost categories.

When asked at hearing whether the purpose of the company's severance program was merely "to help AEP manage its earnings in 2010," AEP Ohio Witness Allen disagreed, and described the purposes of the company's severance program to benefit customers, saying:

> The severance program was – had a couple of purposes. It was *** to reduce staffing levels and expenses in light of a review the company had done of the expected rate increases that may be necessary in the future. And so the company was endeavoring to reduce its costs and those cost reductions had flowed through as a benefit to customers in the future. So we were trying to make sure that the rate increase[s] in the future were held at a more reasonable level than what our current projections had been showing. And in light of some of the continued recessionary pressures that the company was seeing.

(Tr. XI at 2439:20-2440:10.)

Despite the fact that the severance program was undertaken to benefit customers, making the severance costs appropriate for inclusion in rate base, Mr. Smith testified that AEP Ohio's

2010 severance cost "should be removed from 2010 O&M Expense because rates for AEP Ohio's generating capacity are being established prospectively and this was a significant non-recurring cost that was recorded in 2010." (Staff Ex. 103 at 46.) While conceding that the severance cost "perhaps" should be amortized, Mr. Smith testified that "AEP began to realize cost savings due to the reduced salaries as soon as employees accepted the voluntary retirement offer and/or were involuntarily terminated in mid-2010. Amortization of the costs to achieve that savings should have commenced as soon as the savings from the reduced work force and reduced AEPSC charges commenced." (*Id.* at 47.) Relying on an order from Virginia's regulatory commission also pertaining to the company's 2010 workforce reduction, Mr. Smith concluded that there is "no basis" for prospective amortization of CSP or OPCo severance costs. (*Id.* at 50-51.) This conclusion by Mr. Smith led him to remove $9.852 million of severance costs for CSP/AEP Service Company, along with $29.152 million of severance costs for OPCo/AEP Service Company, which had been allocated to the capacity function. (*Id.* at 51.)

AEP Ohio rebuttal witness Allen, however, addressed this issue on cross-examination at the hearing. When asked whether the payroll savings realized by AEP from the beginning of the severance program through June 1, 2012 "have been more than sufficient for AEP to have fully amortized the severance costs," Mr. Allen disagreed, testifying:

> I don't know that to be true, no.
> * * *
> [o]ne of the things you have to recognize is that as part of the severance there's also an add back. There were employees that left who needed to be replaced. The replacement employees may have been at or below cost but those employees in some cases were replaced. Additionally there were incremental O&M expenses related to increased outside services that the company needed to purchase as a result of a reduced workforce. So it's not a one-for-one calculation as you've tried to portray it.

(Tr. XI at 2442:11; 2443:9-21.)

As Mr. Allen explained in his rebuttal testimony, amortizing the $39.004 million in severance costs that Mr. Smith improperly removed from O&M expense over three years would increase the capacity charge rate by $4.07/MW-day. (AEP Ohio Ex. 142 at 17.) As Mr. Allen further testified in rebuttal, these severance costs should not have been excluded from the O&M expense allocated to the generation demand function. (*Id.* at 16.) "The severance costs were properly recorded as O&M expenses in 2010 and the benefits associated with the severance program will be reflected in future annual updates to the formula based capacity cost calculation presented by Company witness Pearce." (*Id.*)

With respect to amortization, as Mr. Allen explained, in AEP Ohio's most recent distribution rate cases (11-0351-EL-AIR & 11-0352-EL-AIR) "the Staff recommended that 50% of the cost of the severance program be amortized over a period of three years. Staff reduced the amount of the amortization by 50% to reflect their position that the severance program benefitted both shareholders and ratepayers. *In this case, the benefits of the severance program are flowing through 100% to CRES providers through reduced capacity charges and therefore no such reduction should be made*." (*Id.* at 16-17 (emphasis added).)

If Mr. Smith's overall goal, as he stated at the hearing, was to adjust Dr. Pearce's FERC-approved formula rate approach to apply Ohio-specific ratemaking practices (Tr. IX at 1979:1-6), then there has been no explanation as to why Mr. Smith looked to Virginia instead of Ohio to address the treatment of severance costs related to the company's 2010 workforce reduction. Mr. Smith's decision to eliminate these severance costs from Dr. Pearce's formula rate understates AEP Ohio's costs and is contrary to the recent practice of this Commission. As Mr. Allen testified, Staff's proposed capacity cost rate should at least be adjusted upward by $4.07/MW-day to reflect the amortization of severance expense that the Staff recommended in the company's most recent distribution rate cases. (AEP Ohio Ex. 142 at 18.)

c. ***Mr. Smith's elimination of prepaid pension expenses differs from the Commission's treatment of the same cost categories in the Company's distribution rate case, and his justifications for the different treatment do not stand up to scrutiny.***

Mr. Smith admitted in his direct testimony that in the company's recent distribution rate cases, Staff *increased* rate base to recognize a prepaid pension asset. (Staff Ex. 103 at 22.) A few lines later, though, he took the opposite position for purposes of this proceeding, saying "[t]o determine AEP Ohio's capacity rates, I have *** removed prepayments including the prepaid pension asset." (*Id.*)

At cross-examination, when confronted with the Staff Reports from the distribution rate cases of Ohio Power (*see* AEP Ohio Ex. 129A) and Columbus Southern Power (*see* AEP Ohio Ex. 129B), Mr. Smith acknowledged that "'Staff increased rate base to recognize a prepaid pension asset.'" (Tr. IX at 1995:13-17, *quoting* AEP Ohio Ex. 129A at 7.) Attempting to explain away the distinction, Mr. Smith testified as follows:

> I was aware that the pension asset had been included by staff in both of those staff reports, and we had discussions with staff about that, and ultimately I concluded that the pension asset, in this instance, is not related to the provision of capacity service. *** So in my judgment, the pension asset did not belong in a rate base for capacity under these fact circumstances, which are discussed in quite a bit of detail in my testimony.

(Tr. IX at 1995:22-1996:8.)

As Mr. Allen testified in rebuttal, however, "prepaid pension assets are appropriate to include in the determination of rate base." (AEP Ohio Ex. 142 at 15.) And, in AEP Ohio's most recent distribution rate cases (11-0351-EL-AIR & 11-0352-EL-AIR) – the ones that Mr. Smith acknowledged during cross-examination – the Staff 'increased rate base to recognize a prepaid pension asset.'" (*Id.*, *quoting* Report by the Staff of the Public Utilities Commission of Ohio in Case No. 11-351-EL-AIR.) In that case, as Staff explained:

> The Staff increased rate base to recognize a prepaid pension asset. The Applicant recorded a prepaid asset of $86,403,823 for additional pension cash contributions as of the date certain, August 31, 2010. The additional contributions represent cash investments above the amount of the pension cost included in the cost of service or the income statement. *The additional contributions benefit customers by reducing future pension costs through increased earnings.* In accordance with generally accepted accounting principles under FASB No. 87 Employers' Accounting for Pensions, the cumulative difference between the pension cost and pension cash contributions is to be recorded on the balance sheet as an asset or liability. A prepaid asset is recorded if pension contributions are greater than the pension cost. A liability is recorded if pension contributions are less than the pension cost. The prepaid pension asset is entirely supported by cash contributions in excess of pension cost. None of the additional pension contributions serve to prefund the pension obligation in advance. The Staff agrees with the Applicant's adjustment. *Including the additional cash contributions in rate base, that will be expensed in the future, allows for ratemaking recognition of the cost of funds for the prepaid contributions.*

(*Id.* at 15-16, *quoting Staff Report* in Case No. 11-351-EL-AIR (emphasis added).) Mr. Smith clearly erred by excluding the prepaid pension asset in his proffered capacity charge rate. Including the prepaid pension asset (net of ADIT) of $96.116 million in rate base would increase the capacity charge rate by $3.20/MW-day. (*Id.* at 16.)

d. Staff witness Smith should not have excluded CWIP from rate base.

Referring to page 5, line 8 of his Exhibits KDP-1 and KDP-2, Dr. Pearce testified that "only 50% of the non-pollution control construction work in progress ("CWIP") is included, which, as previously explained, is a result of the templates used to develop these rates." (AEP Ohio Ex. 102 at 11.) Citing two statutes in the Ohio Revised Code, though, Mr. Smith concluded that CWIP should be entirely excluded from rate base. (Staff Ex. 103 at 15, *citing* R.C. 4909.15

and 4928.143.) Mr. Smith's exclusion of CWIP represents a departure from the FERC-approved formula rate template employed by Dr. Pearce here. Mr. Smith conceded on cross-examination that FERC "has a different standard for [CWIP] insofar as it does not subject the allowance to a percentage-of-completion requirement." (Tr. IX at 1979:16-1980:5.) Indeed, FERC, by allowing a return on only 50% of non-environmental CWIP, provides a reasonable and comparable alternative method to a mechanism which allows not 50% but 100% of such CWIP after it has achieved a particular percentage of completion.

Mr. Allen directly challenged Mr. Smith's exclusion of CWIP – particularly CWIP on environmental investments – in his rebuttal testimony. As Mr. Allen explained:

> Although Staff witness Smith makes several claims regarding the exclusion of CWIP from rate base he fails to recognize that the Company has recovered carrying costs on environmental CWIP through the Environmental Investment Carrying Cost Rider (EICCR). The EICCR is collected through current standard service offer (SSO) rates. *Including, at a minimum, CWIP on environmental investments in rate base would ensure that all customers utilizing the Company's capacity resources, SSO customers and CRES providers, are treated similarly*.

(AEP Ohio Ex. 142 at 14 (emphasis added).)

On cross-examination, Mr. Allen was asked about his testimony regarding both environmental and non-environmental CWIP. He noted that non-environmental CWIP relates to investments that are made "to maintain the long-term operability of the generating fleet, and as such, individual CRES providers that are utilizing that capacity should pay for the carrying cost on those." (Tr. XI at 2446:19-24.) As for environmental CWIP, Mr. Allen emphasized the point he made in his rebuttal testimony about equal treatment, testifying that "[n]onshopping customers pay for environmental investments through the EICCR, and CRES providers and their customers will pay for those same environmental investments on those same plants through the capacity charge." (*Id.* at 2446:9-13.)

The Commission's inclusion of environmental CWIP ($33.862 million) in rate base would increase the capacity charge rate by $1.11/MW-day. (AEP Ohio Ex. 142 at 14.) The inclusion of non-environmental CWIP ($49.422 million) in rate base would increase the capacity charge rate by an additional $1.64/MW-day. (*Id.* at 15.) Mr. Allen provided these calculations in his Exhibit WAA-R7. The Commission should reject Mr. Smith's exclusion of CWIP from the capacity charge that it intends to adopt in this proceeding.

e. Mr. Smith eliminated cash working capital due to the Company's failure to complete a lead-lag study, while conceding that FERC has approved formula-based rates that include cash working capital allowances.

In another largely unexplained departure from federal practice, Mr. Smith eliminated cash working capital, which had been calculated by AEP Ohio using a one-eighth O&M formula method. (Staff Ex. 103 at 10.) The primary justification provided for this adjustment in Mr. Smith's direct testimony was the lack of a so-called "lead-lag" study prepared by the company. (*Id.* at 19) ("Where a lead-lag study is not presented by a large utility such as CSP or OPCo, we cannot recommend a Working Capital allowance.") On cross-examination, though, Mr. Smith conceded that "FERC will sometimes approve 1/8 cash working capital." (Tr. IX at 1979:13-14.) Because positive working capital is required to ensure that AEP Ohio is able to continue its operations, and to ensure that it has sufficient funds to satisfy maturing short-term debt and operational expenses, Dr. Pearce's application of the FERC-approved cash working capital allowance (based on one-eighth of O&M) was appropriate and should not have been eliminated by Mr. Smith.

Mr. Smith testified that "[l]arge utilities are *typically* required to prepare a lead-lag study to support a Cash Working Capital allowance being includable in rate base." (Staff Ex. 103 at 18 (emphasis added).) However, the "requirement" that Mr. Smith referred to here is contained in the Commission's Standard Filing Requirements ("SFRs"), set forth in Appendix A to Ohio Admin. Code §4901-7-01. By the express terms of that Commission rule, these SFRs apply in three circumstances, where a utility is: (1) filing an application for an increase in rates under R.C. 4909.18; (2) filing a complaint under R.C. 4909.34; or (3) filing a petition under R.C. 4909.35. Ohio Admin. Code §4901-7-01. Here, AEP Ohio is not filing an application for a rate increase under R.C. 4909.18. Nor is AEP filing the complaint or petition referred to in the rule. Instead, this proceeding was commenced by the Commission, inviting comments regarding the review of AEP Ohio's capacity charges. Insofar as the Commission seeks to investigate changes to wholesale electricity rates that are regulated by the FERC, AEP Ohio should not be blamed for submitting values for cash working capital that are based on the 1/8 O&M formula that has been approved by FERC. Put another way, Mr. Smith's rejection of Dr. Pearce's cash working capital value cannot properly be based on the company's failure to complete an onerous[20] lead-lag study that is a Standard Filing Requirement by rule in *some* Commission proceedings, but not this proceeding. Ohio Admin. Code §4901-7-01.

Finally, it should be noted that Mr. Smith's direct testimony casts aspersions on the one-eighth O&M formula upon which AEP Ohio's claim for cash working capital is based. He

[20] Lead-lag studies are resource intensive due to the requirement of extensive data tracking and collection. Other state utility commissions have recognized that "a simplified basis may be used to develop a working cash allowance" in circumstances where "a detailed study would be impractical from a work-time viewpoint." *E.g.,* California Public Utilities Commission, *Determination of Working Cash Allowance, Standard Practice U-16-W*, D3 (March 2006). Under the circumstances presented here, a detailed lead-lag study would indeed have been impractical from a work-time viewpoint.

describes the formula as having "conceptual problems" and as being unreliable. (Staff Ex. 103 at 19.) But as Mr. Smith surely knows, "[n]o particular methodology is precise in calculating working capital *** and a determination of working capital is in many respects an exercise of discretion as to what particular method yields the most fair and equitable result in each case." American Jurisprudence, Public Utilities, §107 (2d. Ed. 2012). *See also* Corpus Juris Secundum, Public Utilities, § 64 (2012) (noting that "there is no well-defined rule by which it can be ascertained.") Mr. Smith critiques the one-eighth formula approved by FERC and utilized by Dr. Pearce because it "always produces a positive CWC allowance *** even in situations where the utility's CWC requirement is negative." (Staff Ex. 103 at 19.) Yet the Ohio Supreme Court itself has previously held that Ohio's statutory scheme does not anticipate "negative" working capital allowances, so it is unfair for Mr. Smith to criticize AEP Ohio's O&M formula on that basis. *Office of Consumers' Counsel v. Public Util. Comm.*, 32 Ohio St.3d 263, 266-67, 513 N.E.2d 243 (1987). In that case, the Ohio Supreme Court noted that PUCO itself has previously used a fractional method to calculate a working capital allowance. *Id.* at 266. As such, the fractional and FERC-approved formula utilized here by Dr. Pearce is justified and should not be eliminated as proposed by Mr. Smith. There has been no showing here to justify a zero or negative allowance for cash working capital, because there has been no credible evidence proffered to suggest that AEP Ohio's investors need not provide any capital to fund ongoing operations of the companies.

4. The Commission should increase Smith's merged capacity rate for the foregoing reasons.

As the foregoing discussion shows, Mr. Smith made several significant and unwarranted reductions to the AEP Ohio capacity charge based on Dr. Pearce's FERC-approved formula rate template. Mr. Smith accomplished these reductions by trapping nearly $66.5 million in energy costs, reducing ROE, eliminating severance expenses, excluding the company's prepaid pension asset from rate base, eliminating CWIP, eliminating cash working capital, and computing an unjustified Section 199 deduction in income taxes.

If the Commission agrees with AEP Ohio rebuttal witness Allen, and decides to include: (1) environmental CWIP; (2) non-environmental CWIP; (3) prepaid pension asset; (4) amortization of severance expense; and (5) an ROE of 11.15%, then the cumulative impact of these changes on the merged capacity rate would be an increase from Smith's proposed capacity rate ($305.48/MW-day) to a capacity rate of $325.59/MW-day. (AEP Ohio Ex. 142 at 18.) If the Commission takes that $325.59/MW-day capacity rate and subtracts an energy credit of $47.16/MW-day and ancillary service revenues of $6.66/MW-day, then add the trapped costs of $20.11, the resulting capacity rate would be $291.58/MW-day. (*Id.*) After addition of the trapped cost of $20.11/MW-Day, as described by Company witness Nelson, this rate would be $291.58/MW-Day.

5. Lesser's (and Murray's) stranded cost argument, which would eliminate most of AEP Ohio's fixed production costs of capacity, is meritless.

Dr. Lesser argues that AEP Ohio's cost-based wholesale capacity pricing proposal is an effort to recover stranded costs that should have been recovered under SB 3 and, thus, AEP Ohio has no right to recover the stranded costs now. (FES Ex. 103 at 12-14.) He further contends that AEP Ohio concedes this point in its revised corporate separation plan filing in Case No. 12-1126-EL-UNC. (*Id*. at 13-15.) For the reasons detailed in section VI below, AEP Ohio's cost-based wholesale capacity pricing proposal is not a generation transition charge under R.C. 4928.40, and Mr. Lesser's argument is without merit.

6. Dr. Lesser's proposed adjusted fixed production costs inconsistently include capacity equalization revenues as an offset while excluding the costs of the very generation plant that produced those payments.

Dr. Pearce's formula rate properly includes a calculation of annual production costs that is "reduced by the amount of revenues that are collected from other wholesale entities related to capacity transactions." (AEP Ohio Ex. 102 at 10.) "As a result, CRES providers will get the benefit of these transactions and are not paying for any capacity cost that is associated with transactions to other wholesale entities, including affiliates and PJM RPM market participants." (*Id.*)

Dr. Lesser, however, proposes adjusting Dr. Pearce's fixed production costs by including capacity equalization revenues as an offset *while at the same time excluding the capital costs of the very generation plant that produces those payments*. In his direct testimony, Dr. Lesser complains:

> Among the many failings of AEP Ohio's formula rate is AEP Ohio witness Pearce's inclusion in his capacity cost rate base of the capital costs of the Darby Electric Generating Station and Waterford Energy Center generating facilities. These were purchased by AEP Ohio after the January 1, 2001 transition date as merchant generating plants. Therefore, AEP Ohio has no basis for including the capital costs of these plants, over $400 million, in its capacity cost calculations.

(FES Ex. 103 at 33-34.) Later, then, Dr. Lesser presents a revised embedded capacity cost estimate for AEP Ohio "that eliminates post-2001 transition capital expenditures and accounts for the profits AEP Ohio makes on off-system energy sales." (*Id.* at 45.) As he testified on cross-examination, "[m]y calculation excludes all post-2001 generating capacity." (Tr. IX at 2088:12-13.) Dr. Lesser contends that without these adjustments, AEP Ohio will receive a double recovery of its costs. (FES Ex. 103 at 44-45.) Dr. Lesser, however, admits that if AEP Ohio had not invested in environmental compliance at it coal plants, the plants would not be able to operate, and therefore would not attract capacity equalization payments from other pool members. (Tr. IX at 2098.) AEP Ohio has not recovered its costs associated with keeping these plants in compliance and operating, thus, providing capacity. Contrary to Dr. Lesser's position that such costs were recovered through the EICCR, they were not. Dr. Lesser's double recovery argument is a red herring and is clearly not supported by the facts.

In addition to the fact that there is no double recovery, Dr. Lesser misses the point that AEP Ohio's capacity equalization payments from other pool members are tied directly to AEP Ohio's capacity cost. If costs are driven down as Dr. Lesser advocates by eliminating all post-2001 capacity costs, then AEP Ohio's capacity equalization payments from other pool members will be reduced as well. But, as Mr. Nelson explains in his rebuttal testimony, Dr. Lesser incorrectly "removes both costs and megawatts in his calculation related to stranded cost, but leaves the full AEP Pool capacity credit in place, despite the fact that the AEP Pool capacity receipts are driven by the same costs and megawatts of the AEP Ohio plants that he is removing." (AEP Ohio Ex. 143 at 4-5.) As a result, Dr. Lesser's cost-based rate calculation is both inconsistent and inaccurate.

D. Intervenor and Staff Arguments That AEP Ohio's Proposed Cost-Based Rate Of $355.72/MW-Day Is Not Comparable To The Level Of Capacity Costs It Recovers Through Base Generation Rates Are Incorrect.

FES witness Lesser contends that AEP Ohio will recover a substantially lesser amount of capacity costs from non-shopping customers than it proposes to recover from CRES providers through the cost-based capacity price that Dr. Pearce has sponsored ($355.72/MW-day based on 2010 cost data). Dr. Lesser attempts to support this contention through his Table 1, which he presents at page 21 of his Direct Testimony. (*See* FES Ex. 103 at 21.) Through his testimony and Table 1, he purports to compare the Company's base generation rates to the Company's full cost capacity rate.

There are several flaws in Dr. Lesser's comparison. First, as Mr. Allen explained in his Rebuttal Testimony, Dr. Lesser did not update the rates that he used in his table to reflect the current data presented by Company witnesses Roush and Thomas in the Modified ESP 2 case. (AEP Ohio Ex. 142 at 19.) Specifically, the base generation rate that Dr. Lesser used as the basis for his comparison did not include the Environmental Cost Recovery Rider (EICCR). This has the effect of understating the revenues that the Company is collecting through its non-fuel generation rates. Second, as Mr. Allen also observed, Dr. Lessser incorrectly included the revenues of ancillary services in his analysis. (AEP Ohio Ex. 142 at 19.) Ancillary service costs are recovered through the Transmission Cost Recovery Rider (TCRR), so any corresponding revenues must be excluded from the analysis. (*Id*.) This error has the effect of overstating the revenues that are being recovered through the CRES capacity rate. Third, and in any event, Mr. Allen pointed out that even if one converts Dr. Lesser's "un-updated" rates into revenues (by simply multiplying the rates by the projected usage for each customer class) it is clear that even Dr. Lesser's understated base generation revenues from non-shopping customers are very close to his overstated full capacity (plus ancillary service) revenues from the CRES providers. (AEP Ohio Ex. 142 at 19-20.)

Mr. Allen also demonstrated that if one were to prepare the same analysis that Dr. Lesser presented in his testimony, update his data for current rates (thus including the EICCR revenues in the base generation revenues), and exclude ancillary service revenues (from the revenues collected through CRES capacity charges), then the base generation rates are essentially equivalent to the full cost capacity rates. (*Id.* at 20.) Mr. Allen illustrated this corrected comparison in Table 2 of his Rebuttal Testimony:

Table 2: Lesser Analysis Corrected and Converted into Dollars

		Base Generation		
	R	C	I	Total
($/MWh)	23.82	28.1	18.25	22.87
(GWh)	14,616	14,317	19,262	48,195
($MM)	$ 348	$ 402	$ 352	$ 1,102
		Capacity		
	R	C	I	Total
($/MWh)	30.01	23.01	17.29	22.85
(GWh)	14,616	14,317	19,262	48,195
($MM)	$ 439	$ 329	$ 333	$ 1,101
		Difference		
($MM)				$ (1)
(%)				-0.1%

(*Id.* at 20.)

The clear conclusion to be drawn from the comparison that Dr. Lesser attempted to make, *when done accurately*, is that AEP Ohio is seeking to charge CRES providers essentially the same amount for capacity that it collects from non-shopping customers. Charging a capacity price to CRES providers that is deeply discounted from the level of the Company's costs and that is so dramatically less than what is being collected from SSO customers amounts to a subsidy to CRES providers and is inconsistent with Ohio energy policy and basic economic principles of free-market competition found in §4928.02, Ohio Rev. Code.

Although EVA witness Medine briefly claimed during cross examination that AEP Ohio's proposed cost-based rate is not comparable to the amount of capacity costs that it recovers through base generation rates, she could not back that position up. Indeed, although the prices modeled by Staff witness Medine (*see* AEP Ohio Ex. 133) trend upward during the period between June 1, 2012 and May 31, 2015, Ms. Medine admitted that she is not certain that actual SSO tariff prices will similarly increase during that period, nor did she know whether her projected prices were comparable to either the FAC or base generation SSO rates. (Tr. X at 2202-2204.) She also indicated that she personally did not know how the SSO rates compare with LMP energy prices and that her knowledge on the subject was based purely on what she heard from someone else – but she could not even remember who told her, let alone the basis for the claim. (Tr. X at 2233:17-2234:16.) For these reasons, Staff's opinion as to the comparability of the Company's proposed cost-based charge to the amounts it recovers from SSO customers for capacity through its base generation rates should be afforded little weight.

AEP Ohio has demonstrated that its proposed cost-based capacity charge is comparable in value to the amount the Company receives from SSO customers for capacity through the base generation rates that it charges to them. (*See* AEP Ohio Ex. 142 at 19-20.) Neither Intervenors nor Staff has submitted evidence to refute this fact. Notably, RESA witness Ringenbach agreed that, if AEP Ohio is collecting $355.72/MW-day for capacity from SSO customers, it is appropriate to charge CRES providers $355.72/MW-day in order to match rates and ensure that there is no subsidy. (Tr. IV at 815.) Thus, for this reason too, AEP Ohio should be permitted to recover its proposed cost-based capacity charge from CRES providers.

V. OEG WITNESS KOLLEN'S ESM PROPOSAL SHOULD NOT BE ACCEPTED

OEG Witness Kollen has two recommendations regarding the price that AEP Ohio may charge CRES providers for capacity. Mr. Kollen's primary recommendation, as discussed above, is that capacity should be priced at the prevailing RPM level ($20.01/MW-Day for 2012, $33.71/MW-Day for 2013/2014, and $153.89/MW-Day for 2014/2015). (OEG Ex. 102 at 9.) Mr. Kollen does not address in any extensive manner why his primary recommendation of capacity pricing at the prevailing RPM price should be used. Rather, he makes that recommendation simply "as a foundational assumption". (Tr. VI at 1241:20-1242:5.) In addition, he admits that his primary recommendation of using prevailing RPM prices does not address the Commission's goal of providing adequate compensation to AEP Ohio (*Id.* at 1276:5-1277:10.) He further agrees that if the Commission adopts RPM pricing, the expected return for AEP Ohio, all else equal, would be dramatically reduced from the 11% ROE level (*Id.* at 1261:14-1262:13), which AEP Ohio witness Allen has confirmed (AEP Ohio Ex. 102 at Ex. WAA-2.) If the Commission concludes that the capacity price should be higher than the prevailing RPM price, then Mr. Kollen makes an alternative recommendation. In that event, Mr. Kollen recommends a capacity price that is no higher than the current RPM price (applicable during 2011/2012) of $145.79/MW-Day. (OEG Ex. 102 at 10.) In conjunction with his alternative recommendation of capping above-RPM priced capacity at $145.79/MW-Day, Mr. Kollen also recommends that the Commission establish an "Earnings Stabilization Mechanism" (ESM) that, he claims, would ensure that AEP Ohio does not earn too much or too little. (*Id*. at 15.)

Specifically, Mr. Kollen recommends that the Commission establish an earnings "deadband" with a lower threshold of a 7% return on equity (ROE) and an 11.0% ROE as the upper threshold. (*Id.* at 18.) According to Mr. Kollen's proposal, if AEP Ohio's earnings, measured by ROE, fall below the lower threshold of 7%, then the Company would be allowed to increase its rates through a nonbypassable ESM charge sufficient to increase its earnings to the 7% level. (*Id.*) If earnings exceed the upper threshold of 11%, then AEP Ohio would return the excess earnings to customers through a nonbypassable ESM credit. (*Id.*) If AEP Ohio's earnings are within the earnings "deadband", there would be no rate changes other than those that operate to recover items such as the fuel adjustment clause. However, the Commission "would have the discretion to make modifications as circumstances warrant." (*Id.*) Mr. Kollen believes that the computation of the earned ROE for his earnings test would be performed in a manner consistent with how it would be done for the SEET, with at least one significant exception. Unlike the SEET, from which the Commission excludes OSS margins, Mr. Kollen would include OSS margins in order to increase earnings and, thus, the earned ROE. (Tr. VI at 1290.)

In essence, Mr. Kollen is recommending that AEP Ohio should be subject to a second earnings test, in addition to the "significantly excessive earnings test" (SEET) of §4928.143(F), Ohio Rev. Code. AEP Ohio is subject to the statutory SEET during the current ESP, and it will continue to be subject to it during the next ESP, when Mr. Kollen would apply his ESM earnings test to the Company. Moreover, due to the earnings parameters that Mr. Kollen has proposed for his ESM, in particular the upper threshold of 11%, which is substantially lower than any SEET threshold previously applied to AEP Ohio, the consequence of the proposal would be to render the existing statutory SEET inapplicable and obsolete.

The first problem with Mr. Kollen's ESM/earnings test is that there is no basis under Ohio law for it. The Commission has no statutory authority to impose a second, more stringent, excessive earnings test on AEP Ohio. In short, the 11% upper threshold for determining excessive earnings would be unlawful.

A second fundamental error is that Mr. Kollen's proposal would not permit AEP Ohio to exercise its right, under Schedule 8.1, Section D.8, of the RAA to establish a price for capacity supplied to CRES providers based on AEP Ohio's cost. Neither Mr. Kollen's primary recommendation to use the prevailing RPM prices nor his alternative recommendation of a price capped at $145.79/MW-Day (coupled with his ESM/earnings test) is based upon AEP Ohio's costs of providing capacity.

Third, Mr. Kollen's ESM/earnings test would not provide any material protection to AEP Ohio from under-compensation of its costs incurred to furnish capacity to CRES providers. On the high end, even Mr. Kollen agrees that the 11% ROE is not indicative of a return that AEP Ohio could expect to earn under either his primary or alternative capacity pricing recommendations. (Tr. VI at 1266:15-20.) In short, the 11% return, which Mr. Kollen says is needed on the high side in order to provide symmetry for the under-earnings protection that his recommendation would provide at the 7% low end, is illusory. The protection against under earnings that Mr. Kollen claims he provides to AEP Ohio with his 7% ROE at the low end is also an illusion. Mr. Kollen volunteered that the 7% level is effectively a 5% ROE for the generation function. He also freely conceded that such a low level of earnings is either confiscatory or bordering on confiscatory. (Tr. VI at 1271:16-1272:5.) Providing the Company with some protection against confiscation is not a measure of reasonableness. It is simply a recognition that, at some point, the regulatory treatment is so egregious that the Company's constitutional rights are being trampled.

In any event, Mr. Kollen's ESM would be complex and difficult to administer, and it would be certain to result in protracted litigation on an annual basis. Even he agrees that if the Company earned less than the low-end ROE of this ESM, and it came to the Commission for a rate increase to make up the shortfall, then intervenors would likely challenge the Company's proposal for additional compensation. (Tr. VI at 1281:25-1282:22.) His proposal would also create substantial uncertainty for customers (who would be subject to the risk of future rate increases in the event of under-earnings) and for AEP Ohio (which would be subject to additional risk of over-earnings determinations and, thus, future clawbacks of its prior period earnings).

In short, Mr. Kollen's very low 7% ESM under-earnings threshold, combined with the virtual certainty (based on AEP Ohio witness Allen's testimony regarding the earnings impacts of RPM pricing) that RPM capacity pricing will result in earned ROEs at or below that 7% level, renders Mr. Kollen's proposal as a recipe for financially harming AEP Ohio.

VI. THE COMPANY'S PROPOSED COST-BASED CAPACITY CHARGE DOES NOT CONSTITUTE AN UNTIMELY REQUEST FOR RECOVERY OF STRANDED GENERATION INVESTMENT UNDER SB 3 AND IS NOT BARRED BY THE STIPULATION ADOPTED IN CASE NOS. 99-1729-EL-ETP, *ET AL*.

FES witness Lesser and IEU-Ohio witness Hess both claim that AEP Ohio's cost-based capacity pricing proposal is in conflict with the provisions of SB 3 and the settlement in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP (ETP Stipulation) (FES Ex. 103 at 37-45; IEU-Ohio Ex. 101 at 3-11.) These claims are without merit because SB 3 and the ETP Stipulation are not applicable to this case, and the factual underpinning of their claims is inaccurate.

In the ETP Stipulation, AEP Ohio agreed to forego its claim to recover generation transition charges during the market development period. Generation transition charges were a statutorily-defined (R.C. 4928.40) cost recovery mechanism for stranded generation investment via retail generation transition charges. Specifically, under SB 3, electric utilities were given an opportunity to recover transition revenues via retail rates that could include the amount of generation investment that would not be recoverable in a competitive market. The determination of whether such investments were stranded under SB 3 was done based on an analysis of 2000-vintage information as to whether the net book value for generation assets exceeded the long-term market value of the assets (using projected market price estimates for electricity at that time). As part of the ETP Stipulation, AEP Ohio agreed not to pursue SB 3's opportunity for recovery of stranded generation investment via retail generation transition charges.

Conversely, this proceeding involves establishing a wholesale capacity pricing mechanism based on AEP Ohio's embedded capacity costs. It does involve R.C. 4928.40 retail generation transition charges, which, importantly, were only applicable to a specific and limited time-period (2001-2005). FES witness Lesser and IEU witness Hess conflate these two – retail generation transition charges and wholesale capacity prices - with complete disregard for the differences surrounding each or an appreciation of the relevant regulatory history and stark changes in the regulatory regimes in place.

The issue of whether AEP Ohio could recover stranded asset value from retail customers under SB 3 is a totally different exercise from establishing a wholesale price that permits AEP Ohio's competitors to use that same capacity. There are major differences between the two situations. The following table illustrates some of the basic differences that Messrs. Hess and Lesser ignore:

	Stranded Cost Determination under SB 3	**Wholesale Capacity Charge Determination**
Legal Standard	SB 3 provisions	• Federal Law • Reliability Assurance Agreement (RAA) • SB 221 provisions
Context	One-time historical inquiry for transition revenue during 5-year market development period (MDP); predates major regulatory regime change adopted in SB 221 wherein cost-based rate adjustments are permitted	Ongoing dispute involving AEP's exercise of rights under the RAA based on its status as a Fixed Resource Requirements entity through May 2015
Parties Involved	Restricted recovery of stranded generation costs from retail customers during the MDP, in exchange for charging market-based rates after MDP (which never	Involves wholesale charges for CRES to use OPCo's capacity resources

	happened)	
Valuation Issues	Long-term view of projected energy prices compared to then-present projected revenue stream under cost-based regulation, using 2000 vintage data	Embedded 2010 cost versus the short-term Reliability Pricing Model auction price
PUCO Precedent	• AEP Ohio agreed to forego recovery of transition revenues during MDP relating to stranded generation investment • FirstEnergy authorized to collect nearly $7 billion from retail customers	Case of first impression remains pending

On cross examination, IEU witness Hess admitted that some of these key difference exist and make a difference. For example, Mr. Hess conceded that the capacity charges at issue in this proceeding are wholesale prices (Tr. V at 1097:12-17, 1125:4-8.) This is important because the electric transition plan cases from 2000 did not establish wholesale capacity prices for CSP and OPCo, and any generation transition charges established in those cases would have been retail charges. The ETP cases were retail cases and they have no bearing on a wholesale capacity rate charged to CRES providers. Accordingly, any restrictions on recovery of generation costs through retail pricing that resulted from S.B. 3 and the Commission's 2000 orders in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP are simply inapplicable to wholesale capacity pricing. Moreover, any conclusion that SB 3 precludes AEP Ohio from recovering capacity costs through its wholesale rate conflicts with the RAA and would be preempted under the Federal Power Act.

Mr. Hess also agreed that stranded costs under SB 3 were determined based on then-forward projections of likely market prices and net book value of plants at that time. (Tr. V at 1076:23-1077:4.) This is critical because those future price projections did not contain a capacity component. He agreed that a forward view of energy prices vintage 2000 would be different than a forward view of energy prices as we sit in 2012. (*Id.* at 1078:24-1079:4.) He also conceded that AEP Ohio witness Dr. Landon's formula projections used in the ETP cases covered the period 2001 to 2030, but that the formula rate in this case covers only the 2010 calendar year. (*Id.* at 1071:18-24.) It strains credulity to even compare the product of the long-term analysis done in the ETP to the one-year RPM price that is established by auction three years in advance, let alone reach the conclusions asserted by Mr. Hess. Further, neither Messrs. Hess nor Lesser dispute that numerous factors have changed since 2000, and any determination under SB 3 of whether or not a particular plant was stranded in the competitive market would have no bearing on establishing wholesale capacity prices in this case.[21] Chief among these changed circumstances is the fact that AEP Ohio was not permitted to charge fully market-based generation rates starting in 2006, as was the *raison d'etre* for the market development period and transition cost recovery under SB 3.

FES witness Lesser admits that if AEP Ohio had not invested in environmental compliance at its coal plants, the plants would not be able to operate, and therefore would not have attracted capacity equalization payments from other Pool members as they, in fact, were. (Tr. IX at 2098.) AEP Ohio has not recovered its costs associated with keeping these plants in compliance and operating, thus, providing capacity. Contrary to Mr. Lesser's position that such costs were recovered through the EICCR, they were not. The EICCR merely permitted recovery of carrying charges *incurred during 2009-2011* for incremental environmental investment not previously reflected in rates, as was made clear by the Commission's decision in *ESP I*. *ESP I*, Entry on Rehearing at 12 (July 23, 2009). Obviously, the costs as of 2010 were used to develop

[21] In fact, it is worth noting that the Commission never determined in the ETP proceeding that AEP Ohio had stranded generation investment, and Staff maintained clear through the *ESP I* proceeding in 2009 that there was no stranded investment for AEP Ohio. Mr. Hess agreed that there was never a Commission finding that AEP Ohio had a stranded investment in the ETP proceeding. (Tr. V at 1080:9-1083:23.)

the proposed capacity charge in this case as explained in Dr. Pearce's testimony; this charge would apply prospectively for carrying charges incurred in the future, not for those incurred in 2009-2011. Moreover, the EICCR is only recovered from non-shopping customers and is avoided by shopping customers; to the extent that the wholesale cost-based capacity charge would also reflect carrying charges on incremental environment investment, shopping customers would only pay whatever is reflected in their retail rates charged by the CRES provider.[22] There is no double recovery issue.

Both Messers. Lesser and Hess conveniently ignore the relevant regulatory history, and the Commission's deliberate decision to move AEP Ohio slowly into competition. When electric deregulation passed in 1999, FirstEnergy argued that it would be financially weakened if forced to make full transition to market rates in the time stipulated. It asked for and received a two-phase, five-year transition, and a rate structure that paid it $7 billion to offset costs associated with the transition. The most significant component of these transition costs, approximately $4.9B, consisted of above-market generation costs.[23]

In contrast, when AEP Ohio began its transition, it agreed to forgo its opportunity to recover stranded generation costs through generation transition charges, and for the next decade AEP Ohio provided below market generation rates for customers. In 2005, when AEP Ohio was coming to the time to make a full transition to competitive rates, a competitive market had not developed. At the time, AEP Ohio's regulated rates were significantly lower than market. In order to preserve that advantage for consumers, the Commission asked AEP to suspend the

[22] AEP Ohio notes that, under its Modified ESP proposal, the EICCR is being rolled into base generation rates – but that is also bypassable for shopping customers and the same explanation applies to demonstrate there is no double recovery.

[23] *See* Case No. 99-1212-EL-ETP, Direct Testimony of FirstEnergy Corp. witness Harvey L. Wagner at Attachment 9 (filed Dec. 22, 1999).

progression to full market, and instead to submit a Rate Stabilization Plan (RSP) to promote consistent low rates.[24] AEP Ohio complied with the Commission's request and filed an RSP. Customers continued to enjoy favorable rates as a result. In AEP Ohio's RSP case, the Commission stated: "At the outset, we will note that AEP proposed a rate stabilization plan because we requested it."[25] The Commission found a competitive bidding process would not be effective and that the Company's proposed rates were more favorable to customers than the market-based rates would be, because competitive markets had not adequately developed. (*Id*. at 14.)

At the same time, customers of Monongahela Power Company in southeast Ohio (Mon Power) were faced with big increases if that company went to market under the 1999 law. Thus, the Commission ordered AEP Ohio to pursue the purchase of Monongahela Power (which had refused to submit an RSP) and AEP Ohio obliged.[26] In approving the betrothed purchase, the Commission determined that Mon Power customers would be "far better off under the rates established under the Companies' proposal than by being served at a [competitive bidding process] provided by Monongahela Power."[27]

In 2006, based on its desire to maintain the stable, low rates that AEP Ohio was providing, the Commission strongly encouraged AEP Ohio to operate under the Fixed Resource Requirements (FRR) option. In its public comments, the Commission Staff complimented the

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[24] *See In re DP&L*, Case No. 02-2779-EL-ATA, Opinion and Order at 29 (Sept. 2, 2003); *In re Ohio Edison*, Case No. 03-1461-EL-UNC, Entry at 4-5 (Sept. 23, 2003).

[25] *In re AEP Ohio*, Case No. 04-169-EL-UNC, Opinion and Order at 13 (Jan. 26, 2005) .

[26] *In re Monongahela Power*, Case No. 05-765-EL-UNC, Entry (June 14, 2005).

[27] *In re Monongahela Power*, Case No. 05-765-EL-UNC, Opinion and Order at 10 (Nov. 9, 2005).

FERC for accepting this approach. AEP Ohio followed the Commission's direction and contractually committed to FRR capacity supply through May 31, 2015. In 2008, competitive markets had still not developed as contemplated in the 1999 law. The General Assembly passed SB 221 to change Ohio's regulatory framework once again. Ironically, IEU itself advocated re-regulation leading up to the passage of SB 221. In an advocacy piece used with Ohio legislators, IEU passionately plead that "[t]he rate shock clock is ticking in Ohio" and to avoid rate increases and to return to the "good old days" the General Assembly needed to "repeal the statutory declaration that generation service is a competitive service." (AEP Ohio Ex. 109 at 1-2, 11.) Although a bit red faced and reluctant to address what IEU's reference to the rate shock clock ticking in Ohio may mean (*see* Tr. V. at 1113), Mr. Hess conceded that IEU's position at that time was that generation service was not fully competitive and that re-regulation was needed. (*Id.* at 1114-1116.) IEU's advocacy piece also underscored the view that, under SB 3, the move to lower market-based prices would be forthcoming in exchange for paying stranded costs to the impacted electric utilities. (AEP Ohio Ex. 109 at 3.) On that topic, Mr. Hess acknowledged that AEP Ohio did not recover any stranded generation investment. (Tr. l. V. at 1119.)

SB 221 created a re-regulation hybrid approach where market rates are not permitted until after a long transition period and where cost-based rate adjustments are permitted, among other items. One stark difference between SB 3 and SB 221 is that SB 221 requires an additional 6-10 year transition period to get to fully market-based rates. This difference undercuts the argument that today's rates must be fully market-based and must not have cost-based rate adjustments, especially under an ESP. There is simply no basis for that point under SB 221.

Once again, after SB 221, AEP Ohio followed the Commission's direction and entered into an Electric Security Plan (ESP) that provided below-market generation rates for its customers. Then in 2009, over AEP Ohio's objection, the Commission ordered that "exclusive supplier" provisions be inserted into Ormet and Eramet special contracts, whereby Ormet and Eramet were not permitted to shop for 10 years (even though AEP Ohio advocated that the customers should retain their ability to shop); the result was that AEP Ohio accepted lower rates for a load equivalent of more than 500,000 residential homes.[28]

Last year, a surplus of power driven by the economic downturn, and other forces, has driven market rates below AEP Ohio rates on a short-term basis. AEP Ohio is pursuing rapid fulfillment of the Commission's request to complete the transition to a fully market-based SSO. As part of is Modified ESP II case, AEP Ohio is asking for a three-year transition to market in order to complete corporate separation and unwind its contractual FRR and Pool obligations. This transition will ensure robust competition between strong competitors that will produce the lowest rates possible for all Ohioans, while fairly compensating AEP Ohio for assets that are currently dedicated to its customers, but used by competitors for profit.

The fact that a generation asset or fleet of assets was not found to be stranded investment under SB 3's opportunity for receipt of transition revenues does not preclude the Commission from presently adopting a cost-based capacity charge. This is especially compelling in light of the fact that AEP Ohio has avoided the volatile and uncertain RPM for capacity through its election to be a FRR Entity, which was applauded by the Commission at the time AEP Ohio made its election. AEP Ohio saved its customers billions of dollars by avoiding higher market prices over the past decade. It would be extremely unfair and disingenuous for the Commission to currently find that AEP Ohio's cost-based capacity charge is barred by virtue of a 2000-era

[28] *See* Case No. 09-119-EL-UNC, Opinion and Order at 13-14 (June 15, 2009); Case No. 09-199-EL-UNC, Entry on Rehearing at 7-9, 12-13, 17-18 (Sept. 15, 2009).

market analysis done under the previously-effective provisions of SB 3 that were applied in a different factual and legal context.

Not only is the 2000-vintage view of stranded generation investment inapplicable to the current situation, taking a short-term view cannot support any valid conclusions about whether generation investment is stranded in a competitive market. The RPM auction-clearing prices simply do not represent a long-term view of market prices for capacity. By contrast, the view of stranded generation investment undertaken in connection with SB 3 was based on long-term projections for market prices of electricity. It is unfounded to claim that it amounts to recovery of stranded costs for AEP Ohio to receive a cost-based rate for a very short transition period. As the history above demonstrates, stranded cost has not been an issue for AEP Ohio in the past and if one examined the whole period involved – 2001 through the end of this ESP – the Company's generation cost would be well below market during this time.

Indeed, during the period 2001 through 2008, the Company's generation was well below market, and the Company's retail customers benefited greatly. Yet, even though SB 3 was premised on the ability to charge market rates starting in 2006, at no time during the past decade was AEP Ohio ever permitted to charge a true market rate for its standard service offer. As IEU witness Hess admitted, while SB 3 was premised on collection of market rates after the transition period (Tr. V at 1085), AEP Ohio never got to charge those market rates and instead entered into a Rate Stabilization Plan at rates lower than projected and actual market rates. AEP Ohio does not regret the RSP, as it is consistent with the Company's long track record of balancing its interests with that of its customers and in partnering with its regulators. But it is unfair and disingenuous for IEU and FES to ignore this regulatory background in making their bogus stranded cost argument.

The ESP option under SB 221 now involves several cost-based rate adjustments and amounts to a hybrid system of regulation and market-based pricing. Even an MRO option under SB 221 involves an additional transition period of 6-10 years before a full market price is charged for the standard service offer. Another significant change made through SB 221 regarding generation assets is that a utility is required to obtain approval from the Commission to transfer generation assets. Under SB 3, an electric utility could freely transfer generation assets. In its first ESP filed under SB 221, the Company sought to transfer a limited amount of its generation and its request was denied. Yet another significant aspect of SB 221 is its application of the significantly excessive earnings test. All of these factors limit an electric utility's ability to charge and retain market rates for generation service and manage the business and financial risks associated with its fleet of generation assets.

In sum, Messrs. Hess's and Lesser's two-step argument – first characterizing a cost-based capacity charge as being recovery of stranded generation investment, and second arguing that it is too late to recover stranded investment – is misguided and without merit. The testimony filed in support of the Company's cost-based capacity charge demonstrates that the capacity charge is reasonable and should be adopted by the Commission.

VII. CONCLUSION

Based on the foregoing arguments and the manifest weight of the evidentiary record, the Commission should approve AEP Ohio's proposed capacity charge.

Respectfully submitted,

//s/ Steven T. Nourse

Steven T. Nourse
Matthew J. Satterwhite
Yazen Alami
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
(614) 716-1608
Fax: (614) 716-2950
Email: stnourse@aep.com
mjsatterwhite@aep.com
yalami@aep.com

Daniel R. Conway
Christen M. Moore
Porter, Wright, Morris & Arthur, LLP
41 South High Street
Columbus, Ohio 43215
(614) 227-2270
Fax: (614) 227-2100
Email: dconway@porterwright.com
cmoore@porterwright.com

Counsel for Ohio Power Company

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that a copy of Ohio Power Company's Initial Post-Hearing Brief was served by electronic mail upon counsel for all other parties of record in this case on this 23rd day of May, 2012.

//s/ Steven T. Nourse
Steven T. Nourse

greta.see@puc.state.oh.us,
jeff.jones@puc.state.oh.us,
Daniel.Shields@puc.state.oh.us,
Tammy.Turkenton@puc.state.oh.us,
Sarah.Parrot@puc.state.oh.us,
Jodi.Bair@puc.state.oh.us,
Bob.Fortney@puc.state.oh.us,
Doris.McCarter@puc.state.oh.us,
Greg.Price@puc.state.oh.us,
Werner.Margard@puc.state.oh.us,
William.Wright@puc.state.oh.us,
john.jones@puc.state.oh.us,
Kim.Wissman@puc.state.oh.us,
Hisham.Choueiki@puc.state.oh.us,
Dan.Johnson@puc.state.oh.us,
steven.beeler@puc.state.oh.us,
dclark1@aep.com,
grady@occ.state.oh.us,
keith.nusbaum@snrdenton.com,
kpkreider@kmklaw.com,
mjsatterwhite@aep.com,
ned.ford@fuse.net,
pfox@hilliardohio.gov,
ricks@ohanet.org,
stnourse@aep.com,
cathy@theoec.org,
dsullivan@nrdc.org,
aehaedt@jonesday.com,
dakutik@jonesday.com,
haydenm@firstenergycorp.com,
dconway@porterwright.com,
jlang@calfee.com,
lmcbride@calfee.com,
talexander@calfee.com,
etter@occ.state.oh.us,
terrance.mebane@thompsonhine.com,
cmooney2 @columbus.rr.com,
drinebolt@ohiopartners.org,
trent@theoec.org,
nolan@theoec.org,
gpoulos@enernoc.com,
emma.hand@snrdenton.com,
doug.bonner@snrdenton.com,
clinton.vince@snrdenton.com,
sam@mwncmh.com,
joliker@mwncmh.com,
fdarr@mwncmh.com,
jestes@skadden.com,
paul.wight@skadden.com,
dstahl@eimerstahl.com,
aaragona@eimerstahl.com,
ssolberg@eimerstahl.com,
tsantarelli@elpc.org,
callwein@wamenergylaw.com,
malina@wexlerwalker.com,
jkooper@hess.com,
kguerry@hess.com,
afreifeld@viridityenergy.com,
swolfe@viridityenergy.com,
korenergy@insight.rr.com,
sasloan@aep.com,
Dane.Stinson@baileycavalieri.com,
Jeanne.Kingery@duke-energy.com,
zkravitz@taftlaw.com,
rsugarman@keglerbrown.com,
bpbarger@bcslawyers.com,
dbweiss@aep.com
dboehm@bkllawfirm.com,
mkurtz@bkllawfirm.com,
ricks@ohanet.org,

grady@occ.state.oh.us,
small@occ.state.oh.us,
cynthia.a.fonner@constellation.com,
David.fein@constellation.com,
Dorothy.corbett@duke-energy.com,
Amy.spiller@duke-energy.com,
todonnell@bricker.com,
cmontgomery@bricker.com,
lmcalister@bricker.com,
mwarnock@bricker.com,
gthomas@gtpowergroup.com,
wmassey@cov.com,
sandy.grace@exeloncorp.com,
cmiller@szd.com,
ahaque@szd.com,
gdunn@szd.com,
mhpetricoff@vorys.com,
smhoward@vorys.com,
mjsettineri@vorys.com,
carolyn.flahive@thompsonhine.com,
yost@occ.state.oh.us,
kern@occ.state.oh.us,
tobrien@bricker.com,
jbentine@cwslaw.com,
myurick@cwslaw.com,
zkravitz@cwslaw.com,
jejadwin@aep.com,
msmalz@ohiopovertylaw.org,
jmaskovyak@ohiopovertylaw.org,
henryeckhart@aol.com,
laurac@chappelleconsulting.net,
whitt@whitt-sturtevant.com,
thompson@whitt-sturtevant.com,
lkalepsclark@vorys.com,
bakahn@vorys.com,
Gary.A.Jeffries@dom.com,
Stephen.chriss@wal-mart.com,
dmeyer@kmklaw.com,
holly@raysmithlaw.com,
barthroyer@aol.com,
philip.sineneng@thompsonhine.com,
campbell@whitt-sturtevant.com,