BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
Columbus Southern Power Company and	)	
Ohio Power Company for Authority to	)	Case No. 11-346-EL-SSO
Establish a Standard Service Offer	)	Case No. 11-348-EL-SSO
Pursuant to §4928.143, Ohio Rev. Code,	)	
in the Form of an Electric Security Plan	)	
In the Matter of the Application of	)	
Columbus Southern Power Company and	)	Case No. 11-349-EL-AAM
Ohio Power Company for Approval of	)	Case No. 11-350-EL-AAM
Certain Accounting Authority	)	

TESTIMONY OF
MICHAEL M. SCHNITZER
ON BEHALF OF
FIRSTENERGY SOLUTIONS CORP.

Filed: May 4, 2012

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List of Exhibits

I. Background And Qualifications

Q. PLEASE STATE YOUR NAME.

A. Michael M. Schnitzer.

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is 30 Monument Square, Concord MA 01742.

Q. MR. SCHNITZER, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Director of The NorthBridge Group, Inc. ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries.

Q. MR. SCHNITZER, PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE IN THE ELECTRIC ENERGY INDUSTRY.

A. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have focused throughout this time on advising energy companies about strategic issues, particularly those relating to finance and market structure issues. In so doing, I have experience working with private sector clients in the electric utility, natural gas, private power, and steel industries, as well as with public and nonprofit agencies.

I have testified before the Federal Energy Regulatory Commission ("FERC") and a number of state commissions and departments on issues relating to competitive restructuring and wholesale market design, including Locational Marginal Pricing ("LMP") and Financial Transmission Rights, Regional Transmission Organizations ("RTO"), standard market design, resource adequacy, and transmission expansion pricing. On several occasions I have been invited by FERC staff to participate as a panelist in technical conferences on these subjects. I have also testified before several state commissions and departments on the subject of provision of default service to retail customers, including evaluation of competitive procurement proposals.

Q. MR. SCHNITZER, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science degree in Management from the Sloan School of Management, of the Massachusetts Institute of Technology, which I received in 1979. My concentration was in finance. I also received a Bachelor of Arts degree in chemistry, with honors, from Harvard College in 1975. My resume is attached as Exhibit MMS-1 to this testimony.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY TO THE PUBLIC UTILITIES COMMISSION OF OHIO ("COMMISSION" OR "PUCO")?

A. Yes. I testified on behalf of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company, in Case No. 09-906-EL-

SSO, on behalf of Constellation New Energy and Constellation Energy Commodities Group, Inc. in Case No. 08-0935-EL-SSO, and on behalf of Cinergy Gas & Electric in Docket No. 95-656-GA-AIR. I also previously testified in this proceeding on behalf of FirstEnergy Solutions Corp. ("FES").

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

A. I am testifying on behalf of FES.

II. Purpose Of Testimony And Conclusions

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. AEP Ohio[1] filed on March 30, 2012 a Modified Electric Security Plan ("Modified ESP")[2] that would establish Standard Service Offer ("SSO") rates from June 1, 2012 through May 31, 2015. The Modified ESP includes significant changes from the negotiated ESP that was approved with modifications by the Commission and ultimately rejected by the Commission on February 23, 2012 ("Stipulation ESP"). The Company offers quantification which purports to show that the Modified ESP passes both an Aggregate Market Rate Offer ("MRO") Test as well as the MRO Price Test.[3] As defined by AEP Ohio witness Thomas, the MRO Price Test purports to compare the price that would be charged to non-shopping customers

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[1] Columbus Southern Power Company ("CSP") merged with and into Ohio Power Company ("OPCo") effective December 31, 2011. The combined entity is "AEP Ohio" or the "Company" as referenced in this testimony.

[2] AEP Ohio Application, PUCO Case No. 11-346-EL-SSO et al., 3/30/2012.

[3] Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, Exhibit LJT-1, at 1-2.

under the Modified ESP with the price to the same customers under an MRO. The Aggregate MRO Test purports to include the alleged benefits from the MRO Price Test along with other alleged benefits of the Modified ESP as compared to an MRO. The principal purpose of my testimony is to respond to the Company's quantification of the benefits supporting its claim that the Modified ESP passes these tests. In addition, I compare the Modified ESP to the Stipulation ESP that was rejected by the Commission and evaluate the plan's impact on the competitive retail market in the AEP Ohio service area.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. Yes. I have three main conclusions:

1. AEP Ohio's analysis of the quantifiable benefits of the Modified ESP is flawed in the Aggregate MRO Test, which when corrected, demonstrates that the Modified ESP does not produce net quantifiable benefits under the Aggregate MRO Test.

    a) AEP Ohio continues to claim $989 million of "quantifiable benefits" from "discounted, tiered capacity pricing" in the Aggregate MRO Test, even though it is inappropriate to do so and the Commission has stated that this cannot be considered a benefit of the proposed ESP.[4] Correcting for this one error alone would reverse the Company's

[4] "[T]he Commission agrees with the Non-Signatory Parties that … the discounted capacity rate cannot be considered [a] benefit[] of the Stipulation's proposed ESP." PUCO Opinion and Order, PUCO Case No. 11-346-EL-SSO et al., 12/14/2012, at 32.

overall conclusion and demonstrate that, according to the Company's own analysis, there are no net "quantifiable benefits" under the Aggregate MRO Test.

b) AEP Ohio's MRO Price Test also contains serious flaws:[5]

- AEP Ohio overstates the Competitive Benchmark Price ("CBP") component of the MRO Price by failing to use a market-based capacity price.

- AEP Ohio also understates the Modified ESP price by ignoring the costs associated with the proposed non-bypassable riders. For example, the Company assumes zero costs for the Generation Resource Rider ("GRR") despite the Commission's recent order stating that such costs should be considered in the MRO Price Test.[6] Similarly, AEP Ohio does not include the proposed new Retail Stability Rider ("RSR") in the MRO Price Test.[7] Including the costs of the RSR in the MRO Price Test, holding all else constant, would demonstrate that the Modified

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[5] The MRO Price Test shown in Exhibit LJT-1, p. 2 and LJT-5, p. 1 is included as a component of the Company's Aggregate MRO Test as shown in Exhibit LJT-1, p. 1.

[6] "[W]e believe Ms. Thomas erred by failing to include a cost for the GRR in her price comparison." PUCO Opinion and Order, PUCO Case No. 11-346-EL-SSO et al., 12/14/2012, at 30. AEP Ohio filed supplemental testimony showing projected costs associated with the proposed GRR, but continues to claim that "the benefit or difference to be captured under the Aggregate MRO Test for the [Turning Point Solar] Project is zero." Supplemental Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, at 2.

[7] Ms. Thomas includes the RSR in a newly developed "Aggregate MRO Test" along with the claimed discounted tiered capacity benefit, acknowledging that the RSR represents a new cost of the Modified ESP, but she omits this cost in the MRO Price Test. This cost more than offsets the estimated benefits shown on Exhibit LJT-1, p. 2 and Exhibit LJT-5, p.1. Similar to the Commission's decision on the GRR, the RSR also should be included in the MRO Price Test.

ESP Price is less favorable than the expected price under an MRO.

- In addition, AEP Ohio "double counts" its alleged benefits and fails to fully consider the impact of its Modified ESP on customers that receive service from CRES providers.

c) When AEP Ohio's analysis is corrected, the Modified ESP price would not be more favorable than the price expected under an MRO. The Modified ESP would result in excess costs to the AEP Ohio zone as compared to an MRO – ranging from $400 million to $1.3 billion under a range of reasonable assumptions.[8] The range depends on the expected outcome of the appropriate price levels for capacity to be charged to CRES providers for customers that shop under an MRO, pursuant to PUCO Case No. 10-2929-EL-UNC ("10-2929 Capacity Case").[9]

2. Second, the Modified ESP is about $670 million worse for customers than the Stipulation ESP that was ultimately rejected by the Commission.

[8] Neither of these figures includes any costs related to the Pool Termination Provision, which I discuss later in my testimony. I estimate that this provision could potentially increase costs to customers by about $410 million. If I were to include these costs, the Modified ESP would result in excess costs to the AEP Ohio zone as compared to an MRO by $800 million to $1.7 billion.

[9] The high end of the range is based on the Company's estimates of shopping and AEP Ohio being required to provide capacity to CRES providers at RPM prices for customers that shop under an MRO. The low end of the range is based on AEP Ohio being required to provide capacity to CRES providers at the tiered capacity charges proposed by AEP Ohio in the Modified ESP for customers that shop under an MRO. In all instances, the capacity price included in the CBP component of the MRO is based on market capacity prices (*i.e.*, RPM).

a) The Modified ESP harms shopping customers by approximately $555 million – increasing capacity costs to CRES providers serving Tier 1 customers, reducing the size of Tier 1 capacity allotments, and imposing new RSR costs on Tier 1 and Tier 2 customers.

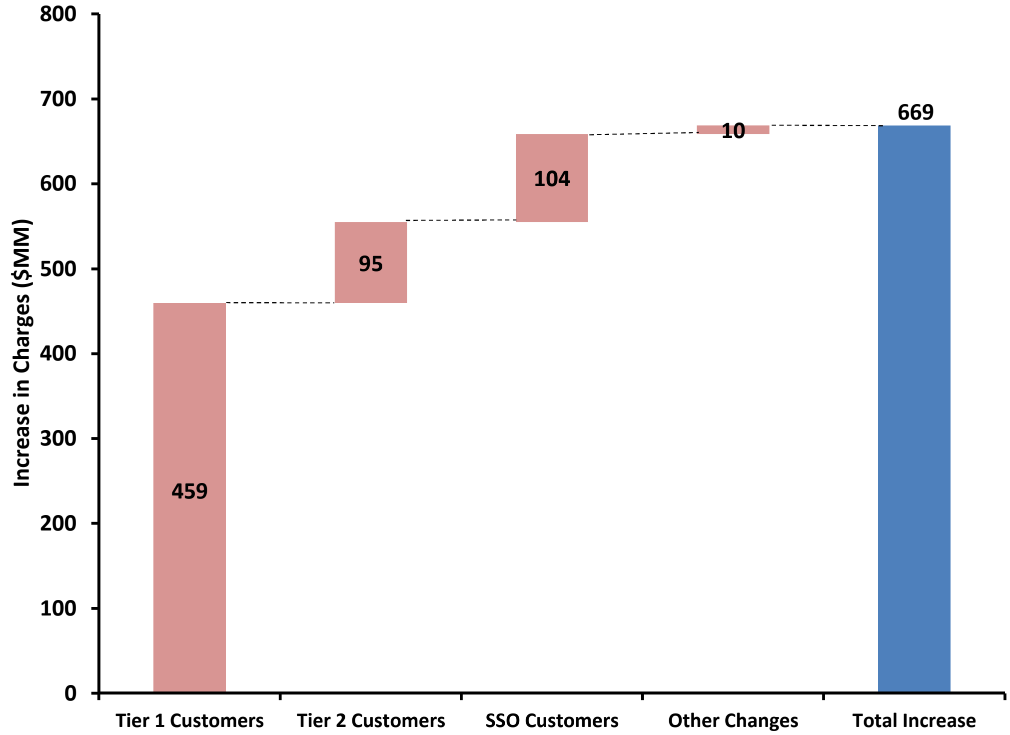
b) The Modified ESP increases rates for SSO customers by approximately $105 million, largely due to the new RSR costs.

c) In addition, the Modified ESP imposes about $10 million in additional costs on customers as compared to the Stipulation ESP due to a) the elimination of grants to the Partnership with Ohio Initiative, b) the elimination of the Ohio Growth Fund, and c) an offsetting reduction due to the elimination of the Market Transition Rider.[10]

In total, the Modified ESP is about $670 million worse than the Stipulation ESP ultimately rejected by the Commission.

[10] Furthermore, the Modified ESP lowers the threshold from $50 million to $35 million above which AEP Ohio can seek recovery from customers for costs related to AEP Pool Termination.

The Modified ESP is about $670 Million Worse than the Stipulation ESP Ultimately Rejected by the Commission
(Modified ESP less Stipulation ESP)



3. The Modified ESP also will impede the development of a robust competitive retail market.

   a) The above-market capacity charges to CRES providers will limit CRES providers' ability to offer savings and will reduce the level of savings they can offer to shopping customers in the AEP Ohio service territory.

   b) The tiered structure of above-market capacity charges will lead to the creation of two classes of shopping customers who pay different rates for otherwise identical service.

My conclusions are described further in the pages that follow after a brief description of the key terms of the Modified ESP.

III. <u>Key Terms Of The Modified ESP</u>

Q. WHAT ARE THE KEY TERMS OF THE MODIFIED ESP?

A. For purposes of my analysis, the key terms of the Modified ESP are described below:

1. AEP Ohio proposes to use a competitive procurement process to meet its SSO obligation (including both energy and capacity), but not until June 1, 2015.[11] The delivery period beginning June 1, 2015 is outside of the Modified ESP delivery period, and thus will be governed by a separate SSO application to be filed by AEP Ohio at an unspecified time in the future.

2. AEP Ohio proposes to use a competitive procurement process to obtain energy for 100% of retained load beginning January 1, 2015 through May 31, 2015. During this delivery period, AEP Ohio would provide capacity to retained load at a rate of $255/MW-day.[12]

3. AEP Ohio proposes to use a competitive procurement process to obtain energy for 5% of retained load beginning six months after final orders are issued approving the Modified ESP and the corporate separation plan as

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[11] Modified ESP Testimony of Robert Powers on Behalf of AEP Ohio, Exhibit RPP-1.

[12] Modified ESP Testimony of Robert Powers on Behalf of AEP Ohio, at 19-20.

filed. AEP Ohio would conduct this auction only "on the express condition of financially being made whole."[13] Delivery would extend through December 31, 2014, and the details of the plan would be developed following the issuance of final orders.

4. AEP Ohio is requesting a new non-bypassable Retail Stability Rider. Under AEP Ohio's plan, the exact level of RSR revenue recovery varies and is subject to reconciliation to achieve a desired revenue target (*i.e.*, gross revenues sufficient to earn a 10.5% ROE using 2011 costs). The Company expects the RSR to average $2.0/MWH based on the Company's modeling assumptions.[14]

5. AEP Ohio proposes tiered capacity charges for CRES providers. The first tier of capacity ("Tier 1") would be available to approximately 21% of AEP Ohio's retail load in 2012, 31% in 2013, and 41% in 2014 continuing through May of 2015.[15] AEP Ohio proposes to charge CRES providers receiving Tier 1 capacity $145.79/MW-day.[16] AEP Ohio proposes to charge CRES providers receiving Tier 2 capacity $255/MW-day.

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[13] Modified ESP Testimony of Robert Powers on Behalf of AEP Ohio, at 20-21.

[14] Modified ESP Testimony of William Allen on Behalf of AEP Ohio, at 13-14 and Exhibit WAA-6.

[15] Modified ESP Testimony of William Allen on Behalf of AEP Ohio, at 6-7.

[16] According to Company witness Allen, "The rate for the Tier 1 priced capacity $145.79/MW-day was established based on the Final Zonal Capacity Price adjusted for the RPM Scaling Factor, the Forecast Pool Requirement and losses for PJM planning year 2011/2012." Modified ESP Testimony of William Allen on Behalf of AEP Ohio, at 7.

6. AEP Ohio proposes to discontinue the Environmental Investment Carrying Cost Recovery Rider ("EICCR") and move the current level of charges into base generation rates. Base generation rates in the Modified ESP would be frozen for the duration of the Modified ESP period.[17]

7. AEP Ohio also would be able to seek approval of the costs of the Turning Point Solar Project in a non-bypassable Generation Resource Rider ("GRR") during the term of the Modified ESP.[18]

8. AEP Ohio also would retain the right to file for recovery of costs due to the termination of the AEP Pool. Such costs could be recovered in a non-bypassable rider pursuant to the proposed Pool Termination Provision if the Company's corporate separation plan is amended or denied. A Pool Modification Rider ("PMR") would recover the difference between the revenues available to AEP Ohio as a member of the AEP Pool and the revenues available to AEP Ohio in competitive markets.[19]

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[17] Modified ESP Testimony of Selwyn Dias on Behalf of AEP Ohio, at 9.

[18] Modified ESP Testimony of Philip Nelson on Behalf of AEP Ohio, at 20.

[19] Modified ESP Testimony of Philip Nelson on Behalf of AEP Ohio, at 21-22.

IV. <u>AEP Ohio's Analysis Of The Quantifiable Benefits Of The Modified ESP Is Flawed In The Aggregate MRO Test, Which When Corrected, Demonstrates That The Modified ESP Does Not Produce Net Quantifiable Benefits Under The Aggregate MRO Test</u>

Q. DOES AEP OHIO ATTEMPT TO SHOW THAT THE MODIFIED ESP SATISFIES THE STATUTORY TEST THAT IT BE MORE FAVORABLE IN THE AGGREGATE THAN THE EXPECTED RESULTS OF AN MRO?

A. AEP Ohio witness Powers offers testimony that states the Modified ESP does "pass the MRO test in the aggregate" and states that "Company witness Thomas shows how the elements of the modified ESP II support favorable aggregate MRO test results."[20] Ms. Thomas concludes in her testimony that "[t]he Company's modified ESP is beneficial in the aggregate … and is more favorable than a MRO by approximately $960 Million as shown on Page 1 of Exhibit LJT-1."[21] Ms. Thomas' testimony includes a test that she refers to as the "Aggregate Market Rate Offer Test," which shows a summary of both "Quantifiable Benefits" and "Not Readily Quantifiable Benefits."[22] Comparing the quantifiable costs of the Modified ESP with the expected costs under an MRO is a key component of the "more favorable in the aggregate" test, and is the primary focus of my testimony.

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[20] Modified ESP Testimony of Robert Powers on Behalf of AEP Ohio, at 24.

[21] Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, at 4.

[22] Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, Exhibit LJT-1, at 1.

Q. PLEASE DESCRIBE THE QUANTIFIABLE METRICS THAT MS. THOMAS USES TO CONCLUDE THAT THE MODIFIED ESP IS MORE BENEFICIAL THAN AN MRO IN THE AGGREGATE MRO TEST.

A. Ms. Thomas shows four numbers in the Aggregate MRO Test in Exhibit LJT-1, p. 1, which sum to the purported $961 million in "Quantifiable Benefits of the ESP."

- First, Ms. Thomas shows the calculation of a $256 million benefit based on the results of an MRO Price Test that she performs and which is shown in Exhibit LJT-1, p. 2.
- Second, Ms. Thomas claims a benefit of $989 million due to "Discounted, tiered capacity pricing for CRES providers."
- Third, Ms. Thomas includes the adverse effect of the new non-bypassable RSR which decreases the purported benefit by $284 million.
- Fourth, Ms. Thomas includes a line item for "Placeholder Riders" listing the GRR and a benefit/cost of $0.

All four of these items are included in the Aggregate MRO Test, while items two through four are excluded from her MRO Price Test. After summing these four components, Ms. Thomas concludes that the Modified ESP provides a net quantifiable benefit of $961 million over an MRO plan. I address each of these items within the next sections of my testimony.

A. <u>AEP Ohio continues to claim $989 million of "quantifiable benefits" from "discounted, tiered capacity pricing" in the Aggregate MRO Test, even though it is inappropriate to do so and the Commission has stated that this cannot be considered a benefit of the proposed ESP. Correcting for this one error alone would reverse the Company's overall conclusion and demonstrate that, according to the Company's own analysis, there are no net "quantifiable benefits" under the Aggregate MRO Test.</u>

Q. DO YOU HAVE ANY INITIAL OBSERVATIONS ABOUT THE CONCLUSION THAT MS. THOMAS DRAWS REGARDING THE QUANTIFIABLE BENEFITS OF THE MODIFIED ESP?

A. Yes, the Company claims $989 million of purported benefits of the Modified ESP due to the "Discounted, tiered capacity pricing for CRES providers." This number should be wholly disregarded. This so-called benefit is illusory because it assumes that, absent the Modified ESP, the Company would have charged its above-market capacity request of $355 per MW-day that has not been approved by either this Commission or the FERC. AEP Ohio's requested above-market compensation is not the appropriate benchmark on which to measure "savings." In fact, whether the Modified ESP capacity charge represents a savings or a cost depends on what you believe would have been in place absent the Modified ESP. AEP Ohio assumes very aggressive "but for" treatment by the Commission with respect to capacity costs, namely that the Commission would have approved the excessive capacity price that the Company requested. I believe it is more appropriate to conclude that the Modified ESP represents an incremental cost since it assumes above-market capacity charges to CRES suppliers in excess of those approved by the Commission.[23]

Indeed, the Commission has already ruled on AEP Ohio's prior attempts to include this calculation in its statutory comparison of the ESP and MRO. The Commission stated, "AEP Ohio cannot claim the discounted capacity price to CRES providers as a benefit. As [Staff witness] Mr. Fortney appropriately stated in his testimony, AEP-Ohio's requested capacity price in its application was never certain, and therefore, it cannot be considered as either a benefit or meaningful number for the purpose of conducting the statutory test."[24]

Correcting this single error in the Aggregate MRO Test reverses the Company's overall conclusion and demonstrates that, according to the Company's own analysis shown in Exhibit LJT-1, the costs of the Modified ESP are $28 million higher than the expected results of an MRO.[25]

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[23] Furthermore, there is no basis to assume that the Commission would have approved a $355/MW-day capacity charge for all shopping customers under an MRO. As I describe later in my testimony, a capacity charge of $255/MW-day would create negative "headroom" and no apparent opportunity for customers to shop with a CRES provider, and so a $355/MW-day capacity charge clearly would provide no opportunity for customers to shop and in any event, would be inconsistent with AEP Ohio's own aggressive switching assumptions under the MRO case.

[24] PUCO Opinion and Order, PUCO Case No. 11-346-EL-SSO et al., 12/14/2012, at 30-31.

[25] Ms. Thomas also shows an alternative MRO Price Test in Exhibit LJT-5 using a Competitive Benchmark Price with a capacity charge based on a blending of $355/MW-day, $146/MW-day, and $255/MW-day. Correcting this single error, but using the results of this alternative MRO Price Test in Ms. Thomas' Aggregate MRO Test, and accepting all other flaws in the analysis, the costs of the Modified ESP are expected to be $203 million higher than the costs of an MRO.

B. <u>AEP Ohio's MRO Price Test also contains serious flaws</u>

Q. DESCRIBE THE FIRST QUANTITATIVE METRIC THAT MS. THOMAS USES IN HER AGGREGATE MRO TEST?

A. Ms. Thomas first uses an MRO Price Test, similar in methodology to her earlier testimony in this case, to compare the price expected under the Modified ESP to the price expected under an MRO. Specifically, her Exhibit LJT-1, pp. 2-3, compares an "MRO Annual Price" (or "MRO Price") that she calculates to the Company's "Proposed ESP Price" (or "Modified ESP Price"). The MRO Price that Ms. Thomas calculates is a blended price consisting partly of a "Competitive Benchmark Price" (or "CBP") and partly of a legacy ESP "Total Generation Service Price." According to Ms. Thomas, the Total Generation Service Price "is the generation base generation rate in effect as of the date of this filing," plus the "generation components of the Transmission Cost Recovery Rider (TCRR), the EICCR, and full cost FAC."[26] The MRO Price calculated for the Modified ESP period is a blend of these two prices because the Ohio Revised Code requires that an MRO offered by an EDU that owns generation phase in an increasing percentage of the necessary default service supply from the market over time.[27] Ms. Thomas notes that the MRO Price Test is one part of the test "in the aggregate."

[26] Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, at 16-17.

[27] Ohio Revised Code Section 4928.142(D).

Q. WHAT DOES MS. THOMAS' ANALYSIS IN EXHIBIT LJT-1, P. 2, SHOW?

A. Ms. Thomas concludes that, between June 2012 and May 2015, the average MRO Price would be $65.39 and that the average Modified ESP Price would be $63.62, and as a result the net benefit of the Modified ESP shown in Ms. Thomas' analysis is $1.77 per MWH. Using this price comparison, Ms. Thomas claims that the Modified ESP Price is more favorable than the expected price under an MRO by $256 million before accounting for the RSR (which, according to the Company's estimates, is expected to cost $284 million).

Q. DO YOU AGREE WITH MS. THOMAS' CONCLUSION?

A. No. Ms. Thomas' conclusion should be disregarded because her analysis contains material flaws and the price benefits claimed by AEP Ohio are significantly overstated.

Q. PLEASE SUMMARIZE THE MAJOR FLAWS IN THE COMPANY'S MRO PRICE TEST ANALYSIS AND YOUR CORRECTIONS.

A. There are three major flaws in the MRO Price Test analysis:

- **AEP Ohio overstates the Competitive Benchmark Price:** The MRO Price shown in Exhibit LJT-1 assumes a $355/MW-day capacity charge in the development of the CBP. This capacity charge is not a market-based price, has never been approved by the Commission, and is inappropriate for use in the CBP portion of the MRO Price. I replaced the $355/MW-day capacity charges assumed in Ms. Thomas' MRO Price Test analyses with RPM market prices. The basis for this change is described later in my testimony. I also calculated the other costs in Ms. Thomas' CBP model, taking into account the "ripple" effects of the capacity assumption above on the other cost components.[28] My corrections to the CBP are shown in Exhibit MMS-2.

- **AEP Ohio understates the Modified ESP Price:** The Modified ESP Price omits important non-bypassable rider costs (*e.g.*, the RSR and GRR) that will be incurred during the ESP period.[29] In addition, Ms. Thomas' forecast of the Modified ESP Price for Jan – May 2015 shown in Exhibit LJT-1, p. 2 assumes capacity is supplied at $355/MW-day for SSO customers, even though the Company's proposal clearly states that it would supply capacity at $255/MW-day to SSO customers during this period. Correcting this mistake therefore would lower the Modified ESP Price as compared to the Company's estimate.

I made the following corrections to the Modified ESP Price. First, I incorporated the Company's forecast of the RSR in the calculation of the Modified ESP Price. The RSR is a cost of the Modified ESP that would

[28] For purposes of comparison I accepted, to the extent practicable, AEP Ohio's assumptions used to develop the CBP. Also, I note that at this time energy forwards have not changed significantly since the trade dates used by the Company, and for this reason I have used the same energy forwards as Ms. Thomas for purposes of comparison.

[29] Ms. Thomas does include the estimated costs of the RSR in her summary table shown in Exhibit LJT-1, p. 1, but does not include these costs in the MRO Price Test shown on Exhibit LJT-1, p. 2 or Exhibit LJT-5.

not be incurred under an MRO, and therefore it should not be omitted in the MRO Price Test. Second, I relied on the Company's forecast of the Turning Point Solar Project revenue requirements and included the GRR cost in the Modified ESP Price. Third, I decreased the Modified ESP Price during the Jan – May 2015 delivery period to reflect capacity costs at $255/MW-day, partially offsetting the increase due to the inclusion of non-bypassable riders. My corrections to the Modified ESP Price are shown in Exhibit MMS-3.

- **AEP Ohio "double counts" its alleged benefits and ignores the full impact of the Modified ESP on Shopping Customers:** AEP Ohio assumes significant increases in customer switching, but does not appropriately analyze the effects of the Modified ESP on these customers in the MRO Price Test. In fact, as I describe later in my testimony, it appears that AEP Ohio has "double-counted" its alleged benefits in Exhibit LJT-1, p.1 by assuming that customers can receive the Company's claimed "benefit" of lower SSO prices (assuming no shopping) <u>and</u> "discounted capacity" (assuming significant shopping) at the same time. AEP Ohio ignores in the MRO Price Test the fact that switched customers would pay higher costs under the Modified ESP than under an MRO due to the proposed non-bypassable charges and due to the potential for higher capacity charges than under an MRO. I account for the fact that switched load will be charged the RSR and GRR non-bypassable riders proposed under the Modified ESP. I also account for the above-market capacity charges that will be charged to CRES providers under the Modified ESP and compare these charges to a range of capacity charges that could be charged to CRES providers under an MRO.[30]

After correcting the various flaws I have identified in Ms. Thomas' analysis, I conclude that under a reasonable set of assumptions, the Modified ESP is expected to cost customers $400 million to $1.3 billion more than an MRO. The corrected MRO Price Test (*i.e.*, the corrected LJT-1) that results from the above adjustments is shown in Exhibit MMS-4. My corrections and the underlying rational for the changes to the CBP, Modified ESP Price, and analysis of the impact on shopping customers are described further below.

C. AEP Ohio overstates the Competitive Benchmark Price in the MRO Price by failing to use a market-based capacity price

Q. HOW DID AEP OHIO MODEL THE MRO PRICE?

A. The MRO Price calculated by Ms. Thomas is a blended price consisting partly of a CBP and partly of a legacy ESP Total Generation Service Price.

Q. HAVE YOU MADE ANY CHANGES TO THE LEGACY ESP TOTAL GENERATION SERVICE PRICE CALCULATED BY MS. THOMAS?

A. No. For the purposes of my analysis, I have accepted Ms. Thomas' calculation of the legacy ESP Total Generation Service Price.[31]

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[30] The MRO represents the "but for" world that would occur absent Commission approval of the Modified ESP. I have modeled a range of reasonable estimates of the capacity charge that would be billed to CRES providers under this "but for" world.

Q. TURNING NOW TO THE CBP COMPONENT OF THE MRO PRICE, HAVE YOU MADE ANY CHANGES TO THE CBP?

A. Yes. I recalculated the CBP using RPM capacity charges. The other costs were calculated using a model provided by Ms. Thomas. As a result, other than changing the capacity prices used in the development of the CBP, I have accepted all other modeling assumptions relied upon by Ms. Thomas in her analysis.[32]

Q. WHAT CAPACITY CHARGE IS USED IN AEP OHIO'S ANALYSIS OF THE CBP?

A. AEP Ohio shows two MRO Price analyses, located in Exhibit LJT-1 and LJT-5. The MRO Price shown in Exhibit LJT-1 includes a CBP with a capacity charge of $355/MW-day. The MRO Price shown in Exhibit LJT-5 includes a CBP with a capacity charge based on a blending of $355/MW-day, $146/MW-day, and $255/MW-day. AEP Ohio states that the Commission should rely upon the MRO Price Test shown in Exhibit LJT-1, which relies on the $355/MW-day capacity figure.[33]

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[31] In the testimony I filed pertaining to the Stipulation ESP, I made additional corrections to the legacy ESP Total Generation Service Price in order to forecast the fuel rider (FAC) and EICCR. In this testimony I have accepted Ms. Thomas' legacy ESP Total Generation Service Price, which freezes the EICCR and fuel riders at their current levels, in response to the Commission's recent order, which stated in part, "We also agree with the Signatory Parties in their assertion that forecasted fuel costs do not need to be included in the price test based on Section 4928.143(D), Revised Code, as well as Commission precedent in the ESP 1 case and Duke energy SSO Case" (citations omitted). PUCO Opinion and Order, PUCO Case No. 11-346-EL-SSO et al., 12/14/2011, at 31. All else equal, higher EICCR costs over time would tend to increase the relative benefit of the Modified ESP as compared to an MRO.

[32] I based my analysis on a model included in Ms. Thomas' workpapers. Workpapers provided 3/30/2012, "Ohio model to LT 032912.xlsm."

[33] Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, at 22 lines 21-23.

Q. WHAT IS THE PROPER CAPACITY PRICE TO INCLUDE IN THE CBP?

A. As described by FES witness Stoddard, the RPM price should be used to develop the CBP. The RPM price is the price that best supports wholesale and retail competition, and the RPM price is the market price of capacity. Furthermore, I have been advised by counsel that, as contemplated by Ohio Revised Code Section 4928.142(C), only the market price of capacity may be utilized in the MRO Price Test.

Q. IN A PRIOR ESP FILING MADE BY THE COMPANY, DID AEP OHIO RELY ON PJM RPM PRICES TO DETERMINE THE CAPACITY COST COMPONENT OF THE CBP?

A. Yes. Contrary to Ms. Thomas' analysis, AEP Ohio used PJM's RPM prices for capacity cost in its filing for its 2009-2011 ESP. In this prior ESP proceeding, Company witness Baker described the capacity cost component as follows:

> "PJM Capacity Obligations - This component reflects the cost of PJM's required capacity obligations for load serving entities <u>and was derived from the PJM Reliability Pricing Model (PJM Capacity Auction) results for the relevant time period</u>."[34]

Thus, AEP Ohio clearly relied on PJM's RPM capacity price to derive the capacity cost component of the CBP under an MRO.

[34] Direct Testimony of Craig Baker on Behalf of CSP and OPCo, Case No. 08-918-EL-SSO, at 11, lines 11-14, (emphasis added).

Q. HAS THE COMMISSION ADOPTED THE $355/MW-DAY CAPACITY CHARGE RELIED UPON BY THE COMPANY IN ITS MRO PRICE TEST?

A. No. The Commission has never approved the $355/MW-day price for capacity that the Company assumes in their development of the CBP. The Company has *proposed* this $355/MW-day capacity charge in the 10-2929 Capacity Case. On December 8, 2010, the Commission issued an order in this case finding it necessary to review the proposed changes,[35] and adopted the RPM clearing prices as AEP Ohio's allowed compensation mechanism during the review.[36] In a more recent order, the Commission has established an interim capacity charge, set to expire at the end of May 2012, which is based upon a tiered structure utilizing an RPM capacity charge and a $255/MW-day capacity charge: "This interim rate will be in effect until May 31, 2012, at which point the rate for capacity under the state compensation mechanism shall revert to the current RPM."[37] AEP Ohio's proposed change to its capacity charge also remains pending at FERC in Dockets No. ER11-2183 and EL11-32, after FERC initially "rejected [AEP Ohio's] rate schedules as unauthorized under the RAA."[38]

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[35] As stated on page 2 of the Order, "As an initial step, the Commission seeks public comment regarding the following issues: (1) what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio competitive retail electric service (CRES) providers; (2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio."

[36] PUCO Entry Order, Case No. 10-2929-EL-UNC, 12/8/2010, at 2.

[37] PUCO Entry Order, Case No. 10-2929-EL-UNC, 3/7/2012, at 17.

[38] Request for Rehearing of American Electric Power Service Corporation, FERC Docket ER11-2183, 2/22/2011 at 1, quoting *American Electric Power Service Corp.*, 134 FERC ¶ 61,039 (2011) at 1.

Q. HOW DOES AEP OHIO'S ASSUMED CAPACITY CHARGE COMPARE WITH RPM CAPACITY PRICES?

A. RPM prices are $116.16/MW-day for June 2011 – May 2012, $16.52/MW-day for June 2012 – May 2013, $27.73/MW-day for June 2013 – May 2014, and $125.94/MW-day for June 2014 – May 2015.[39] In comparison, Ms. Thomas' capacity charge of $355/MW-day is substantially higher than the applicable capacity prices established under RPM.

Q. HOW DOES MS. THOMAS' ESTIMATE OF THE CBP CHANGE WHEN YOU CORRECT THE FLAWS THAT YOU HAVE IDENTIFIED?

A. Correcting for the capacity and other related cost components results in a significantly lower CBP. In Exhibit LJT-1, Ms. Thomas calculates the CBP with a $355/MW-day capacity cost, equal to $71.60/MWH over the Modified ESP delivery period. In Exhibit LJT-5, Ms. Thomas calculates the CBP with a blending of the $355/MW-day, $255/MW-day, and $146/MW-day capacity costs, equal to $63.80/MWH over the Modified ESP delivery period. Using Ms. Thomas' modeling assumptions and using RPM capacity, the CBP over the duration of the ESP delivery period is $50.96/MWH. As a result, when corrected, the CBP shown in Exhibit LJT-1 would decrease by $21/MWH and the CBP shown in Exhibit

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[39] These prices represent the Base Residual Auction prices in RPM which are adjusted prior to determining the final charge to customers.

LJT-5 would decrease by $13/MWH.[40] These results are summarized in Exhibit MMS-2.

D. <u>AEP Ohio understates the Modified ESP Price in the MRO Price Test by ignoring the costs associated with the proposed non-bypassable riders</u>

Q. TURNING NOW TO THE MODIFIED ESP PRICE USED IN THE MRO PRICE TEST, PLEASE EXPLAIN FURTHER MS. THOMAS' UNDERESTIMATION OF THE MODIFIED ESP PRICE.

A. Ms. Thomas' Modified ESP Price is too low because it omits the costs and risks that customers would face related to the RSR and GRR (and potentially PMR) under the Modified ESP. Including the costs associated with these proposed non-bypassable riders, and accounting for the offsetting change in the expected price during the Jan – May 2015 delivery period,[41] the Modified ESP Price would increase by more than $1/MWH (and as much as $4/MWH if the PMR were included). My adjustments are summarized in Exhibit MMS-3.

Q. HOW DID AEP OHIO DEVELOP THE MODIFIED ESP PRICE?

A. The Modified ESP Price shown on line 13 of Exhibit LJT-1, p. 2, was provided by AEP Ohio witness Roush through December 2014. The Modified ESP Price

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[40] As shown in Exhibit MMS-2, when the capacity prices are adjusted in Ms. Thomas' CBP model, the costs of other price components are also affected. In addition, Ms. Thomas weighted the CBP over time and across customer classes using system loads. Because the CBP would apply only to retained load served under an MRO, I have also made a correction to weight the CBP using forecasted retained loads. This correction accounts for less than $1/MWH of the total reduction in the corrected CBP shown in Exhibit MMS-2.

[41] To a lesser degree, the Modified ESP Price is too high because it overstates the expected price during the Jan – May 2015 delivery period as I described earlier.

includes the current base generation rate, increased by the current EICCR rate and frozen for the duration of the Modified ESP delivery period. This charge plus a transmission adjustment[42] equals the "market comparable base g rate." The fuel rider is then added to the "market comparable base g rate" to obtain the Modified ESP Price.[43] The Modified ESP Price during the Jan – May 2015 delivery period will be equal to a CBP using $255/MW-day capacity.[44] However, Ms. Thomas' forecast of the Modified ESP Price for Jan – May 2015 shown in Exhibit LJT-1, p. 2 assumes capacity is supplied at $355/MW-day, even though the company intends to supply capacity at $255/MW-day.[45]

Q. HAVE YOU MADE ANY CHANGES TO THESE COMPONENTS OF THE MODIFIED ESP PRICE CALCULATED BY MR. ROUSH?

A. No. For the purposes of my analysis, I have accepted Mr. Roush's calculation of these components of the Modified ESP Price through December 2014. However, I have corrected the calculation of the Modified ESP Price for the Jan – May 2015

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[42] These include PJM administrative, scheduling, and certain ancillary service charges for a 12 month 2010/11 period that represent the types of charges that a competitive supplier would also incur. The charges included in the Modified ESP Price shown by Ms. Thomas are identified in Exhibit DMR-2.

[43] Modified ESP Testimony of David Roush on Behalf of AEP Ohio, at 11 and Exhibit DMR-2.

[44] Modified ESP Testimony of Robert Powers on Behalf of AEP Ohio, at 19-20

[45] In addition, in Exhibit LJT-5, Ms. Thomas' forecast of the Modified ESP Price during this delivery period assumes a blended capacity price using $355/MW-Day, $146/MW-Day, and $255/MW-Day, rather than the $255/MW-Day proposed by the Company.

delivery period to use a $255/MW-day capacity charge, thus reducing the Modified ESP Price.[46]

Although I accepted Mr. Roush's calculation of the Modified ESP Price for the purposes of my analysis, I did notice that Mr. Roush uses lower costs for the Fuel Factor and Transmission Adjustment in the Modified ESP than Ms. Thomas uses in the legacy ESP component of the MRO.[47] The use of lower charges in the Modified ESP than in the legacy ESP component of the MRO increases the alleged benefit of the Modified ESP by approximately $10 million.

Q. TURNING NOW TO THE INCLUSION OF THE NON-BYPASSABLE RIDERS, DO YOU AGREE WITH MS. THOMAS' ASSERTION THAT THE GRR SHOULD BE MODELED AS A ZERO-COST RIDER FOR PURPOSES OF THE MRO PRICE TEST?[48]

A. No. The GRR is a new generation-related rider specific to the Company's ESP application. It is not a rider that would be an element of an MRO. Therefore, it should be included in the Modified ESP Price but not the MRO Price.

Q. DID THE COMMISSION ADDRESS THIS ISSUE BEFORE IN ITS ORDER ON THE STIPULATION ESP?

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[46] In addition, I have modeled the prices for Jun – Dec 2014 and Jan – May 2015 separately, while AEP Ohio's analysis assumes the same price during both delivery periods.

[47] The Modified ESP Price developed by Mr. Roush uses the "Proposed" Fuel Factor and Transmission Adjustment charges shown in Exhibit DMR-2 while the legacy ESP component of the MRO uses the "Current" Fuel Factor and Transmission Adjustment charges shown in Exhibit DMR-2.

[48] Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, at 8, lines 11-18.

A. Yes. The Commission stated that a forecast of the GRR costs should be included in the MRO Price Test and that AEP Ohio erred in the Stipulation ESP's MRO Price Test by failing to include a forecast of the GRR costs.[49] Despite this fact, AEP Ohio has again failed to include a forecast of the GRR in the MRO Price Test. Although AEP Ohio filed supplemental testimony showing the forecasted costs to be included in the GRR due to the Turning Point Solar Project, Company witness Thomas continues to claim that the inclusion of these costs "does not change the zero impact of Rider GRR in Item 4 as shown in Exhibit LJT-1 Page 1."[50]

Q. HOW DOES MS. THOMAS TREAT THE PROPOSED RSR IN HER ANALYSIS?

A. Ms. Thomas includes the costs of the RSR in her Aggregate MRO Test shown in Exhibit LJT-1. I accept the quantitative analysis of the RSR, as calculated by AEP Ohio, and simply account for the identical costs in the MRO Price Test to better demonstrate their effect on the expected Modified ESP Price.

Ms. Thomas does not include the RSR costs in the two MRO Price Tests shown on Exhibit LJT-1, p. 2 or Exhibit LJT-5, p.1. In both cases, even if I accepted all of Ms. Thomas' other assumptions, which I do not, simply including

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[49] "We believe there are several material flaws in AEP-Ohio's testimony for determining whether the proposed ESP meets the statutory test. First, we believe Ms. Thomas erred by failing to include a cost for the GRR in her price comparison. As Staff witness Fortney testified, it is reasonable to include an estimated charge for the GRR, as AEP-Ohio has produced a revenue requirement for the Turning Point project, and AEP-Ohio has claimed the Turning Point project as a benefit of the proposed ESP." PUCO Opinion and Order, PUCO Case No. 11-346-EL-SSO et al., 12/14/2011, at 30.

[50] Supplemental Modified ESP Testimony of Laura Thomas on Behalf of AEP Ohio, at 2.

the Company's estimated RSR costs in the MRO Price Test would reverse the Company's conclusion and show that the expected price under the Modified ESP is not more favorable than the expected price under an MRO plan.

Q. WHAT CORRECTIONS DID YOU MAKE TO THE MODIFIED ESP PRICE TO ACCOUNT FOR THESE PROPOSED NON-BYPASSABLE, GENERATION-RELATED RIDERS?

A. Rather than assume that the GRR costs are zero, and in accordance with the recent Commission order in this case, I have included the GRR costs estimated by the Company in the Modified ESP Price. Similarly, with respect to the RSR, I have accepted AEP Ohio's forecasts of the relevant costs and simply incorporated these costs into the MRO Price Test. Finally, I did not include the PMR in the MRO Price Test (*i.e.*, I considered it be a $0 placeholder); however, I did develop an estimate of the financial impact of the PMR based on the Company's description of the potential charge.

Q. HOW DID YOU ESTIMATE THE GRR?

A. I accepted AEP Ohio's forecast of the Turning Point Solar Project's net costs.[51] For the purposes of comparing the Modified ESP to the expected results under an MRO, I assume that AEP Ohio will not seek recovery of the costs of any additional generation resources through the GRR for the duration of the Modified ESP. If AEP Ohio does seek to recover any additional costs through the GRR

[51] Supplemental Modified ESP Testimony of David Roush on Behalf of AEP Ohio, Exhibit DMR-8, at 1.

during the Modified ESP delivery period, then the Modified ESP Price would increase relative to the MRO Price. For purposes of comparison to an MRO, I have included in the Modified ESP Price a GRR of $0.00/MWH in June 2012 – May 2013, $0.05/MWH in June 2013 – May 2014, and $0.13/MWH in June 2014 – May 2015.

Q. DID YOU PREPARE AN ESTIMATE OF THE POTENTIAL POOL TERMINATION PROVISION COSTS?

A. Yes. If the Company's corporate separation plan is amended or denied, AEP Ohio could propose a new non-bypassable rider (which I refer to as the PMR) to recover "lost revenues as part of the move to competitive markets."[52] The PMR would recover the net difference between the revenues available to AEP Ohio as a member of the AEP Pool and the revenues available to AEP Ohio in the competitive market.

Q. HOW DID YOU ESTIMATE THE FINANCIAL IMPACT OF THE PMR?

A. AEP Ohio has provided a forecast of the capacity revenues available to it as a member of the AEP Pool through 2014.[53] Market prices for capacity are known through May 2015, and as a result it is also possible to estimate the market revenues available to AEP Ohio in the absence of the AEP Pool. I based my

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[52] Modified ESP Testimony of Philip Nelson on Behalf of AEP Ohio, at 22.

[53] Forecasted pool transfer prices for 2012-2014 were provided by AEP Ohio in AEP Ohio Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES 6th Set, INT-6-9 Attachment 1, "FES 6-009 Attachment 1." The average transfer price and monthly volumes from 2014 were extended through the first five months of 2015.

estimate of the total costs of pool termination on the difference between these two sources of revenue.[54] I also assumed that AEP Ohio would offset the lost capacity revenues with the associated incremental energy revenues as a result of pool termination.[55] This technique for estimating the costs of pool termination is similar to the methodology used by AEP in a study performed for the Indiana Utility Regulatory Commission.[56]

I estimated the financial impact of the PMR beginning on January 1, 2014 with calculation of the impact extending through May 31, 2015 and recovery of the PMR terminating with the end of Modified ESP on May 31, 2015.[57] Based on my analysis, the total potential impact of pool termination, net of offsetting increases in energy revenue, could be approximately $410 million over the Modified ESP delivery period.

Q. MR. SCHNITZER, DO YOU BELIEVE IT IS APPROPRIATE TO CONSIDER THE COSTS OF THE PMR IN THE AGGREGATE MRO TEST?

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[54] To the extent that AEP Ohio would seek to recover other costs associated with pool termination besides lost capacity revenues, the PMR costs could be even higher than what I include in my analysis.

[55] AEP Ohio Interrogatory Response, FES 17th Set, STIP-FES-INT-17-17-043(G).

[56] When AEP modeled the costs associated with the termination of the AEP Pool for a study conducted in Indiana, it assumed that replacement capacity prices were those available from PJM's RPM market. (Study Report of AEP Interconnection Agreement submitted by Indiana Michigan Power to the Indiana Utility Regulatory Commission, IURC Cause No. 43306, 12/11/2009, at 25-30.)

[57] Pool termination/modification is assumed to occur by January 1, 2014 based on the Modified ESP Testimony of Philip Nelson on Behalf of AEP Ohio, at 21. The losses were assumed to be calculated through May 31, 2015 and collection was assumed to occur through the end of the Modified ESP Period.

A. Yes. The pool termination provision is a part of the Modified ESP Plan and the PMR costs potentially could be significant. While I recognize that the magnitude of these costs could vary, simply ignoring the potential costs of the PMR altogether biases the comparison in favor of the Modified ESP. That is why I have developed an estimate of these costs for the Commission's consideration.

E. AEP Ohio "double counts" its alleged benefits and fails to fully consider the impact of its Modified ESP on customers that receive service from CRES providers

Q. PLEASE EXPLAIN THE PROPOSED CHARGES THAT WILL AFFECT SHOPPING CUSTOMERS.

A. AEP Ohio's Modified ESP includes a variety of non-bypassable charges and tiered capacity charges to CRES providers serving shopping customers.

Q. DOES THE MRO PRICE TEST PERFORMED BY MS. THOMAS ACCOUNT FOR THE FACT THAT SWITCHED LOAD WOULD PAY THESE ADDITIONAL CHARGES?

A. AEP Ohio's MRO Price Test shown in Exhibit LJT-1, p. 2 does not fully account for the inclusion of these charges. Ms. Thomas' analysis fails to consider the fact that under an MRO, non-bypassable charges such as the GRR (and potentially the PMR) would not be incurred by customers. Ms. Thomas does include the estimated costs of the RSR in her Aggregate MRO Test shown in Exhibit LJT-1, p. 1, but does not include these costs in the MRO Price Test shown on Exhibit LJT-1, p. 2 or Exhibit LJT-5. In addition, Ms. Thomas' analysis fails to consider that the above-market capacity charges imposed on switched load in the Modified ESP may not be available to AEP Ohio under an MRO.

In fact, Ms. Thomas' lack of clearly distinguishing the financial impacts on retained customers versus shopping customers has resulted in a significant flaw in her analysis shown in the Aggregate MRO Test in Exhibit LJT-1, p. 1.

Q. PLEASE EXPLAIN THE SIGNIFICANT FLAW IN THE AGGREGATE MRO TEST SHOWN IN EXHIBIT LJT-1.

A. Even if one accepts all of the Company's assumptions and analysis, which I do not, it appears that the Company has "double counted" its alleged benefits in Exhibit LJT-1, p.1. Line 1 of the Exhibit shows the Company's results of the MRO Price Test, whereby the Company claims that SSO customers receive the price benefit of the Modified ESP. Ms. Thomas refers to Exhibit LJT-1, page 3, as the source for the $256 million in claimed benefits. However, page 3 of this Exhibit clearly shows that the $256 million figure is based on total "Connected Load" or system load. Obviously, only customers that remain on SSO service would receive the alleged benefit of the SSO price. In effect, Ms. Thomas' MRO Price Test assumes zero percent shopping. At the same time, line 2 of Exhibit LJT-1, p.1 shows the alleged discounted capacity benefit of $989 million. AEP Ohio witness Allen calculates this alleged benefit to CRES providers based on the Company's estimated shopping load (which is about 68% of the load on average over the ESP period). It is not possible that customer load assumed to be shopping could receive the alleged benefit of "discounted, tiered capacity pricing for CRES providers" as shown in line 2 of the Aggregate MRO Test, <u>and at the same time</u>, receive the alleged benefit of a lower ESP price. By not clearly distinguishing the financial impacts on shopped versus retained customers, Ms. Thomas significantly "double counts" the alleged benefits in her Aggregate MRO Test. As a result, even if one were to accept AEP Ohio's analysis, which I do not, the Modified ESP Benefit of $1.77/MWH that Ms. Thomas calculates on page 2 of Exhibit LJT-1 should only be applied to retained SSO load. In other words, the $256 million figure in Ms. Thomas' Exhibit LJT-1 p. 1 and 3 is significantly overstated and, when corrected to reflect the Company's retained load assumptions, should be only about $80 million before accounting for the other corrections that I have described.

Q. WHAT CORRECTIONS HAVE YOU MADE TO ACCOUNT FOR THE FACT THAT SWITCHED LOAD WOULD HAVE TO PAY THE NON-BYPASSABLE GRR UNDER THE MODIFIED ESP?

A. Because the GRR is a new non-bypassable rider included as a component of the Modified ESP filed with the Commission, and would not be available to AEP Ohio under an MRO, I have included the total costs of this rider in my calculation of the expected costs under the Modified ESP. I do not include any costs resulting from this rider in my calculation of the expected costs under an MRO. This treatment is similar to Ms. Thomas' treatment of the non-bypassable RSR.

Q. WHAT CORRECTIONS HAVE YOU MADE TO ACCOUNT FOR THE FACT THAT CRES PROVIDERS WOULD BE CHARGED THE

PROPOSED TIERED CAPACITY CHARGES UNDER THE MODIFIED ESP?

A. AEP Ohio's Modified ESP requests Commission approval of the right to charge tiered capacity charges that are above-market to CRES providers serving shopping customers. In the absence of Commission approval of AEP Ohio's Modified ESP, the rates AEP Ohio charges CRES providers serving shopping customers would be determined by the outcome of the 10-2929 Capacity Case. In order to more accurately model the expected costs of the Modified ESP, I have quantified the cost to shopping customers of these above-market charges using AEP Ohio's forecast of switching. In order to estimate the total costs expected under an MRO, I have modeled a range of capacity costs for switched load that is intended to represent the range of reasonable outcomes in the 10-2929 Capacity Case. My base case assumes that AEP Ohio is allowed to charge CRES providers RPM rates, per the state compensation mechanism currently scheduled to be in place beginning June 1, 2012.[58] In this case, using AEP Ohio's forecast of customer switching, its Modified ESP would cost shopping customers about $875 million in above-market capacity costs that would not be incurred under an MRO.[59]

As a sensitivity scenario, I also show the expected costs under an MRO assuming AEP Ohio is allowed to charge CRES providers the identical capacity charges that it requested in the Modified ESP (*i.e.*, there is no difference between

[58] PUCO Entry Order, Case No. 10-2929-EL-UNC, 3/7/2012, at 17.

[59] This assumes that CRES providers would pass the capacity costs onto customers they serve.

the capacity charges billed to CRES providers in the Modified ESP and under the MRO).[60]

F. Under reasonable assumptions, the Modified ESP Price would not be more favorable than the MRO Price, resulting in excess costs to the AEP Ohio zone ranging from $400 million to $1.3 billion

Q. DID YOU CORRECT THE PRICE COMPARISON SHOWN IN EXHIBIT LJT-1?

A. Yes. I used a similar methodology as Ms. Thomas to blend the corrected CBP and the Total Generation Service Price to derive a corrected MRO Price. The corrected MRO Price was then compared with the corrected Modified ESP Price, taking into account all charges to the AEP Ohio zone. Based on my analysis, the Modified ESP would result in excess costs to the AEP Ohio zone as compared to an MRO under a wide range of reasonable assumptions – ranging from $400 million to $1.3 billion.[61] The difference in the two figures depends on the expected outcome of the 10-2929 Capacity Case under an MRO. The $1.3 billion figure is based on AEP Ohio being required to set capacity charges at RPM for CRES providers serving shopping customers under an MRO. The $400 million figure is based on AEP Ohio being allowed to charge tiered above-market capacity charges for CRES providers serving shopping customers in the MRO identical to those proposed in

[60] If the Commission were to permit AEP Ohio to continue to charge the interim rates that are in place today and currently scheduled to expire, this scenario would fall within the range of possible outcomes that I analyzed, as shown in Exhibit MMS-4, at 2.

[61] Neither of these figures includes any costs related to the Pool Termination Provision, which as I estimate, could increase costs to customers by about $410 million. If I were to include the PMR costs, the Modified ESP would result in excess costs to the AEP Ohio zone as compared to an MRO by $800 million to $1.7 billion.

the Modified ESP.[62] In both instances, the Modified ESP fails the MRO Price Test.

The corrected MRO Price Test results are summarized in Exhibit MMS-4. This conclusion corrects the summary that Ms. Thomas shows in the Aggregate MRO Test shown in Exhibit LJT-1, p.1. In addition to correcting the MRO Price Test, I have eliminated the Company's alleged "benefit" of offering discounted capacity as ordered by the Commission, and I have incorporated the financial costs of the RSR into my MRO Price Test. Thus, correcting Ms. Thomas' errors leads to the opposite conclusion: the Modified ESP Price is <u>not</u> more favorable than the expected price under an MRO. This remains true under a wide range of assumptions.[63]

V. <u>The Modified ESP Is About $670 Million Worse For Customers Than The Stipulation ESP That Was Ultimately Rejected By The Commission</u>

Q. HOW DOES THE MODIFIED ESP COMPARE TO THE STIPULATION ESP THAT WAS ULTIMATELY REJECTED BY THE COMMISSION?

A. The Modified ESP is in many respects worse for customers than the Stipulation ESP that was ultimately rejected by the Commission. The Modified ESP imposes new costs on Tier 1 and Tier 2 customers that shop with CRES providers. At the

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[62] For purposes of my analysis, I have assumed that the size of the Tier 1 capacity allotments is identical in the MRO (as determined by the outcome of the 10-2929 Capacity Case) and in the Modified ESP. To the extent that the Commission requires additional Tier 1 capacity allotments relative to the size proposed in the Modified ESP, this would increase the relative costs of the Modified ESP as compared to the MRO.

[63] I have not included the impact of the Distribution Investment Rider in my analysis. To the extent that this rider would result in additional costs beyond what would be recovered in an MRO, this would increase the costs of the Modified ESP.

same time, the Modified ESP also imposes additional costs on SSO customers that remain with AEP Ohio. Finally, the Modified ESP includes other provisions that are less favorable than the Stipulation ESP. Each of these is addressed in turn in this section of my testimony.

A. <u>The Modified ESP harms shopping customers by approximately $555 million – increasing capacity costs to CRES providers serving Tier 1 customers, reducing the size of Tier 1 capacity allotments, and imposing new RSR costs on Tier 1 and Tier 2 customers</u>

Q. HOW DOES THE MODIFIED ESP AFFECT CUSTOMERS THAT SHOP?

A. The Modified ESP will increase the rates charged to customers that shop by increasing the Tier 1 capacity charge ($146/MW-day instead of RPM prices) and by imposing a new non-bypassable RSR.[64] These new charges will increase costs by an additional $555 million based on assumptions provided in the Company's own analysis.

Q. WHAT WOULD BE THE FINANCIAL IMPACT ON TIER 1 CUSTOMERS?

A. The Modified ESP would increase the cost of Tier 1 capacity from RPM to $146/MW-day. The higher capacity charge increases the costs to serve Tier 1 customers by about $250 million over the three-year period. In addition, due to the

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[64] As described later, the Modified ESP makes certain changes in customer eligibility to receive Tier 1 capacity allotments, which would reduce the quantity of Tier 1 capacity available to shopping customers. CRES providers serving these customers would have been charged RPM prices under the Stipulation ESP, but under the Modified ESP, would have to pay the Tier 2 capacity charge of $255/MW-day under the Modified ESP.

increased restrictions on aggregation load's ability to receive Tier 1 capacity, approximately 7 TWH of load which was eligible for Tier 1 capacity at RPM charges under the Stipulation ESP will receive Tier 2 capacity under the Modified ESP at $255/MW-day.[65] This portion of aggregation load will pay approximately $110 million in increased costs due to the Modified ESP. Finally, Tier 1 customers would also pay the new RSR charge, adding another $100 million of costs. In total, these customers would be responsible for paying approximately $460 million more under the Modified ESP than under the Stipulation ESP, holding all else constant.

Q. WHAT WOULD BE THE FINANCIAL IMPACT ON TIER 2 CUSTOMERS?

A. As compared to the Stipulation ESP, AEP Ohio's proposed capacity charge of $255/MW-day is unchanged for CRES providers serving Tier 2 customers. However, Tier 2 customers would incur the costs associated with the new non-bypassable RSR in the Modified ESP. Based on the Company's shopping assumptions, these new costs would total approximately $95 million over the Modified ESP period.

[65] Under the Stipulation ESP, all governmental aggregation load, including mercantile load, would receive Tier 1 capacity allotments (*i.e.*, RPM prices) without counting toward the 21% allocation in 2012, and the capacity allotments in later years would be expanded to the extent necessary to accommodate this load. Under the Modified ESP, governmental aggregation load is counted towards the 21% allocation of Tier 1 capacity, and once Tier 1 is fully subscribed only non-mercantile aggregation load is eligible to receive additional Tier 1 capacity in 2012. Thus, the Modified ESP effectively reduces the overall size of the Tier 1 allocation and separately introduces new restrictions on the ability of mercantile aggregation load to receive Tier 1 capacity.

B. <u>The Modified ESP increases rates for SSO customers by approximately $105 million</u>

Q. AS COMPARED TO THE STIPULATION ESP, WHAT WOULD BE THE FINANCIAL IMPACT OF CHANGES TO GENERATION RATES FOR SSO CUSTOMERS

A. The Modified ESP would result in higher costs for SSO customers as compared to the Stipulation ESP. Rates are expected to be $2.3/MWH higher under the Modified ESP than the Stipulation ESP, resulting in almost $105 million in increased charges to retained load. Over 85% of this increase in rates is attributable to the new non-bypassable RSR in the Modified ESP.

The remaining increase is due to two offsetting effects. On one side, the Company has lowered the "Current Base ESP 'g' Rate" slightly and held it flat rather than have it increase over time as in the Stipulation ESP. The Company claims this as a benefit of the Modified ESP. However, this change is more than offset by the increase in costs due to the Company's proposal to charge SSO customers $255/MW-day for capacity when it uses a competitive procurement process to obtain energy for 100% of retained load beginning January 1, 2015 through May 31, 2015. Using the Company's market price assumptions and models, SSO customers actually would pay more under the Modified ESP than under the earlier Stipulation ESP during the June 2012 – May 2015 delivery period. When considered together, these two effects result in a net cost to SSO customers.

C. <u>In addition, the Modified ESP imposes about $10 million of additional costs on customers as compared to the Stipulation ESP</u>

Q. ARE THERE OTHER COSTS TO CUSTOMERS INCLUDED IN THE MODIFIED ESP THAT WERE NOT APPLICABLE UNDER THE STIPULATION ESP?

A. Yes. The Modified ESP includes additional net costs that would not have been applied under the Stipulation ESP. First, it eliminates the grants to the Partnership with Ohio initiative ($9 million). Second, it eliminates the Ohio Growth Fund ($15 million), and third, there is an offsetting reduction in costs due to the elimination of the Market Transition Rider ($14 million). Therefore, when all of these items are considered together, the Modified ESP includes additional net costs (or removal of benefits) totaling about $10 million that would not have been applied under the Stipulation ESP.

Furthermore, the provisions related to the Pool Modification Rider have been adjusted. Under the Stipulation ESP, customers were shielded from the first $50 million of costs related to pool modification or termination. Additionally, if costs exceeded $50 million, AEP Ohio was not able to seek recovery of the first $50 million in costs. However, under the Modified ESP, customers will be insulated only from the first $35 million in costs related to pool modification or termination.

Q. PLEASE SUMMARIZE YOUR FINDINGS REGARDING THIS COMPARISON.

A. Altogether, the total generation revenues collected by AEP Ohio under the Modified ESP exceed those included in the Stipulation ESP. Between the higher Tier 1 capacity charges, the new RSR, and the increased generation rates for retained SSO customers, AEP Ohio has requested about $660 million in new generation charges, as compared to the generation charges requested under the Stipulation ESP. In addition, AEP Ohio is taking away $10 million of other previously offered benefits from customers included in the Stipulation ESP but not included in the Modified ESP. Therefore, AEP Ohio's Modified ESP is substantially worse for customers than the Stipulation ESP, as summarized in the table below.

The Modified ESP is About $670 Million Worse than the Stipulation ESP

(June 1, 2012 – May 31, 2015)

	Increase in Charges in Modified ESP
	$MM
Tier 1 Customers	
Increase in capacity charge	248
Reduction in Tier 1 allotment	112
New RSR charge	99
Subtotal	459
Tier 2 Customers	
New RSR charge	95
SSO Customers	
Net increase in Base G Rate	14
New RSR charge	90
Subtotal	104
Total Increase in Generation Charges	
Increase in capacity charge	360
New RSR charge	284
Net increase in Base G Rate	14
Subtotal	659
Other Modified ESP Changes:	
Elimination of grants to Partnership with Ohio	9
Elimination of Ohio Growth Fund	15
Less elimination of MTR	-14
Subtotal	10
Total Impact	**669**

Note: Total dollars are based on AEP Ohio's switching assumptions.

VI. If Approved, The Modified ESP Also Will Impede The Development Of A Robust Competitive Retail Market

Q. HOW WILL THE MODIFIED ESP IMPEDE THE DEVELOPMENT OF A ROBUST COMPETITIVE RETAIL MARKET?

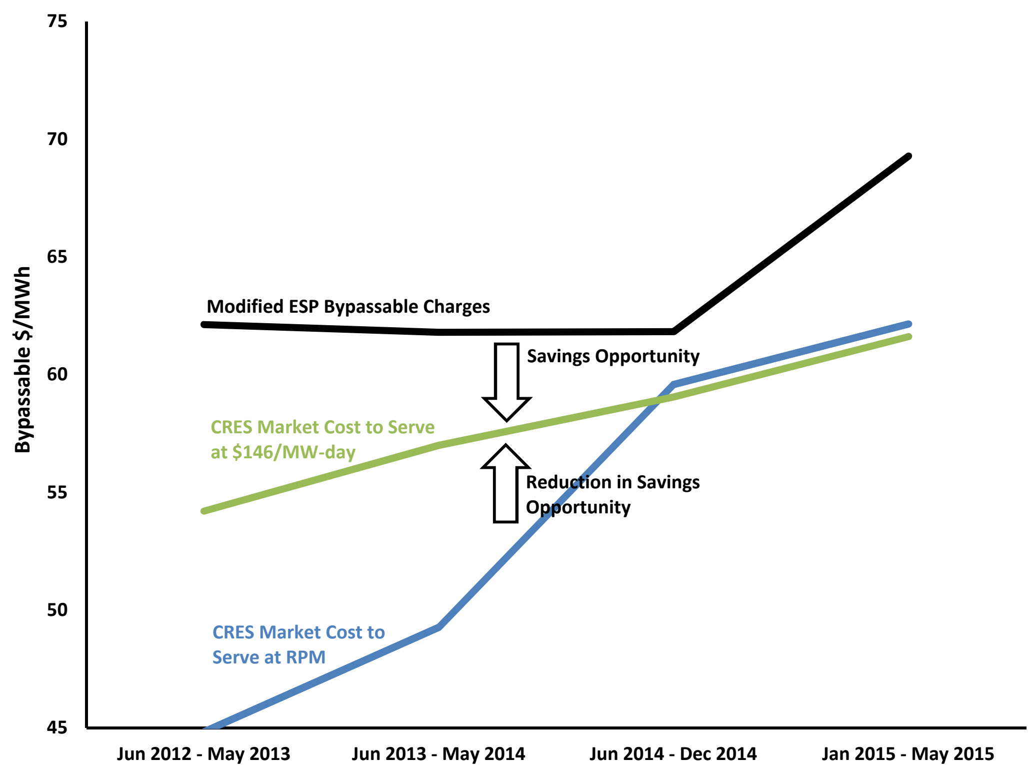
A. The Modified ESP contains tiered above-market capacity charges to CRES providers that could limit CRES providers' ability to offer savings and will reduce the level of savings they can offer to customers in AEP Ohio's service area. Furthermore, the tiered capacity structure will result in customers paying different prices for otherwise identical service.

A. The above-market capacity charges to CRES providers under the Modified ESP will limit CRES providers' ability to offer savings and will reduce the level of savings they can offer to shopping customers

Q. BASED ON CURRENT MARKET PRICE EXPECTATIONS, WILL TIER 1 CUSTOMERS BE ABLE TO SHOP FOR ELECTRICITY?

A. Yes. The chart below compares the generation-related bypassable charges in the Modified ESP Price (*i.e.*, the "Market Comparable Base g" rate plus the "Current Fuel Factor") with the market cost to serve customers when a) RPM capacity prices are available to CRES providers, as proposed in the Stipulation ESP, and b) with the $146/MW-day Tier 1 capacity charge in the Modified ESP. As can be seen from the chart, the Modified ESP bypassable charges significantly exceed the CRES market cost to serve when RPM capacity prices are available to CRES providers. This "headroom" represents a potential savings opportunity for customers if they could fully access competitive market pricing.[66] Under the Modified ESP, the higher capacity charge would reduce this savings opportunity for customers by approximately $250 million or $5/MWH over the three-year period. As shown below, despite the higher Tier 1 capacity charge, headroom would still exist for these customers, suggesting that Tier 1 customers will still have an opportunity to shop.

Customers See a Lower Benefit from Retail Shopping When Tier 1 Capacity is Charged to CRES Providers



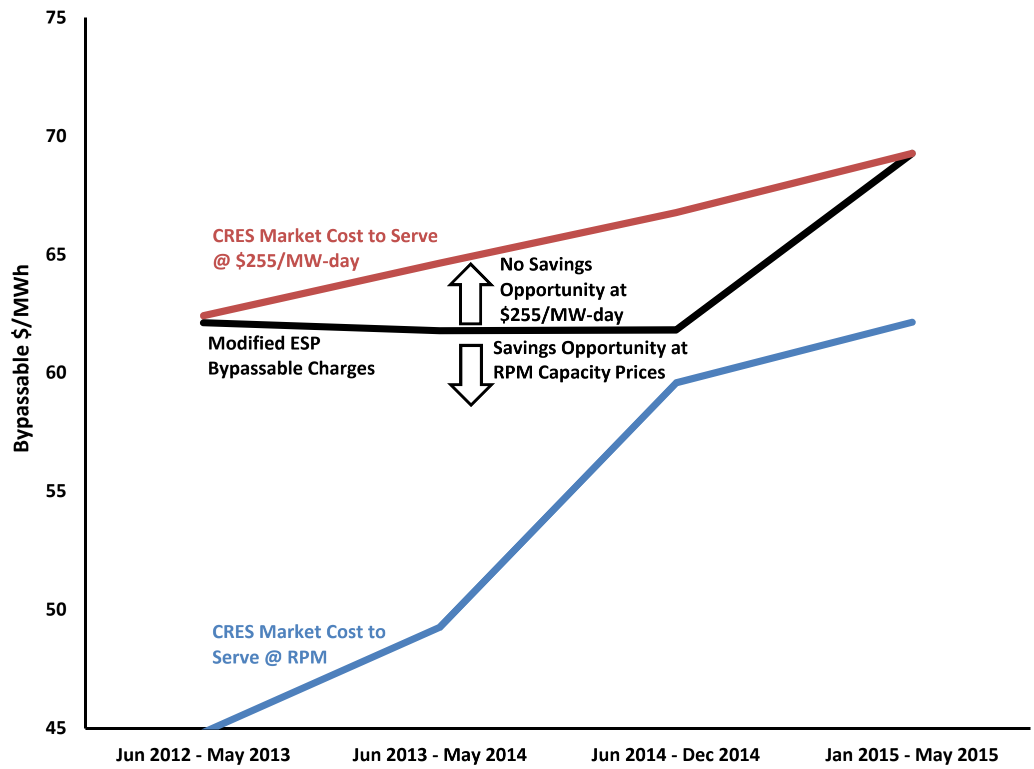
[66] This savings opportunity has increased since the Stipulation ESP was approved due to the decline in market prices.

Q. MR. SCHNITZER, WHAT ARE THE PROSPECTS FOR TIER 2 CUSTOMERS TO SHOP FOR ELECTRICITY?

A. AEP Ohio's outlook for shopping opportunities has changed considerably for Tier 2 customers. In the Stipulation ESP, the Company assumed switching levels up to the Tier 1 percentage levels. In other words, the Company assumed that Tier 2 customers would not shop with a CRES provider, and, as a result, no customers would pay the above-market capacity charge. In the Modified ESP, the Company assumes much higher levels of customer shopping (approximately 68% of the total load on average over the three-year period). This implies significant shopping among Tier 2 customers. In fact, based on the Company's updated switching assumptions, the Tier 2 capacity charge would result in approximately $630 million or $13/MWH in above-market charges over the three-year period.

Although the recent decline in market prices has improved the prospects for customer shopping since the Stipulation ESP was initially approved, the Modified ESP Tier 2 capacity charge of $255/MW-day would result in negative headroom according to AEP Ohio's price forecasts. Therefore, there is little opportunity for customers to shop with a CRES supplier at the Tier 2 capacity charge because the bypassable generation charges in the Modified ESP are below the costs that a CRES supplier would have to incur when faced with paying AEP Ohio's above-market $255 per MW-day capacity charge.

The Modified ESP Would Limit Retail Competition When CRES Suppliers Have to Pay AEP Ohio's Above-Market $255/MW-Day Capacity Charge



As a result, the Modified ESP is likely to limit the opportunity for Tier 2 customers to shop, especially as the headroom becomes more negative over time. This analysis was performed using the Company's own estimates of bypassable charges versus the competitive market price assuming a $255/MW-day capacity charge. Thus, the Company's projected shopping assumptions appear to be inconsistent with the underlying Modified ESP Price and market price estimates.

Q. GIVEN THIS INCONSISTENCY, WHAT DID YOU ASSUME IN YOUR EARLIER ANALYSIS WHEN COMPARING THE MRO TO THE MODIFIED ESP?

A. For purposes of comparison, I adopted the Company's projected shopping estimates in the MRO Price Test. But as a sensitivity case, I also conducted the MRO Price Test assuming that no Tier 2 customers shopped for electricity, and only Tier 1 customers were able to shop. Under this scenario, the Modified ESP still would result in excess costs to the AEP Ohio zone as compared to an MRO under a wide range of reasonable assumptions – ranging from $330 million to as much as $580 million.

B. <u>The tiered structure of above-market capacity charges will lead to the creation of two classes of customer who pay different rates for otherwise identical service</u>

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE PROPOSED TIERED CAPACITY STRUCTURE?

A. Yes, due to this tiered capacity structure, similarly situated customers with the same consumption characteristics could face discriminatory treatment in terms of shopping opportunities and pricing. In the prior Stipulation, the Company assumed that Tier 1 customers were able to shop, while Tier 2 customers were not expected to shop. Thus, there were effectively two types of customers – SSO customers and Tier 1 shopping customers at RPM capacity charges. Based on the Company's current shopping assumptions, there are now three types of customers: retained SSO customers, Tier 1 shopping customers at $146/MW-day, and Tier 2 customers at $255/MW-day. As a policy matter, it is not clear why two customers with identical consumption characteristics – one who is classified as a Tier 1 customer and the other who is classified as a Tier 2 customer – should be exposed to very different sets of charges.

Q. MR. SCHNITZER, IS THERE A WAY FOR THE COMMISSION TO ADDRESS BOTH ISSUES THAT YOU HAVE RAISED REGARDING THE MODIFIED ESP – NAMELY, THE INCREMENTAL COSTS AS COMPARED TO THE STIPULATION ESP AND THE IMPEDIMENTS TO THE DEVELOPMENT OF A ROBUST COMPETITIVE RETAIL MARKET?

A. Yes, the Commission could address both of these issues simultaneously by taking the following steps. First, it could eliminate the tiered capacity structure and lower the level of the proposed capacity charges to RPM levels. Eliminating the tiered capacity structure (*i.e.*, having the same capacity charge for Tier 1 and Tier 2 customers) would remove the complication and controversy of having to track Tier 1 and Tier 2 customers and would avoid the potential for discriminatory pricing for similarly situated customers that want to shop with a CRES provider. Plus it would have the added benefit of simplifying the administration of the retail access program. Meanwhile, lowering the capacity charges to RPM levels would better support the development of a robust competitive retail market by increasing the savings opportunity to customers that shop. Second, at the same time that the Commission lowers the capacity charge revenues, the Commission could also eliminate the RSR.[67] If AEP Ohio were required to make capacity available to CRES providers at RPM prices for all shopping customers, the lower capacity charges would save shopping customers approximately $875 million in above-market costs for capacity as compared to the Modified ESP based on the Company's switching estimates. This change, when coupled with the elimination of the RSR,[68] would more than offset the requested increase in revenues as compared to the Stipulation ESP. In this case, all customers would be able to access competitive market prices (both energy and capacity) and have an opportunity shop.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD AT THIS TIME?

A. Yes. I would like to mention that the discovery responses that I relied on in my testimony are attached as Exhibit MMS-5.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

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[67] According to the methodology the Company has proposed to adjust the RSR, any decrease in capacity revenues that results from lowering AEP Ohio capacity charges to CRES providers would be recovered with an offsetting increase in the RSR. Thus, if the Commission wants to limit AEP Ohio's cost recovery, lowering the Tier 1 and Tier 2 capacity charges would not be sufficient.

[68] The elimination of the RSR would save $284 million for all customers according to the Company's estimates.

Michael M. Schnitzer, Director

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Concord, MA 017742

Michael Schnitzer is a Director of The NorthBridge Group. He has over 25 years of experience in management consulting to clients in energy industries, with a primary focus on the electricity industry. Working with utility and non-utility clients, he has developed initiatives in strategy, marketing, pricing, regulatory relations, and generation investment. He also has broad experience in the transition to competitive wholesale and retail electricity markets and has developed and evaluated numerous electricity restructuring proposals.

Mr. Schnitzer has been an expert witness in a number of regulatory proceedings involving electric industry restructuring, utility supply planning, and environmental issues. He has testified before the Federal Energy Regulatory Commission on issues relating to competitive restructuring and wholesale market design, including Locational Marginal Pricing and Financial Transmission Rights, Regional Transmission Organizations, standard market design, resource adequacy, and transmission expansion pricing policy. On several occasions he has been invited by FERC staff to participate as a panelist in technical conferences on market design issues. Mr. Schnitzer has also testified before several state commissions and departments on the subject of provision of default service to retail customers, including evaluation of competitive procurement proposals.

He is a former adjunct research fellow at the Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University. Before joining NorthBridge, Mr. Schnitzer was a Managing Director at Putnam, Hayes & Bartlett, Inc., where he co-directed the firm's regulated industry practice.

Mr. Schnitzer received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

Exhibit MMS-2: Corrections to the June 2012 - May 2015 Competitive Benchmark Price (Expected Bid Price)

	Col. 1	*Col. 2*	*Col. 3*	*Col. 4 = Blend of Cols. 1, 2, and 3*	*Col. 5*	*Col. 6 = 5 - 1*	*Col. 7 = 5 - 4*	
($/MWh)	**Thomas "Full Cost" CBP (Used in LJT-1, p. 2)**	**Thomas Tier 1 CBP**	**Thomas Tier 2 CBP**	**Thomas Blended CBP (Used in LJT-5, p. 1)**	**Corrected CBP (RPM)**	**Total Corrections to CBP in LJT-1, p. 2**	**Total Corrections to CBP in LJT-5, p. 1**	**Corrections**
Simple Swap	35.26	35.26	35.26	35.26	35.02	-0.24	-0.24	Due to load-weighting differences [1]
Basis Adjustment	0.49	0.49	0.49	0.49	0.49	0.00	0.00	
Load Following/Shaping Adjustment	3.48	2.41	2.95	2.92	2.10	-1.38	-0.82	Primarily a "ripple effect" due to the change in capacity prices
Capacity	21.97	9.01	15.75	15.14	4.01	-17.96	-11.13	LJT uses above-market capacity prices instead of RPM capacity
Ancillary Services	0.85	0.85	0.85	0.85	0.85	0.00	0.00	
Alternative Energy Requirement	0.72	0.72	0.72	0.72	0.71	-0.02	-0.02	Due to load-weighting differences [1]
ARR Credit	-1.14	-1.14	-1.14	-1.14	-1.16	-0.03	-0.03	Due to load-weighting differences [1]
Losses	1.55	1.49	1.52	1.52	1.52	-0.03	0.00	
Transaction Risk Adder	3.41	2.70	3.07	3.04	2.43	-0.98	-0.61	Primarily a "ripple effect" due to the change in capacity prices
Retail Administration	5.00	5.00	5.00	5.00	5.00	0.00	0.00	
Total	**71.60**	**56.79**	**64.48**	**63.80**	**50.96**	**-20.63**	**-12.84**	

Note: AEP Ohio weights the Competitive Benchmark Price over time and across customer classes (Residential, Commercial, and Industrial) using system loads rather than retained loads. Because the CBP would apply only to the retained load served under an MRO, the corrected numbers are weighted by retained loads.

Exhibit MMS-3: Corrections to the Modified ESP Price

($/MWh)	Jun 2012 - May 2013	Jun 2013 - May 2014	Jun 2014 - Dec 2014	Jan 2015 - May 2015	Load-Wtd Avg	Corrections
Modified ESP Price Estimate Used by AEP Ohio						
Base Generation Rate	22.86	22.86	22.89	NA		
Transmission Adjustment	2.91	2.91	2.91	NA		
Market Comparable Base 'g' Rate	25.77	25.77	25.80	74.34		
AEP Ohio Estimate of 2011 Full Fuel	36.35	36.02	36.02	NA		
AEP Ohio Estimated Modified ESP Price	**62.12**	**61.79**	**61.82**	**74.34**	**63.62**	
Corrected Modified ESP Price						
Base Generation Rate	22.86	22.86	22.89	NA		None
Transmission Adjustment	2.91	2.91	2.91	NA		None
Market Comparable Base 'g' Rate	25.77	25.77	25.80	69.27		Jan 2015 - May 2015 price changed to reflect $255/MW-day capacity
Current Fuel Factor	36.35	36.02	36.02	NA		None
Estimate of GRR	0.00	0.05	0.11	0.15		Estimate of GRR costs based on Company forecasts
Estimate of Retail Stability Rider	1.96	1.96	1.96	1.96		RSR included in Modified ESP Price
Corrected Modified ESP Price	**64.08**	**63.80**	**63.90**	**71.39**	**64.87**	
Total Corrections to Modified ESP Price	**1.96**	**2.01**	**2.08**	**-2.95**	$\boxed{\textbf{1.26}}$	

Exhibit MMS-4: MRO Price Test for the Modified ESP

(MRO Capacity for Switched Load: Tier 1 at RPM and Tier 2 at RPM)

($/MWh except where noted)	Jun 2012 - May 2013	Jun 2013 - May 2014	Jun 2014 - Dec 2014	Jan 2015 - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.26	21.26	21.28	21.22	21.26
Transmission Adjustment	2.95	2.95	2.95	2.94	2.95
Current EICCR	1.60	1.60	1.61	1.60	1.60
Market Comparable Base 'g' Rate	25.81	25.81	25.84	25.76	25.81
Current Fuel Factor	36.35	36.36	36.39	36.32	36.36
Total Generation Service Price	62.16	62.17	62.23	62.08	62.17
Generation Service Price Weight	90%	80%	70%	70%	
Competitive Benchmark Price					
Simple Swap	32.68	35.34	36.54	39.46	35.02
Capacity (RPM)	1.30	2.07	9.45	9.54	4.01
Other	10.84	11.85	13.59	13.14	11.93
Competitive Benchmark Price	44.83	49.27	59.58	62.15	50.96
CBP Weight	10%	20%	30%	30%	
Estimate of MRO Price	**60.43**	**59.59**	**61.44**	**62.10**	**60.56**
Modified ESP Price					
Modified ESP					
Tariff Generation Price	22.86	22.86	22.89	NA	
Transmission Adjustment	2.91	2.91	2.91	NA	
Market Comparable Base 'g' Rate	25.77	25.77	25.80	69.27	
Current Fuel Factor	36.35	36.02	36.02	NA	
GRR	0.00	0.05	0.11	0.15	0.06
Retail Stability Rider ("RSR")	1.96	1.96	1.96	1.96	1.96
Estimate of Modified ESP Price	**64.08**	**63.80**	**63.90**	**71.39**	**64.87**
Total Above-MRO Charges					
Average AEP Ohio Zone Price Under MRO	50.54	52.08	59.73	61.90	54.41
Average AEP Ohio Zone Price Under ESP	61.42	62.73	63.79	67.96	63.22
AEP Zone ESP Price Benefit	**-10.88**	**-10.65**	**-4.06**	**-6.05**	**-8.80**
Estimate of Total Charges Under ESP ($MM)	2,960	3,027	1,814	1,341	9,143
Estimate of Total Charges Under MRO ($MM)	2,436	2,513	1,698	1,222	7,870
Excess Costs Charged Under ESP ($MM)	**524**	**514**	**115**	**120**	**1,273**
Above-MRO Costs of Bypassable Generation Rates ($MM	30	30	3	41	105
Above-MRO Costs of Tier 1 Capacity ($MM)	130	128	-6	-4	248
Above-MRO Costs of Tier 2 Capacity ($MM)	269	258	59	41	628
Above-MRO Costs of GRR ($MM)	0	2	3	3	8
Above-MRO Costs of RSR ($MM)	95	95	56	39	284
Excess Costs Charged Under ESP ($MM)	**524**	**514**	**115**	**120**	**1,273**

Exhibit MMS-4: MRO Price Test for the Modified ESP

(MRO Capacity for Switched Load: Tier 1 at RPM and Tier 2 at $255/MW-Day)

($/MWh except where noted)	Jun 2012 - May 2013	Jun 2013 - May 2014	Jun 2014 - Dec 2014	Jan 2015 - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.26	21.26	21.28	21.22	21.26
Transmission Adjustment	2.95	2.95	2.95	2.94	2.95
Current EICCR	1.60	1.60	1.61	1.60	1.60
Market Comparable Base 'g' Rate	25.81	25.81	25.84	25.76	25.81
Current Fuel Factor	36.35	36.36	36.39	36.32	36.36
Total Generation Service Price	62.16	62.17	62.23	62.08	62.17
Generation Service Price Weight	90%	80%	70%	70%	
Competitive Benchmark Price					
Simple Swap	32.68	35.34	36.54	39.46	35.02
Capacity (RPM)	1.30	2.07	9.45	9.54	4.01
Other	10.84	11.85	13.59	13.14	11.93
Competitive Benchmark Price	44.83	49.27	59.58	62.15	50.96
CBP Weight	10%	20%	30%	30%	
Estimate of MRO Price	**60.43**	**59.59**	**61.44**	**62.10**	**60.56**
Modified ESP Price					
Modified ESP					
Tariff Generation Price	22.86	22.86	22.89	NA	
Transmission Adjustment	2.91	2.91	2.91	NA	
Market Comparable Base 'g' Rate	25.77	25.77	25.80	69.27	
Current Fuel Factor	36.35	36.02	36.02	NA	
GRR	0.00	0.05	0.11	0.15	0.06
Retail Stability Rider ("RSR")	1.96	1.96	1.96	1.96	1.96
Estimate of Modified ESP Price	**64.08**	**63.80**	**63.90**	**71.39**	**64.87**
Total Above-MRO Charges					
Average AEP Ohio Zone Price Under MRO	56.12	57.43	61.82	64.00	58.75
Average AEP Ohio Zone Price Under ESP	61.42	62.73	63.79	67.96	63.22
AEP Zone ESP Price Benefit	**-5.30**	**-5.30**	**-1.97**	**-3.96**	**-4.46**
Estimate of Total Charges Under ESP ($MM)	2,960	3,027	1,814	1,341	9,143
Estimate of Total Charges Under MRO ($MM)	2,705	2,772	1,758	1,263	8,497
Excess Costs Charged Under ESP ($MM)	**255**	**256**	**56**	**78**	**645**
Above-MRO Costs of Bypassable Generation Rates ($MM	30	30	3	41	105
Above-MRO Costs of Tier 1 Capacity ($MM)	130	128	-6	-4	248
Above-MRO Costs of Tier 2 Capacity ($MM)	0	0	0	0	0
Above-MRO Costs of GRR ($MM)	0	2	3	3	8
Above-MRO Costs of RSR ($MM)	95	95	56	39	284
Excess Costs Charged Under ESP ($MM)	**255**	**256**	**56**	**78**	**645**

Exhibit MMS-4: MRO Price Test for the Modified ESP

(MRO Capacity for Switched Load: Tier 1 at $146/MW-Day and Tier 2 at $255/MW-Day)

($/MWh except where noted)	Jun 2012 - May 2013	Jun 2013 - May 2014	Jun 2014 - Dec 2014	Jan 2015 - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.26	21.26	21.28	21.22	21.26
Transmission Adjustment	2.95	2.95	2.95	2.94	2.95
Current EICCR	1.60	1.60	1.61	1.60	1.60
Market Comparable Base 'g' Rate	25.81	25.81	25.84	25.76	25.81
Current Fuel Factor	36.35	36.36	36.39	36.32	36.36
Total Generation Service Price	62.16	62.17	62.23	62.08	62.17
Generation Service Price Weight	90%	80%	70%	70%	
Competitive Benchmark Price					
Simple Swap	32.68	35.34	36.54	39.46	35.02
Capacity (RPM)	1.30	2.07	9.45	9.54	4.01
Other	10.84	11.85	13.59	13.14	11.93
Competitive Benchmark Price	44.83	49.27	59.58	62.15	50.96
CBP Weight	10%	20%	30%	30%	
Estimate of MRO Price	**60.43**	**59.59**	**61.44**	**62.10**	**60.56**
Modified ESP Price					
Modified ESP					
Tariff Generation Price	22.86	22.86	22.89	NA	
Transmission Adjustment	2.91	2.91	2.91	NA	
Market Comparable Base 'g' Rate	25.77	25.77	25.80	69.27	
Current Fuel Factor	36.35	36.02	36.02	NA	
GRR	0.00	0.05	0.11	0.15	0.06
Retail Stability Rider ("RSR")	1.96	1.96	1.96	1.96	1.96
Estimate of Modified ESP Price	**64.08**	**63.80**	**63.90**	**71.39**	**64.87**
Total Above-MRO Charges					
Average AEP Ohio Zone Price Under MRO	58.83	60.08	61.61	63.78	60.47
Average AEP Ohio Zone Price Under ESP	61.42	62.73	63.79	67.96	63.22
AEP Zone ESP Price Benefit	**-2.60**	**-2.64**	**-2.19**	**-4.18**	**-2.75**
Estimate of Total Charges Under ESP ($MM)	2,960	3,027	1,814	1,341	9,143
Estimate of Total Charges Under MRO ($MM)	2,835	2,900	1,752	1,259	8,745
Excess Costs Charged Under ESP ($MM)	**125**	**127**	**62**	**82**	**397**
Above-MRO Costs of Bypassable Generation Rates ($MM	30	30	3	41	105
Above-MRO Costs of Tier 1 Capacity ($MM)	0	0	0	0	0
Above-MRO Costs of Tier 2 Capacity ($MM)	0	0	0	0	0
Above-MRO Costs of GRR ($MM)	0	2	3	3	8
Above-MRO Costs of RSR ($MM)	95	95	56	39	284
Excess Costs Charged Under ESP ($MM)	**125**	**127**	**62**	**82**	**397**

Exhibit MMS-5: Discovery Responses Relied Upon

Discovery Responses	**Ex. MMS-5 Pages**
1. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., OEG, Set 3, INT-3-003.	2
2. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., OEG, Set 3, INT-3-003, Attachment 1, at 4.	3-14
3. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 6, INT-6-9.	15
4. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 6, INT-6-9 Attachment 1.	16-18
5. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 17, STIP-FES-INT-17-17-043.	19-20
6. AEP Ohio Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Modified ESP Set 1, INT-1-003.	21
7. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Modified ESP Set 2, RPD-2-14.	22
8. AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Modified ESP Set 2, RPD-2-14 Attachment 1.	23-31

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
OHIO ENERGY GROUP
DISCOVERY REQUEST
PUCO CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
THIRD SET**

INTERROGATORY

INT-3-003. Please provide monthly, for the most recently available 12 month period, the AEP East Interchange Power Statement showing Interconnection Agreement monthly billing/credit statements for each of the AEP East Companies Also, provide all supporting schedules showing the basis for monthly billings and credits to each Company.

RESPONSE

See OEG 3-3 Attachment 1 for the most recently available 12 months AEP East Interchange Power Statements. The Company objects to this request for all supporting schedules as being overbroad and unduly burdensome. Without waiving these objections or any general objection the Company may have, the Company states as follows. The supporting schedules are voluminous and may be inspected at the Company's offices at a mutually agreed date and time.

March 2010

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	595,810	680,800	24,069,945	29,112,930
RECOVERY AND MLR	KPCO	119,858	76,828	5,033,685	3,241,785
ALLOCATION FOR ALL	I&M	341,746	268,940	13,733,544	12,249,257
AEP SYSTEM	OPCO	386,214	463,548	15,671,574	16,465,348
DELIVERIES TO	CSP	333,619	287,131	13,617,421	11,056,849
NON-AFFILIATED COS.	AEP	1,777,247	1,777,247	72,126,169	72,126,169
ADJUSTMENT TO	APCO	(436,825)	(436,825)	(18,796,465)	(18,796,465)
PREVENT RECOGNITION	KPCO	(63,702)	(63,702)	(2,877,571)	(2,877,571)
OF SALES BY POOL	I&M	(198,371)	(198,371)	(8,628,085)	(8,628,085)
MEMBERS TO	OPCO	(260,933)	(260,933)	(10,523,276)	(10,523,276)
THEMSELVES	CSP	(196,190)	(196,190)	(8,342,424)	(8,342,424)
(PAGE 7)	AEP	(1,156,021)	(1,156,021)	(49,167,821)	(49,167,821)
SUBTOTAL	APCO	158,985	243,975	5,273,480	10,316,465
AEP EXTERNAL	KPCO	56,156	13,126	2,156,114	364,214
ENERGY	I&M	143,375	70,569	5,105,459	3,621,172
	OPCO	125,281	202,615	5,148,298	5,942,072
	CSP	137,429	90,941	5,274,997	2,714,425
	AEP	621,226	621,226	22,958,348	22,958,348
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,130,045	0	28,109,640	0
ENERGY	KPCO	20,201	54,276	505,453	1,460,674
(PAGE 8)	I&M	89,530	144,676	2,265,076	2,857,929
	OPCO	0	1,765,296	0	44,594,908
	CSP	724,472	0	18,033,342	0
	AEP	1,964,248	1,964,248	48,913,511	48,913,511
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,289,030	244,557	33,383,120	10,357,487
	KPCO	76,357	67,507	2,661,567	1,832,944
	I&M	232,905	216,866	7,370,535	6,590,456
	OPCO	127,896	1,967,911	5,330,526	50,536,980
	CSP	861,901	91,249	23,308,339	2,736,220
	AEP	2,588,089	2,588,090	72,054,087	72,054,087

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	526,269	615,966	20,646,790	25,922,632
RECOVERY AND MLR	KPCO	105,606	73,979	4,281,835	2,733,253
ALLOCATION FOR ALL	I&M	302,194	240,536	11,780,146	10,894,169
AEP SYSTEM	OPCO	342,285	383,483	13,442,178	12,960,126
DELIVERIES TO	CSP	295,085	257,475	11,680,597	9,321,366
NON-AFFILIATED COS.	AEP	1,571,439	1,571,439	61,831,546	61,831,546
ADJUSTMENT TO	APCO	(354,610)	(354,610)	(14,955,109)	(14,955,109)
PREVENT RECOGNITION	KPCO	(47,394)	(47,394)	(2,014,676)	(2,014,676)
OF SALES BY POOL	I&M	(150,076)	(150,076)	(6,443,246)	(6,443,246)
MEMBERS TO	OPCO	(196,910)	(196,910)	(7,635,924)	(7,635,924)
THEMSELVES	CSP	(149,788)	(149,788)	(6,100,284)	(6,100,284)
(PAGE 7)	AEP	(898,778)	(898,778)	(37,149,239)	(37,149,239)
SUBTOTAL	APCO	171,659	261,356	5,691,681	10,967,523
AEP EXTERNAL	KPCO	58,212	26,585	2,267,159	718,577
ENERGY	I&M	152,118	90,460	5,336,900	4,450,923
	OPCO	145,375	186,573	5,806,254	5,324,202
	CSP	145,297	107,687	5,580,313	3,221,082
	AEP	672,661	672,661	24,682,307	24,682,307
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	540,961	1,657	12,534,665	45,177
ENERGY	KPCO	45,542	96,905	1,092,737	2,608,199
(PAGE 8)	I&M	3,803	551,518	105,086	10,511,386
	OPCO	5,361	530,993	108,358	14,688,328
	CSP	585,406	0	14,012,244	0
	AEP	1,181,073	1,181,073	27,853,090	27,853,090
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	712,620	263,305	18,226,346	11,038,553
	KPCO	103,754	123,531	3,359,896	3,330,483
	I&M	155,921	645,160	5,441,986	15,230,686
	OPCO	154,367	717,566	6,222,663	20,012,530
	CSP	730,703	107,803	19,592,557	3,231,196
	AEP	1,857,365	1,857,365	52,843,448	52,843,448

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY *					
ENERGY COST	APCO	469,419	533,868	19,679,521	23,912,708
RECOVERY AND MLR	KPCO	92,991	56,655	4,081,238	2,409,994
ALLOCATION FOR ALL	I&M	270,104	227,162	11,228,265	10,782,152
AEP SYSTEM	OPCO	304,630	335,776	12,812,434	12,187,509
DELIVERIES TO	CSP	263,361	247,044	11,133,380	9,642,475
NON-AFFILIATED COS.	AEP	1,400,505	1,400,505	58,934,838	58,934,838
ADJUSTMENT TO	APCO	(334,575)	(334,575)	(14,957,985)	(14,957,985)
PREVENT RECOGNITION	KPCO	(48,482)	(48,482)	(2,187,618)	(2,187,618)
OF SALES BY POOL	I&M	(152,483)	(152,483)	(6,889,264)	(6,889,264)
MEMBERS TO	OPCO	(192,575)	(192,575)	(7,983,570)	(7,983,570)
THEMSELVES	CSP	(153,713)	(153,713)	(6,625,283)	(6,625,283)
(PAGE 7)	AEP	(881,828)	(881,828)	(38,643,720)	(38,643,720)
SUBTOTAL	APCO	134,844	199,293	4,721,536	8,954,723
AEP EXTERNAL	KPCO	44,509	8,173	1,893,620	222,376
ENERGY	I&M	117,621	74,679	4,339,001	3,892,888
	OPCO	112,055	143,201	4,828,864	4,203,939
	CSP	109,648	93,331	4,508,097	3,017,192
	AEP	518,677	518,677	20,291,118	20,291,118
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	524,037	746	11,894,364	21,421
ENERGY	KPCO	228,804	33,684	5,561,875	1,021,062
(PAGE 8)	I&M	2,429	545,190	65,634	9,643,322
	OPCO	350	651,823	6,645	17,541,211
	CSP	481,618	5,795	10,868,945	170,447
	AEP	1,237,238	1,237,238	28,397,463	28,397,463
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	658,881	200,362	16,615,900	9,013,421
	KPCO	273,313	41,885	7,455,495	1,247,970
	I&M	120,567	619,869	4,473,036	13,536,210
	OPCO	112,405	795,113	4,835,509	21,759,378
	CSP	591,266	99,203	15,377,042	3,200,003
	AEP	1,756,432	1,756,432	48,756,982	48,756,982

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	860,934	901,142	32,956,634	36,833,425
RECOVERY AND MLR	KPCO	175,367	217,749	6,834,712	8,201,691
ALLOCATION FOR ALL	I&M	493,935	384,476	18,803,600	15,716,520
AEP SYSTEM	OPCO	560,456	643,531	21,456,553	21,523,570
DELIVERIES TO	CSP	485,552	429,346	18,644,699	16,420,992
NON-AFFILIATED COS.	AEP	2,576,244	2,576,244	98,696,198	98,696,198
ADJUSTMENT TO	APCO	(479,176)	(479,176)	(20,875,845)	(20,875,845)
PREVENT RECOGNITION	KPCO	(64,789)	(64,789)	(3,053,334)	(3,053,334)
OF SALES BY POOL	I&M	(198,186)	(198,186)	(8,941,124)	(8,941,124)
MEMBERS TO	OPCO	(275,987)	(275,987)	(11,239,739)	(11,239,739)
THEMSELVES	CSP	(202,235)	(202,235)	(9,010,380)	(9,010,380)
(PAGE 7)	AEP	(1,220,373)	(1,220,373)	(53,120,422)	(53,120,422)
SUBTOTAL	APCO	381,758	421,966	12,080,789	15,957,580
AEP EXTERNAL	KPCO	110,578	152,960	3,781,378	5,148,357
ENERGY	I&M	295,749	186,290	9,862,476	6,775,396
	OPCO	284,469	367,544	10,216,814	10,283,831
	CSP	283,317	227,111	9,634,319	7,410,612
	AEP	1,355,871	1,355,871	45,575,776	45,575,776
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,342,611	0	29,453,015	0
ENERGY	KPCO	33,950	50,037	749,023	1,365,759
(PAGE 8)	I&M	1,948	756,221	45,246	14,338,711
	OPCO	0	1,343,267	0	31,200,066
	CSP	778,700	7,684	16,920,385	263,133
	AEP	2,157,209	2,157,209	47,167,669	47,167,669
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,724,369	422,684	41,604,067	15,957,580
	KPCO	144,528	203,146	4,544,281	6,514,116
	I&M	298,317	943,124	9,956,093	21,179,616
	OPCO	285,842	1,710,962	10,233,412	41,604,855
	CSP	1,062,017	235,157	26,592,059	7,673,745
	AEP	3,515,073	3,515,073	92,929,912	92,929,912

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY *					
ENERGY COST	APCO	1,273,204	1,407,507	47,130,739	54,006,402
RECOVERY AND MLR	KPCO	264,358	135,026	9,774,995	5,147,368
ALLOCATION FOR ALL	I&M	698,778	508,850	25,819,740	20,837,845
AEP SYSTEM	OPCO	827,578	1,045,374	30,684,876	33,854,813
DELIVERIES TO	CSP	712,620	679,781	26,352,236	25,916,159
NON-AFFILIATED COS.	AEP	3,776,538	3,776,538	139,762,586	139,762,586
ADJUSTMENT TO	APCO	(671,133)	(671,133)	(29,159,087)	(29,159,087)
PREVENT RECOGNITION	KPCO	(68,772)	(68,772)	(3,546,042)	(3,546,042)
OF SALES BY POOL	I&M	(225,295)	(225,295)	(11,226,440)	(11,226,440)
MEMBERS TO	OPCO	(380,444)	(380,444)	(15,825,356)	(15,825,356)
THEMSELVES	CSP	(261,637)	(261,637)	(12,380,303)	(12,380,303)
(PAGE 7)	AEP	(1,607,281)	(1,607,281)	(72,137,228)	(72,137,228)
SUBTOTAL	APCO	602,071	736,374	17,971,652	24,847,315
AEP EXTERNAL	KPCO	195,586	66,254	6,228,953	1,601,326
ENERGY	I&M	473,483	283,555	14,593,300	9,611,404
	OPCO	447,134	664,930	14,859,520	18,029,457
	CSP	450,983	418,144	13,971,933	13,535,856
	AEP	2,169,257	2,169,257	67,625,358	67,625,358
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,339,003	0	30,451,648	0
ENERGY	KPCO	91	239,101	2,023	5,727,902
(PAGE 8)	I&M	4,501	811,032	109,081	16,303,369
	OPCO	0	1,210,382	0	29,356,608
	CSP	916,920	0	20,825,127	0
	AEP	2,260,515	2,260,515	51,387,879	51,387,879
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,941,074	737,291	48,423,300	24,918,981
	KPCO	195,677	305,477	6,230,976	7,340,352
	I&M	478,174	1,095,116	14,724,649	25,957,155
	OPCO	449,381	1,875,358	15,035,618	47,391,772
	CSP	1,367,903	418,967	34,797,060	13,603,344
	AEP	4,432,209	4,432,209	119,211,604	119,211,605

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	995,065	1,134,653	37,981,066	44,721,765
RECOVERY AND MLR	KPCO	204,450	122,761	7,876,598	4,923,160
ALLOCATION FOR ALL	I&M	599,386	455,258	22,839,085	19,420,264
AEP SYSTEM	OPCO	701,856	774,011	26,724,592	26,314,468
DELIVERIES TO	CSP	568,612	582,686	21,894,691	21,936,376
NON-AFFILIATED COS.	AEP	3,069,369	3,069,369	117,316,032	117,316,033
ADJUSTMENT TO	APCO	(548,371)	(548,371)	(24,391,308)	(24,391,308)
PREVENT RECOGNITION	KPCO	(58,718)	(58,718)	(3,166,303)	(3,166,303)
OF SALES BY POOL	I&M	(219,777)	(219,777)	(10,879,158)	(10,879,158)
MEMBERS TO	OPCO	(324,489)	(324,489)	(13,958,880)	(13,958,880)
THEMSELVES	CSP	(233,311)	(233,311)	(10,966,909)	(10,966,909)
(PAGE 7)	AEP	(1,384,666)	(1,384,666)	(63,362,558)	(63,362,558)
SUBTOTAL	APCO	446,694	586,282	13,589,758	20,330,457
AEP EXTERNAL	KPCO	145,732	64,043	4,710,295	1,756,856
ENERGY	I&M	379,609	235,481	11,959,927	8,541,106
	OPCO	377,367	449,522	12,765,712	12,355,589
	CSP	335,301	349,375	10,927,782	10,969,467
	AEP	1,684,703	1,684,703	53,953,474	53,953,475
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,621,120	1,120	37,754,638	34,189
ENERGY	KPCO	313	235,268	7,195	5,687,133
(PAGE 8)	I&M	0	824,443	0	16,905,203
	OPCO	0	1,273,114	0	31,638,156
	CSP	714,467	1,955	16,563,509	60,661
	AEP	2,335,900	2,335,900	54,325,342	54,325,342
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,067,814	588,317	51,344,396	20,471,155
	KPCO	146,045	299,462	4,717,490	7,463,898
	I&M	379,894	1,060,342	12,001,351	25,495,529
	OPCO	379,124	1,722,716	12,968,539	44,005,311
	CSP	1,049,768	351,808	27,491,291	11,087,175
	AEP	4,022,645	4,022,645	108,523,067	108,523,068

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	526,076	567,214	20,215,391	23,863,968
RECOVERY AND MLR	KPCO	107,673	96,462	4,192,313	3,429,451
ALLOCATION FOR ALL	I&M	316,785	231,756	12,156,084	10,050,152
AEP SYSTEM	OPCO	370,578	503,952	14,224,142	16,573,433
DELIVERIES TO	CSP	298,344	220,072	11,653,431	8,524,357
NON-AFFILIATED COS.	AEP	1,619,456	1,619,456	62,441,361	62,441,360
ADJUSTMENT TO	APCO	(299,315)	(299,315)	(13,459,597)	(13,459,597)
PREVENT RECOGNITION	KPCO	(39,069)	(39,069)	(1,870,507)	(1,870,507)
OF SALES BY POOL	I&M	(128,495)	(128,495)	(6,062,418)	(6,062,418)
MEMBERS TO	OPCO	(208,361)	(208,361)	(8,382,191)	(8,382,191)
THEMSELVES	CSP	(120,434)	(120,434)	(5,566,321)	(5,566,321)
(PAGE 7)	AEP	(795,674)	(795,674)	(35,341,034)	(35,341,034)
SUBTOTAL	APCO	226,761	267,899	6,755,794	10,404,371
AEP EXTERNAL	KPCO	68,604	57,393	2,321,806	1,558,944
ENERGY	I&M	188,290	103,261	6,093,666	3,987,734
	OPCO	162,217	295,591	5,841,951	8,191,242
	CSP	177,910	99,638	6,087,110	2,958,036
	AEP	823,782	823,782	27,100,327	27,100,326
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,569,349	6,228	35,540,578	199,095
ENERGY	KPCO	3,071	167,378	74,917	4,696,626
(PAGE 8)	I&M	2,389	1,030,984	67,226	20,653,702
	OPCO	1,350	1,069,982	43,081	25,890,356
	CSP	708,686	10,273	16,027,015	313,038
	AEP	2,284,845	2,284,845	51,752,817	51,752,817
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,796,110	274,127	42,296,372	10,603,466
	KPCO	71,675	224,771	2,396,723	6,255,570
	I&M	190,679	1,134,245	6,160,892	24,641,436
	OPCO	163,567	1,365,573	5,885,032	34,081,598
	CSP	886,596	109,911	22,114,125	3,271,074
	AEP	3,108,627	3,108,627	78,853,144	78,853,143

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	428,785	429,462	16,548,563	18,620,000
RECOVERY AND MLR	KPCO	86,672	77,187	3,431,878	2,724,689
ALLOCATION FOR ALL	I&M	258,842	222,573	9,951,117	9,687,756
AEP SYSTEM	OPCO	302,699	413,665	11,644,054	13,443,105
DELIVERIES TO	CSP	243,161	177,272	9,539,639	6,639,702
NON-AFFILIATED COS.	AEP	1,320,159	1,320,159	51,115,251	51,115,252
ADJUSTMENT TO	APCO	(294,698)	(294,698)	(12,207,427)	(12,207,427)
PREVENT RECOGNITION	KPCO	(49,494)	(49,494)	(1,950,664)	(1,950,664)
OF SALES BY POOL	I&M	(155,519)	(155,519)	(6,310,919)	(6,310,919)
MEMBERS TO	OPCO	(220,252)	(220,252)	(8,027,096)	(8,027,096)
THEMSELVES	CSP	(140,399)	(140,399)	(5,523,517)	(5,523,517)
(PAGE 7)	AEP	(860,362)	(860,362)	(34,019,624)	(34,019,624)
SUBTOTAL	APCO	134,087	134,764	4,341,136	6,412,573
AEP EXTERNAL	KPCO	37,178	27,693	1,481,214	774,025
ENERGY	I&M	103,323	67,054	3,640,198	3,376,837
	OPCO	82,447	193,413	3,616,958	5,416,008
	CSP	102,762	36,873	4,016,122	1,116,184
	AEP	459,797	459,797	17,095,627	17,095,628
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,866,883	0	43,576,856	0
ENERGY	KPCO	293	220,957	6,722	6,009,370
(PAGE 8)	I&M	0	857,039	0	19,309,092
	OPCO	0	1,484,399	0	34,467,744
	CSP	695,651	432	16,217,023	14,395
	AEP	2,562,827	2,562,827	59,800,601	59,800,601
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,000,970	134,764	47,917,992	6,412,573
	KPCO	37,471	248,650	1,487,936	6,783,395
	I&M	103,323	924,093	3,640,198	22,685,929
	OPCO	82,447	1,677,812	3,616,958	39,883,752
	CSP	798,413	37,305	20,233,145	1,130,579
	AEP	3,022,624	3,022,624	76,896,228	76,896,229

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	402,152	447,213	15,386,134	18,485,403
RECOVERY AND MLR	KPCO	81,732	59,942	3,190,811	2,163,628
ALLOCATION FOR ALL	I&M	242,406	198,590	9,252,116	8,572,650
AEP SYSTEM	OPCO	283,358	370,335	10,826,135	12,327,173
DELIVERIES TO	CSP	228,311	161,879	8,869,542	5,975,882
NON-AFFILIATED COS.	AEP	1,237,959	1,237,959	47,524,738	47,524,737
ADJUSTMENT TO	APCO	(245,166)	(245,166)	(10,275,596)	(10,275,596)
PREVENT RECOGNITION	KPCO	(32,601)	(32,601)	(1,372,803)	(1,372,803)
OF SALES BY POOL	I&M	(110,969)	(110,969)	(4,741,673)	(4,741,673)
MEMBERS TO	OPCO	(165,557)	(165,557)	(6,255,747)	(6,255,747)
THEMSELVES	CSP	(99,292)	(99,292)	(4,090,418)	(4,090,418)
(PAGE 7)	AEP	(653,585)	(653,585)	(26,736,237)	(26,736,237)
SUBTOTAL	APCO	156,986	202,047	5,110,538	8,209,806
AEP EXTERNAL	KPCO	49,131	27,341	1,818,008	790,825
ENERGY	I&M	131,437	87,621	4,510,443	3,830,978
	OPCO	117,801	204,778	4,570,388	6,071,426
	CSP	129,019	62,587	4,779,124	1,885,463
	AEP	584,374	584,374	20,788,501	20,788,499
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,609,191	0	38,004,429	0
ENERGY	KPCO	2,925	138,057	70,083	3,704,621
(PAGE 8)	I&M	669	667,542	17,811	15,342,117
	OPCO	0	1,318,114	0	30,979,633
	CSP	521,499	10,571	12,287,445	353,397
	AEP	2,134,284	2,134,284	50,379,768	50,379,768
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,766,177	202,047	43,114,967	8,209,806
	KPCO	52,056	165,398	1,888,091	4,495,446
	I&M	132,106	755,163	4,528,254	19,173,095
	OPCO	117,801	1,522,892	4,570,388	37,051,059
	CSP	650,518	73,158	17,066,569	2,238,860
	AEP	2,718,658	2,718,658	71,168,269	71,168,267

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	488,686	665,857	23,510,322	31,000,525
RECOVERY AND MLR	KPCO	98,834	63,527	4,875,623	3,338,341
ALLOCATION FOR ALL	I&M	294,565	218,001	14,137,419	12,457,738
AEP SYSTEM	OPCO	344,264	293,831	16,542,552	13,707,914
DELIVERIES TO	CSP	278,149	263,282	13,552,838	12,114,237
NON-AFFILIATED COS.	AEP	1,504,498	1,504,498	72,618,754	72,618,755
ADJUSTMENT TO	APCO	(369,432)	(369,432)	(19,293,535)	(19,293,535)
PREVENT RECOGNITION	KPCO	(48,049)	(48,049)	(2,872,370)	(2,872,370)
OF SALES BY POOL	I&M	(153,212)	(153,212)	(9,054,280)	(9,054,280)
MEMBERS TO	OPCO	(191,343)	(191,343)	(10,560,431)	(10,560,431)
THEMSELVES	CSP	(155,117)	(155,117)	(8,679,300)	(8,679,300)
(PAGE 7)	AEP	(917,153)	(917,153)	(50,459,916)	(50,459,916)
SUBTOTAL	APCO	119,254	296,425	4,216,787	11,706,990
AEP EXTERNAL	KPCO	50,785	15,478	2,003,253	465,971
ENERGY	I&M	141,353	64,789	5,083,139	3,403,458
	OPCO	152,921	102,488	5,982,121	3,147,483
	CSP	123,032	108,165	4,873,538	3,434,937
	AEP	587,345	587,345	22,158,838	22,158,839
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,867,523	0	43,936,261	0
ENERGY	KPCO	137,868	76,484	3,281,185	2,206,181
(PAGE 8)	I&M	0	1,319,744	0	27,884,869
	OPCO	94	840,388	2,335	21,719,827
	CSP	312,801	81,670	7,259,091	2,667,995
	AEP	2,318,286	2,318,286	54,478,872	54,478,872
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,986,777	297,504	48,153,048	11,822,272
	KPCO	188,653	92,172	5,284,438	2,695,567
	I&M	141,827	1,385,496	5,110,538	31,377,797
	OPCO	155,511	942,997	6,257,463	24,874,461
	CSP	435,833	190,432	12,132,629	6,168,020
	AEP	2,908,601	2,908,601	76,938,116	76,938,117

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	614,985	745,915	22,776,475	28,086,552
RECOVERY AND MLR	KPCO	129,406	97,241	4,768,529	3,424,124
ALLOCATION FOR ALL	I&M	360,412	199,539	13,367,469	8,929,518
AEP SYSTEM	OPCO	416,601	417,550	15,641,776	14,260,397
DELIVERIES TO	CSP	350,620	411,779	13,038,989	14,892,646
NON-AFFILIATED COS.	AEP	1,872,024	1,872,024	69,593,238	69,593,237
ADJUSTMENT TO	APCO	(319,544)	(319,544)	(13,229,841)	(13,229,841)
PREVENT RECOGNITION	KPCO	(29,029)	(29,029)	(1,405,114)	(1,405,114)
OF SALES BY POOL	I&M	(91,565)	(91,565)	(4,561,137)	(4,561,137)
MEMBERS TO	OPCO	(153,336)	(153,336)	(6,400,620)	(6,400,620)
THEMSELVES	CSP	(129,361)	(129,361)	(5,582,524)	(5,582,524)
(PAGE 7)	AEP	(722,835)	(722,835)	(31,179,235)	(31,179,235)
SUBTOTAL	APCO	295,441	426,371	9,546,634	14,856,711
AEP EXTERNAL	KPCO	100,377	68,212	3,363,415	2,019,010
ENERGY	I&M	268,847	107,974	8,806,332	4,368,381
	OPCO	263,265	264,214	9,241,156	7,859,777
	CSP	221,259	282,418	7,456,465	9,310,122
	AEP	1,149,189	1,149,189	38,414,003	38,414,002
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	2,062,275	0	43,472,366	0
ENERGY	KPCO	11,957	91,198	272,426	2,417,659
(PAGE 8)	I&M	2,503	1,281,103	67,942	22,419,303
	OPCO	0	1,039,576	0	25,155,663
	CSP	383,891	48,749	7,837,989	1,658,098
	AEP	2,460,626	2,460,626	51,650,723	51,650,723
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,357,716	428,473	53,019,000	15,015,038
	KPCO	112,334	159,673	3,635,841	4,459,353
	I&M	272,268	1,389,889	8,967,708	26,845,455
	OPCO	266,547	1,303,920	9,475,495	33,034,700
	CSP	605,150	332,060	15,294,454	11,037,950
	AEP	3,614,015	3,614,015	90,392,498	90,392,497

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	516,642	596,561	18,301,306	22,092,437
RECOVERY AND MLR	KPCO	108,981	146,896	3,831,598	4,792,648
ALLOCATION FOR ALL	I&M	303,508	148,519	10,741,001	6,630,494
AEP SYSTEM	OPCO	350,232	364,456	12,568,448	11,489,582
DELIVERIES TO	CSP	295,292	318,223	10,477,062	10,914,255
NON-AFFILIATED COS.	AEP	1,574,655	1,574,655	55,919,415	55,919,416
ADJUSTMENT TO	APCO	(248,397)	(248,397)	(9,572,419)	(9,572,419)
PREVENT RECOGNITION	KPCO	(26,082)	(26,082)	(1,007,322)	(1,007,322)
OF SALES BY POOL	I&M	(65,960)	(65,960)	(2,924,348)	(2,924,348)
MEMBERS TO	OPCO	(123,816)	(123,816)	(4,435,885)	(4,435,885)
THEMSELVES	CSP	(96,359)	(96,359)	(3,664,501)	(3,664,501)
(PAGE 7)	AEP	(560,614)	(560,614)	(21,604,475)	(21,604,475)
SUBTOTAL	APCO	268,245	348,164	8,728,887	12,520,018
AEP EXTERNAL	KPCO	82,899	120,814	2,824,276	3,785,326
ENERGY	I&M	237,548	82,559	7,816,653	3,706,146
	OPCO	226,416	240,640	8,132,563	7,053,697
	CSP	198,933	221,864	6,812,561	7,249,754
	AEP	1,014,041	1,014,041	34,314,940	34,314,941
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,227,342	0	26,627,297	0
ENERGY	KPCO	30,825	68,315	680,750	1,906,331
(PAGE 8)	I&M	0	663,570	0	11,166,555
	OPCO	0	993,705	0	24,067,538
	CSP	480,642	13,219	10,239,798	407,421
	AEP	1,738,809	1,738,809	37,547,845	37,547,845
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,495,587	348,533	35,356,184	12,558,833
	KPCO	113,724	189,212	3,505,026	5,699,783
	I&M	237,548	746,638	7,816,653	14,912,674
	OPCO	227,587	1,234,345	8,241,698	31,121,235
	CSP	679,575	235,293	17,052,359	7,679,396
	AEP	2,754,021	2,754,021	71,971,920	71,971,921

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSES TO
FIRSTENERGY SOLUTIONS CORPORATION'S
DISCOVERY REQUEST
CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
SIXTH SET**

INTERROGATORY

INT-6-9. Referring to OCC INT-097, please identify the forecast of the monthly power pool capacity revenues (or expenses) for Ohio Power and CSP for each of 2012, 2013, and 2014, and the associated MWs sold (or purchased) to AEP pool members.

RESPONSE:

See FES INT-6-009 Attachment 1.

Prepared by: Philip J. Nelson

AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 6, INT-6-9 Attachment 1, p. 1 of 3.

	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	Jun 2012	Jul 2012	Aug 2012	Sep 2012	Oct 2012	Nov 2012	Dec 2012
MEMBER CAPACITY SURPLUS (MW)												
APCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CSP	337.13	337.13	341.16	341.16	341.16	341.16	341.16	344.65	521.90	521.90	521.90	383.64
I&M	70.21	70.21	75.04	75.04	75.04	75.04	75.04	0.00	0.00	0.00	0.00	0.00
KPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPCO	2,236.74	2,236.74	2,241.84	2,241.84	2,241.84	2,241.84	2,241.84	2,323.75	2,278.36	2,278.36	2,278.36	2,313.89
Sum:	2,644.07	2,644.07	2,658.03	2,658.03	2,658.03	2,658.03	2,658.03	2,668.39	2,800.25	2,800.25	2,800.25	2,697.52
MEMBER CAPACITY DEFICIT (MW)												
APCO	2,222.85	2,222.85	2,244.34	2,244.34	2,244.34	2,244.34	2,244.34	2,237.36	2,310.41	2,310.41	2,310.41	2,253.50
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.69	62.73	62.73	62.73	28.55
KPCO	421.22	421.22	413.70	413.70	413.70	413.70	413.70	412.35	427.12	427.12	427.12	415.47
OPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum:	2,644.07	2,644.07	2,658.04	2,658.04	2,658.04	2,658.04	2,658.04	2,668.40	2,800.26	2,800.26	2,800.26	2,697.52
SYSTEM (PAYMENTS)/ RECEIPTS ($000)												
APCO	(31,381.735)	(31,381.735)	(31,686.121)	(31,686.121)	(31,686.121)	(31,686.121)	(31,686.121)	(31,491.100)	(32,214.028)	(32,214.028)	(32,214.028)	(31,650.432)
CSP	4,067.174	4,067.174	4,115.793	4,115.793	4,115.793	4,115.793	4,115.793	4,157.897	6,296.271	6,296.271	6,296.271	4,628.279
I&M	1,111.746	1,111.746	1,188.227	1,188.227	1,188.227	1,188.227	1,188.227	(263.064)	(874.644)	(874.644)	(874.644)	(400.985)
KPCO	(5,946.696)	(5,946.696)	(5,840.714)	(5,840.714)	(5,840.714)	(5,840.714)	(5,840.714)	(5,803.874)	(5,955.331)	(5,955.331)	(5,955.331)	(5,835.281)
OPCO	32,149.511	32,149.511	32,222.816	32,222.816	32,222.816	32,222.816	32,222.816	33,400.141	32,747.732	32,747.732	32,747.732	33,258.419
Sum:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 6, INT-6-9 Attachment 1, p. 2 of 3.

	Jan 2013	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Dec 2013
MEMBER CAPACITY SURPLUS (MW)												
APCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CSP	383.52	383.52	395.53	395.53	395.53	395.53	395.53	400.34	403.27	403.27	396.01	396.01
I&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPCO	2,314.47	2,314.47	2,330.21	2,330.21	2,330.21	2,330.21	2,330.21	2,373.46	2,372.65	2,372.65	2,363.06	2,363.06
Sum:	2,697.99	2,697.99	2,725.74	2,725.74	2,725.74	2,725.74	2,725.74	2,773.80	2,775.92	2,775.92	2,759.07	2,759.07
MEMBER CAPACITY DEFICIT (MW)												
APCO	2,253.76	2,253.76	2,302.07	2,302.07	2,302.07	2,302.07	2,302.07	2,292.46	2,293.53	2,293.53	2,309.12	2,309.12
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I&M	28.71	28.71	13.23	13.23	13.23	13.23	13.23	73.02	73.82	73.82	38.21	38.21
KPCO	415.52	415.52	410.45	410.45	410.45	410.45	410.45	408.31	408.58	408.58	411.75	411.75
OPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum:	2,697.99	2,697.99	2,725.75	2,725.75	2,725.75	2,725.75	2,725.75	2,773.79	2,775.93	2,775.93	2,759.08	2,759.08
SYSTEM (PAYMENTS)/ RECEIPTS ($000)												
APCO	(32,206.043)	(32,206.043)	(32,881.822)	(32,881.822)	(32,881.822)	(32,881.822)	(32,881.822)	(32,748.588)	(32,759.040)	(32,759.040)	(32,990.255)	(32,990.255)
CSP	4,782.741	4,782.741	4,932.514	4,932.514	4,932.514	4,932.514	4,932.514	4,992.498	5,029.037	5,029.037	4,938.500	4,938.500
I&M	(410.264)	(410.264)	(188.972)	(188.972)	(188.972)	(188.972)	(188.972)	(1,043.116)	(1,054.389)	(1,054.389)	(545.904)	(545.904)
KPCO	(5,937.746)	(5,937.746)	(5,862.699)	(5,862.699)	(5,862.699)	(5,862.699)	(5,862.699)	(5,832.850)	(5,835.846)	(5,835.846)	(5,882.647)	(5,882.647)
OPCO	33,771.311	33,771.311	34,000.979	34,000.979	34,000.979	34,000.979	34,000.979	34,632.057	34,620.237	34,620.237	34,480.306	34,480.306
Sum:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 6, INT-6-9 Attachment 1, p. 3 of 3.

	Jan 2014	Feb 2014	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014
MEMBER CAPACITY SURPLUS (MW)												
APCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CSP	396.77	396.77	401.85	401.85	401.85	401.85	401.85	399.71	405.59	389.33	389.33	389.33
I&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.61	56.61	56.61
KPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPCO	2,364.27	2,364.27	2,371.23	2,371.23	2,371.23	2,371.23	2,371.23	2,369.36	2,367.75	2,346.24	2,346.24	2,346.24
Sum:	2,761.04	2,761.04	2,773.08	2,773.08	2,773.08	2,773.08	2,773.08	2,769.07	2,773.34	2,792.18	2,792.18	2,792.18
MEMBER CAPACITY DEFICIT (MW)												
APCO	2,310.21	2,310.21	2,338.55	2,338.55	2,338.55	2,338.55	2,338.55	2,343.36	2,346.04	2,381.15	2,381.15	2,381.15
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I&M	38.87	38.87	31.92	31.92	31.92	31.92	31.92	22.02	23.36	0.00	0.00	0.00
KPCO	411.97	411.97	402.61	402.61	402.61	402.61	402.61	403.68	403.95	411.03	411.03	411.03
OPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum:	2,761.05	2,761.05	2,773.08	2,773.08	2,773.08	2,773.08	2,773.08	2,769.06	2,773.35	2,792.18	2,792.18	2,792.18
SYSTEM (PAYMENTS)/ RECEIPTS ($000)												
APCO	(33,562.588)	(33,562.588)	(33,968.391)	(33,968.391)	(33,968.391)	(33,968.391)	(33,968.391)	(34,041.202)	(34,070.365)	(34,760.226)	(34,760.226)	(34,760.226)
CSP	5,037.631	5,037.631	5,102.130	5,102.130	5,102.130	5,102.130	5,102.130	5,074.959	5,149.615	4,943.168	4,943.168	4,943.168
I&M	(564.701)	(564.701)	(463.651)	(463.651)	(463.651)	(463.651)	(463.651)	(319.877)	(339.246)	1,010.057	1,010.057	1,010.057
KPCO	(5,985.075)	(5,985.075)	(5,848.074)	(5,848.074)	(5,848.074)	(5,848.074)	(5,848.074)	(5,864.124)	(5,866.364)	(6,000.250)	(6,000.250)	(6,000.250)
OPCO	35,074.732	35,074.732	35,177.986	35,177.986	35,177.986	35,177.986	35,177.986	35,150.244	35,126.359	34,807.252	34,807.252	34,807.252
Sum:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
RESPONSE TO
FIRST ENERGY SOLUTIONS'S DISCOVERY REQUEST
IN PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
SEVENTEENTH SET**

INTERROGATORY

STIP-FES-INT-17-17-043 Referring to Section IV.5 of the Stipulation, which states that "if the impact of the Pool termination/modification on AEP Ohio during the ESP term is greater than $50 million prior to May 31, 2015, the company may pursue cost recovery of the entire impact during the ESP term and obtain approval by the Ohio commission . . . .":

(a) Under the Stipulation, would AEP Ohio be permitted to recover lost capacity revenues attributable to months after May 31, 2015? If so, what is the last possible date that lost capacity revenues could be calculated?

(b) Under the Stipulation, would AEP Ohio be permitted to begin recovery of lost capacity revenues as of January 1, 2013? September 1, 2013?

(c) What is the estimated date of termination of the pool? If You do not have an estimate, what is the earliest feasible date for termination of the pool? What is the latest possible date for termination of the pool?

(d) For the collection period of the proposed Pool Modification Rider, what is Your estimate of the initial date upon which the proposed Pool Modification Rider is expected to be collected from customers?

(e) For the collection period of the proposed Pool Modification Rider, what is the date through which the proposed Pool Modification Rider will be collected from customers?

(f) Assuming pool termination occurs January 1, 2014:

i. When would the Pool Modification Rider begin to be collected from SSO customers?
ii. What time period of lost capacity revenues would be collected through the rider?
iii. Would there be a time lag between when the capacity revenues are lost versus collected in the rider?

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
RESPONSE TO
FIRST ENERGY SOLUTIONS'S DISCOVERY REQUEST
IN PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
SEVENTEENTH SET**

STIP-FES-INT-17-17-043

(g) If AEP Ohio is able to increase energy revenues as a result of pool termination (i.e., by selling energy at a higher rate than under the existing Pool Agreement), will AEP Ohio offset lost capacity revenues with these increased energy revenues?

RESPONSE

A. No, however recovery of the impacts of the pool termination/modification on AEP Ohio incurred prior to May 31, 2015 could occur through May 31, 2016.

B. The calculation of the impact of the pool termination/modification would begin upon the effective date of the modification/termination of the pool. Once the calculation of the impact is completed, a recovery request could be filed with the Commission for approval.

C. See the testimony of Company witness Munczinski and Appendix B of the Joint Stipulation and Recommendation.

D. See B. above

E. See A. and B. above

F. See A. and B. above

G. The impact of the modification/termination of the pool is a net impact on AEP Ohio.

Prepared By: Richard E. Munczinski

OHIO POWER COMPANY'S RESPONSES
TO FIRSTENERGY SOLUTIONS CORPORATION
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
FIRST SET

INTERROGATORY

FES-INT-1-003 Discussing the proposed AEP Pool termination provision, AEP Ohio witness Nelson states, "The Company will not adjust the proposed ESP rates if the annual effect of the AEP Pool termination or any new affiliate arrangement is less than $35 million on an annual basis during the term of this ESP."

a. If AEP Ohio determines that the annual effect of the AEP Pool termination or any new affiliate arrangement is greater than $35 million on an annual basis during the term of this ESP and AEP Ohio seeks to avail itself of this provision to seek recovery of the lost net revenue from retail customers, would AEP Ohio seek recovery of the total annual effect or only that portion of the annual effect greater than the $35 million threshold?

b. If AEP Ohio invokes the AEP Pool termination provision what is the latest date through which the financial impact of the pool termination/modification could be calculated?

c. If AEP Ohio invokes the AEP Pool termination provision what is the latest date through which the financial impact of the pool termination/modification could be collected from customers?

RESPONSE

a. As discussed on pages 22 and 23 of Company witness Nelson's testimony, the Pool Termination Provision would not be triggered at all if the Company's requested Corporate Separation plan, including the plan for the Amos and Mitchell unit transfers, is approved as filed and the Company would bear the cost of terminating the pool. If the Corporate Separation plan is not approved as filed, the Company would bear the cost of terminating the pool up to a threshold amount of $35 million on an annual basis.

b. The annual impact will be computed as discussed on page 23 of Company witness Nelson's testimony. Any such impact would be applied during the period beginning with the Pool Termination date and ending with the end of the ESP.

c. The collection period would be as determined by the Commission pursuant to the Company's subsequent application, if any, regarding the Pool Termination Provision.

Prepared by: P. Nelson

**OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THEOHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
SECOND SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

OCC-RPD-014 Please provide copies of all workpapers, including electronic spreadsheets with cell formulas and linkages intact, e-mail correspondence, memoranda, reports, or other documents relied on to derive the forecast of the percentage of load that is expected to migrate from SSO service due to governmental aggregation initiatives.

RESPONSE

The Company objects to the form of the question as this request is vague, overbroad and/or unduly burdensome. Without waiving the foregoing objection, see the Company's response to OCC-INT-2-33. See also OCC Set RPD 2-14 Attachment 1.

Prepared by: Counsel/William A. Allen

	GWh			
Expansion of Modification	Maximum Incremental Impact in 2012	Projected Incremental Impact in 2012	Maximum Incremental Impact in 2013	Projected Incremental Impact in 2013
Inclusion of Mercantile Customers	6,560	2,449	6,560	4,092
Addition of Pre-Nov. 2011 Communities	1,966	878	1,966	1,368
Elimination of September Reallocation	1,275	744	-	-
Aggregation to be Above Set-Aside in 2012	2,524	1,028	-	-
Aggregation to be Above Set-Aside beyond 2012	-	-	2,524	1,826
Total	12,324	5,099	11,049	7,286

	Maximum Financial Impact				
Expansion of Modification	Incremental Impact in 2012	Incremental Impact in 2013	Incremental Impact in 2014	Incremental Impact in 2015	Incremental Impact Over ESP
Inclusion of Mercantile Customers	$135 M	$141 M	$117 M	$40 M	$434 M
Addition of Pre-Nov. 2011 Communities	$41 M	$42 M	$35 M	$12 M	$130 M
Elimination of September Reallocation	$26 M	$0 M	$0 M	$0 M	$26 M
Aggregation to be Above Set-Aside in 2012	$52 M	$0 M	$0 M	$0 M	$52 M
Aggregation to be Above Set-Aside beyond 2012	$0 M	$54 M	$45 M	$15 M	$115 M
Total	$254 M	$238 M	$198 M	$68 M	$757 M

	Projected Financial Impact				
Expansion of Modification	Incremental Impact in 2012	Incremental Impact in 2013	Incremental Impact in 2014	Incremental Impact in 2015	Incremental Impact Over ESP
Inclusion of Mercantile Customers	$51 M	$88 M	$73 M	$25 M	$237 M
Addition of Pre-Nov. 2011 Communities	$18 M	$29 M	$24 M	$8 M	$80 M
Elimination of September Reallocation	$15 M	$0 M	$0 M	$0 M	$15 M
Aggregation to be Above Set-Aside in 2012	$21 M	$0 M	$0 M	$0 M	$21 M
Aggregation to be Above Set-Aside beyond 2012	$0 M	$39 M	$33 M	$11 M	$83 M
Total	$105 M	$157 M	$130 M	$45 M	$437 M

Lost Revenues ($/MWh)

Year	Base "G"	Capacity Offset	Total
2012	22.70	-2.07	20.63
2013	23.30	-1.80	21.50
2014	24.10	-6.21	17.89
2015	24.10	-9.36	14.74

Expansion of Modification	Maximum Incremental Impact Over ESP	Projected Incremental Impact Over ESP
Inclusion of Mercantile Customers	$434 M	$237 M
Addition of Pre-Nov. 2011 Communities	$130 M	$80 M
Elimination of September Reallocation	$26 M	$15 M
Aggregation to be Above Set-Aside in 2012	$52 M	$21 M
Aggregation to be Above Set-Aside beyond 2012	$115 M	$83 M
Total	$757 M	$437 M

Total Potential Aggregation Load (GWh) With Mercantile

Class	Nov 2011 Communities	Pre-Nov 2011 Communities	Total
Residential	1,822	1,081	2,903
Commercial	1,403	1,770	3,173
Industrial	3,992	981	4,973
Total	7,217	3,832	11,049

Assumptions:

PIPP Load	10.1%
Individual Residential Shopping	6.3%
Residential Opt-Out Rate	10.0%
Commercial Opt-Out Rate	10.0%
Commercial Customers that are Mercantile	50.0%
Commercial Mercantile Opt-In Rate	85.0%
Commercial Customers Currently Shopping w/RPM	30.0%
Commercial Customers Currently Shopping w/o RPM	7.0%
Commercial Customers Currently Shopping w/o RPM Opt-In	75.0%
Industrial Customers that are Mercantile	100.0%
Industrial Mercantile Opt-In Rate	75.0%
Industrial Customers Currently Shopping w/RPM	17.0%
Industrial Customers Currently Shopping w/o RPM	5.0%
Industrial Customers Currently Shopping w/o RPM Opt-In	100.0%

Expected Aggregation Load at Year End 2012 (GWh)

Class	Nov 2011 Communities	Pre-Nov 2011 Communities	Total
Residential	1,381	820	2,201

Total Potential Aggregation Load (GWh) With Mercantile

Monthly Spread

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Nov 2011													
Residential	0%	0%	20%	35%	50%	70%	90%	100%	100%	100%	100%	100%	
Commercial	0%	0%	15%	30%	45%	60%	80%	95%	100%	100%	100%	100%	
Industrial	0%	0%	10%	25%	40%	65%	85%	95%	100%	100%	100%	100%	
Pre-Nov 2011													
Residential	50%	60%	70%	80%	90%	90%	90%	90%	90%	90%	90%	90%	
Commercial	25%	30%	45%	60%	65%	75%	85%	90%	90%	90%	90%	90%	
Industrial	0%	0%	20%	40%	60%	80%	85%	90%	90%	90%	90%	90%	
Load (Nov)													
Residential	-	-	-	-	-	81	104	115	115	115	115	115	760
Commercial	-	-	11	21	32	43	57	67	71	71	71	71	515
Industrial	-	-	21	53	84	137	180	201	211	211	211	211	1,521
Total	-	-	32	74	116	260	340	383	397	397	397	397	2,795
Load (Pre-Nov)													
Residential	-	-	-	-	-	61	61	61	61	61	61	61	430
Commercial	22	27	40	54	58	67	76	81	81	81	81	81	748
Industrial	-	-	10	21	31	42	44	47	47	47	47	47	382
Total	22	27	51	75	89	170	182	189	189	189	189	189	1,560
Total Load													
Residential	-	-	-	-	-	142	165	177	177	177	177	177	1,190
Commercial	22	27	51	75	90	110	133	148	152	152	152	152	1,263
Industrial	-	-	32	74	116	179	224	247	258	258	258	258	1,902
Total	22	27	82	149	206	431	522	572	586	586	586	586	4,355

Commercial	852	1,075	1,927
Industrial	2,535	623	3,158
Total	4,768	2,517	7,286

Expected Aggregation Load During 2012 (GWh)	**4,355**	**9.3%**

Total Potential Aggregation Load (GWh) Without Mercantile

Class	Nov 2011 Communities	Pre-Nov 2011 Communities	Total
Residential	1,822	1,081	2,903
Commercial	702	885	1,587
Industrial	-	-	-
Total	2,524	1,966	4,490

Assumptions:

PIPP Load	10.1%
Individual Residential Shopping	6.3%
Residential Opt-Out Rate	10.0%
Commercial Opt-Out Rate	10.0%
Commercial Customers Currently Shopping w/RPM	30.0%
Commercial Customers Currently Shopping w/o RPM	7.0%
Commercial Customers Currently Shopping w/o RPM Opt-In	75.0%

Expected Aggregation Load at Year End 2012 (GWh)

Class	Nov 2011 Communities	Pre-Nov 2011 Communities	Total
Residential	1,381	820	2,201
Commercial	444	548	992
Industrial	-	-	-
Total	1,826	1,368	3,193

Expected Aggregation Load During 2012 (GWh) **1,906** **4.1%**

Total Potential Aggregation Load (GWh) Without Mercantile

Monthly Spread

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Nov 2011													
Residential	0%	0%	20%	35%	50%	70%	90%	100%	100%	100%	100%	100%	
Commercial	0%	0%	15%	30%	45%	60%	80%	95%	100%	100%	100%	100%	
Industrial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Pre-Nov 2011													
Residential	50%	60%	70%	80%	90%	90%	90%	90%	90%	90%	90%	90%	
Commercial	50%	60%	70%	80%	90%	90%	90%	90%	90%	90%	90%	90%	
Industrial	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Load (Nov)													
Residential	-	-	-	-	-	81	104	115	115	115	115	115	760
Commercial	-	-	6	11	17	22	30	35	37	37	37	37	268
Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	6	11	17	103	133	150	152	152	152	152	1,028
Load (Pre-Nov)													
Residential	-	-	-	-	-	61	61	61	61	61	61	61	430
Commercial	23	27	32	37	41	41	41	41	41	41	41	41	448
Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	23	27	32	37	41	103	103	103	103	103	103	103	878
Total Load													
Residential	-	-	-	-	-	142	165	177	177	177	177	177	1,190
Commercial	23	27	38	48	58	63	71	76	78	78	78	78	716
Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	23	27	38	48	58	205	236	253	255	255	255	255	1,906

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Michael M. Schnitzer on Behalf of FirstEnergy Solutions Corp.* was served this 4th day of May, 2012, via e-mail upon the parties below.

s/ Laura C. McBride
One of the Attorneys for FirstEnergy Solutions Corp.

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